WPCA NEWS

Executive Summary

Mercury Compliance Monitoring for MATS / Startup and Shutdown Considerations for Sorbent Trap Monitoring Systems

By James Wright, Chief Operating Officer, Clean Air Engineering

The Mercury and Air Toxics Standards, or MATS, requires fossil-fuel fired electric utilities to monitor mercury emissions during all periods of operation, including startup and shutdown events. Many utilities are choosing sorbent trap monitoring systems to report mercury compliance for MATS. This article addresses the challenge with these systems to differentiate the mercury concentrations emitted during startup and shutdown from those that represent normal operation.
Full Story….

Mercury Re-emission from Wet FGDs Re-considered

By Steve Feeney, Babcock & Wilcox

Mercury re-emission results when a WFGD absorber system is saturated with elemental mercury, which is then desorbed from the system. This mercury re-emission can be effectively controlled via sub-saturation strategies, which are delineated in the short article that follows.
Full Story….

Evolution in the Mercury Control Market

By Michael Thiel, Technical Services Group Manager, Nol-Tec Systems

The evolving market for new generation PAC and non-carbon sorbents to increase mercury removal rates to meet MATS has created some issues with the ability of current eductor injection technology to handle finer particle sizes, longer conveying distances and increased injection rates. This article discusses some testing of a new flexible technology involving non-eductor material handling systems to meet these needs.
Full Story….

A New Approach to NOx Control

By Blake Stapper, AECOM (URS)

Utilities that are subject to the Regional Haze Rule are faced with increasingly stringent standards for NO_x emissions. This article describes a new approach for NO_x control, in which two technologies are applied in combination, for a cost-effective alternative to SCR that avoids the associated concerns for minimum operating temperature and air heater deposition.
Full Story….

Hot Flow Physical Model Study of Flyash Re-entrainment at Gulf Power Plant Crist

By Jeffrey Everett, Robert Mudry, P.E., Airflow Sciences Corp.; Lauren Porter, Alabama Power, Darryl Wall, Southern Company

An engineering design study combining CFD and physical flow modeling allowed Gulf Power Plant Crist to solve an Air Heater pluggage issue at the Crist Power Plant. The flow modeling and design work was completed by Airflow Sciences Corporation (ASC) and involved a novel modeling technique that is rarely, if ever, used in the industry: a hot-flow physical model. The results of the design study were implemented by Gulf Power during a unit outage in 2013, and over the course of operation in 2014 the plant observed that the air heater pluggage issue had been resolved completely.
Full Story….

WORLDWIDE POLLUTION CONTROL ASSOCIATION

Mercury Compliance Monitoring for MATS
Startup and Shutdown Considerations for Sorbent Trap Monitoring Systems

By James Wright, Chief Operations Officer, Clean Air Engineering

Background

On February 16, 2012, the EPA issued the final National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units (77 FR 9304). This rule is otherwise known as the Mercury and Air Toxics Standards, or MATS, and is contained in 40 CFR Part 63, Subpart UUUUU.

Since the original proposal, the issue of MATS compliance during startup (SU) and shutdown (SD) has been a point of contention. On November 30, 2012, the EPA announced a proposed reconsideration of parts of MATS that included, among other things, changes to the operating requirements applicable during periods of startup and shutdown, as well as a revision to the definitions of startup and shutdown (77 FR 71323). After nearly two years of solicitation and review of comments, the EPA completed its reconsideration of the startup and shutdown provisions and published the final rule on November 7, 2014 (79 FR 68777).

One constant throughout this debate has been the EPA's requirement that emissions must be measured during all process operating conditions, including SU/SD events. Although the EPA will not count emissions measured during SU/SD towards compliance with numerical limits, facilities will be required to monitor and report hourly emissions from these events. This will include mercury (Hg) monitoring.

SU/SD Issue for Hg Monitoring with Sorbent Trap Monitoring Systems

Because of lingering concerns over the long-term cost and reliability of mercury continuous emissions monitoring systems (Hg CEMS), many electric utilities are choosing sorbent trap monitoring systems (STMS) instead to report mercury compliance for MATS. The STMS approach, defined in EPA Performance Specification 12B, is widely viewed as simpler and more reliable than currently available Hg CEMS in this application. However, the requirement to separately report hourly emissions during startup and shutdown poses a special challenge to facilities that choose sorbent traps as their primary mercury monitoring approach.

The conventional Hg CEMS analyzers provide a constant data stream with a new measured value every minute or less. Sorbent trap systems, however, provide a single integrated measurement that represents the average concentration of the emissions over a certain

Figure 1: Commercial Sorbent Trap Monitoring System (CleanAir MET-8)

period of time (the "sampling event"). This singular concentration value is used to calculate the hourly emissions in units of the standard (e.g., lb/TBtu) for every operating hour during the event. There is no ability to disaggregate the integrated sorbent trap data into discrete sub-periods within the overall sampling event.

The duration of the sampling event for a STMS is normally several days, and can be as long as two weeks. If a single sampling event were to encompass both normal plant operations and a boiler shutdown, the emissions from those two operating modes would be comingled in the single average mercury concentration that the traps would provide. There would be no way to differentiate between the mercury concentrations emitted during normal plant operation from those that were emitted during the period in which the unit went through its shutdown.

In its reconsideration of the SU/SD provisions in MATS, the EPA recognized this inability of a single sorbent trap sampling system to differentiate mercury concentrations on an hourly basis. Accordingly, the final reconsidered rule now contains two alternatives for operators that wish to use only sorbent trap monitoring systems to comply with the mercury monitoring requirements. These alternatives are:
1. Single System Alternative: Use only one sorbent trap monitoring system for all periods of operation and include emissions data collected during periods of startup and shutdown in the compliance reporting average.
2. Redundant System Alternative: Use two or more separate sorbent trap monitoring systems, with at least one system dedicated to monitoring during startup or shutdown periods, and another system dedicated to monitoring for compliance purposes during normal operation.

The first alternative is a compromise position for the EPA since it will not allow startup and shutdown data to be differentiated from normal process data at facilities that choose to monitor this way. Therefore, this information will not be available to address numeric emissions limits for startup and shutdown periods at a later date.

Depending on the relative magnitude of mercury emissions during startup and shutdown periods, the first alternative could also be a compromise for the EGU facilities. Since this approach will lump startup and shutdown emissions into the reporting average, the potential exists for

these emissions to detrimentally affect the determination of compliance when they occur. The extent of this effect, though likely small, is unknown.

The second alternative enables the operator to report and assess startup and shutdown emissions separately from emissions during normal operations. This comes with an increase in hardware and operating costs since multiple redundant systems must be purchased, installed, and maintained. However, some of this added complexity and cost can be mitigated through a variety of hardware and operational modifications as discussed herein.

Figure 2: Typical Dual-Trap Probe

Challenges with the Conventional Redundant Solution
The redundant system alternative listed above would involve collecting separate trap samples for the different operating modes. Sampling events collected during normal operation would be used for MATS reporting and compliance, while sampling events dedicated solely to periods of SU/SD would allow operators to report those emissions separately from those during normal operations.

Although simple in principle, this approach is problematic in its implementation. The most significant issue arises from the manual nature of STMS operation – the traps must be handled manually both prior to and after each sampling event. These sorbent trap "exchanges" require that, prior to the sampling event, a technician install a pair of traps into a probe, verify that the installation is free of leaks, and insert the probe into the smokestack or duct. At the conclusion of the event, these steps must be reversed to recover the traps. Trap exchanges are typically scheduled in advance. Although startups are anticipated events, the time of transi-

tion from startup mode to normal operational mode is often not known precisely. The timing for a shutdown is typically even less pre-defined, especially when it occurs due to a plant malfunction. Because of these uncertainties, scheduling plant labor to perform trap exchanges for the transitions between normal operation and either startup or shutdown can be difficult.

Furthermore, any process operating hour in which valid mercury concentration data are not obtained is considered monitoring system downtime. Therefore, the transition from operating a startup system to operating a normal system (or from a normal system to shutdown) needs to be done with minimal delay to avoid gaps in monitoring data. Automating this process and providing attentive manpower scheduling are two key factors in making this approach successful.

Options for a Redundant System

A solution for this scheduling issue is the use of an automated sample switching system so that the transition between systems dedicated to different operating modes can be made unattended. In order for this approach to yield the greatest scheduling advantage, the traps for each system must be pre-installed into the gas stream prior to initiation of the sampling event.

Figure 1 shows the hardware of a typical primary STMS that would be used for MATS compliance. The hardware for any standard sorbent trap system is comprised of three major components: a dual-trap sampling probe (see Figure 2), a heated dual-core transfer line (umbilical), and an automated gas sampler. There are several options to implement a duplicate sampling system approach that will meet the requirements of the redundant monitoring alternative. Each option has advantages and disadvantages.

1. Option 1. Redundant backup STMS (Figure 3). In addition to the primary STMS for normal operation, a second complete STMS is used to capture SU/SD events. An additional sampling port is typically required to facilitate the sorbent trap probe of the redundant system. The greatest advantage to this approach is that the redundant system also provides a temporary back-up to the primary system in case the primary system becomes inoperable (or vice versa). Disadvantages include higher capital and installation cost, the need for two sampling ports, and increased space requirements for the hardware.
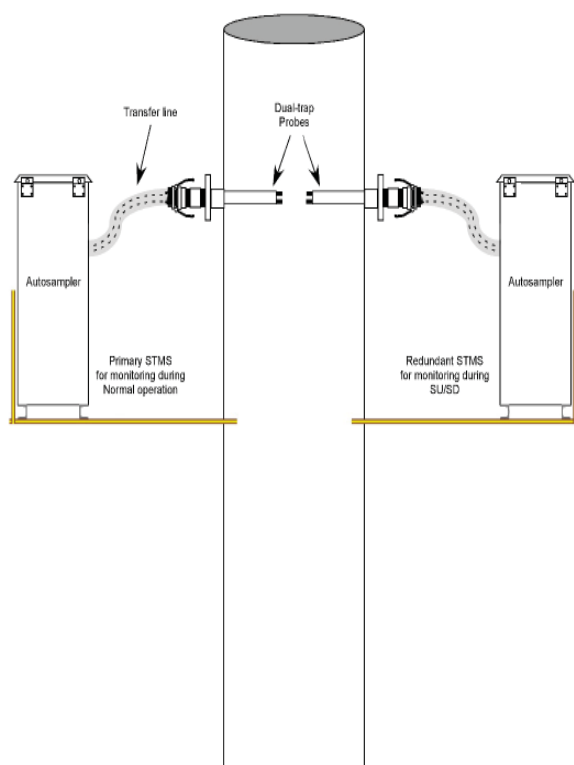

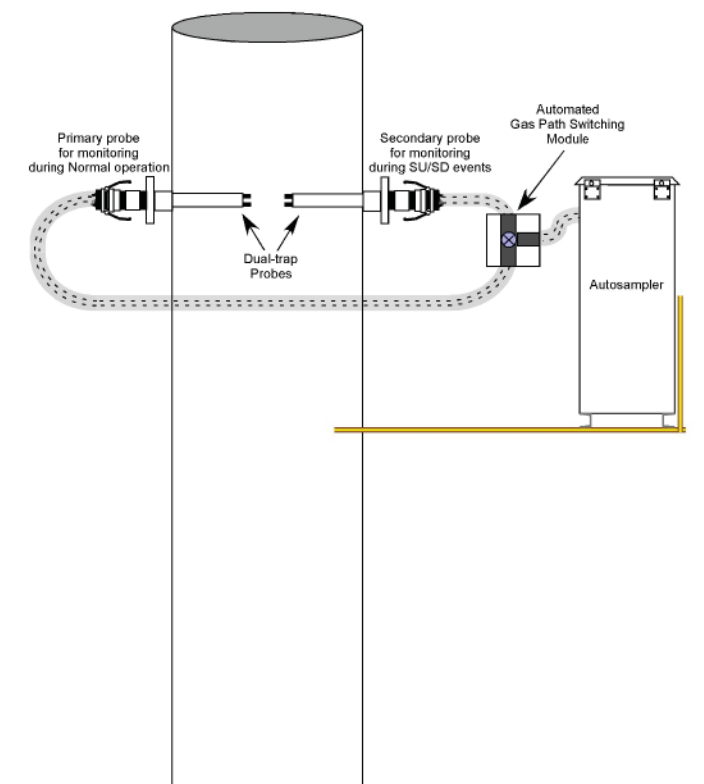*Figure 3: Configuration Option 1: Redundant Systems*

Figure 4. Configuration Option 2: Two Dual-Trap Probes with Shared Autosampler

2. Option 2. Redundant probe/umbilical with shared autosampler (Figure 4). This configuration uses two independent dual-path sorbent trap probes and umbilicals, but incorporates a switching mechanism that allows one automated sampler to be shared between the two probes. Although the hardware itself is not completely redundant, the core monitoring elements are. There is also a practical advantage of the second probe and umbilical providing a potential temporary back-up to the primary hardware. This configuration would still require that two sampling ports be available.

