TECHNICAL CHALLENGES IN NO_X CONTROL: COST-COMPETITIVE COMPLIANCE FOR COAL-FIRED BOILERS

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ABSTRACT

In the decade since the Clean Air Act Amendments (CAAA) were enacted, the power generation business has undergone rapid change. In many parts of the U. S., utilities are being restructured into separate generating and distribution companies in preparation for a competitive market for wholesale and retail power. To survive in the emerging marketplace, generating companies are striving to produce the most power (high capacity and availability) for the lowest cost (3 to 3.5 cents per kWh).

At the same time that costs are being reduced, utilities are challenged with meeting tougher new NO_x emission limits imposed by Title IV (acid rain) and Title I (ozone non-attainment) of the CAAA. Title IV limits can generally be met by applying combustion NO_x controls (low-NO_x burners and overfire air) with additional flexibility provided by reburning and selective non-catalytic reduction (SNCR). The cost impacts of these technologies have been recognized and endured. Now Title I will require more drastic NO_x reductions in the 2003 to 2007 timeframe in the 19 eastern states where ozone is highest. The only technology capable of consistently meeting Title I limits is selective catalytic reduction (SCR). Competitive pressures may eventually force all coal-fired plants to meet Title I regulations. The utilities that are able to reduce emissions at the lowest cost will survive.

Since the CAAA were enacted, ADA Environmental Solutions (ADA-ES) has developed and implemented a suite of strategies to reduce the cost of low-NO_x operation through the use of sensors and controls. This paper will provide field data from several plants showing how cost savings were achieved by the test team and maintained by the utility. Examples of cost savings include reduced consumption of SNCR reagent, lower combustion NO_x via biased firing and burners out of service, system-wide NO_x averaging to minimize SCR, reducing the cost of SCR operation by controlling the NO_x going into the reactor, and monitoring and controlling flyash salability by preventing carbon or ammonia contamination.

BACKGROUND

Salem Harbor Station, now owned by PG&E Generating, installed both combustion NO_x controls and Non-selective Catalytic Reduction (SNCR) to meeting NO_x emission goals of 0.33 lb./M Btu for their three coal-fired units. Emission limits were met, but the consumption of urea was a significant operating cost. The original control system metered urea to pre-selected injectors based on a look-up table of inlet NO_x as a function of load generated during pre-retrofit testing by the plant. The urea flow rate was then adjusted to maintain the stack NO_x emission safely below 0.33 lb./M Btu over the load range of each unit. Unfortunately, this control scheme often cranked up the urea flow when furnace temperatures were high, leading to urea combustion instead of NO_x reduction. The author verified the high temperatures by measuring furnace exit gas temperatures (FEGT) with an accurate, on-line, continuous optical temperature monitor called GasTemp. Sootblowing practices had a lot to do with these high temperatures.

RESULTS AND DISCUSSION

First, testing was performed on Units #1 and #2; both 81-MW front-fired boilers equipped with low-NO_x burners and overfire airports. The tests yielded the following conclusions:

- Reagent was injected at the upper end of the temperature window at full load, resulting in only 15 to 22 percent reagent utilization (especially with a dirty furnace at the tail end of a sootblowing sequence).
- Utilization was higher (30-35 percent) at low loads.
- Ammonia slip was experienced, especially during load transients.
- Reagent utilization improved to 26 percent at full load when FEGT was below 2020 F.
- Reagent utilization could be increased to 42 percent at 70% load when FEGT was below 1880 F.

