National Energy Technology Laboratory

DOE/NETL-2007/1255

Achieving New Source Performance Standards (NSPS) Emission Standards through Integration of Low-NO_x Burners with an Optimization Plan for Boiler Combustion

A DOE Assessment

November 2006

U.S. Department of Energy
Office of Fossil Energy
National Energy Technology Laboratory

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

The Power Plant Improvement Initiative (PPII) is a follow-up to the U.S. Department of Energy's (DOE's) Clean Coal Technology Demonstration Program (CCTDP) whose purpose was to offer the energy marketplace more efficient, cost effective or environmentally benign coal-fired power production options by demonstrating these technologies in commercial settings. One of the projects selected under PPII was Achieving New Source Performance Standards (NSPS) Emission Standards through Integration of Low-NO_x Burners with an Optimization Plan for Boiler Combustion, sited at Sunflower Electric Power Corporation's Holcomb Station Unit 1. Unit 1 is a Babcock & Wilcox (B&W) opposed wall-fired unit, with a nominal full-load capacity of 373 MW (gross). The cost of this project was $5.9 million, with DOE's share being 48 percent.

The overall goal of this project was to decrease NO_x while simultaneously increasing power output using a combination of advanced sensor upgrades, low-NO_x burner modifications, and advanced overfire air. In addition to Sunflower Electric Power Corporation, other project team members included the Electric Power Research Institute, co-funder, and GE Energy and Environmental Research Corporation (GE EER), technology supplier.

To demonstrate the synergistic effect of layering NO_x control technologies, the project was divided into three phases:

Phase I	Advanced sensors upgrade and burner and separated overfire air (SOFA) design
Phase II	Low-NO_x burner modifications and coal-flow balancing
Phase III	Advanced separated overfire air system installation

The objective of Phase I was to demonstrate the effectiveness of various sensors with respect to the control of factors leading to reduced NO_x emissions and improved thermal efficiency with minimal physical modifications to the boiler. Sensors installed to optimize the combustion process included CO monitors, loss-of-ignition (LOI) sensors, NO_x sensors, and coal flow measurement sensors. System physical modeling and computer modeling were completed by GE EER, using a computational fluid dynamics (CFD) model to evaluate heat transfer, flow rates, combustion temperatures, and emission rates. GE EER built a 1:20 scale model of the Holcomb boiler out of Plexiglas®, plastic, blowers and hoses. Modeling results were used in the design of the SOFA ports.

The objective of Phase II was to demonstrate the effectiveness of low-cost modifications to the existing, first generation low-NO_x burners for reducing NO_x emissions. The 25 existing B&W dual-register burners were modified to optimize combustion emissions when operated in conjunction with the SOFA system that was to be installed in Phase III.

The objective of Phase III was to demonstrate NO_x control competitive with selective catalytic reduction (SCR) by the addition of an overfire air system that, coupled with the Phase I and II modifications, was expected to result in reduced NO_x emissions and improved power plant performance and output.

During combustion optimization testing, more than 100 test runs were completed. Unfortunately, optimization testing did not show NO_x emissions below pre-modification levels. In fact, NO_x was higher after completion of the burner modifications. Prior to installation of the modifications, NO_x emission rates were very consistent at around 0.28 to 0.29 lb/million Btu. Following installation of the modified burners, NO_x emissions began to increase and reached a level of 0.326 lb/million Btu during the first quarter of 2005. In addition to increasing NO_x levels, furnace exit gas temperatures also increased, which caused increased slagging in the upper portions of the furnace.

The burner modifications also resulted in significant maintenance issues. The modifications at the burner tips included a new, flared coal nozzle with a stabilization ring attached around the outside perimeter of the nozzle tip. Stabilization “teeth” were added along the inner perimeter of the nozzle tip, and both the coal nozzle and the inner air sleeve were inserted four inches farther into the boiler than with the previous design.

The first problems encountered with the modified design were associated with the scanners and ignitors. Because of the flared coal nozzle and the stabilizing ring, the gap between the coal nozzle and the inner air sleeve, which is utilized as a viewing port for the flame scanners, was considerably reduced. Since the viewing area was significantly obstructed by the stabilizing ring, it was very difficult to sight the scanners to the flame. The gap between the coal nozzle and the inner air sleeve is also the place where the gas ignitor is inserted. The reduction in this gap made it very difficult on many of the burners to squeeze the ignitor into its fully inserted position.

The extension of the coal nozzle and inner air sleeve also resulted in overheating problems that resulted in significant damage. With the extension of components, the ignitor did not insert far enough into the boiler to extend beyond the end of the inner air sleeve. Flame impingement from the ignitor resulted in overheating of the steel in the inner air sleeve. In addition, the extension of the burner tip exposed the burner to increased radiant heat from the furnace that resulted in overheating damage to the burner tips. This damage and its impact on air flow distribution may have contributed to the increased NO_x emissions and the increased furnace exit gas temperature.

Based on results of operations with the modified burners, it was determined that the burners were not performing satisfactorily and that new burners would need to be installed with the SOFA equipment. Because of the problems encountered in trying to utilize the existing scanners and ignitors, a determination was made that new scanners and ignitors would have to be part of the upgrade package. Because of budget constraints, the installation of SOFA and modified burners was deferred, and Phase III was not implemented.

This project was well conceived and had a worthy goal of meeting NSPS NO_x emission goals and increasing unit output by fairly easy to install modifications, thus avoiding the need to install SCR with its rather high capital and operating costs. The project was to be implemented in three phases. Phase I, which involved the installation of sensors of various kinds, was successful, in that the sensors were successfully installed and appear to have functioned as intended.

Phase II was only partially successful. The coal flow balancing system was successfully installed and worked well, resulting in a reduction in average deviation in coal flow among the various pipes. However, the results of the burner modifications were disappointing. Not only did the modified burners not result in reduced NO_x, but maintenance problems arose as well. Because of the problems encountered in Phase II, it was concluded that it would not be logical to proceed with Phase III (installation of SOFA) unless new burners, ignitors, and scanners were also installed. Since the budget allocated for the project was insufficient to accommodate this, Phase III was not implemented.

Since the goal of the project was to decrease NO_x while simultaneously increasing power output, the goal of this project was not met. This does not mean, however, that the concept of reducing NO_x and increasing capacity by relatively simple unit modifications and improved control is not valid. It is quite possible that, with a new burner design and installation of SOFA, the goal of the project could be met. However, until that is done, the question will remain open as to whether the proposed approach can achieve NSPS NO_x standards without the need for installation of an SCR unit.

I. INTRODUCTION

The Power Plant Improvement Initiative (PPII) is a follow-up to the U.S. Department of Energy's (DOE's) Clean Coal Technology Demonstration Program (CCTDP) that was successfully implemented in the 1980s and 1990s. The purpose of the CCTDP was to offer the energy marketplace more efficient and environmentally benign coal-fired power production options by demonstrating these technologies in commercial settings.

On October 11, 2000, the PPII was established under U.S. Public Law 106-291 for the commercial scale demonstration of technologies to ensure a reliable supply of energy from the Nation's existing and new electric generating facilities. Congress directed that PPII was to "demonstrate advanced coal-based technologies applicable to existing and new power plants… The managers expect that there will be at least a 50 percent industry cost share for each of these projects and that the program will focus on technology that can be commercialized over the next few years. Such demonstrations must advance the efficiency, environmental controls and cost-competitiveness of coal-fired capacity well beyond that which is in operation now or has been operated to date."

To fund the PPII, $95 million in previously appropriated funds were transferred from the U.S. Department of Energy's CCTDP. The PPII program solicitation was issued on February 6, 2001, and 24 applications were received. On September 26, 2001, eight applications were selected for negotiation of a cooperative agreement. One of the projects selected was Achieving New Source Performance Standards (NSPS) Emission Standards through Integration of Low-NO_x Burners with an Optimization Plan for Boiler Combustion, sited at Sunflower Electric Power Corporation's Holcomb Station Unit 1. The objective of this project, as stated in the cooperative agreement, was to demonstrate the achievement of NSPS NO_x emission standards by a combination of low-NO_x burners and an integrated combustion optimization system based on neural network or other artificial intelligence technology, thus avoiding the need to install selective catalytic reduction (SCR) equipment. The initial cost of this project was $5.9 million, with DOE's share being 48 percent. This document is a DOE post-project assessment of the project.