3. Option 3. Quad probe/umbilical with shared autosampler (Figure 5). Rather than use two dual-path probes and umbilicals as described above, this configuration uses a single quad-path sorbent trap probe (see Figure 6) and umbilical. One autosampler is shared between the two pairs of traps and associated gas paths using a switching mechanism similar to that above. This approach requires only one sampling port.

Each of these configurations relies on both sets of traps being inserted into the port(s) and ready to sample at all times. The plant control system would provide signals to the STMS controller(s) to initiate gas sampling with the appropriate set of traps and cease gas sampling for the other set. For example, as a plant transitions from startup to normal operation, a plant signal would be sent to the STMS to terminate gas sampling with the startup traps and begin sampling with the normal operation traps.

Operational Considerations

For the shared configurations, trap exchanges for the two sets of traps must be coordinated with one another to avoid conflicts between leak checks and gas sampling, since the same set of hardware would be required to perform both activities. Obviously, the quad-probe configuration further limits any operations involving both sets of traps, since all traps are either in or out of the gas stream at any given time.

Regardless of the configuration, best practices will likely dictate that both sets of traps be exchanged on the same schedule. There are limited performance data for traps that are immersed in stack gas for prolonged periods of time without sampling occurring. Even with no gas flow through the traps, there may be impacts to spike recovery, bed breakthrough, and sample contamination brought about by soaking the traps at elevated temperature or diffusion of gas
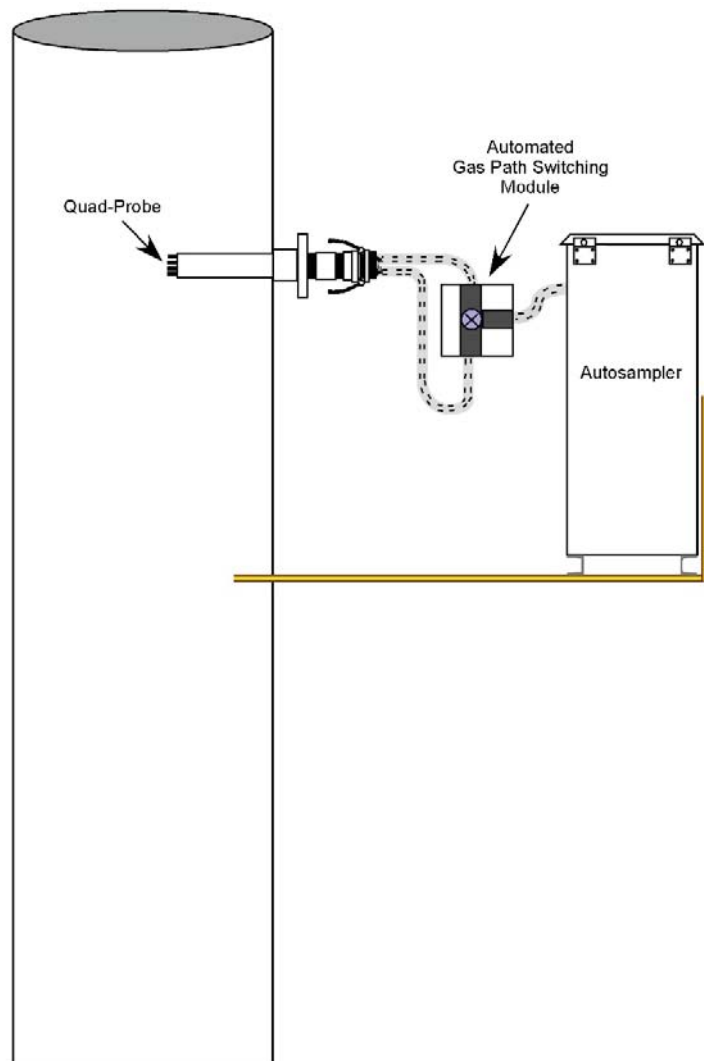

Figure 5: Configuration Option 3: One Quad-Probe with Shared Autosampler

into the trap openings. To minimize these potential effects, it is prudent to have a well-managed trap exchange program and perform trap exchanges of all traps every seven days or less, irrespective of whether the traps were used to sample stack gas during that period.

Certification Considerations

Appendix A to Subpart UUUUU requires any Hg STMS that is used "to account for Hg emissions in units of the applicable emissions standard" must be certified through an annual Relative Accuracy Test Audit (RATA). This requirement would apply to each of the SU/SD systems discussed above (as well as, obviously, any system used to monitor normal operations).

However, the implications of this requirement are slightly different for the two dual-probe configurations (Options 1 and 2) than for the single quad-probe configuration (Option 3). Since the dual-probe configurations require a second port to sample flue gas at a different extraction point in the stack, a separate RATA would have to be performed on each of the two probes, i.e., a RATA of the normal operations traps and a RATA of the SU/SD traps.

Since all monitoring with the quad-probe configuration would be done out of one port and one extraction point, one could argue that a single RATA of either the normal operation traps or the SU/SD traps would suffice in certifying both systems.

Final Thoughts

Sorbent trap monitoring systems have progressed a long way since they were originally conceived as a "cheap" back-up to Hg CEMS under the now-defunct Clean Air Mercury Rule. The STMS approach has proven to be a reliable and robust solution to mercury monitoring, and has the sensitivity needed to measure controlled emissions under MATS with ease. Many MATS-affected facilities have made strategic decisions to implement STMS for primary compliance monitoring, while relegating their existing Hg CEMS as uncertified process monitors to trim their control parameters.

The original MATS requirement to monitor and separately report emissions during SU/SD was initially a curveball for makers and users of sorbent trap systems. With the reconsidered rule, source operators using sorbent trap monitoring systems may essentially ignore this issue by choosing the first alternative described above and just lump all of

the process data into one reporting average. However, this approach does not come without a compliance risk. The redundant system alternative eliminates this risk but adds cost and complexity to monitoring. New hardware configurations now commercially available, along with a good trap management program, should make this approach more attractive in time for MATS reporting next April.

For further information contact
James Wright at jwright@cleanair.com

James Wright
Chief Operations Officer
Clean Air Engineering

Mr. Wright has been with CleanAir for over 20 years and is currently the Chief Operations Officer for the company. He started up CleanAir's Advanced Monitoring division in 2006 and led the development of the MET-80, CleanAir's sorbent trap-based mercury monitoring system for coal-fired utilities and other combustion processes. Previously, he managed CleanAir's emissions testing operations corporate-wide. He has been involved with the source testing business in one form or another for over 25 years and is a Qualified Source Testing Individual under the SES QSTI/QSTO Program. He holds a Bachelor of Science degree in chemical engineering from Virginia Tech and resides in Pittsburgh, PA.

Figure 6: Typical Quad-Trap Probe

Mercury Re-emission from Wet FGDs Re-considered

By Steve Feeney, Babcock & Wilcoxr

Those involved in the design, supply, installation and operation of Wet Flue Gas Desulfurization (WFGD) systems for electric generating units generally define mercury re-emission as occurring when "the concentration of elemental mercury in the flue gas exiting the WFGD exceeds the concentration of elemental mercury entering the WFGD."

Yet, the crux of the matter remains: what is the cause of mercury re-emission? The overwhelming consensus within the industry is that an increase in elemental mercury exiting the WFGD is caused when a portion of the oxidized mercury is reduced to elemental mercury through the scrubbing process. Once the oxidized form of mercury is reduced within the liquid phase to the elemental form of mercury, it immediately desorbs from the liquid phase since elemental mercury is insoluble.

Many early investigators, held to the position that the elemental form of mercury was insoluble. This was a reasonable assumption when compared to the solubility of sulfur dioxide or oxidized mercury, since these were several orders of magnitude higher than elemental mercury.

The solubility of elemental mercury has been investigated for more than eighty years. At a typical WFGD operating temperature of 130°F, the solubility of elemental mercury in water is approximately 120 ppb. At this level of solubility, one could assume that elemental mercury is insoluble. Until, of course, this is compared to the typical WFGD inlet flue gas mercury concentrations of approximately 10 ppb. At that level of mercury concentration, 120 ppb is relatively significant.

Due to the inconsistencies in data resulting from many various mercury emissions field trials, some experts in the field have begun to re-examine the assumption that mercury re-emission is the result of the oxidized form of mercury being reduced to the elemental form within the WFGD absorber liquid phase.

For instance, suppressing re-emission has been known to work on some units, at certain times but not at other times. The ability to suppress re-emission is dependent on the mer-cury mass balance. If mercury does not exit through the slurry bleed stream, it must exit through the WFGD outlet flue gas. Furthermore, on numerous occasions, mercury re-emission suppression field trials have been scheduled, only to have the testing firm determine that the unit is not currently experiencing re-emission, requiring the test to be postponed or cancelled. Is it simply that one day oxidized mercury is being reduced, and the following day, it is no longer being reduced? If this is true, why is it happening? This had led to some very intricate kinetic theories, but provides owners little in the way of positive steps they can take to meet Mercury and Air Toxics Standards (MATS) emissions limits.

When the WFGD is operated at low oxidation reduction potential (ORP) levels (a reducing environment), it would be expected that oxidized mercury would be reduced to elemental mercury, and potentially cause mercury re-emission. However, field data have also shown that mercury re-emission occurs when the WFGD is operated at moderate to elevated levels of ORP (an oxidizing environment). As longer term tests are performed and more data is examined, perhaps the definition of mercury re-emission needs to be re-examined. An emerging theory is that the cause of mercury re-emission is due to the liquid phase of the absorber slurry/solution becoming saturated with elemental mercury. Once saturated, elemental mercury will be stripped, or desorbed, from the liquid.

Figure 7 on page 7 illustrates the control of mercury re-emissions through precipitation of aqueous phase mercury, in this case using aqueous sulfide. Both WFGD inlet and stack elemental mercury are represented by yellow and green dots, respectively. As the boiler load increases mercury re-emission occurs as indicated by a significant increase in stack elemental mercury while the WFGD inlet concentration of elemental mercury is relatively constant. Within minutes of aqueous sulfide injection, as shown by the black horizontal line, the aqueous phase mercury is precipitated and re-emission is controlled. When the sulfide injection was stopped, mercury precipitation is minimized, the absorber slurry becomes saturated with elemental mercury, elemental mercury is desorbed and re-emission again occurs. Sulfide injection was stopped twice during this 24-hour period with similar

results. Once sufficient sulfide is added, and sub-saturation is achieved, elemental mercury in the stack becomes equivalent to the inlet elemental mercury and re-emission is avoided.

Ultimately, mercury re-emission is controlled by reducing the concentration of the oxidized form of mercury within the liquid phase. Whether activated carbon or aqueous sulfide is used to control the re-emission of mercury, both work by sub-saturating the liquid phase with respect to elemental mercury; activated carbon through adsorption and aqueous sulfide through absorption and precipitation of mercury.

The mercury MATS strategy for many WFGD owners and operators is to ensure sufficient upfront mercury oxidation such that the flue gas elemental mercury concentration at the WFGD inlet is below the MATS limit. Once that is achieved, both activated carbon and aqueous sulfide will work, and the only question remaining is, "based on my particular site-related equipment and issues, what is my least-cost op-

tion?" Looking at the co-benefits of WFGD mercury control through the thermodynamic principle of saturation will improve success in achieving MATS compliance.