After the initial tests, the plant agreed to modify the control system and incorporate the temperature signal into the control logic for the SNCR system on Unit #3.[1]

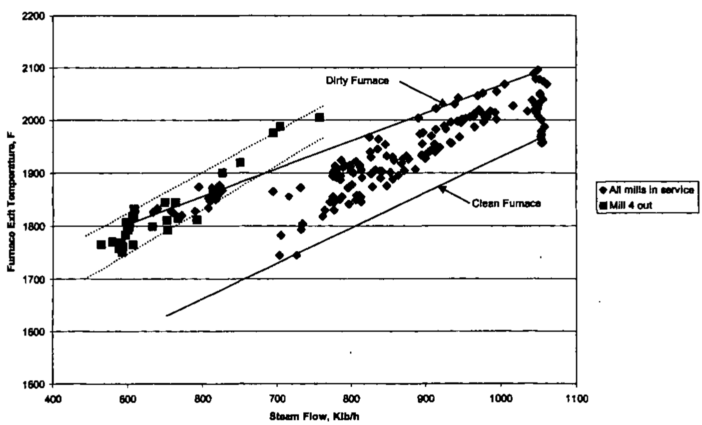
Fuel Tech, the original equipment supplier, designed the control modifications and worked with the plant to install the new software. ADA-ES planned the demonstration tests, collected and analyzed the data, and interpreted the results. The program, results from which are described in reference 1, included 24 days of baseline measurements documenting the original system performance and 35 days of demonstrating the improvements.

Salem Harbor #3 is a front-fired boiler rated at 155 gross MW. The unit is equipped with four levels of urea injectors as well as low-NO_x burners and overfire air to control NO_x emissions below 0.33 lb./M Btu. A complete division wall divides the furnace into two chambers. After the burner retrofit, the unit has had difficulty achieving the designed steam temperature due to lower FEGT. Therefore, furnace sootblowing was only performed a few times a week prior to the test program as necessary to maintain primary superheater steam temperatures below 950 F.

Historical reagent consumption prior to the demonstration varied from 70 to 200 GPH, and averaged about 125 GPH in 1995 and 1996. On the first day of baseline testing, the reagent consumption averaged about 112 GPH over the 24-hour period. On the second test day, operators blew all 36 furnace sootblowers and watched as the reagent consumption at full load dropped to about 62 GPH (the minimum flow allowed by the original control system)! As a result, the operators immediately decided to change their sootblowing practices to better control NO_x. The initial drastic sootblowing decreased reheat steam temperatures by about 15-degrees F, but also reduced superheater attemperator spray flows from 52,000 to 15,000 lb./h. Reheat steam temperatures recovered in a matter of hours, but the reagent consumption continued at the minimum level for another day. Further experience indicated that frequent sootblowing using only a few blowers at a time could maintain low reagent consumption without any adverse effects on boiler performance.

FEGT at full load varied from 1950 to 2100 F, depending on sootblowing, as shown on Figure 1. As a result of this "baseline" testing experience, the FEGT signal was incorporated into the revised control system.

Fig. 1 Relationship of FEGT to Steam Flow at Salem Harbor #3



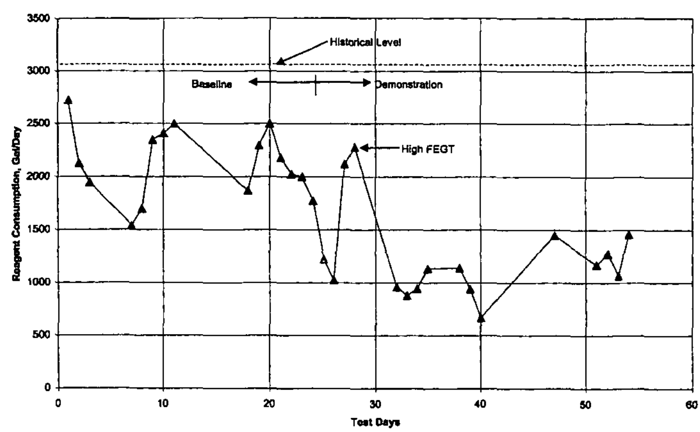
The changes to the SNCR system included mechanical upgrades, new instrumentation, and software replacement. Fuel Tech first installed a remote pressure regulator on each reagent metering module so that atomizing pressure and reagent flow could be controlled across the load range at each injection elevation. This modification allowed flexibility to use temperature to dictate system operation. Then Fuel Tech updated the Allen-Bradley and FactoryLink software to include the temperature signal among other changes listed in Table 1.

