MILLIKEN CLEAN COAL PROJECT-UPDATE

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INTRODUCTION

The Milliken Clean Coal Demonstration Project was selected for funding in Round 4 of the U.S. DOE's Clean Coal Demonstration Program. The project's sponsor is New York State Electric and Gas Corporation (NYSEG). Project team members include CONSOL Inc., Saarberg-Hölter-Umwelttechnik (S-H-U), NALCO/FuelTech, Stebbins Engineering and Manufacturing Co., DHR Technologies, and ABB/CE Air Preheater. The project will provide full-scale demonstration of a combination of innovative emission-reducing technologies and plant upgrades for the control of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from a coal-fired steam generator without a significant loss of station efficiency.

The demonstration project is being conducted at NYSEG's Milliken Station, located in Lansing, New York. Milliken Station has two Combustion Engineering 150 MWe pulverized coal-fired units built in the 1950s. The S-H-U FGD process and the LNCFS-Level III low-NO_x burner are being installed on both units.

I. S-H-U Process

A. Background

The Saarberg-Hölter Umwelttechnik GmbH (S-H-U) flue gas desulfurization (FGD) process commenced operation at the NYSEG Milliken Station in mid-January 1995; Unit 1 operation is scheduled to begin in late June. The S-H-U SO_2 control technology is based on a forced oxidation, formic acid-enhanced wet limestone scrubber. Project goals include:

- Demonstration of up to 98 percent SO_2 removal efficiency while burning high-sulfur coal;
- Production of commercial grade gypsum and calcium chloride by-products to minimize waste disposal;
- Zero wastewater discharge;
- Space-saving design;
- A low-power-consumption scrubber system.

Parametric testing of the S-H-U process is scheduled to begin September 1, 1995. The test program will provide operation and performance data to confirm that the S-H-U FGD process can meet regulatory requirements for new and existing utility boilers. The data also will provide a basis for process optimization and for economic evaluation. The physical and chemical data required for by-product sales or disposal of gypsum, FGD blowdown sludge, and calcium chloride will be developed.

B. Description of the S-H-U Contactor

As shown in Figure 1, the absorber has a cocurrent section followed by a countercurrent section. There are four slurry spray headers on the cocurrent side and three on the countercurrent side. The two-stage design helps maintain the slurry pH in the optimum range. Also, cocurrent operation reduces pressure drop. The two-stage absorber is designed to be compact, allowing easier retrofit. The absorber is constructed of concrete and is lined with corrosion- and abrasion-resistant ceramic tiles. This design is expected to reduce maintenance.

The FGD system is designed for zero waste water discharge. A blowdown stream is removed and treated to control the scrubber chloride concentration and produces a saleable concentrated calcium chloride solution.

C. Start-up Results

The scrubber is operating using four or five spray headers which provides an L/G of 119 to 157 gal/kacfm. The dewatering system produces gypsum containing less than 10% moisture by weight. To achieve the design slurry chloride concentration, the brine concentrator system started up until June 1995. The following table shows preliminary SO_2 removal results.

L/G, gal/kacf	119	123	129	130	154	157
%SO_2 Removal	95.0	95.4	95.6	96.4	97.2	97.6

D. Parametric Test Plan

To define the performance limits of the S-H-U FGD system, Unit 1 will operate at design conditions, provide long-term data, and evaluate the FGD load-following capability. The steady-state chloride level is expected to be about 40,000 ppm Cl by wt. Limestone utilization will be held constant at the design level. For each test, the scrubber pressure drop and SO_2 removal will be measured. The effect of process variables on gypsum crystal morphology will be studied during tests using the design sulfur coal. The project will use coals which contain 1.6, 3.2 (design coal), and 4 weight percent sulfur. The following is a discussion of the parameters to be varied.

The plant design is based on a coal sulfur content of 3.2 weight percent. The coal sulfur content will be varied over a range of 1.6 to 4.0 weight percent using at least three different coals. The purpose is to demonstrate the S-H-U technology with low-sulfur coal, design coal, and high-sulfur coal. Parametric tests will not be performed using the high-sulfur coal; instead, the process will be operated at optimum conditions based on the results of parametric tests using the design coal and computer modeling results.

The design scrubber slurry formic acid concentration is 800 ppm. Formic acid concentrations of 0, 400, 800, and 1600 ppm will be tested. The purpose is to demonstrate the effect of formic acid concentration on SO_2 removal and scrubber operability.

Various combinations of spray headers in the cocurrent and countercurrent sections will be tested. The purpose is to generate data to optimize SO_2 removal performance and scrubber energy consumption. The mass transfer coefficients will be determined individually for the cocurrent and countercurrent sections using the results from these tests. By changing the number of spray headers in operation at constant flue gas flow, the scrubber L/G ratio will be varied.