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For further information contact Steve Feeney at sfeeney@babcock.com

Steve Feeney has worked at the Babcock and Wilcox company for 36 years and is currently Mercury and Waste Water Treatment Product Line Manager.
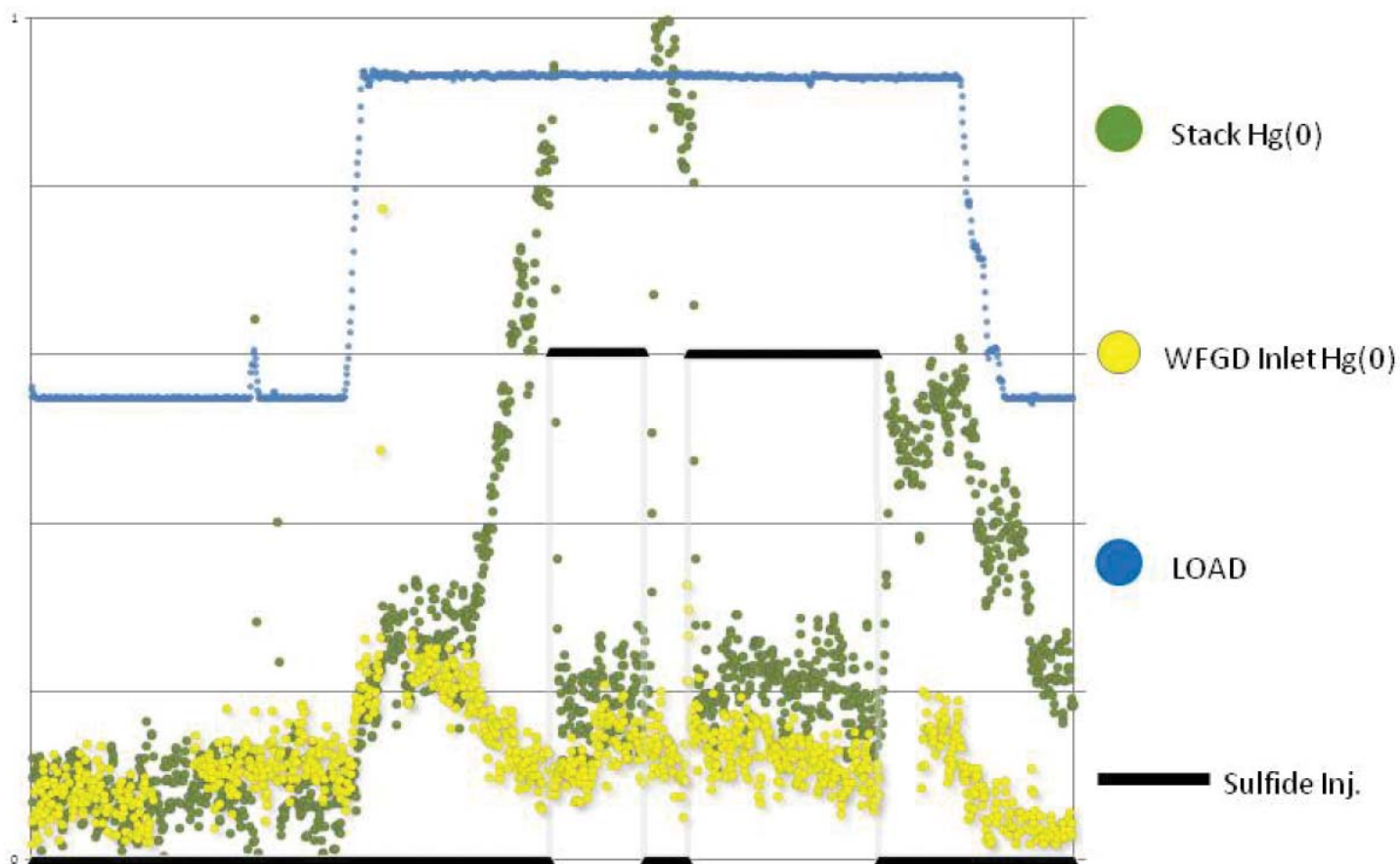
Inlet Hg(0) & Stack Hg(0) Hg(0)

Figure 7: The graph represents a 24-hour period. As load picks up in the AM, Hg re-emission begins. Introduction of aqueous sulfide controls re-emission. Sulfide ends. Re-emission begins. Injection begins, re-emission is controlled.

Evolution in the Mercury Control Market

By Michael Thiel, Technical Services Group Manager, Nol-Tec Systems

An Evolving Market

The Environmental Protection Agency (EPA) standards for electrical generating units (EGUs) and industrial boilers (IBs) pollution mitigation are continuing to move forward, now also covering mercury and various acid gas pollutants. Due to the stringent regulation on mercury and the many variables surrounding in-duct capture technology, the mercury and PAC market is evolving. But activated carbon injection (ACI) continues to show proven results in meeting the increasing standards for mercury (Hg) compliance.

New generation PAC products, non-carbon sorbents (e.g. amended silicates), and a combination of the two are being developed in finer particle sizes with uniquely designed features, to increase the mercury removal rates to meet compliance. These finer sizes and the unique features impact the pneumatic conveying properties of the material. Injection rates are higher to meet the newest standards. Longer

conveying distances are desired for offloading convenience. Convey line back pressures are increasing above the eductor limit and require more energy to convey. Injection technology must be designed to reliably convey various sorbents, at any injection rate wanted, for whatever distance is needed.

Flexible Technology

Eductor technology is limited and can't meet these needs for the Hg mitigation market. With a 1.2 – 2.7 PSI maximum convey pressure range (depending on system design), an eductor-fed system will not allow for the increased material amounts and distances required for appropriate residence times to meet regulations.

Some systems have moved to using a zero clearance airlock. This technology doesn't greatly increase the energy in the system, though it will produce up to 6 PSI of convey energy. However, this level is not entirely reliable at the top end
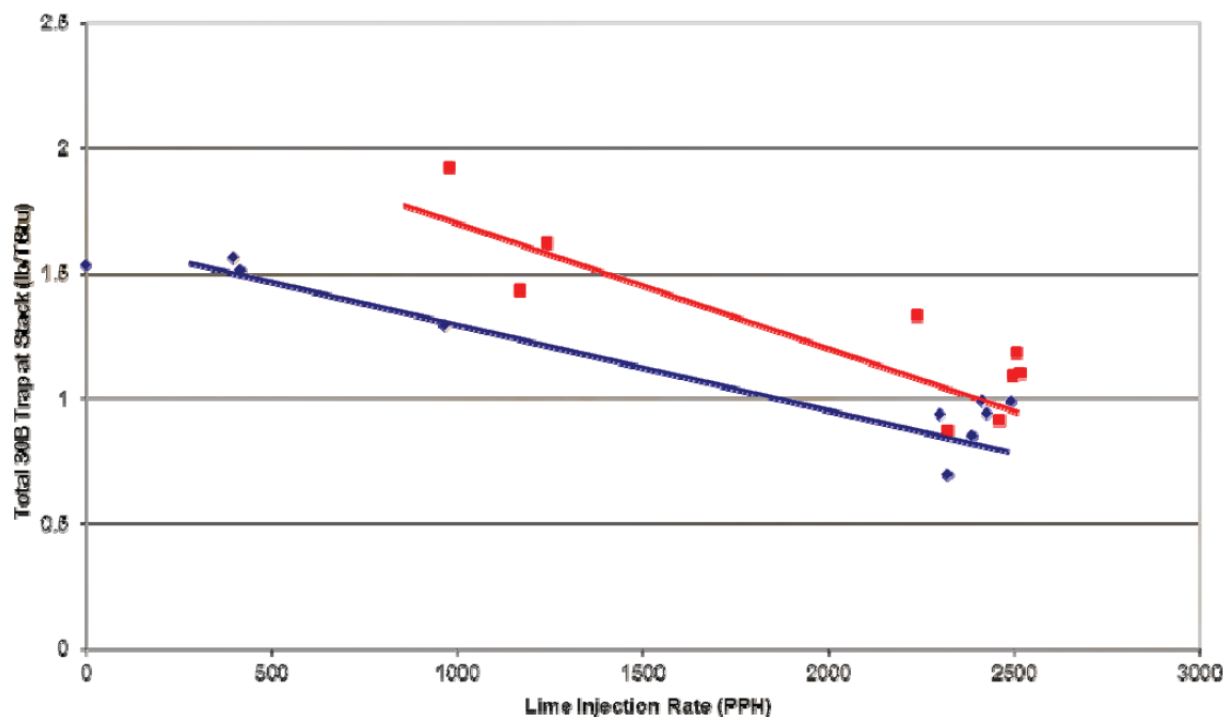

Figure 8: SO$_3$ control to enhance PAC performance

of its range. Also, because of the size of PAC particles, for example, airlock leakage is still a substantial problem with a rotary valve. Effectiveness of the sorbent and system is negatively impacted.

By listening to customer needs, a supplier has pioneered a continuous transport system able to meet the need to convey higher rates, longer distances, and different sorbent types. This system, by equalizing the pressure between the weigh hopper and the convey line, provides the capability to meter material into pressure zones up to 12 PSI and addresses the need for longer distance conveying of complex materials. The supplier started implementing this proven technology during on-site demonstrations by conveying sorbents for mercury mitigation.

A Year of Testing
The supplier company invested a lot of time in MATS testing in 2013. Utilizing a large fleet of portable, self-contained testing equipment, this testing took place on site of both power plants and industrial boilers, in real-world conditions. Most tests were for mercury compliance with MATS standards. However, EGUs and IBs also wanted to control SO_3 emissions that are not directly included in MATS, but necessary nonetheless for enhanced Hg removal. Many tests included injecting both alkaline products and Hg sorbents.

An early spring 2013 trial looked at enhancing PAC performance in conjunction with SO_3 control. The two test units were 200-300 MW each. HCl control was done via an existing wet FGD. The goal was to reach 1.2 lb/Tbtu Hg emission, then optimize from there. The challenges were a short residence time between lime and PAC (less than 1 second) and between ACI and ESP (also less than 1 second).

The supplier injected PAC at a consistent rate, while increasing the hydrated lime for SO_3 removal. Testing showed that increasing the hydrated lime rate allowed PAC to remove Hg to below MATS limits, without increasing PAC usage.
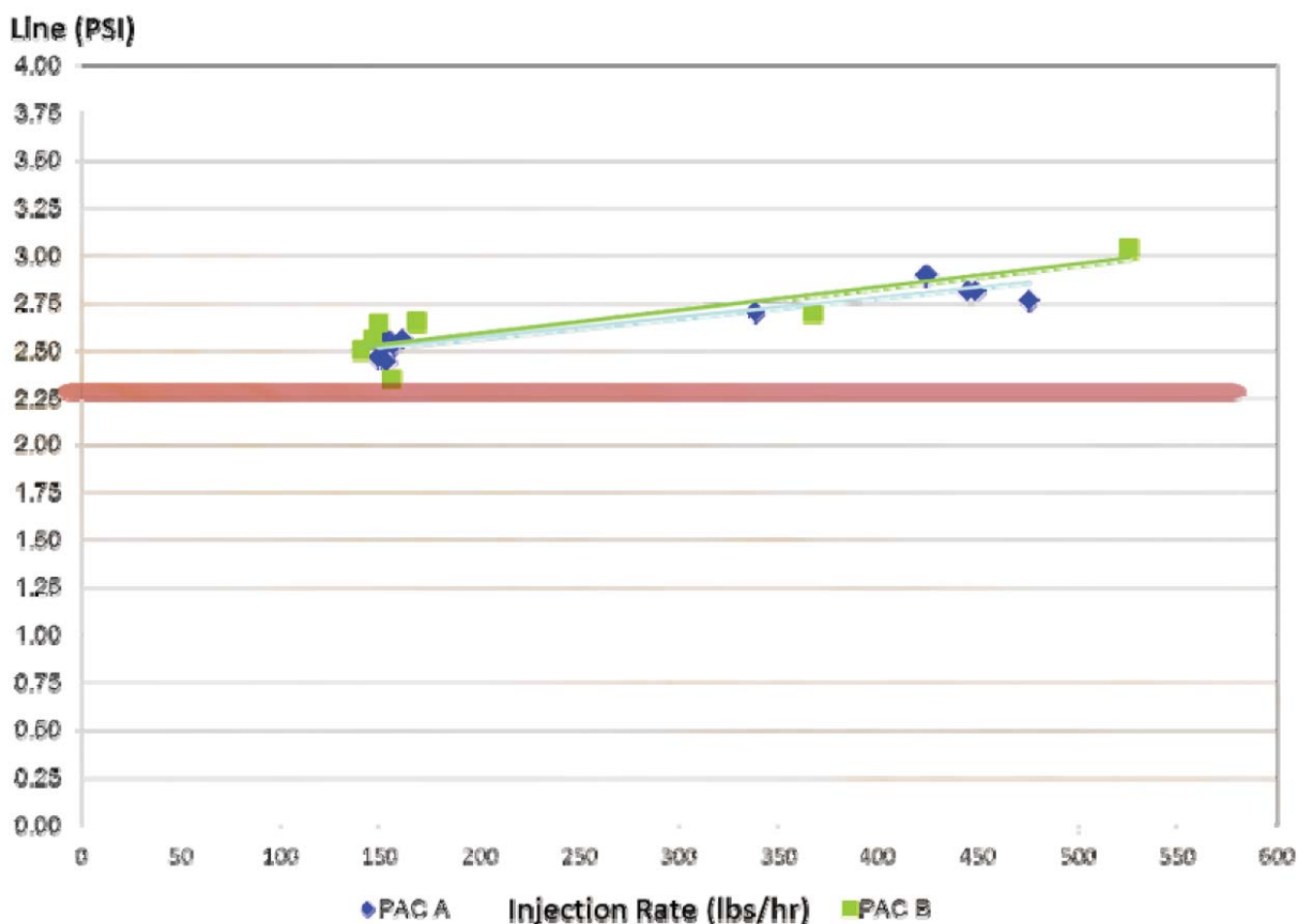

Figure 9: Test site A for Gen 3 technology

On one initial test site, the supplier company injected PAC at higher rates than standard eductor technology allowed for. As shown in Figure 9, non-eductor technology allowed for conveying pressures that are beyond an eductor's capability. The increased injection rate required more energy to convey the material into the duct, as was expected. The non-eductor system handled that increased rate without failure, which an eductor could not.