The results achieved with the new control system were dramatic. Figure 2 shows daily reagent consumption for both the baseline and demonstration periods. Historical reagent usage had been over 3000 gal/day based on Unit #3's share of the total station consumption. During the baseline test period, consumption ranged from 1500 to 2700 gal/day, depending on how the operators chose to apply the IR sootblowers. Sootblowing schedules were formally introduced in order to maintain FEGT at full load in the range of 1950 to 2000 degrees F during the demonstration period in conjunction with the control system modifications. As a result, the reagent consumption was reduced to 600-1500 gal/day (less than half of the historical level). Moreover, these savings were sustainable after the test crew had gone home. The resulting cost savings was estimated by the plant to be about $600K/y at a urea price of $0.90/gallon.

Table 1. Software Changes

Original Control System	Upgraded Control System
Initial reagent flow rate selected from look-up tables based on steam flow and mills in service.	Initial reagent flow rate calculated from curves based on steam flow and FEGT.
Look-up table values for reagent flow were established during tests when sootblowers were not used.	The reagent flow curves extended to much lower values based on the sootblower performance data.
Injector liquid pressure constant.	Injector pressure varied with rate of temperature change. Rapid FEGT decrease results in reduced atomizer pressure, thus reducing both reagent flow rate and droplet size.
NO_x set point selected automatically, but operator override possible.	Included a new screen showing average daily NO_x and projected NO_x if current set point is maintain. Operators could then adjust set point to reduce reagent flow at the end of the day and still assure compliance.
System response time set to avoid instabilities given original inputs.	System response time shortened to take advantage of new inputs.

Figure 2. Daily Reagent Use at Salem Harbor #3



Biased Firing and BOOS: a Poor Man's OFA.

Another low-cost step for reducing NO_x from existing boilers is to increase the amount of staged combustion that the boiler can achieve. Figure 3 shows a general relationship between NO_x emissions and stoichiometric ratio at the lower burners. The background data for this curve are somewhat complicated to explain [2,3,4], but the main points are that NO_x can be further reduced when:

1. The SR approaches 0.7
2. The OFA ports are located well above the top burner elevation.

The poor-man's way to achieve these low-NO_x conditions is to try biased firing and burners out of service. Biased firing increases the size of locally fuel-rich regions within the flame zone by redistributing the air and fuel within the furnace. To best reduce NO_x, the fuel should be biased lower or toward the middle of the furnace, while the air is biased upward and toward the furnace sidewalls. The result is to decrease the SR for the lower (or center) burners, and increase the SR for the upper (or wing) burners and OFA ports. Since NO_x emissions decrease more drastically at low SR than they increase at high SR, the overall result is usually a substantial NO reduction. The only trick is choosing fuel-rich burners such that their flames will contact enough combustion air in the upper furnace to complete burnout.

Biased firing taken to the extreme is taking burners out of service entirely. In this case, the lower burners are operated fuel-rich, while the upper burners are operated on air only and essentially become a second set of OFA ports. Flame-zone NO_x reduction is maximized at a SR of 0.7, the additional residence time between active burners and OFA ports enhances NO_x reduction, and very little NO_x is formed in the burnout zone as long as burnout is slow.

To take advantage of BF/BOOS, the operator must have accurate control over fuel and airflow to each burner. On-line measurement of both air and fuel can be achieved by installing flow sensors in the burner lines. Alternatively, combustion optimization software has been used to help operators maintain BF/BOOS conditions. The software will often select biased firing conditions from the normal operating range as lowest possible NO_x. Given total airflow to the burners and overfire air ports, the software can learn to control biased firing, even if fuel distributions are not well characterized. If the fuel flow to each burner is measured, the system is even more robust.