The design gas velocity is 20 ft/sec in the cocurrent scrubber section and 12 ft/sec in the countercurrent section. Tests at higher velocity (15 to 20 ft/sec in the countercurrent section) will be performed on the Unit 2 scrubber by shunting gas flow from Unit 1 to the Unit 2 scrubber. The purpose is to provide data on high gas velocity scrubbers. Recent literature (e.g., Ref. 2) suggests that FGD capital cost can be reduced significantly by increasing the design velocity in the absorber. These tests will be performed using the design formic acid concentration (800 ppm).

The design limestone grind is 90% -170 mesh when using formic acid and 90% -325 mesh with no formic acid. For comparison purposes, tests will be performed using 90% -170 mesh without formic acid and using 90% -325 mesh at 800 ppm formic acid concentration in the scrubber.

The test coal sequence is low-sulfur coal (1.6%) followed by the design coal (3.2%), and lastly the high-sulfur coal (4%). The test plan includes 103 six-hour tests using low-sulfur coal, 61 seven-day tests using design sulfur coal, and one two-month test using high-sulfur coal. The tests are statistically designed to study parametrically the effect of formic acid concentration, L/G ratio, and mass transfer on scrubber performance.

II. Low-NO_x Concentric Firing System-Level III (LNCFS-III)

A. Background

Both Milliken units were retrofitted with the LNCFS-III burners. The objective was to reduce NO_x emissions to comply with the 1990 Clean Air Act Amendments

(CAAA), while continuing to produce marketable fly ash. The Unit 1 burner retrofit was in 1993 and the Unit 2 retrofit in 1994. New coal mills were installed during the burner outage.

The effectiveness of LNCFS-III burner retrofit to reduce NO_x emissions was evaluated in short-term tests (2-4 hours each) and long-term tests (60 days) while burning a high-volatile eastern bituminous coal. The short-term tests were statistically designed to evaluate the impact of burner operating parameters on NO_x emissions and loss-on-ignition (LOI). The long-term test consisting of 60 measurement days was used to estimate the annual NO_x emissions and was consistent with the Utility Air Regulatory Group (UARG) recommendations. The baseline tests were conducted on Unit 2 and the post-retrofit tests were conducted on Unit 1, since Unit 1 was not available for baseline testing prior to its retrofit. Conducting baseline testing on one unit and post-retrofit testing on the other unit was an acceptable option because pre-retrofit NO_x emissions from the two units differed by less than 0.03 lb/MM Btu. Long-term NO_x emissions from the two Milliken units were 0.64-0.68 lb/MM Btu at 3.5%-4.5% O_2 at the economizer outlet.

B. Parametric Test Program Results

The short-term parametric tests evaluated the impact of boiler load, excess O_2, and burner tilt on NO_x emissions and LOI. Post-retrofit testing included as additional parameters mill classifier speed, SOFA tilt, and SOFA yaw. Variation of CO was not a consideration in this study because CO measurements were less than 13 ppm for the baseline tests and less than 23 ppm for the post-retrofit tests.

Figure 2 shows full boiler load (140-150 MWe) variations of NO_x emissions and LOI with economizer O_2 for the baseline and the post-retrofit tests. Only post-retrofit tests in which over-fire air (SOFA and CCOFA) flows and mill classifier speeds did not vary were included in Figure 2. At the same O_2 level, the scatter of the data was partly due to experimental variation and to the variation of other parameters, such as burner tilt. Under both baseline and post-retrofit conditions, higher O_2 levels increased NO_x emissions and reduced LOI. A simple inverse relationship was observed between baseline NO_x emissions and LOI. The post-retrofit relationship between NO_x emissions and LOI was more complex because of the larger number of the LNCFS-III parameters. The LNCFS-III configuration typically had 0.17-0.19 lb/MM Btu lower NO_x emissions and 2.4%-2.9% (absolute) higher LOI relative to the baseline. In general, NO_x reductions were about 35% and post-retrofit LOI levels were about 4%.

The effect of mill classifier setting on NO_x emissions and LOI at 120 MWe for different economizer O_2 levels (3.0%, 3.4%, and 4.5% nominal) are shown in Figure 3. Increasing the classifier speed corresponds to finer pulverized coal (increasing classifier speed 40 rpm is estimated to increase coal fineness from 75% to 90% through 200 mesh) which dramatically reduced LOI. Furthermore, NO_x emissions could be reduced by as much as 0.05 lb/MM Btu by increasing the classifier speed 40 rpm. Similar trends were observed at full boiler loads.

Baseline changes in burner tilt had a significant effect on NO_x emissions and a minor effect on LOI, whereas, post-retrofit changes in burner tilt had significant effects on both NO_x emissions and LOI. Increasing the LNCFS-III burner tilt below the horizontal (negative tilt) was effective in reducing both NO_x emissions and LOI, but was limited by its impact on the main steam temperature. Following the burner retrofit, a control algorithm provided automatic variation in burner tilt to maintain the main steam temperature.