When an eductor runs at the borderline of its capabilities at higher pressures, back pressures will vary, producing fluctuating pressures or upset conditions. The supplier company has determined that using their non-eductor technology means conveying was not affected by the upset conditions.

On-site testing can be invaluable for an EGU or IB who is making decisions about most effective sorbents and which has the highest value. In these tests, the supplier company was able to run them all without having to move equipment, which would have introduced costly delays to the process.

Non-Eductor Systems Work for MATS Compliance

The supplier company's testing work throughout 2013 has shown that ACI systems can work – and work well – for MATS compliance. It's important, however, that the system be properly designed for an EGU or IB's specific needs. Proper material distribution within the ductwork is an essential aspect of ensuring ACI meets the mercury mitigation standards. Flexible injection rates will help ensure successful mitigation, and flexibility in sorbent types will allow the ACI system to work for more than Hg mitigation.

Non-eductor technology is proving to provide striking benefits for MATS compliance. With convey pressure potential of up to 12 PSI, convey distance is no longer a limiting factor. This allows for the needed residence times, as well as greater flexibility in plant layout. This higher pressure also enables the use of resistive splitter technology. Reliable material dispersal is ensured, as the system can be designed with more ducts that can be consistently filled with sorbent.
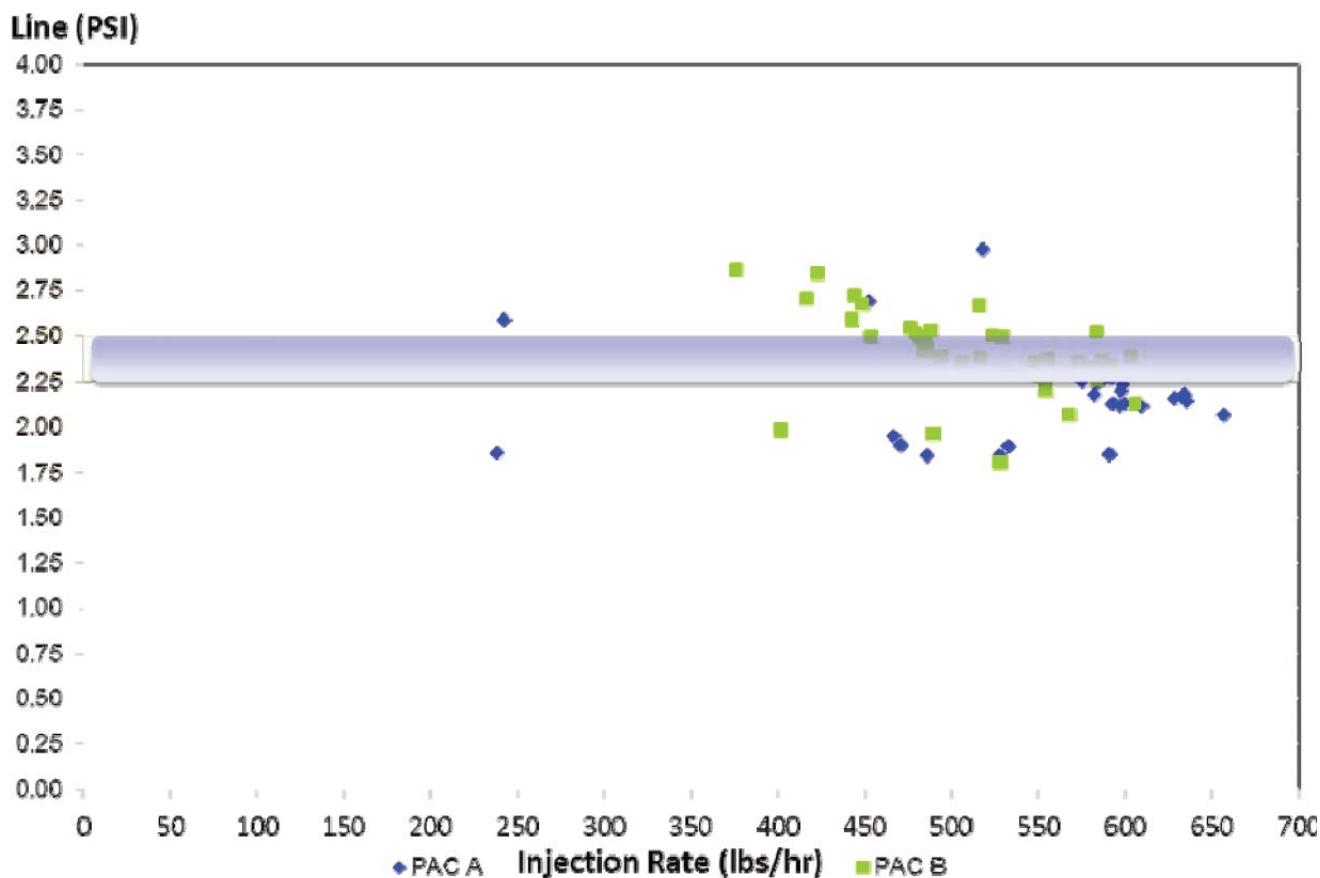

Figure 10: Test site B for Gen 3 non-eductor technology

Non-eductor design provides great flexibility, in injection rates and in sorbent usage. Non-eductors can provide rates as low as 10 pph and as high 5,000+ pph. With a broad range of injection rates, an EGU or IB can select less expensive sorbents or more effective sorbents that may require more material, depending on their operational budget. As regulations continue to change, flexibility in the amount and types of sorbents that can be used can have a huge impact on capital and maintenance costs.

It is important to select your mitigation partner carefully, to ensure they have the expertise or equipment to fully explore and test all the variables that can impact your decision. With due consideration to all factors, Hg sorbent injection technology can bring EGUs and industrial boilers into compliance with MATS regulations in an efficient and cost effective manner.

For more information about Nol-Tec's testing process, please contact Michael Thiel at MichaelThiel@nol-tec.com or 651.780.8600.

Michael Thiel is the Technical Services Manager of Nol-Tec Systems, Inc. in Lino Lakes, MN. Nol-Tec is a supplier of pneumatic conveying systems and dry sorbent injection technology known as Sorb-N-Ject®.

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Reinhold Environmental Ltd.

Comments & Other Inquiries to:

Reinhold Environmental
3850 Bordeaux Drive
Northbrook, IL 60062 USA
1.847.291.7396
sreinhold@reinholdenvironmental.com
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A New Approach to NOx Control

By Blake Stapper, AECOM (URS)

Abstract

Utilities that are subject to the Regional Haze Rule are faced with increasingly stringent standards for NOx emissions. In many cases, the choices for a plant have been either to shut down units, convert to natural gas firing, or to install a costly selective catalytic reduction (SCR) system to achieve the target emission rates. This article describes a new approach for NOx control, in which two technologies are applied in combination, for a cost-effective alternative to SCR that avoids the associated concerns for minimum operating temperature and air heater deposition.

Introduction

The regional haze rule was established in July 1999 (and amended in 2004) for the purpose of improving visibility in 156 national parks and wilderness areas. One of its requirements is that affected facilities must install best available retrofit technology (BART) to control oxides of nitrogen (NOx) emissions. Under the rule, states are required to periodically review whether control technologies are available to reduce emissions below the current level. BART determinations are intended to consider the cost of the controls, their impacts on reliability, the remaining useful life of the equipment, and the resulting improvement in visibility.

In recent years, there have been a number of instances in which the EPA has taken exception to a state's BART determination for a particular power plant. The states' analyses have often identified less expensive selective non-catalytic reduction (SNCR), while EPA has pushed for the installation of more stringent NOx controls (typically SCR). In most cases, this has been followed by a period of negotiations between the interested parties to agree on a compliance plan. For plants firing North Dakota lignite, these discussions have focused on technical issues, especially the concern that the sodium present in the lignite would blind the catalyst, making SCR infeasible. In most other cases, the dispute has centered on the high cost of installing and operating SCR.

Where economics are the point of contention, the challenge is the disparity in the performance of SNCR and SCR. The removal efficiency for an SNCR installation is about 15-25%, while that of an SCR is 80% or more. Arguments that SCR is not cost-effective are countered with the reality that SNCR does not accomplish a more significant reduction in NOx emissions. The resulting settlements have allowed some flexibility of control for multiple units at a plant, typically with some combination of retirements, conversions to natural gas, and the installation of SNCR or SCR on the remaining units. The number of units for which SCR installations is planned, or for which it is not technically feasible, creates a need for a cost-effective alternative to achieve "SCR-like" NOx emission reduction performance.

Technology Descriptions

The concept presented here for a cost-effective alternative to achieve reductions similar to those for SCR (e.g., outlet emissions of 0.05-0.06 lb/MMBtu) is to combine an advanced overfire air system with a process to inject ozone to oxidize the NOx to a soluble state that would then be captured in a flue gas desulfurization system. This technology pairing is synergistic because the reduction achieved by an overfire air system is more cost-effective, but is unable to achieve the low emission rates that are required; meanwhile, the ozone injection system has a higher operating cost, but is able to efficiently control NOx to very low concentrations. By using an advanced overfire air system to limit inlet concentration to the ozone injection system, the ozone utilization is minimized, and the cost-effectiveness of the overall system is improved.

Rotating Opposed Fire Air (ROFA™)

The ROFA system (offered by Mobotec, LLC) is comprised of multiple levels of air injection ports located in the upper furnace between the burner zone and the nose cone. Each port is fitted with a box that contains multiple high-velocity air injection nozzles. The air is drawn from the air heater outlet, boosted in pressure by a dedicated fan, and delivered with high momentum to the injection ports. The location of the boxes and the orientation of the nozzles are determined by the application of computation fluid dynamic (CFD) engineering of the furnace.

Another aspect of a ROFA installation is the modification of some of the existing secondary and primary burner nozzles. The purpose for the changes to the selected nozzles is two-fold. The first is to increase the pressure drop in the windbox to avoid any windbox/furnace differential pressure issues as-

sociated with the air staging that is being implemented. The second is to ensure the proper location for flame attachment. Experience has shown that the best mixing occurs when the high-momentum air is introduced with the ports located asymmetrically, resulting in complete burnout and low carbon monoxide (CO) and loss-on-ignition (LOI). Figure 11 presents the CFD models of the kinetic energy on a 500 MWe twin-furnace application. It illustrates the energy that baseline condition. The increased mixing energy produces for more complete combustion of the coal, prior to exiting the furnace. This allows the unit to operate with a more fuel-rich stoichiometry in the flame zone without increasing LOI or CO, as compared to the baseline condition. The lower stoichiometric ratio results in reduced NOx formation and emission rates. The enhanced mixing makes it possible to operate at a lower overall level of excess oxygen, which reduces the net unit heat rate without increasing products of incomplete combustion. ROFA also produces a more uniform temperature profile at the furnace exit, which improves

steam temperature management by reducing the need for at-temperation sprays.