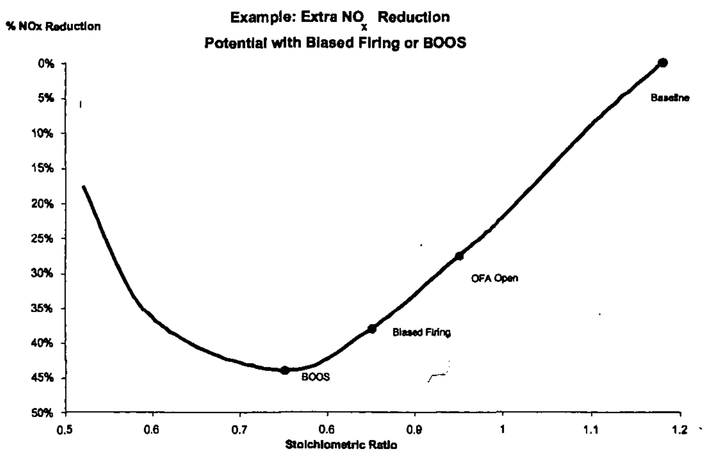
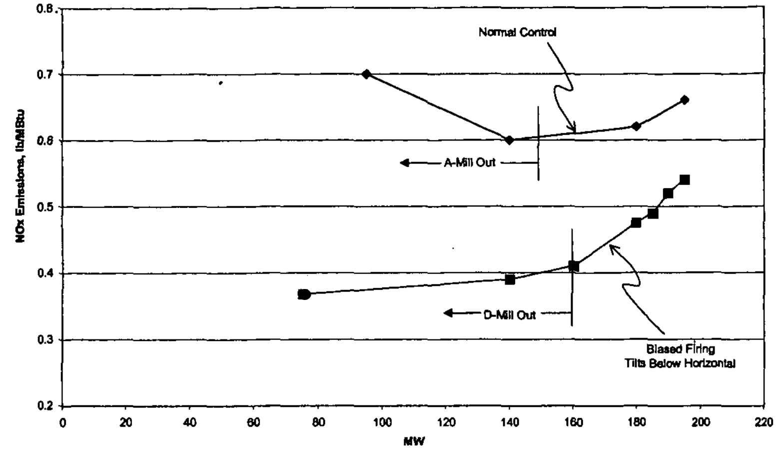


Figure 3. NO_x Reduction from Staged Combustion.

ADA-ES has recently completed a test series on a 180-MW tangentially fired boiler already equipped with closed-coupled OFA ports. Figure 4 shows the trends of NO_x with load before and during the tests. The situation at this utility is that they need to meet Title IV NO_x limits now while looking ahead to Title I. Low-cost NO_x control will partially offset the cost of credits in the nearterm, and reduce the cost of SCR (if required) in the long term. It can be seen that BF/BOOS can achieve up to 50% reduction in low-load NO_x, and 20% NO_x reductions are sustainable at full load. BF/BOOS operation has been adopted by the operators and is now the preferred mode of operation.

Figure 4.
NOx Emissions Vs. Load at a 180 MW Tangential Unit



System-Wide NO_x Averaging.
Title I NO_x controls will be enforced within each state on a system-wide basis. Therefore, another way to save money on NO_x control is to over-control NO_x on units that have advantages and under-control NO_x on other units where there are barriers to NO_x control. Since SCR is the most expensive control method in terms of $/ton of NO_x removed, the objective of this strategy is to juggle the suite of NO_x-control technologies such that the fewest number of SCR units are required.

One utility company that we have worked with operates 24 boilers in two states. Since most of these boilers already used low-NO_x burners and overfire air for NO_x control, they only needed 10 SCR units on their largest boilers to achieve a system-wide average NO_x of 0.15 lb./M Btu. Accordingly, high performance SCR treats flue gas from equipment that generates 72% of the seasonal power production. However, this was not the least-cost scenario.