Changes in SOFA tilt had minor effects on NO_x emissions, LOI, and steam temperatures. Furthermore, changes in SOFA yaw had minor effects on NO_x emissions, but increased LOI if the SOFA yaw was different from the fuel firing angle. However, SOFA yaw changes were accompanied by automatic changes in burner tilt to maintain steam temperatures, and the effects of the two parameters on LOI could not be isolated.

C. Long-Term Test Results

Long-term measurements (60 days) were used to estimate the achievable annual NO_x emissions, and to evaluate the effectiveness of the LNCFS-III burner retrofit. Figure 4 compares long-term NO_x emissions from the two Milliken units (baseline and LNCFS-III) at full boiler load (145-150 MWe). At 3.3%-3.6% economizer O_2, NO_x emissions dropped from baseline levels of 0.64 lb/MM Btu to post-retrofit levels of 0.39 lb/MM Btu, corresponding to a reduction of about 39%. At a boiler load of 80-90 MWe and at 4.5%-5.0% economizer O_2, NO_x emissions dropped from baseline levels of 0.57 lb/MM Btu to post-retrofit levels of 0.41 lb/MM Btu, corresponding to a reduction of about 28%.

In summary, NYSEG believes LNCFS-III burner retrofit is a cost-effective technology to comply with Title IV of the 1990 CAAA. NO_x emissions below 0.4 lb/MM Btu could be achieved, while maintaining salable fly ash. To date, burner operations are acceptable.

REFERENCES

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2. Carey, T.R., Skarupa, R.C., Hargrove, O.W., and Moser, R.E. "EPRI ECTC Test Results: Effect of High Velocity on Wet Limestone Scrubber Performance," Presented at the 1995 SO_2 Control Symposium, Miami, FL, March 28-31, 1995.

Figure 1.
SCHEMATIC OF S-H-U FGD SYSTEM AT THE NYSEG MILLIKEN STATION
(One of Two Absorbers Shown)

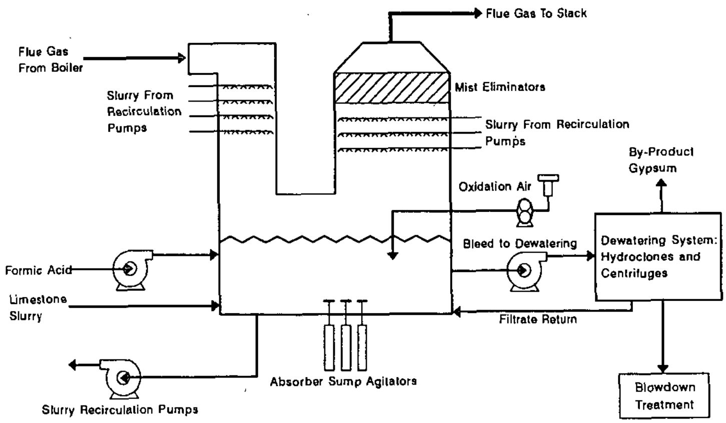

Figure 2. Comparing Milliken Units 1 and 2 at 140-150 MWe

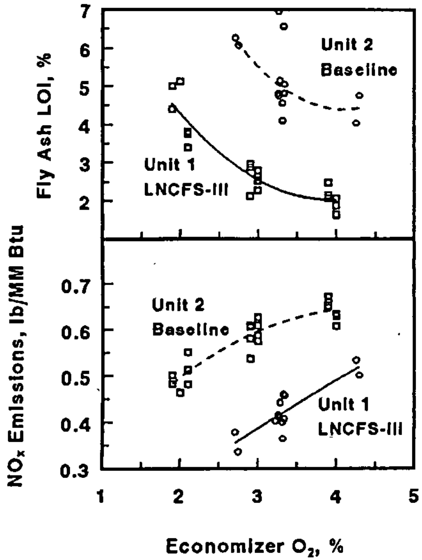

Figure 3. Effect of Classifier Setting, LNCFS-III at 120 MWe

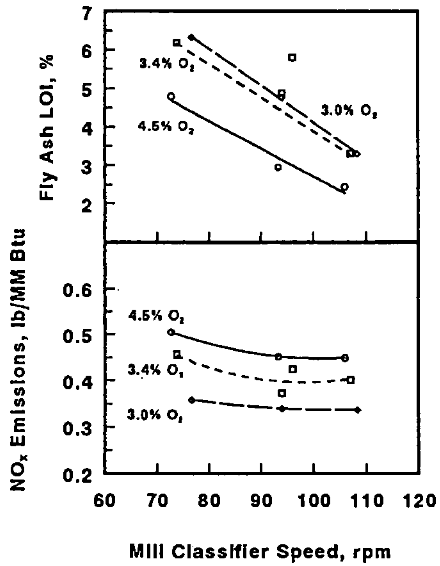

Figure 4. Comparing Long-Term NO_x Emissions at 145-150 MWe