Recent installations have demonstrated that ROFA is capable of achieving significant NOx reductions when applied to larger furnaces that are already equipped with conventional overfire air systems such as close-coupled overfire air (CCOFA) and separated overfire air (SOFA). An example of this performance is demonstrated from the results of a retrofit for which startup was completed in February 2014. The unit is a 500 MWe sub-critical twin-furnace tangential coal-fired boiler burning a variety of coals supplied from North America, Russia, Columbia, South Africa, and Scotland.

This unit was already equipped with SOFA and CCOFA, and had a baseline NOx emission rate of about 0.34 lb/MMBtu (483 mg/Nm^3), which varied depending on the coal blend. During the acceptance test, the ROFA reduced the emissions to 0.18 lb/MMBtu (256 mg/Nm^3), a decrease of 48%. CO
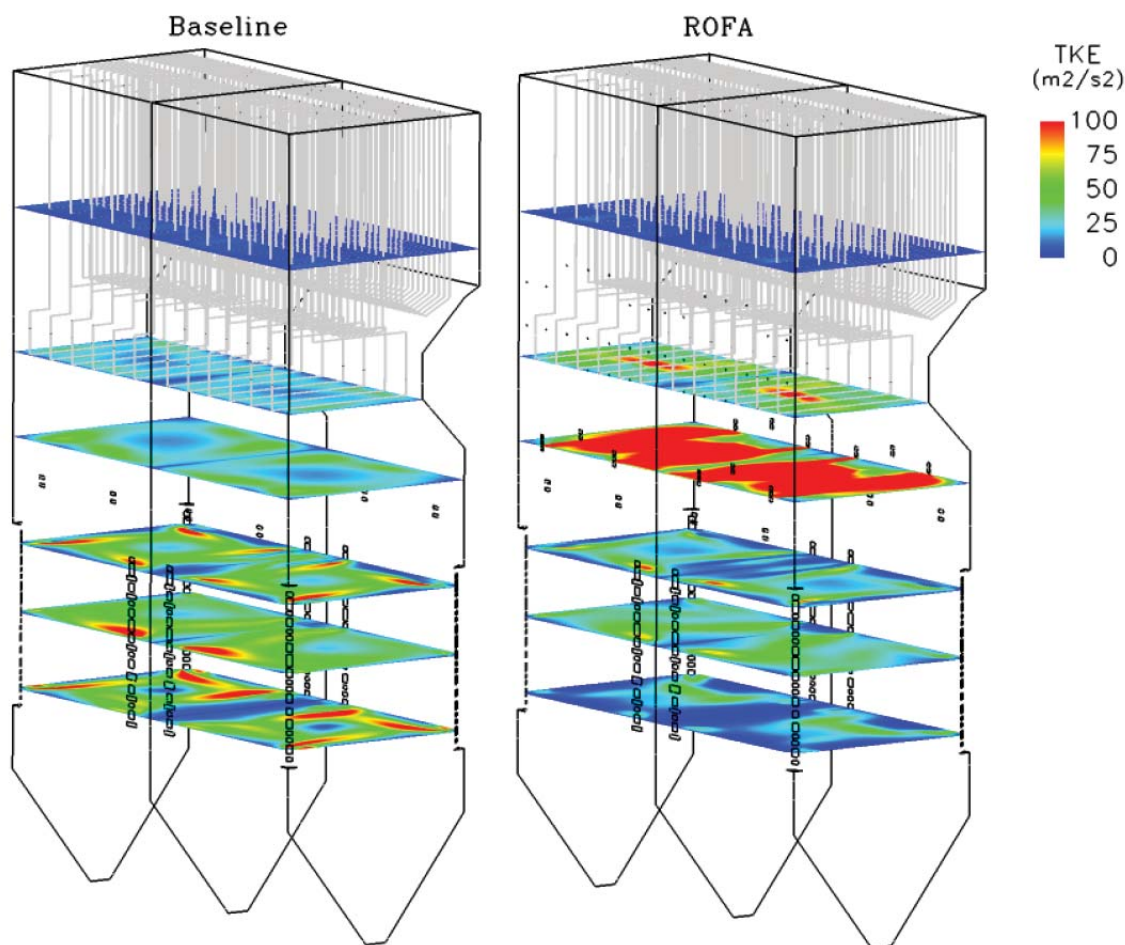

Figure 11: CFD model comparing kinetic energy of flue gas for baseline vs. ROFA

emissions decreased from 184 ppm to 157 ppm. The baseline LOI was measured at 8.4%, and was determined to be 8.9% with the ROFA system in operation. There was no discernable change to the boiler efficiency. Figure 12 shows a typical day of NOx data from Unit 2 at a constant load, on a coal blend having a slightly lower NOx baseline. In the figure, the ROFA is enabled and the NOx emissions decrease by 40% from a baseline of 430 mg/Nm³ (0.30 lb/MMBtu) to 260 mg/Nm³ (0.18 lb/MMBtu).

These results demonstrate that ROFA is capable of achieving significant NOx reductions, even in cases where an advanced overfire air system was already installed. While combustion controls are much more cost effective than SCR, there is a practical limit to how far they can reduce NOx emissions. Depending on the type of coal, it is difficult to achieve an outlet NOx concentration less than about 0.10 lb/MMBtu.

Therefore, to achieve SCR-like emission rates (0.05-0.06 lb/MMBtu) it is necessary to utilize ROFA in combination with a post-combustion control technology.

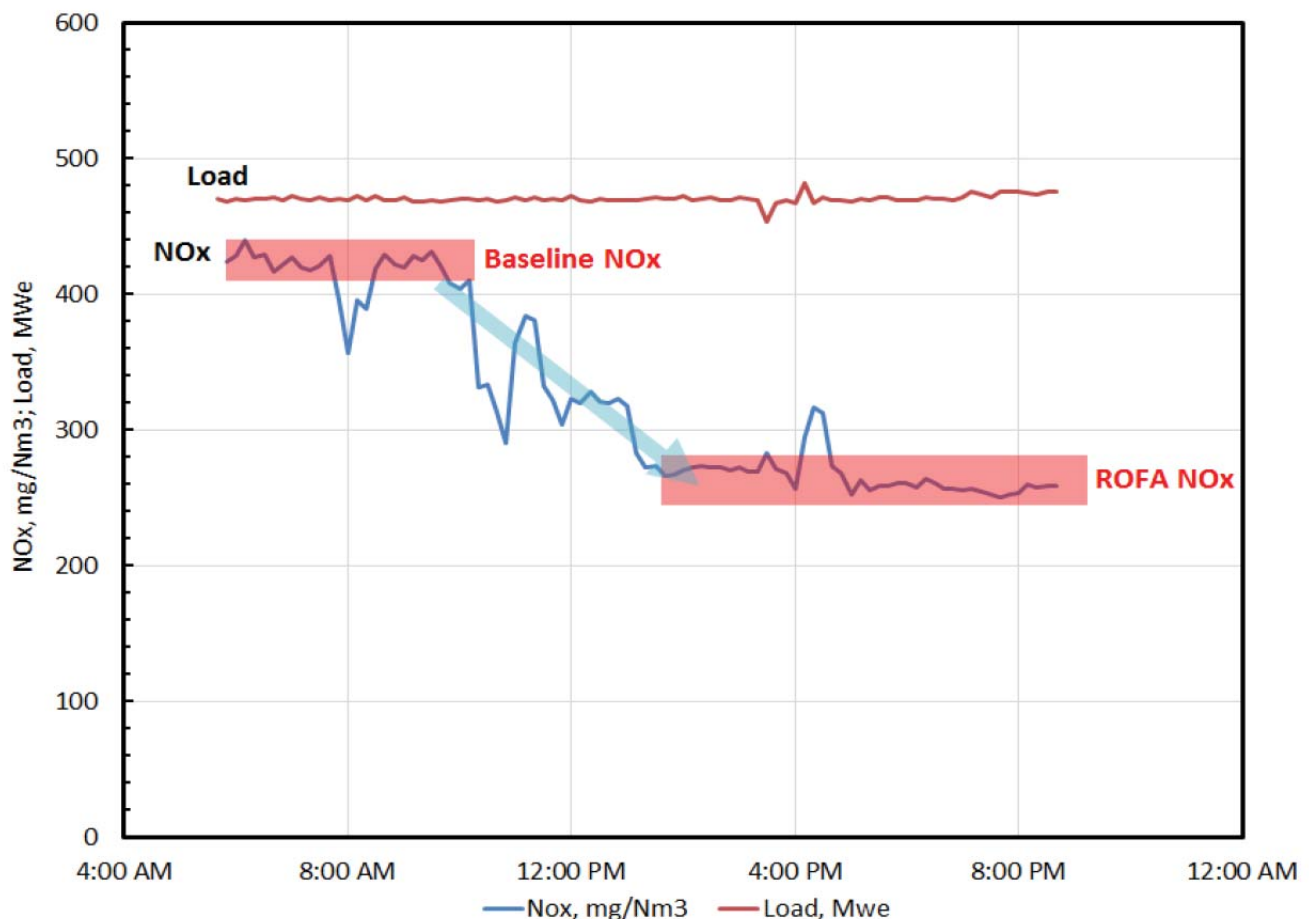*Figure 13: LoTOx system installation on coal-fired boiler at Medical College of Ohio*


Figure 12: Plot of NOx at baseline condition and with ROFA enabled for 500MW unit

Low Temperature Oxidation (LoTOx™)

The LoTOx (a trademark of Linde LLC) process injects ozone into the flue gas downstream of the air heater to oxidize insoluble NOx to higher oxides that are readily soluble for capture in either a wet or dry flue gas desulfurization system. The low temperature process (optimally ≤300°F) allows stable and constant control regardless of variation in load or NOx concentration. Unlike SCR, there are no adverse effects of acid gases or particulates on the LoTOx system. The LoTOx process is currently in use at a number of oil refinery fluidized catalytic cracking units, and on a 25MW coal-fired institutional boiler (See Figure 13 on page 14) to achieve NOx removal rates in excess of 90%.

The LoTOx™ process is based on the excellent solubility of higher order nitrogen oxides. Coal-fired utility boilers produce NOx that is made up of NO and NO_2, which are relatively insoluble in aqueous streams. The injection of ozone at low temperature oxidizes the NOx to N_2O_5, which is highly soluble. The flue gas moisture and the liquid in the FGD system easily and quickly converts N_2O_5 to nitric acid (HNO_3) based on the following reactions:

$$NO + O_3 \rightarrow NO_2 + O_2$$

$$2NO_2 + O_3 \rightarrow N_2O_5 + O_2$$

$$N_2O_5 + H_2O \rightarrow 2HNO_3$$
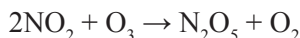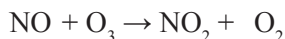
The rapid reaction rate of the first two reactions makes ozone highly selective for treatment of NOx in the presence of other compounds such as CO and sulfur oxides (SOx). This results in high ozone utilization efficiency for NOx removal with no oxidation of CO or SOx in the design retention time. Any unreacted ozone in the flue gas readily absorbs into the aqueous medium. The conversion of the N_2O_5 into the aqueous phase is rapid and irreversible, allowing for near-complete removal of NOx.

Ozone is produced onsite by passing oxygen through a conventional ozone generator. Oxygen is stored as a liquid, or can be generated onsite. Ozone generators are used for a variety of applications, including drinking water, wastewater, pulp bleaching, and swimming pool water treatment. In LoTOx applications, the amount of ozone production capacity is determined by the amount of NOx present in the flue gas and the targeted removal efficiency. During operation, the ozone is generated "on demand" based on the incoming NOx level, so that no onsite ozone storage is required.

The LoTOx system includes an oxidation duct where ozone is delivered into the flue gas stream via an array of injection lances. The reaction zone within the duct provides uniform distribution of the ozone and adequate mixing to effect a rapid reaction. Typically, the injection location is selected to allow a short residence time prior to entering the scrubber.

The LoTOx process utilizes some parasitic power for the ozone generation (and to produce the oxygen, where applicable). However, since the ozone requirement is directly proportional to the mass of NOx that is being removed, the operating costs can be managed by minimizing the inlet NOx to the system. Therefore, when used in combination with ROFA, it provides a cost-effective alternative for achieving emissions comparable to SCR. The LoTOx system has been successfully commercialized in a number of industrial applications.