II. PROJECT/PROCESS DESCRIPTION

A. Project Site

This project was sited at Sunflower Electric Power Corporation's Holcomb Station, which is located approximately six miles south of Holcomb, Kansas. Holcomb Station consists of a single unit (Unit 1). Unit 1 is a Babcock & Wilcox (B&W) opposed wall-fired unit, with a nominal full-load capacity of 373 MW (gross). The unit, which is designed to burn Powder River Basin coal, came on line in August 1983. The boiler has a total of 25 coal nozzles, arranged in three rows of five on the front wall and two rows of five on the rear wall. From the bottom up, rows C, B, and D are on the front wall, and rows A and E are on the back wall; rows A and C are opposite each other, as are rows D and E. There are five coal mills, one to supply pulverized coal (PC) for each row of burners.

B. Project Goal

The goal of this project was to decrease NO_x while simultaneously increasing power output using an integrated combustion optimization system including a combination of advanced sensor upgrades, low-NO_x burner modifications, and advanced overfire air. The specific goal was to achieve a NO_x emissions level of 0.15 to 0.22 lb/million Btu and simultaneously increase power output by 7 MW, thus illustrating a concept that had not been previously demonstrated on a unit burning subbituminous coal, that is, avoiding the need for an SCR unit and saving the associated capital and operating expense.

C. Project Description

In addition to Sunflower Electric Power Corporation, other project team members included the Electric Power Research Institute, co-funder, and GE Energy and Environmental Research Corporation (GE EER), technology supplier.

To demonstrate the synergistic effect of layering NO_x control technologies, the project was divided into three phases:

Phase I	Advanced sensors upgrade and burner and separated overfire air (SOFA) design
Phase II	Low-NO_x burner modifications and coal-flow balancing
Phase III	Advanced separated overfire air system installation

1. Phase I

The objective of Phase I was to demonstrate the effectiveness of various sensors for supplying data to control operating variables leading to reduced NO_x emissions and improved thermal efficiency with only minimal physical modifications to the boiler. Phase I also included design work for the burner modifications required to support SOFA to lower NO_x. Phase I involved the following six tasks:

- Process design and performance analysis
- Preparation of design and fabrication/construction documents
- Installation of boiler combustion optimization sensors
- Sensor integration/testing
- Baseline testing
- Prevention of significant deterioration environmental review

2. Phase II

The objective of Phase II was to demonstrate the effectiveness of low-cost modifications to the existing, first generation low-NO_x burners for reducing NO_x emissions. This phase included modifications to the existing PC piping to permit automated fuel balancing among all burners. Phase II involved the following three tasks:

- Low-NO_x burner modifications

- Pulverized coal flow control and balancing system installation and testing
- Design of OFA penetrations

3. Phase III

The objective of Phase III was to demonstrate a level of NO_x control competitive with SCR by the addition of an overfire air system coupled with the Phase I and Phase II modifications to optimize overall system performance. The integration of all three project phases was expected to reduce NO_x emissions and improve power plant performance and output. However, because of problems encountered during Phase II testing, it was decided to defer implementation of Phase III. This is discussed in Section III.C.

D. Technology Description

To reduce NO_x, this project planned to use a combination of five technologies: (1) low-NO_x burners, (2) SOFA, (3) fuel flow measurement transducers, (4) fuel balancing, and (5) advanced network controls. This section discusses the technology involved in implementing the Sunflower project.

1. Low-NO_x Burners

Most of the NO_x formed during combustion is the result of two oxidation mechanisms: (1) reaction of nitrogen in the combustion air with excess oxygen at elevated temperatures, referred to as thermal NO_x; and (2) oxidation of nitrogen that is chemically bound in the coal, referred to as fuel NO_x. The quantity of NO_x formed depends primarily on the “three t’s” of combustion: temperature, time, and turbulence. In other words, flame temperature, the residence time of the fuel/air mixture at temperature, and mixing, along with the nitrogen content of the coal and the quantity of excess air used for combustion, determine NO_x levels in the flue gas.

The principle of low-NO_x burner operation involves staged combustion, which consists of decreasing the amount of air introduced into the primary combustion zone, thereby creating a fuel-rich, reducing environment and lowering the temperature, both of which suppress NO_x formation. The remaining air required for complete burnout of combustibles is added after the primary combustion zone, where the temperature is sufficiently low so that additional NO_x formation is minimized. When low-NO_x burners are the only NO_x control strategy, all of the combustion air is delivered to the furnace via the low-NO_x burners, but the burners are designed so that staged combustion occurs.

2. Separated Overfire Air

Under conditions in which the desired NO_x level is not achieved in spite of the use of low-NO_x burners, it may be necessary to more deeply stage combustion. In this case, not all the air required for combustion is introduced through the low-NO_x burners. The remaining air required for complete combustion is introduced through separate overfire air ports at a higher elevation in the boiler where the temperature is lower, thus limiting the production of additional NO_x. This is the principle of overfire air operation. The overfire air is necessary to achieve the desired levels of carbon burnout and to limit CO emissions.

3. Fuel Flow Measurement Transducers

Coal flow measurement instruments, supplied by Air Monitor, were installed on each burner coal pipe. The technique used to measure coal flow is based on microwave technology used to measure coal density and particle velocity. From these two parameters, the coal flowrate can be determined.

4. Fuel Balancing

Coal flow balancing dampers were installed on the coal pipes coming off the top of each pulverizer. The dampers are a GE EER patented design called Flow MastEER. Figure 1 is a drawing of the Flow MastEER damper design, and Figure 2 shows the location of the dampers on top of the pulverizers. The flow data from the flow measurement sensors were used in conjunction with the coal flow balancing valves to balance the flow of coal through each coal pipe on a given mill. Prior to this project, Sunflower Electric had no means to continuously measure flow rate through individual coal pipes and no way to adjust the flow.