To reduce compliance costs, ADA-ES walked down each unit and examined design and operating data to determine additional NO_x reduction potential. Technologies considered included:

- Biased firing/burners-out-of-service
- Low-NO_x burners (if not already there)
- Overfire air booster fan for deeper staging
- Optimization software and sensors for temperature, LOI, per-burner coal flow
- Conversion to natural gas
- Reburning with coal or natural gas
- Fuel lean gas reburning
- Amine-enhanced gas reburning
- Selective non-catalytic reduction

Several units in this system have spare mill capacity and sufficient furnace volume to take maximum advantage of BF/BOOS. Therefore, it was not surprising that some combination of BF/BOOS, optimization software, and SNCR for the smaller megawatt units saved considerable money. In addition, by applying these techniques in all 24 boilers, the NO_x emission limit could be met using only seven SCR units. The overall savings were about $17M/y.

SCR Control Improvements.
There are now ten Selective Catalytic Reduction (SCR) NO_x control systems operating in the United States on coal-fired boilers. Within the next year, SCR technology will be adopted by many other utilities faced with meeting low NO_x emission limits driven by Title I of the Clean Air Act Amendments. Currently, there are an estimated 40 SCR units either under construction or in procurement within the Ozone Transport Region. Estimates of the number of SCR units to be built between now and 2007 in the US range from 80 to 200.

SCR systems employ relatively simple instrument and control (I&C) schemes to meter the correct amount of ammonia into the flue gas to maintain NO_x below the regulated value. System designs contain some margin of safety to account for the range of temperature, inlet NO_x concentration, or particulate matter expected under steady-state conditions. However, these parameters can change very quickly during transient operation (load swings, start-up, shutdown) or off-design operation (mills or burners out of service, feedwater heaters out of service). Also, the local NO_x or temperature distributions can change at the ammonia injection point, even though the total NO_x or heat input remains the same. The results could be wasted reagent or worse, the formation of ammonium sulfate or bisulfate that can foul air preheater surfaces, contaminate flyash that the utility may want to sell, and increase stack opacity above regulated limits.

Weaknesses in conventional SCR control systems, as described by operators, include:

- Unreliable NO_x analyzer sampling system upstream of the SCR reactor.
- Slow ammonia reagent flow response based on a 5 to 10 minute lag time in the feedback NO_x signal from the stack CEM.
- Over-feeding ammonia reagent when the SCR inlet NO_x concentration undergoes a step change decrease (as occurs when a top mill is taken out of service or a lower mill is put into service).
- Reagent flow reverts to default values during CEM calibration.

ADA Environmental Solutions, LLC (ADA-ES) was contracted by EPRI to evaluate SCR design and operating data from US SCR installations in order to quantify the extent of any adverse impacts from the problems listed above. We then evaluated whether improvements can be made to existing control systems to manage potential side effects of SCR, which could include air heater fouling, flyash contamination, catalyst poisoning, or stack opacity.

Control system upgrades devised by ADA-ES were described in two papers given at the recent EPRI/EPA/DOE Mega Symposium [5,6]. However, one of the most effective ways to reduce the cost and risk of SCR operation is to minimize the NO_x concentration going into the reactor. Lower inlet NO_x means lower ammonia consumption and lower ammonia/NO_x ratios. The ammonia/NO_x ratio defines the risk of ammonia slip: if the ratio can be held less than 0.8, then the ammonia slip will not exceed 1 PPM. The catalyst lifetime (defined as the time until ammonia slip exceeds 2 PPM) can also be increased significantly when the inlet NO_x is low. Biased firing was one technique recommended by ADA-ES to reduce ammonia/NO_x ratio.