Case Study

To illustrate the relative cost for the installation of SCR to the combination of the ROFA and LoTOx processes, a simplified case study has been developed for a 400MW unit firing a bituminous coal, and equipped with wet FGD. The unit has CCOFA and SOFA, producing baseline NOx emissions of 0.30 lb/MMBtu. Based on similar applications, ROFA will reduce the NOx to 0.16 lb/MMBtu. A LoTOx system is then installed to lower the emissions to 0.06 lb/MMBtu. The cost of this scenario is compared with those for an SCR with 80% NOx removal to achieve the same outlet emission rate.

The relative cost for the two control solutions are presented in Figure 14. The capital cost for the retrofit with SCR is about $100MM, with an ongoing annual operating cost of $3.1MM. The capital cost for ROFA is approximately $17MM, and $51MM for the LoTOx system. The total capi-

tal cost for the combination is $68MM, with annual O&M costs of $2.9MM. The overall cost effectiveness for the combined ROFA/LoTOx solution for this case is $4,100/ton, compared to $5,700/ton for the SCR.

It is important to note that the characteristics of a particular unit will dictate the eventual cost to implement a specific technology. The availability (or lack) of retrofit space at the economizer outlet of a unit may cause the capital cost assumed for SCR in this analysis to vary significantly. Conversely, the ozone injection grid for a LoTOx system is relatively compact, and less sensitive to the layout of the duct at the air heater outlet.

The relative annual cost advantage of the ROFA/LoTOx system in the figure is understated because there are inherent improvements in operational flexibility and reductions in
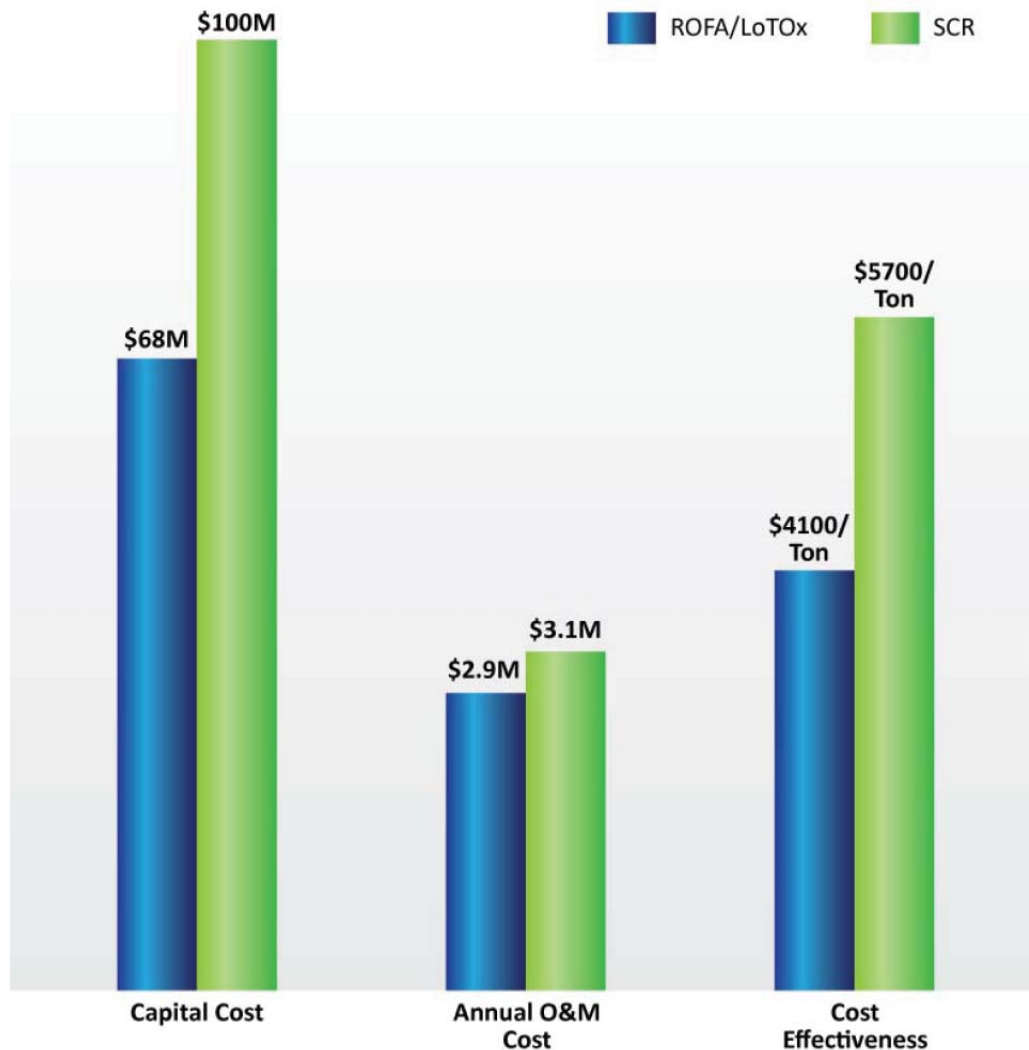

Figure 14: Cost comparison of ROFA/LoTOx to SCR

maintenance that are not quantified. The system is simpler to operate because it alleviates the need to maintain a minimum operating temperature to avoid catalyst deposition. In fact, the performance of the LoTOx technology improves at low loads. Less ozone is required because the utilization improves due to the increased residence time in the duct where the reactions take place, and because the mass of NOx to be oxidized is lower. Air heater maintenance costs associated with the buildup of ammonium salts due to SCR will also be eliminated.

The ROFA/LoTOx system avoids the risk of premature catalyst deactivation that is an ongoing concern for SCR. In particular, it provides a solution for units firing North Dakota lignite, for which SCR is not an option due to the blinding caused by the high sodium content of the coal. The combined system would also make it possible to switch to a less expensive, higher sulfur coal without having to take into account the detrimental effects on deposition and SO_3 emissions that would occur on a unit equipped with SCR.

Summary

Utilities that are subject to the Regional Haze Rule are under increasing pressure from EPA to further reduce their NOx emissions. In many cases, the solution has been to shut units down, or to install an expensive SCR. The implementation of a combination of the ROFA and LoTOx technologies offers a cost-effective alternative for achieving these stringent emission limits. A case study is presented in which the capital cost of the combined system is about two thirds the cost of an SCR. And, although the annual O&M costs appear to be similar, the ROFA/LoTOx system possesses greater operating flexibility, especially at reduced loads, and is not susceptible to the same deposition and deactivation issues associated with SCR. The combined system is also a potential solution for achieving low NOx emissions from units firing North Dakota lignite, for which SCR has been shown to be technically infeasible. A more detailed analysis of the relative cost-effectiveness of SCR versus the ROFA/LoTOx system is underway and will provide greater certainty to the potential benefits.

For further information contact Blake Stapper at blake.stapper@urs.com

Blake Stapper is the NOx control business manager in AECOM's (URS) Austin Process Technologies office. He received B.S. in mechanical engineering from The University of Texas at San Antonio, and a M.S. in mechanical engineering from The University of California – Irvine. He is a registered professional engineer in the state of Texas, and has worked in the field of combustion engineering for 25 years. During his career, he has managed numerous combustion and air pollution control projects in the utility, petrochemical, and manufacturing industries. The primary emphasis of these projects has been control of NOx emissions arising from large-scale coal- and gas-fired combustion sources. His current focus is on the identification, development, and implementation of innovative pollution control technologies.

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Hot Flow Physical Model Study of Flyash Re-entrainment at Gulf Power Plant Crist

By Jeffrey Everett, Robert Mudry, P.E., Airflow Sciences Corporation; Lauren Porter, Alabama Power
Darryl Wall, Southern Company

Flyash deposition and build-up is a common problem at coal-fired power plants which can lead to significant performance and maintenance issues. Figure 1 shows a typical accumulation of flyash in a duct. These deposits can grow over time and lead to major performance issues and maintenance costs. The root cause of the flyash build-up is generally a localized low-velocity zone or dead flow region. The problem is exacerbated when the plant operates at lower output and thus the overall flow rate and velocities are reduced.

Figure 1: Typical accumulation of flyash in a coal-fired power plant duct

Flow modeling is a standard engineering approach to understand and resolve these flyash accumulation problems. A typical flow model study can utilize Computational Fluid Dynamics (CFD) and/or laboratory physical modeling techniques to evaluate and minimize the potential for excessive ash accumulation in the ductwork. CFD provides an effective means of identifying low-velocity regions where build-up may occur and evaluating potential design modifications quickly and efficiently. Scale physical models are also used to assess velocity patterns in these ductwork systems. The physical model "dust tests" are then conducted using a model dust that simulates the drop-out and re-entrainment behavior of the plant ash. These laboratory tests tend to give a better assessment of the expected patterns of build-up than can be predicted by the CFD model, as well as provide a visual representation of the drop-out and re-entrainment behavior.

Traditionally, physical model dust tests have been performed using a laboratory dust (sand, cork, salt, etc.) that simulates the flyash behavior. It is often left to the modeler to determine the best method of mimicking the actual flyash aerodynamic behavior using the laboratory dust. Over the past decade, Airflow Sciences Corporation (ASC) has refined its procedure of using a wind tunnel to determine these aerodynamic characteristics. Wind tunnel testing of both the actual plant flyash and the laboratory dust is performed, and the aerodynamic properties are appropriately scaled when performing the model dust testing. Both the wind tunnel testing and the model dust tests are performed at ambient laboratory conditions, roughly 70 ºF [21 ºC], which is why this type of modeling is referred to as "cold flow" physical modeling. Figure 2 shows a typical example of a physical model during dust testing.
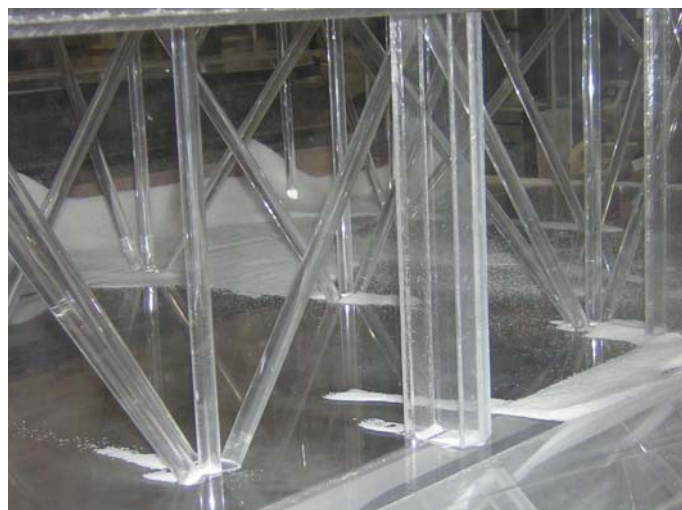

Figure 2: Dust testing in a cold flow physical model

Physical model testing using this methodology has shown acceptable correlation to the full scale for many actual plants. There are some cases, however, where the model results do not correlate as well as desired with the full scale. Two of the major factors that appear to cause correlation issues are a) flyash type/composition and b) operating temperature.

The two are inter-related, because it is the "stickier" ashes, such as Powder River Basin (PRB), that tend to exhibit different behavior in an operating plant compared to a lab environment. For instance, PRB ash will form piles on horizontal surfaces with an angle of repose of 60º or larger; PRB will also cling to vertical surfaces. In a laboratory environment, neither PRB nor model dusts display this behavior. Both PRB and other ashes will bridge across small gaps (such as catalyst openings or heat exchanger tubes) in an operating plant, but will not bridge similar gaps in an ambient temperature laboratory environment.

To develop more accurate correlations between actual fly-ash behavior and scale model dust testing, ASC has been conducting research with its "Hot Wind Tunnel". This system is capable of achieving a highly-controlled flow velocity with temperatures up to 650 ºF. The Hot Wind Tunnel runs on heated air and features a particle injection system that can preheat the particulate as well. Although the Hot Wind Tunnel does not yet simulate actual flue gas chemical composition or moisture content, it is ASC's experience that the temperature seems to play a primary role in the flyash aerodynamic behavior. Using the Hot Wind Tunnel, ASC can more closely simulate actual plant operating conditions (velocity, density, viscosity) and provide a more accurate prediction of the aerodynamic behavior of the flyash. ASC

research using this tunnel has involved both horizontal and vertical flow situations.

Recently, Gulf Power was experiencing a flyash accumulation issue that was affecting operational performance of Unit 6 at the Crist Generating Station. Plant Crist Unit 6 is a 370 megawatt coal-fired power boiler located in Pensacola, Florida. The plant was having an air heater pluggage issue as shown in Figure 3.