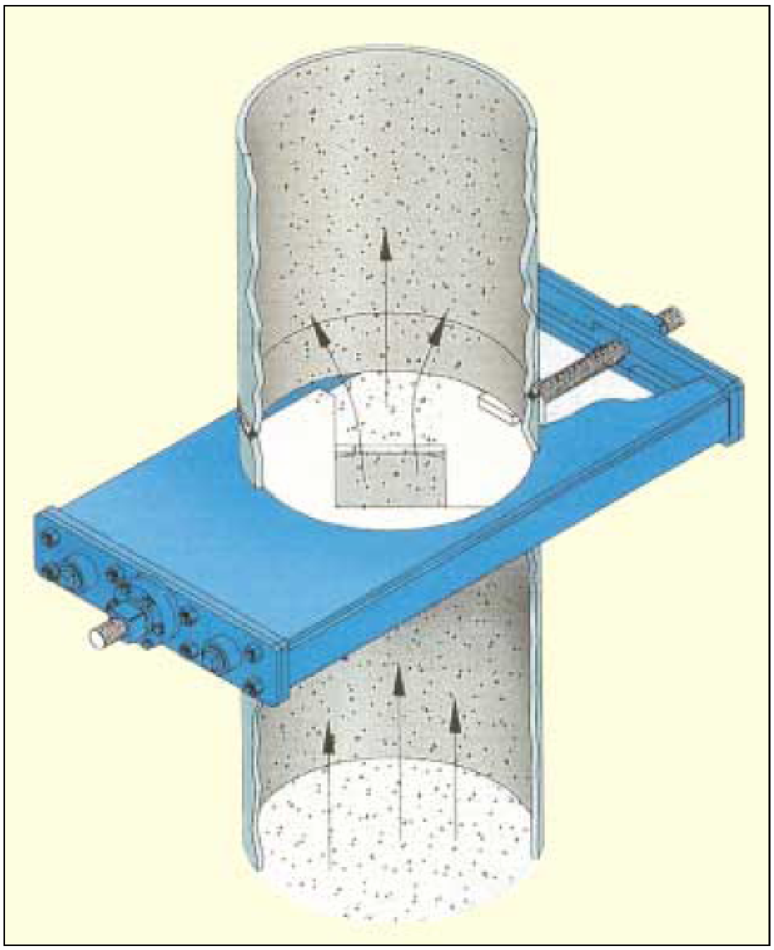

Figure 1. Schematic of GE EER Flow MastEER Damper Design

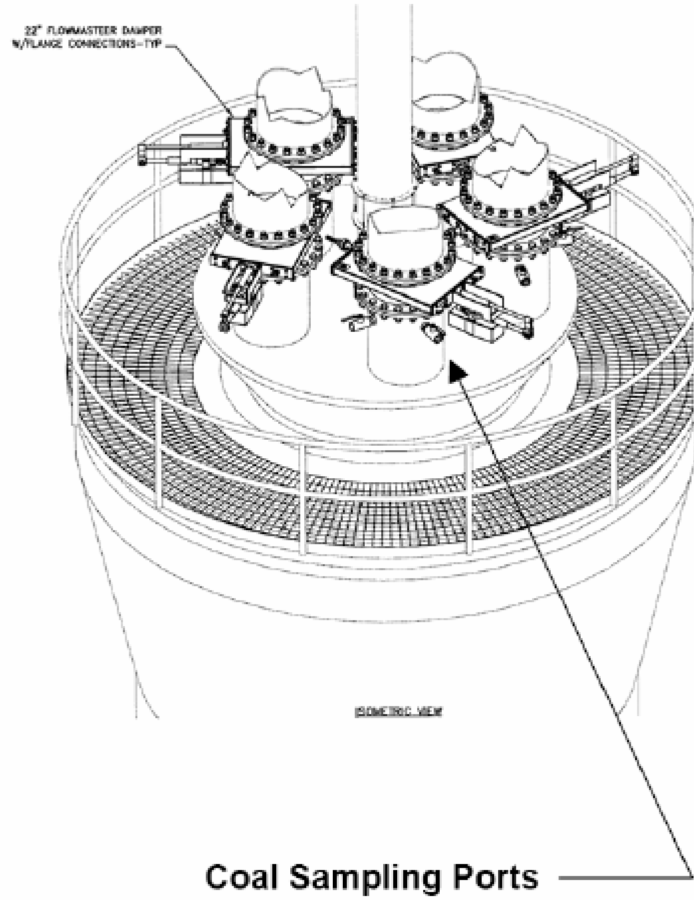

Figure 2. Coal Flow Balancing Dampers General Arrangement

5. Advanced Controls

Neural networks and other artificial intelligence systems can be used to provide advanced control of a boiler. Such systems receive data from sensors on the boiler and auxiliary equipment and use algorithms to predict optimum operating set points. One common form of a neural network (computer code that models a system's responses) consists of three layers: an input layer, a hidden layer, and an output layer. The input layer receives signals from the monitored variables and transmits them to the hidden layer, which contains interconnected neurons for pattern recognition. After processing, signals are sent to the output layer, which outputs recommended settings for control variables. Thus, a neural network is, in effect, a sophisticated curve fitting tool. Neural networks recognize patterns in input data, but before the network can associate a particular pattern with a corresponding plant state, it must be "trained." Once a network has been trained, it can respond very rapidly to new inputs.

Neural networks and other advanced control systems can operate in either open loop or closed loop configurations. In open loop operation, the system presents recommended instrument settings, but the actual changes are made by plant operators. In closed loop operation, the system itself changes instrument settings. Closed loop operation can respond very rapidly to changing conditions.

No sophisticated control system was implemented for this project. Because Phase III was deferred and SOFA was an integral part of the strategy for achieving project goals, implementation of an advanced control system was not justified.

III. REVIEW OF TECHNICAL AND ENVIRONMENTAL PERFORMANCE

This section discusses the performance of the NO_x control system installed at the Holcomb Station.

A. Phase I

The objective of Phase I was to demonstrate the effectiveness of various measuring sensors with respect to the control of factors leading to reduced NO_x emissions and improved thermal efficiency with minimal physical modifications to the boiler. The sensors installed to optimize the combustion process consisted of a grid of 15 CO monitors in the boiler backpass, five loss-on-ignition (LOI) sensors in the upper portion of the furnace, 25 NO_x sensors, one on each burner, and 25 coal flow measurement sensors, one on each burner coal pipe. The boiler sensors were provided in a package supplied by MK Engineering. The coal flow sensors were supplied by Air Monitor. All furnace sensors were installed during the spring 2002 outage, and the coal flow sensors were installed in 2003.

System physical modeling and computer modeling were completed by GE EER, which used a computational fluid dynamics (CFD) model to evaluate heat transfer, flow rates, combustion temperatures, and emission rates. GE EER built a 1:20 scale model of the Holcomb boiler out of Plexiglas®, plastic, hoses, and blowers. The burners were scaled using a modified Thring-Newby approach to ensure that the flow characteristics of the model accurately reflected actual flow in the Holcomb boiler. Smoke and bubbles were used for visual observation of combustion gases and overfire air mixing, as well as for velocity mapping and tracer dispersion measurements.

Results of flow studies in the model were consistent with expected results for an opposed wall-fired boiler. The flow tended to stay in the center of the furnace between the front and rear walls. Additionally, the swirl pattern of the burners tended to push flow towards the two side walls. The flow modeling showed a recirculation zone above the two upper burner elevations. Velocity profiles were measured in two horizontal planes during the modeling. The first horizontal plane was at the elevation at which the new overfire air injectors were intended to be installed, and the second horizontal plane was at an elevation even with the tip of the furnace bullnose. At the overfire air plane, the highest velocities were measured in the center of the furnace. At the boiler nose plane the highest velocities were measured on the east and west side walls, with velocities decreasing closer to the front wall. Figure 3 shows a graphical representation of the velocity profile modeling.

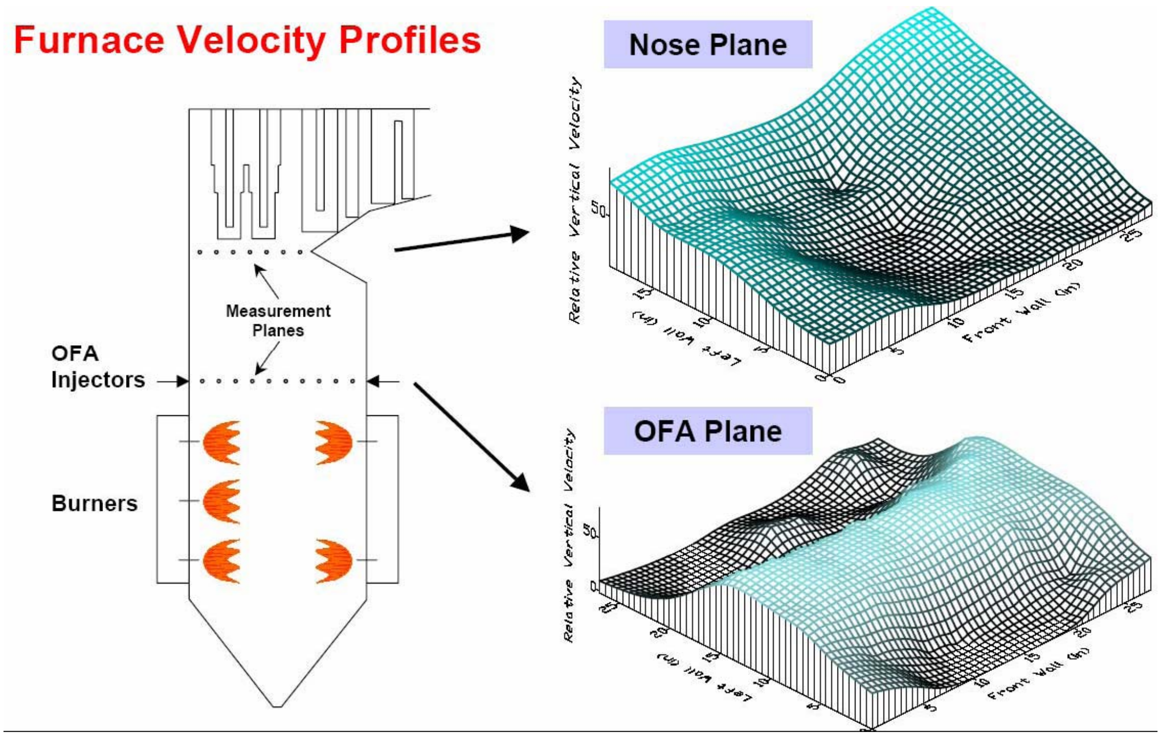

Figure 3. Furnace Velocity Profiles from Physical Modeling

Results from the flow modeling and velocity profile tests were used to develop the design for the overfire air injectors. The overfire air configuration in the model used six injectors on the front wall and six on the rear wall. To account for the biased combustion air flow towards the furnace sidewalls, the four end injectors were made larger. Smoke visualization was used initially to evaluate how effectively the overfire air mixed with the combustion gases. Tracer dispersion measurements were then used to further quantify the overfire air mixing effectiveness. Methane was injected as a tracer in the overfire air, and the dispersion of methane was measured at the nose plane. The modeling confirmed that there was sufficient secondary duct pressure to achieve adequate mixing without the need for booster fans.