Recent operating experience at Stanton has incorporated many of the improvements suggested by the results of this EPRI project. In their third year of operation, Stanton experienced higher than expected catalyst deactivation, which motivated operators to modify combustion to reduce NO_x going into the SCR. One change that worked well was operating with the top mill (out of five) out of service to increase the staging effect. This allowed Stanton to reduce boiler outlet NO_x from 0.4 to as low as 0.26 lb./M Btu, and consistently maintain this value below 0.32 lb./M Btu! Another change was to move the NO_x emission set point closer to the permitted NO_x value. As a result of these improvements, reagent consumption has dropped to about 200 lb./h at full load, saving about 25%, and ammonia slip episodes have been less frequent. Further efforts are underway to improve the feedback NO_x signal from the stack CEM to achieve faster response to load swings.

Improved Flyash Sales

Before the CAAA, utilities found it easy to meet unburned carbon specifications for flyash sold to use in cement and concrete products. Flyash loss-on-ignition (LOI) must be below 3-5% in order to prevent absorption of air entrainment chemicals used in the cement industry to control the strength and prevent cracking of concrete products. Flyash sales also represent a significant revenue stream for some utilities. The difference between landfill costs and flyash sales can be as much as \$25/T. A 500 MW coal-fired unit firing a bituminous coal will produce about 280 tons/day of flyash, which could represent about \$2M/y in revenues and avoided costs.

ADA-ES has been working with Solvera Particulate Controls, Inc to help utilities realize these cost benefits. Solvera has obtained the rights to the CAMRAC online LOI monitor[7], and has applied this monitor to determine whether flyash removed from the precipitator is saleable or not. In this application, the LOI monitor takes an ash sample from the pneumatic line under each collection hopper. Solvera has also mounted the LOI monitor in the economizer outlet duct and developed reliable procedures to extract a representative, isokinetic sample for analysis every ten minutes. The resulting LOI readings are accurate and close enough to real time to make online combustion tuning feasible.

ADA-ES has recently installed the CAMRAC on a 50 MW coal-fired boiler to measure and reduce LOI that impairs precipitator performance. First, the instrument will be used to troubleshoot the root cause of the LOI problem. The problem developed after installation of low-NO_x burners, but changes to burner operation (airflow distribution, primary airflow) or sealing windbox leaks into the furnace may help alleviate the problem. We will also try biased firing for simultaneous NO_x and LOI reduction. We have already talked about the NO_x benefits of BF/BOOS. Sometimes this technique can also reduce LOI by injecting more coal lower into the furnace, thus extending combustion burnout time for more of the fuel. As of this writing, no data are available from this test but results should be ready to incorporate into the presentation of this paper in August.

CONCLUSIONS

Meeting the NO_x emission limits required by Title IV and Title I of the CAAA can be costly, but cost improvements are possible for most boiler operators. The key to achieving cost savings is to monitor and control those factors that can be related to cost. For SNCR installations, the furnace temperature at the point of reagent injection can be monitored and controlled to maximize reagent utilization. In the example given above, utilization was doubled from less than 20 percent to over 40 percent. For SCR, it is cost-effective to monitor and minimize the NO_x concentration coming into the reactor to save on reagent cost. For both these technologies, reducing NH_3/NO_x ratios will also cut back on ammonia carryover, a major cause of air heater pluggage and possible source of flyash contamination.

Combustion NO_x controls (low-NO_x burners, overfire air, reburning) slow down the combustion process, often leading to more unburned carbon in the flyash unless operators can make adjustments. Combustion NO_x controls also decrease the margin of error for maintaining per-burner air-fuel ratios, since a single burner can produce enough carbon to contaminate the flyash product. Sensors are available to monitor LOI and furnace temperature. LOI provides direct feedback for combustion tuning and other firing strategies to reduce NO_x. It is also a required input for optimization software systems that provide operators with operating settings for maintaining NO_x within compliance while not exceeding LOI or heat rate constraints. Furnace temperature can also be used by these optimization systems as a way to measure and control boiler heat balance.

Payback for sensor-driven systems can be very rapid. The reward is reliable emission compliance and more power sales in a competitive market.

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