Observations inside the plant ductwork showed significant ash buildup in the SCR outlet duct and on the floor of the air heater inlet duct (Figure 4). The ash was building up in the outside corner of a duct elbow, and although this type of localized deposit often causes no operational issues, in this case the elbow happened to be the final turn before the flow entered a horizontal air heater. Over time, the deposition in the corner would grow, especially under lower load plant operation when flow velocity in the duct was low. The ash pile would thus grow toward the air heater, eventually causing a significant pluggage issue due to blinding of the air heater flow passages. Over time, the system pressure drop would increase due to the plugged air heater, and the unit output had to be curtailed since the fans could not accommodate the pressure losses. Gulf Power would clean the air heater and duct each maintenance outage, but then would
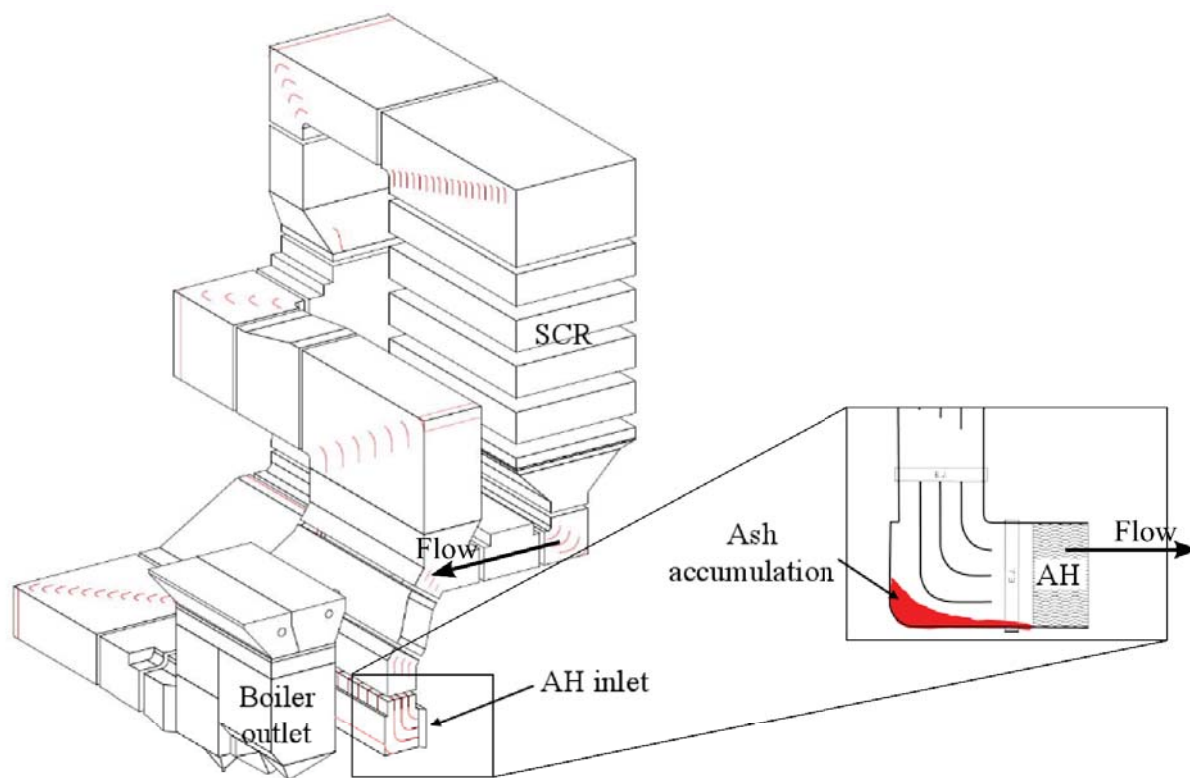

Figure 3: Gulf Power Company's Plant Crist geometry and location of ash accumulation upstream of air heater (AH)
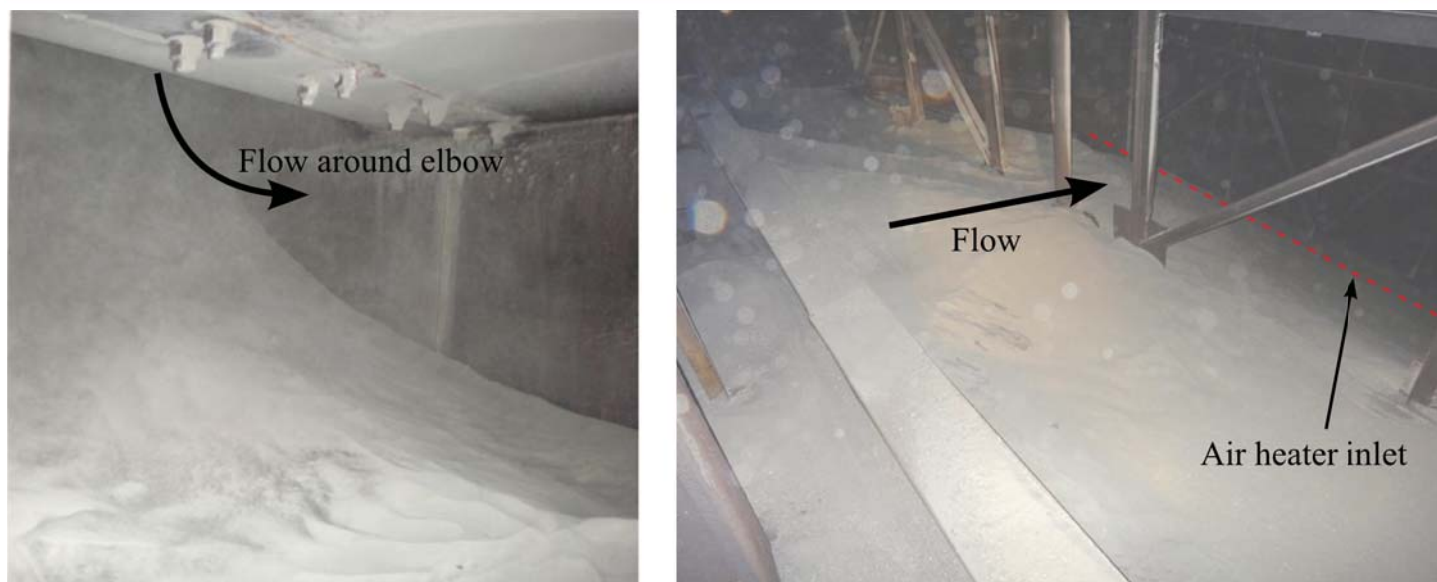
Figure 4: Plant Crist photos indicate that ash buildup in the ductwork upstream of the air heater was causing a significant pluggage issue

observe the air heater pressure drop gradually increase over time. Eventually unit load had to be derated until the next available outage for cleaning.

ASC started working with personnel from Gulf Power and its parent Southern Company to solve this flow problem and develop low-cost design recommendations that could be implemented during an upcoming outage. ASC conducted CFD flow simulations of the upstream ductwork, identifying low velocity regions and flow recirculation zones. The modeling simulated several unit operating conditions, with a focus on low load for ash accumulation and full load for pressure drop and velocity patterns at the air heater. The model was used

to investigate a variety of modifications including alterations to the existing turning vanes and localized changes in cross sectional area. Several potential design modifications were identified to increase the gas velocity along the duct floor where the most significant ash build-up was observed. CFD results from the baseline and recommended design solution are shown for low load (Figure 5) and high load (Figure 6) operations.

To verify the CFD solution to the air heater pluggage issue at Plant Crist, a physical model representing the Unit 6 ductwork from the SCR outlet to the air heater inlet was constructed. Because of the sticky nature of the flyash and
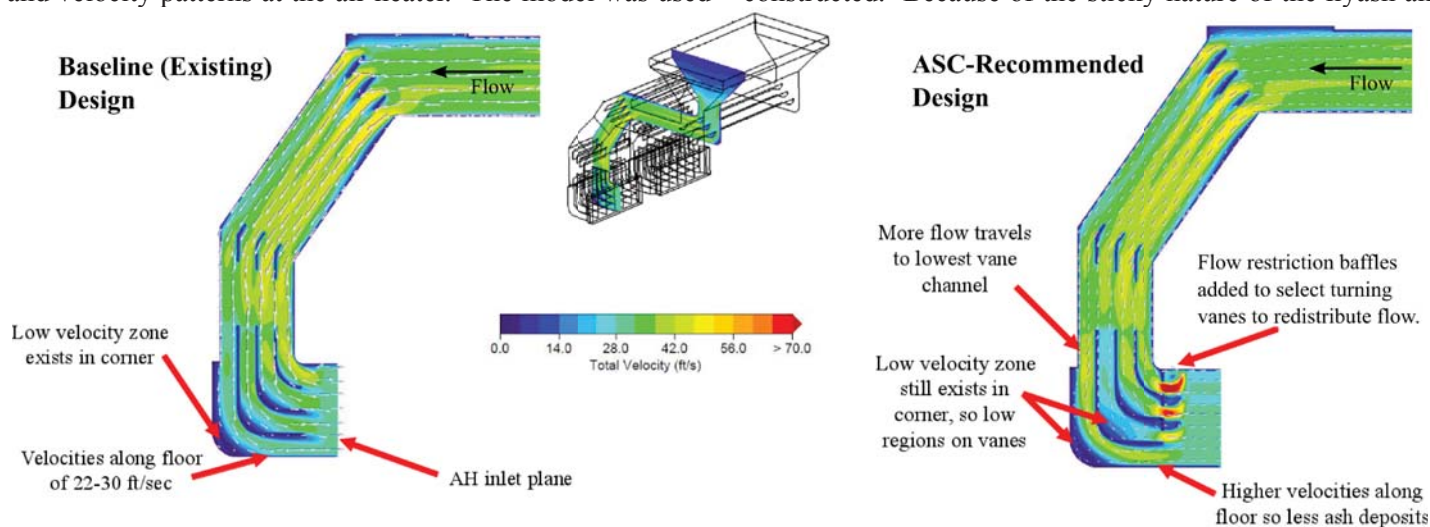

Figure 5: CFD results at low unit load from the SCR to air heater (baseline – left, recommended design – right). Results show an increase in velocity along the floor, resulting in a reduction in ash drop out during low load operation
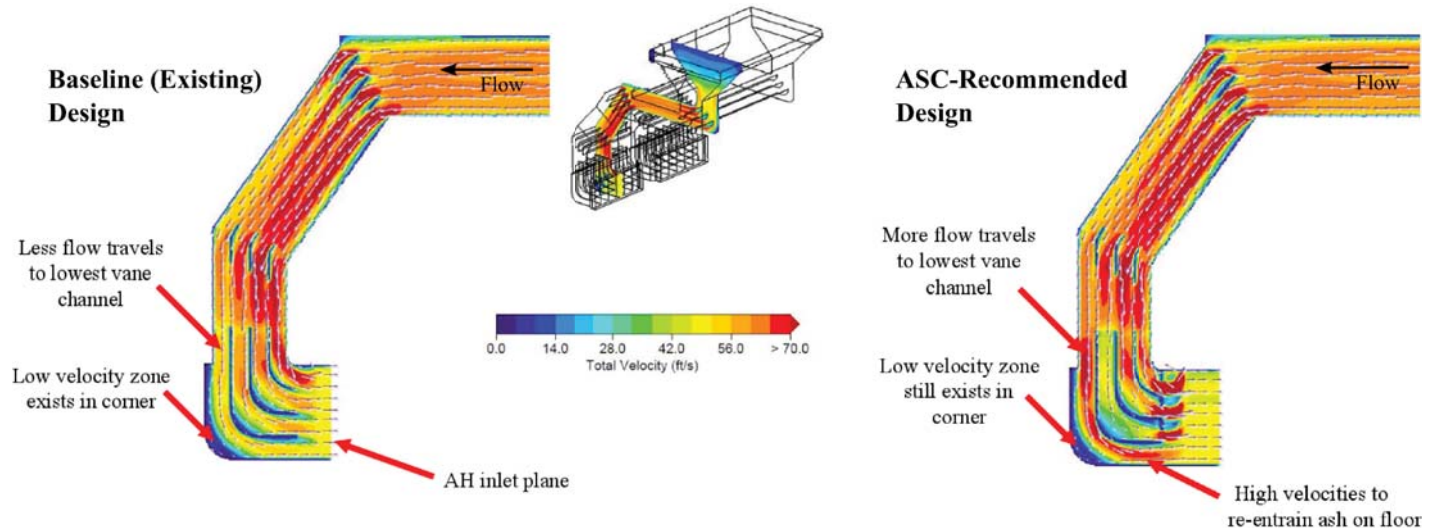
Figure 6: CFD results at full unit load from the SCR to air heater show the deficit in flow near the floor for the baseline design (left). When the design recommendations were incorporated (right), velocities in the lower vane channel were increased, resulting in improved re-entrainment of any flyash deposits on the floor during high load operation

the unique, time-dependent behavior of the flyash deposition, it was decided to do more than just the "standard" cold flow physical modeling. So a "Hot Flow" physical model was devised, and ASC's Hot Wind Tunnel was converted to match the complex geometry of the actual plant ductwork. This includes the duct routing, the internal turning vanes, and the air heater. In order to fit within the dimensions of the existing Hot Wind Tunnel components, the model was built at 1/30 scale, using stainless steel ductwork with clear windows for viewing (Figure 7). Instead of using a simulated laboratory dust, actual flyash from Plant Crist was used.