A CFD model was developed by GE EER to evaluate the impact of burner modifications and overfire air on heat transfer, combustion emissions, and gas flow within the boiler. The CFD model utilized a three-dimensional representation of the boiler broken down into approximately 380,000 cells. The CFD model was first used to develop flow and temperature path lines for each burner elevation that show the path taken by the flue gas from the combustion zone of each burner elevation through the furnace to the upper crossover and into the boiler backpass. The CFD model was also used to determine velocity, temperature, and oxygen dispersion at various planes within the boiler.

The CFD model was modified to include overfire air. Temperature and flow path lines were first predicted for the twelve OFA ports. A comparison of these profiles with the full-load, no-OFA profiles showed that the temperature of the flue gas at the boiler nose plane did not appear to increase with the addition of OFA. Keeping temperatures at or below existing levels is a critical factor in the success of any modification. Increased temperatures in this zone lead to increased boiler slagging that has a detrimental effect on unit availability and reliability.

In addition to increased gas temperature, another potential negative consequence of adding OFA is increased CO emissions. The CFD model predicted increased CO emissions with OFA. Because of the flow bias in the boiler towards the center of the furnace, GE EER felt that CO emissions could be improved by increasing velocity in the OFA ports to achieve better penetration in the center of the furnace where combustion gas flow is the highest. GE EER developed a double concentric jet port design which could be used to control jet penetration. The OFA port has adjustable dampers that allow flow to be biased at various ratios through the inner and outer portions of the port. Figure 4 shows a simple diagram of the port design with the double concentric discharge shown to the left. GE EER used the CFD model to predict the impact on CO emissions of a positive bias of the core jet velocity to achieve improved penetration. The model indicated that biasing the OFA injector ports in this way would result in reduced CO emissions.

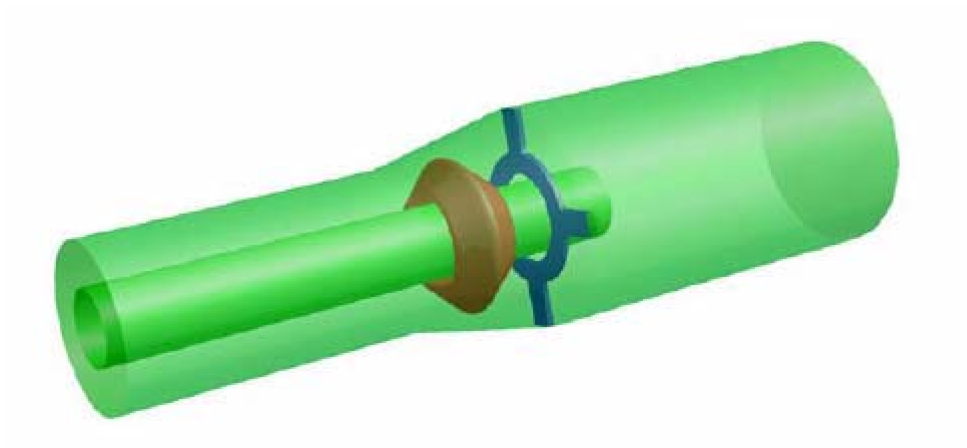

Figure 4. Schematic of GE EER Designed OFA Injection Port

The next step in the CFD modeling process was to further evaluate the effects of OFA on furnace exit gas temperature (FEGT) and overall boiler performance. Figure 5 shows calculated mean gas temperature profiles at various OFA levels as compared to baseline data with no OFA. These results indicated that the addition of OFA would result in higher gas temperatures in the burner zone but reduced gas temperatures at the furnace bullnose (the defined measurement plane for FEGT). The CFD model was further used to evaluate the impact of OFA on overall boiler performance.

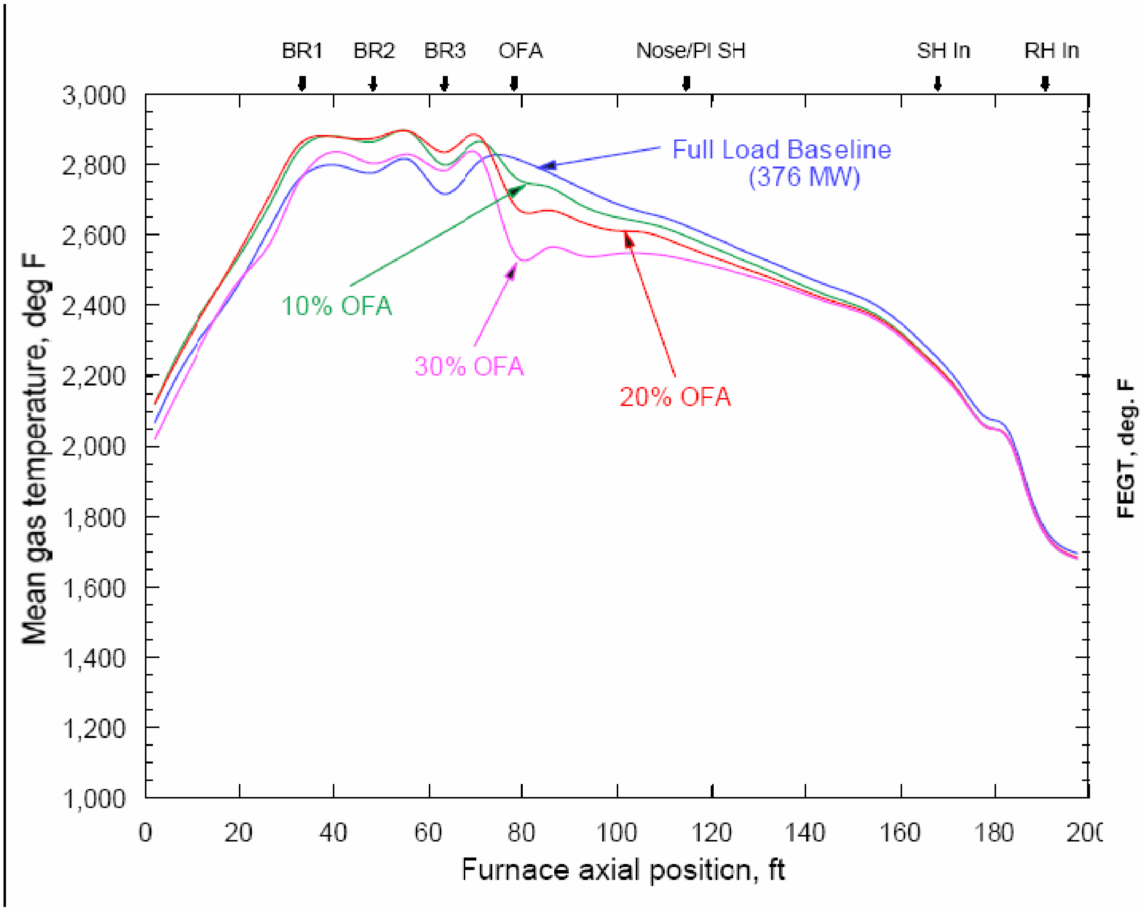

Figure 5. Mean Gas Temperature Profiles at Full Load

One of the primary goals of the project was to be able to increase unit capacity while achieving reduced NO_x emission levels. This extra capacity could only be utilized if emissions were reduced at the increased load level and furnace exit gas temperature was not increased. Excessive slagging had previously prevented Sunflower Electric from realizing full boiler potential. Slagging on boiler tubes decreases heat transfer and lowers boiler efficiency, and increased FEGT increases slagging. It was expected that the project would lower FEGT and decrease or eliminate slagging in the upper boiler, thus permitting operation at full design rating. GE EER modeling indicated not only that NO_x emissions would be reduced with the implementation of burner modifications and further reduced with SOFA but also predicted that the FEGT at a 7 MW increase in full load with 30 percent OFA would be 65°F lower than the FEGT at full load with no OFA.

Phase I also included design work for burner modifications required to support SOFA and lower NO_x. GE EER completed design and fabrication drawings for burner modifications, coal flow balancing damper installation, and SOFA installation. The burner modifications included replacement of the existing burner coal nozzle with a nozzle that flared out and included a flame stabilization ring and stabilizing teeth. The tip of the burner was designed to extend into the furnace an additional four inches, which required an extension of the secondary air sleeve. Because of this extension and a concern about increased exposure to temperatures beyond the design temperature of the steel in the burner tips, a thermocouple was added to measure tip temperature. An adjustable shroud was also included in the design. The shroud was designed to slide axially across the burner outer register opening to allow for air flow balancing between the burners at each burner elevation. Figure 6 shows a drawing of the burner with the GE EER design modifications.

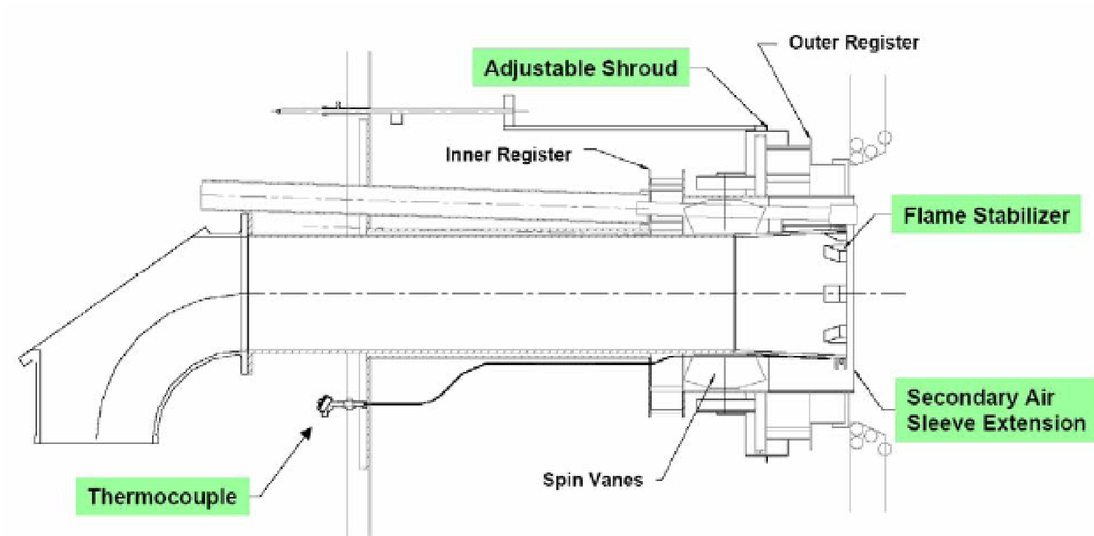

Figure 6. GE EER Low-NO_x Burner Design Modifications

Data from the new boiler and coal flow sensors were integrated into the existing plant performance monitoring system for tracking and trending. The existing plant performance monitoring system is a package called EtaPro, supplied by General Physics. General Physics was hired to assist with incorporating new data into the EtaPro database.

Figure 7 shows a schematic of the computer networking configuration devised by GE EER and General Physics. The schematic shows the GE EER PLC (programmable logic controller) used for coal flow balancing control.

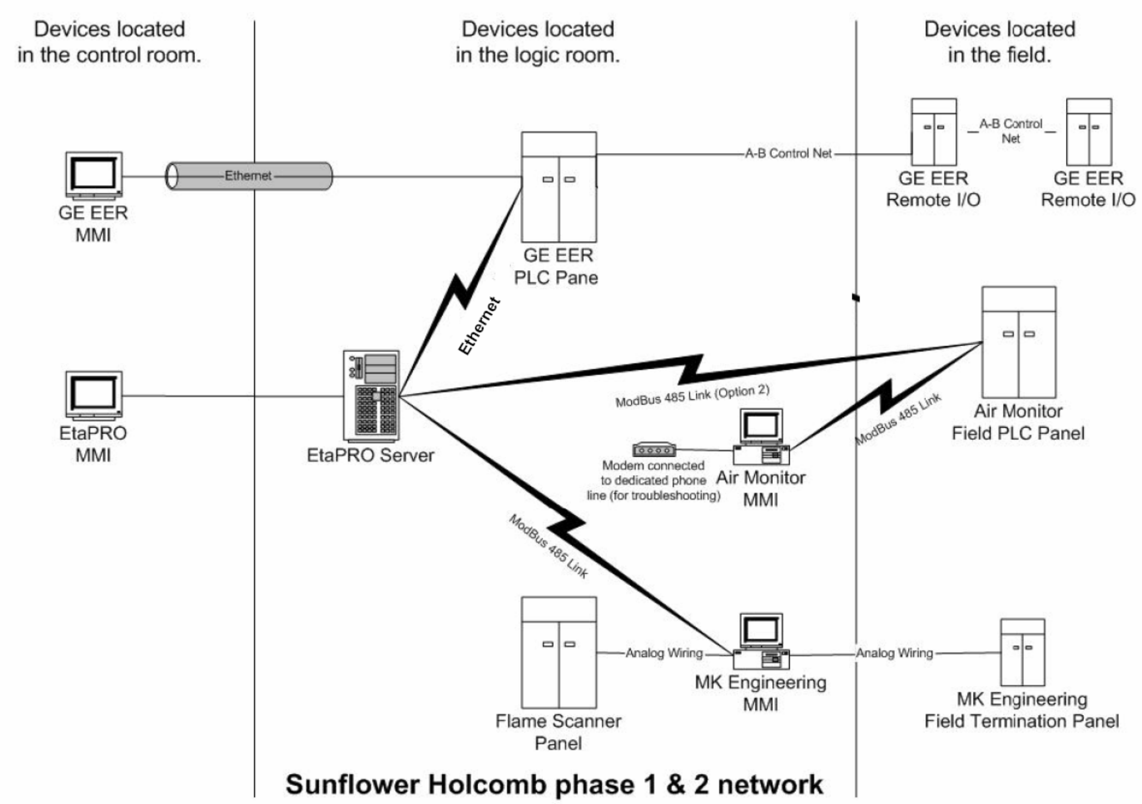

Figure 7. Schematic of Computer Network

Tests were performed to gather baseline performance and emissions data prior to retrofit of the emissions control equipment. These data served as a reference for the results of optimization tests performed on the unit. Baseline testing, which was completed in February 2003, covered a wide range of loads, excess O_2 levels, and mill biasing configurations. Emissions data from the full load test runs at various excess O_2 levels were used to develop plots of NO_x and CO emissions versus boiler O_2. Figure 8 shows the baseline emissions curves. Similar data were collected for FEGT. Figure 9 shows FEGT and economizer O_2 levels versus plant O_2 levels. Baseline data were also collected from the new CO monitors, LOI combustion sensors, and burner NO_x sensors.

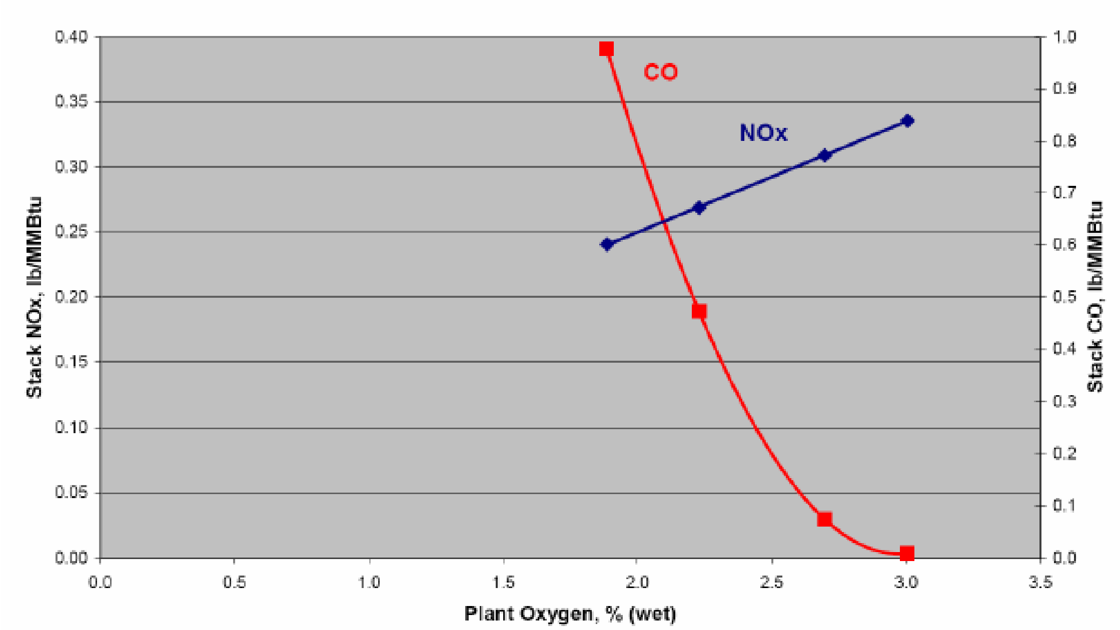

Figure 8. Baseline NO_x and CO Emissions Data at Full Load

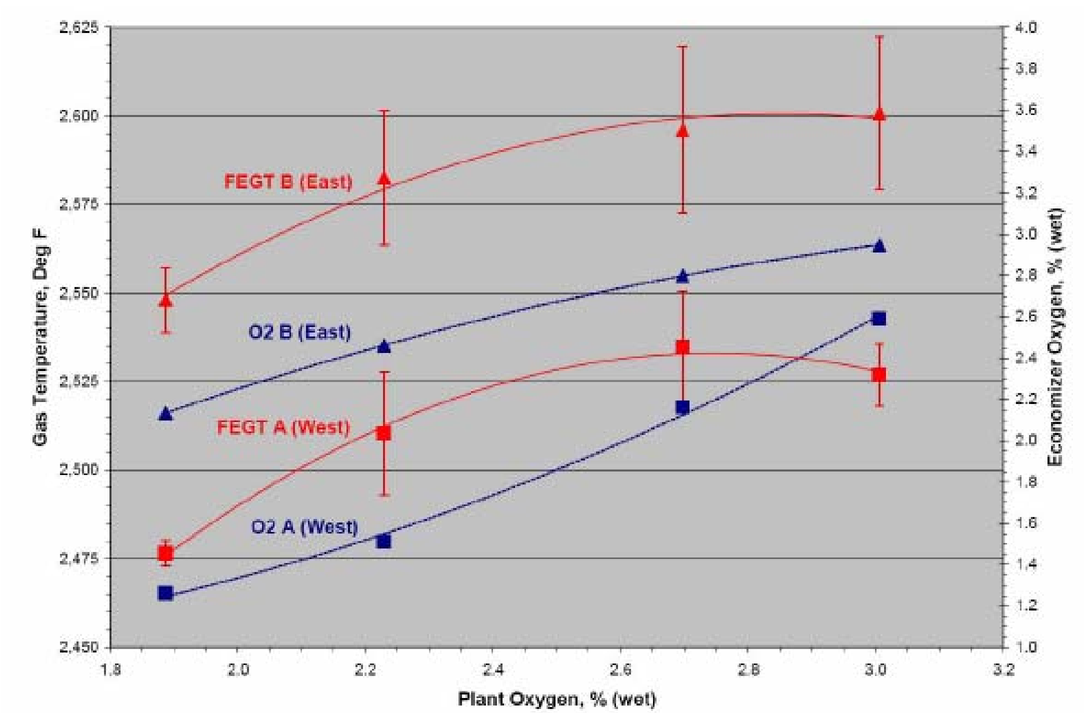

Figure 9. Baseline FEGT and Oxygen Level Data at Full Load

A prevention of significant deterioration (PSD) review was completed by Burns and McDonnell but was never submitted to the Kansas Department of Health and Environment, because Phase III of the project was not implemented.

B. Phase II

The objective of Phase II was to demonstrate the effectiveness of low-cost modifications to the existing, first generation low-NO_x burners to reduce NO_x emissions. This phase also included modifications to the existing PC piping to permit automated fuel balancing among all burners.

The 25 existing B&W dual-register burners on Unit 1 were modified to improve flame stability and reduce NO_x emissions. The modified burners were designed to minimize emissions when operated in conjunction with the SOFA system that was to be installed in Phase III. The burner modifications were completed in 2003 by Power Maintenance and Construction, along with installation of the coal flow balancing dampers on one mill and coal flow measurement sensors on all five mills. Figure 10 shows a picture of one of the modified burners.

Figure 10. Picture of Modified Burner

Combustion optimization testing began after startup following the 2003 spring outage. GE EER put together a test plan that included coal flow balancing, burner tuning, CO tuning, and primary air flow measurements. More than 100 test runs were completed over a two month period during the optimization process. Unfortunately, optimization testing did not show reduced NO_x emission levels below pre-modification levels. Figure 11 shows optimization data compared to baseline data for NO_x and CO emissions.

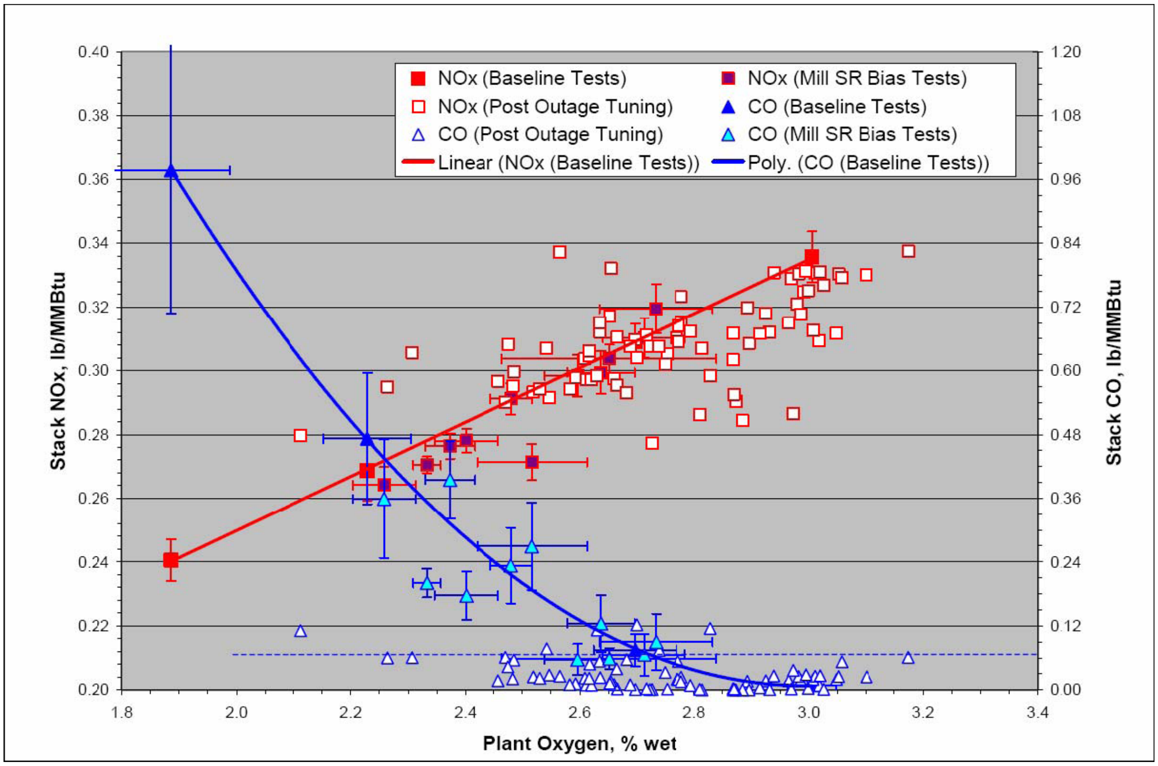

Figure 11. Optimization Test Data Compared to Baseline Test Results

At first, as indicated by Figure 11, there appears to have been a slight improvement (or at least no increase) in NO_x and CO emissions. However, with time (probably due to continued overheating damage to the burners), results deteriorated. The failure to reduce NO_x emissions is illustrated in Figure 12. Following completion of optimization testing, the performance of the modified low-NO_x burners continued to be monitored closely. Prior to installation of the modifications, annual NO_x emission rates were very consistent at around 0.28 to 0.29 lb/million Btu. Annual average NO_x emissions over the period of

1996 to 2002 from the certified Continuous Emissions Monitoring System (CEMS) at the plant are shown in Table 1.

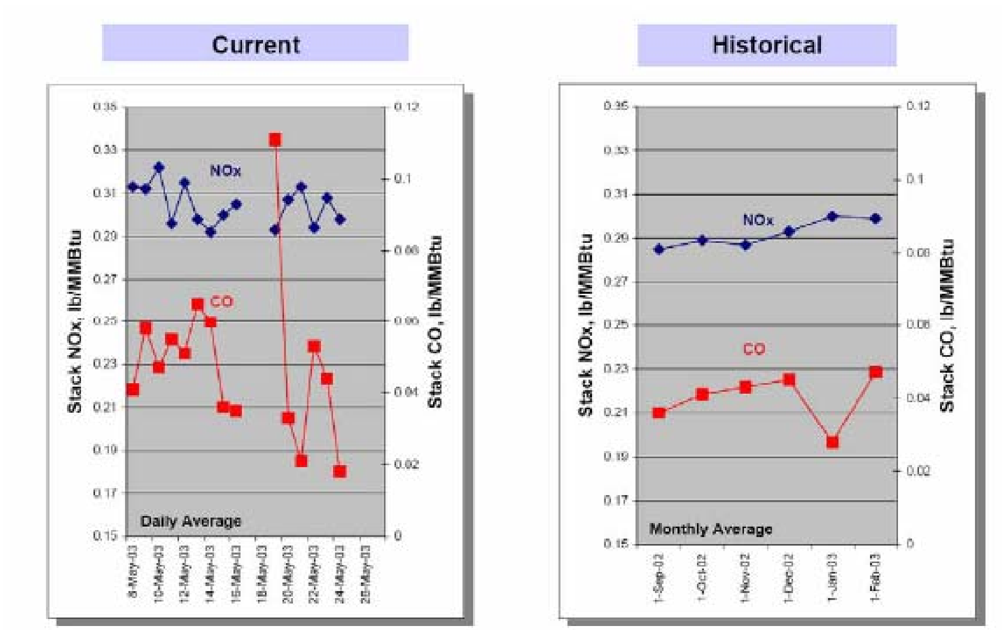

Figure 12. Comparison of Emission Results Before (Graph Labeled Historical) and After (Graph Labeled Current) Burner Modifications

Table 1. Annual NO_x Emissions Rate for the Period 1996-2002

Year	Annual NO_x Emissions Rate, lb/10^6 Btu
1996	0.280
1997	0.280
1998	0.290
1999	0.280
2000	0.275
2001	0.286
2002	0.284
Period Average	0.282

From May through September 2003, following installation of the burner modifications, daily average NO_x emissions began to increase. The average daily NO_x emission rate for this time period was 0.304 lb/million Btu. NO_x emissions continued to run higher than normal throughout 2004. The annual average NO_x emission rate for 2004 was 0.317 lb/million Btu. The NO_x emission rate for the first quarter of 2005 was 0.326 lb/million Btu. These data are summarized in Figure 13.

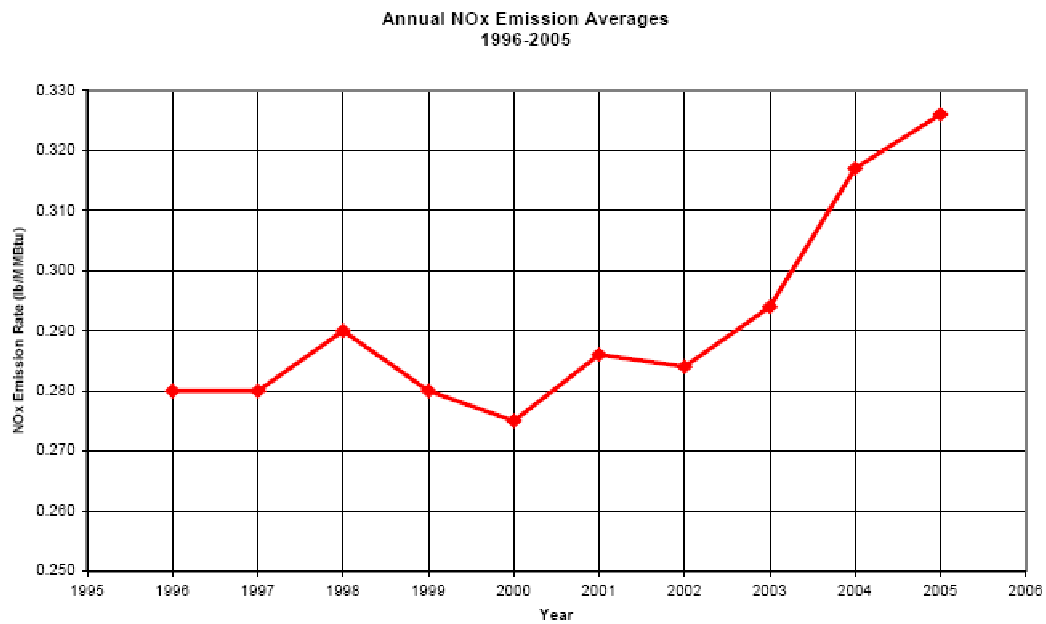

Figure 13. Annual Average NO_x Emission Level

In addition to increasing NO_x emission rates, the burner modifications also resulted in increased furnace exit gas temperatures. These elevated temperatures led to increased slagging in the upper portions of the furnace, the exact opposite of the desired result. Figure 14 shows a plot of FEGT for periods both before and after the burner modifications that were completed in March 2003.

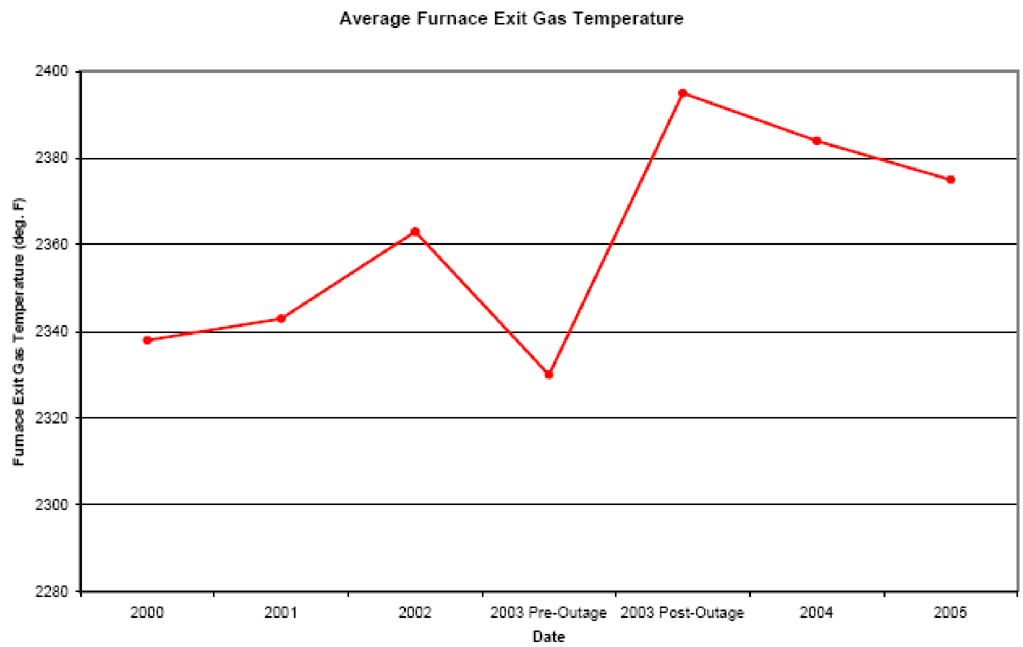

Figure 14. Average Furnace Exit Gas Temperature

The burner modifications also resulted in significant maintenance issues. The modifications at the burner tips included a new, flared coal nozzle with a stabilization ring attached around the outside perimeter of the nozzle tip. Stabilization “teeth” were added along the inner perimeter of the nozzle tip, and both the coal nozzle and the inner air sleeve were inserted four inches farther into the boiler than with the previous design.

The first problems encountered with the modified design were associated with the scanners and ignitors. Because of the flared coal nozzle and the stabilizing ring, the gap between the coal nozzle and the inner air sleeve, which is utilized as a viewing port for the flame scanners, was considerably reduced. Since the viewing area was significantly obstructed by the stabilizing ring, it was very difficult to sight the scanners to the flame. The gap between the coal nozzle and the inner air sleeve is also the place where the gas ignitor is inserted. The reduction in this gap made it very difficult to squeeze the ignitor into its fully inserted position on many of the burners.

The extension of the coal nozzle and inner air sleeve also caused overheating problems that resulted in significant damage. With the extension of these components, the ignitor did not insert far enough into the boiler to extend beyond the end of the inner air sleeve. Flame impingement from the ignitor resulted in overheating of the steel in the inner air sleeve. The extension of the burner tip also exposed the burner to increased radiant heat from the furnace that also resulted in overheating damage to the burner tips. Figure 15 shows an example of the damage that occurred. It is likely that this damage and its impact on air flow distribution contributed to the increased NO_x emissions and the increased furnace exit gas temperature.

Figure 15. Example of Overheating Damage to Modified Burner

The five pulverizers were equipped with a coal-flow balancing system consisting of automated coal-balancing dampers on each coal pipe. The automated coal dampers were integrated with the coal-flow monitoring system to provide for automatic balancing of all the burners over the boiler load range. The flow data from these sensors were used in conjunction with the coal flow balancing valves to balance the flow of coal through each coal pipe on a given mill.

Automation of the coal flow balancing system showed improved balancing of coal flow across the coal pipes for each burner elevation. Figure 16 shows the trend of improved coal flow distribution with the automated coal flow system in service. Unfortunately, improved balancing did not translate into improved NO_x control.

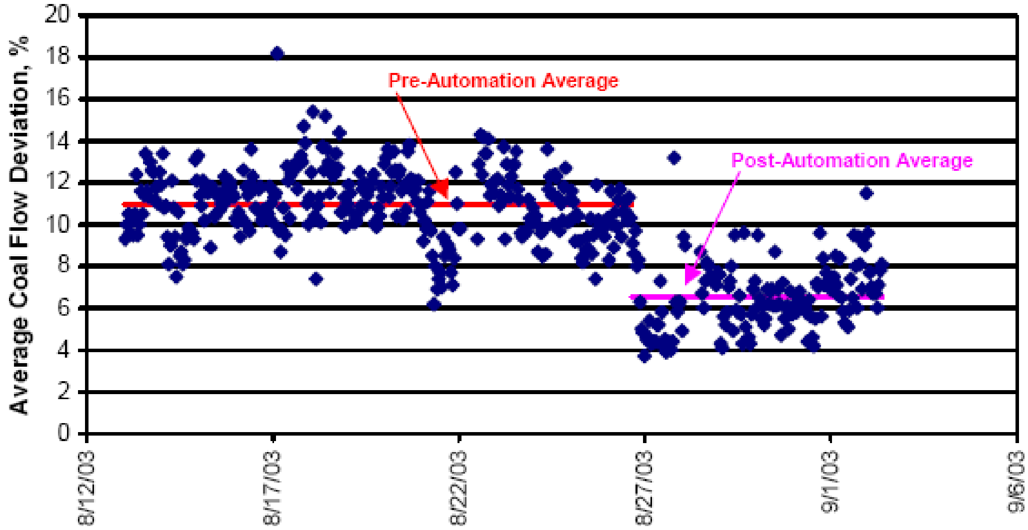

Figure 16. Improvement in Coal Flow Deviation as a Result of Automation

C. Phase III

To support implementation of Phase III, a detailed design of an optimum overfire air system for Unit 1 was prepared by GE EER. The system was designed to pull secondary air from the existing secondary air ductwork in the plant. The outboard OFA injectors on both the front and rear walls were sized larger than the inner injectors based on results of the modeling work. The design included control dampers in each of the secondary air supply ducts.

The objective of Phase III was to demonstrate NO_x control competitive with SCR by the addition of an overfire air system coupled with the Phase I and II modifications to optimize overall system performance. The integration of all three phases of improvements was expected to result in reduced NO_x emissions and improved power plant performance and output.

Based on results of operations with the modified burners, it was determined that the modifications were not performing satisfactorily and that new burners would need to be installed with the SOFA equipment. Because of the problems encountered in trying to utilize the existing scanners and ignitors, a determination was made that new scanners and ignitors would have to be part of the upgrade package. A request for proposal to provide new burners and SOFA was developed and sent to several bidders. Five bids were received, ranging in cost from $5.5 million to $8.4 million. All these bids were significantly higher than the original budget for Phase III. One reason for the increased price was the need for new burners, scanners, and ignitors; but it also appears that the original project budget significantly underestimated what would be required to complete the SOFA installation. The original budget was put together in 2001 with significant input from GE EER. This budget included approximately $2.3 million for SOFA material and installation costs. The bid GE EER submitted in 2005 included over $3.6 million for SOFA. After evaluating the bids that were received and factoring in budget constraints, the installation of SOFA and modified burners was deferred, and Phase III was not implemented. The original burner tips were reinstalled, and the plant continues to operate and remains in compliance.

IV. DISCUSSION OF RESULTS

This project was well conceived and had a worthy goal of meeting NSPS NO_x emission goals and increasing unit output by fairly easy to install modifications, thus avoiding the need to install SCR with its rather high capital and operating costs. The project was to be implemented in three phases. Phase I, which involved the installation of sensors of various kinds, was successful, in that the sensors were successfully installed and appear to have functioned as intended.

Phase II was only partially successful. The coal flow balancing system was successfully installed and worked well, resulting in a reduction in average deviation in coal flow among the various pipes. However, the results of the burner modifications were disappointing. Not only did the modified burners not result in reduced NO_x, but maintenance problems arose as well. The design of the modified burners interfered with the installation of the ignitors and scanners. Furthermore, the extension of the coal nozzle and the inner air sleeve an additional four inches into the furnace resulted in overheating damage to the burners. This damage may have contributed to the increased NO_x and furnace outlet temperature observed during testing of the modified burners.

Because of the problems encountered in Phase II, it was concluded that it would not be logical to proceed with Phase III (installation of SOFA) unless new burners, ignitors, and scanners were also installed. Since the budget allocated for the project was insufficient to accommodate this, Phase III was not implemented.

V. MARKET ANALYSIS

This market analysis assumes that an improved design for burner modifications could result in achieving the goals initially set forth.

Individual boilers most likely to install the technology, whose demonstration was the objective of this project, have the following characteristics:

- They are equipped with low-NO_x burners.
- They burn subbituminous coal.
- They have current NO_x emission rates such that a 50 percent reduction would result in emission levels of 0.15 to 0.22 lb/million Btu.

Based on the National Energy Technology Laboratory (NETL) Coal Power Data Base, in 2003 there were 133 such boilers with a combined capacity of a little over 56,000 MW_e. Assuming a penetration of 10 to 20 percent, the potential market for this technology is 5,600 to 11,200 MW, or about 15 to 25 boilers [Pukanic, 2003].

A. Economics

The original budget for this project was $5.9 million, or approximately $16/kW of generating capacity. Based on the results of this project, it appears that the initial budget may have been low. Assuming that the budget should have been about 25 percent higher gives an estimated cost of this technology of $20/kW[1]. On this basis, the cost of installing the technology on the 15 to 25 units indicated above would be $112 to 224 million.

The major competitor for this technology is SCR, which has a cost of approximately $70/kW [Rubin, et al., 2004]. Thus, this technology, if it can be demonstrated, has the

[1] Although costs will vary depending on site specific conditions, based on results of bids received by Sunflower Electric, it is estimated that the cost would be split approximately as follows: burner upgrade, 45%; SOFA, 40%; and controls, 15%.

potential to reduce NO_x control costs by 70 percent compared to SCR, or a savings of $280 to 560 million for the postulated market penetration. Furthermore, operating costs should be very low compared to SCR, which continuously uses ammonia and requires periodic catalyst replacement. Reported operating costs for SCR are in the range of $0.50 to $1.00/MWh, which includes expenses for labor, maintenance, catalyst replacement, and reagent [DOE, 2005]. With the combustion optimization technology, the only operating cost should be a small amount of labor to keep the sensors, instruments, and control system operating satisfactorily.

This project was expected to increase efficiency by 2 percent. Sunflower estimates that net profit from the added power production would be $0.018/kWh. On this basis, and assuming a capacity factor of 60 percent, the increased efficiency would generate $1.89 per kW of generating capacity per year, for a payout period of 20/1.89 = 10.6 years. Clearly, a plant would not initiate such a project because of the expected efficiency gain. The project could look attractive only if, by its implementation, the plant could avoid installing an SCR.

VI. CONCLUSION

The goal of this project was to decrease NO_x emissions while simultaneously increasing power output using a combination of advanced sensor upgrades, low-NO_x burner modifications, and advanced overfire air, thus avoiding the need for an SCR unit and saving the associated capital and operating expense. Because of problems with the modified low-NO_x burners, Phase III, which is essential to achieving the NO_x goal, was not implemented. Therefore, the goal of this project was not met. This does not mean, however, that the concept of reducing NO_x and increasing capacity by relatively simple unit modifications and improved control is not valid.

Problems arose with the modified burners. They suffered overheating damage, so that it was not possible to insert the ignitors and scanners properly on all the burners. Thus, the conclusion was reached at the end of Phase II that it was not reasonable to install SOFA unless new burners, ignitors, and scanners were also installed. Since there was insufficient money in the budget to accomplish this, Phase III was not implemented. It is quite possible that, with a new burner design and installation of SOFA, the goal of the project could be met. However, until that is done, the question will remain open as to whether the proposed approach can achieve NSPS NO_x standards without the need for installation of an SCR unit.

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