With the Hot Flow physical model, dust tests were conducted for both the baseline and CFD-recommended design configurations. Baseline test results indicated patterns of accumulation similar to plant observations (Figure 8 on page 22). When the CFD design recommendations were implemented, there was a significant reduction in the amount of ash accumulation on the duct floor at low load, as anticipated. At full load, the quantity of ash remaining on the duct floor and turning vanes was significantly reduced (Figure 9 on page 22).

Based on ASC's recommendations and the strong correlation between the CFD model and the Hot Flow physical model, Gulf Power incorporated the design modifications to Unit 6 during the outage. Over subsequent periods of operation, it was observed that the air heater pressure drop increased only slightly over time. This was considered to be due to normal fouling, and no significant pluggage occurred. During a later plant inspection during an outage, it was reported that dust accumulation in the ductwork was minimal, matching the Hot Flow physical model results. Overall, Plant Crist personnel are very pleased with the outcome of the modeling study, and air heater pluggage is no longer an issue.

Figure 7: Physical model with clear windows for viewing ash flow during Hot Wind Tunnel operation

*For further information contact
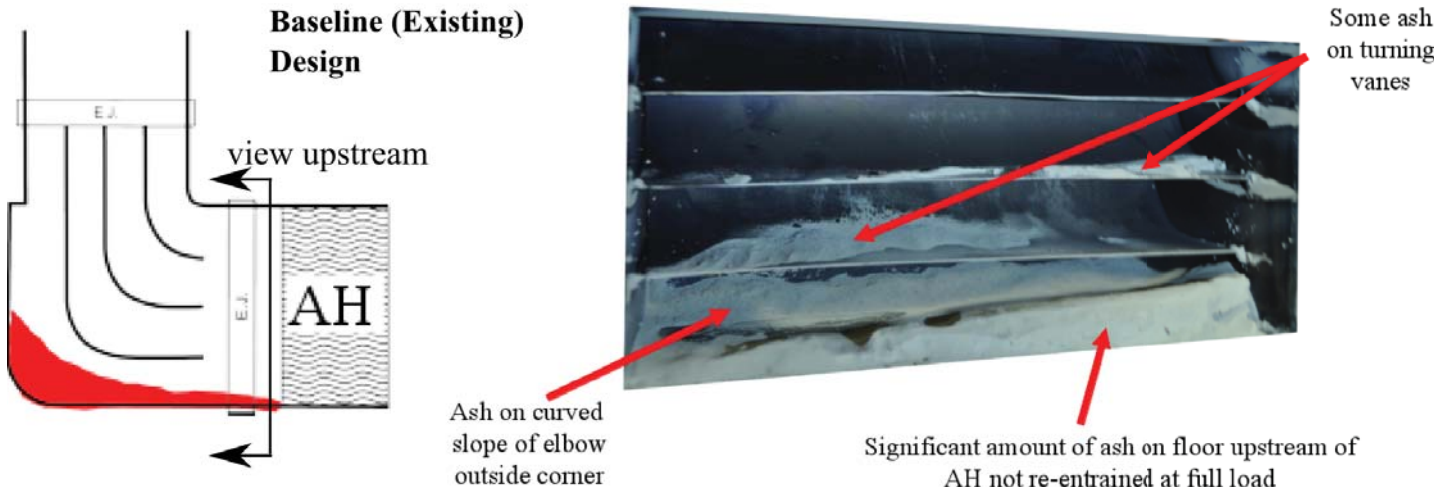Robert Mudry at rmudry@airflowsciences.com*

Baseline (Existing) Design

view upstream

E.J.

E.J.

AH

Ash on curved slope of elbow outside corner

Some ash on turning vanes

Significant amount of ash on floor upstream of AH not re-entrained at full load

Figure 8: Baseline physical model results showed similar dust accumulation to what was identified at the plant.

ASC-Recommended Design

Restrictor baffles (3) in upper turning vane channels

Some ash still on turning vanes

Flow Direction

Quantity of ash remaining on floor greatly reduced, though not eliminated

Air Heater (2 perforated plates)

Some ash still on turning vanes

Restrictor baffles (3) in upper turning vane channels

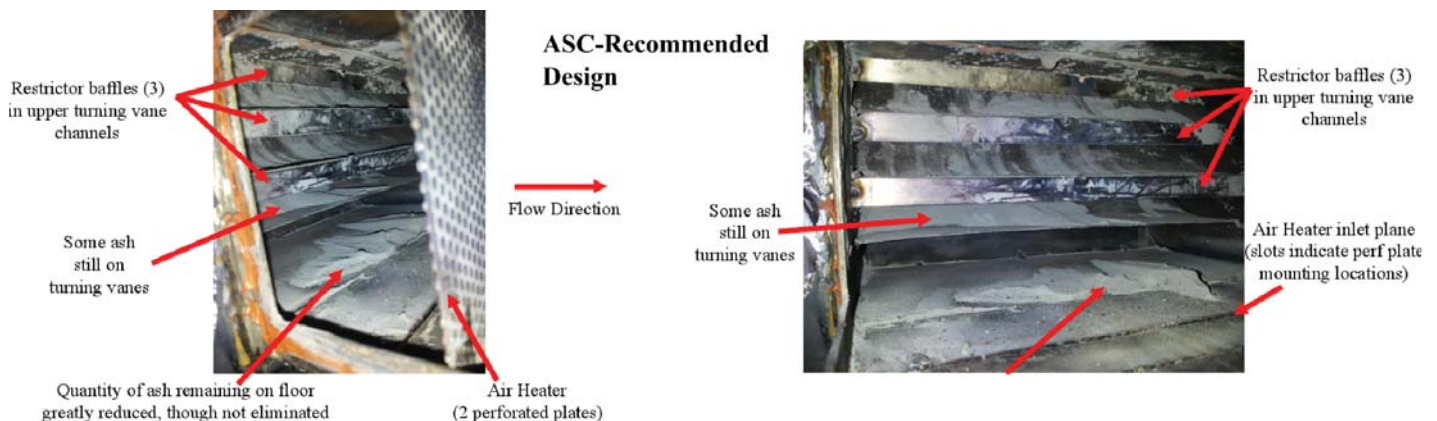Air Heater inlet plane (slots indicate perf plate mounting locations)

Figure 9: Ash accumulation can be viewed during operation (left) of the physical model. With the recommended flow control devices, ash accumulation (right) was reduced

Jeffrey Everett
Mr. Everett is a project engineer at Airflow Sciences Corporation and has worked on numerous flow model studies for the power industry over the past 6 years. He received his Bachelor's degree in Aerospace Engineering and Masters degree in Mechanical Engineering from the University of Michigan

Robert Mudry
Mr. Mudry is President of Airflow Sciences Corporation has been a consulting engineer in the areas of fluid dynamics, heat transfer, and combustion for 25 years. He obtained both a Bachelors and a Masters in Aerospace Engineering from the University of Michigan and is a registered Professional Engineer in four states.

Lauren Porter
Mr. Porter is a process engineer at Alabama Power and graduated from the University of Kentucky.
Darryl Wall
Mr. Wall is the process engineering manager at Southern Company and a graduate of Auburn University.

Airflow Sciences Corporation

WPCA Corporate Sponsors

WPCA Chairman
Robert Hilton,
VP Power Tech for Gov. Affairs
Alstom
1409 Centerpoint Blvd., Knoxville, TN 37932
Email: robert.g.hilton@power.alstom.com

WPCA Secretary
Jason Horn, Dir. of Env. Controls
Stock Equipment Company
16490 Chillicothe Rd, Chagrin Falls, OH 44023
Email: jason.horn@stockequipment.com

WPCA Treasurer
Robert Mudry, President
Airflow Sciences Corporation
12190 Hubbard Street, Livonia, MI 48150 USA
Email: rmudry@airflowsciences.com

WPCA Vice President
Nate White, Dir. Business Development
Haldor Topsoe, Inc.
5510 Morris Hunt Dr., Fort Mill, SC 29708 USA
Email: tnw@topsoe.com

David Novogoratz, Business Dev. Mgr.
Babcock & Wilcox
20 S. Van Buren Ave., Barberton, OH 44203 USA
Email: dmnovogoratz@babcock.com

Chetan Chothani, COO
Breen Energy Solutions
104 Broadway Street, Carnegie, PA 15106 USA
Email: cchothani@breenes.com

Todd Clark, Business Dev. Mgr.
Babcock Power Inc.
5 Neponset Street, Worcester, MA 01606 USA
Email: tlicata@babcockpower.com

Allen Kephart, President
CleanAir Engineering
110 Technology Dr., Pittsburgh, PA 15275
Email: akephart@cleanair.com

Mark Ehrnschwender, VP Bus. Dev&Engr
Steag Energy Services LLC
304 Linwood Rd, Ste.102, Kings Mountain, NC
28086 USA
Email: mark.ehrnschwender@steag.us

Jean Bustard, COO
ADA-ES
9135 S. Ridgeline Blvd., Ste. 200,
Highlands Ranch, CO 80129
Email: jeanb@adaes.com

Tim Stark, Director
CLARCOR Industril Air
11501 Outlook St., Ste. 100,
Overland Park, KS 66211 USA
Email: timothy.stark@clarcor.com

Cindy Khalaf, Vice President
Johnson Matthey Catalysts LLC
1121 Alderman Dr. Ste 204, Alpharetta, GA 30005
Email: cindy.khalaf@jmusa.com

Richard Staehle, CEO
KC Cottrell, Inc.
8 Bartles Corner Rd., Ste 204,
Flemington, NJ 08822 USA
Email: rstaehle@kccottrell.us

Jerry VanDerWerff, Nat. Sales Manager
Sorb-N-Ject; Nol-Tec Systems, Inc.
425 Apollo Dr., Lino Lakes, MN 55014 USA
Email: JerryVanDerWerff@nol-tec.com

Ken Fairleigh, President & CEO
Paragon Airheater Technologies
23143 Temescal Canyon Rd., Ste. B,
Corona, CA 92083 USA
Email: kfairleigh@paragonairheater.com

Susan Reinhold, CEO
Reinhold Environmental Ltd.
3850 Bordeaux Drive, Northbrook, IL 60062 USA
Email: sreinhold@reinholdenvironmental.com

Michael Hatsfelt, General Manager
Southern Environmental, Inc.
6690 West Nine Mile Rd., Pensacola, FL 32526
Email: mhatsfelt@sei-group.com

Gordon Maller, Bus. Development Mgr.
URS Corporation
9400 Amberglen Blvd., Austin, TX 78729 USA
Email: gordon.maller@urs.com

Tom Lugar, VP Product Development
MET
200 North 7th St., Lebanon, PA 17046 USA
Email: tlugar@met.net

Michael Atwell, Market Dev. Mgr.
SOLVAir Sol. Solvay Chemicals
3333 Richmond, Houston, TX 77098 USA
Email: michael.atwell@solvay.com

Jamie Fessenden, Bus. Mgr. Emission
Control Tech \ Cabot Norit Americas
3200 University Ave., Marshall, TX 75670 USA
Email: jfessenden@cabotcorp.com

Curt Biehn, Mgr., Mkt & Tech Services
Mississippi Lime
3870 S. Lindbergh Blvd., St. Louis, MO 63127
Email: crbiehn@mississippilime.com

Paul Ford, President
Redkoh Industries
300 Valley Road, Hillsborough, NJ 08844 USA
Email: paul.ford@redkoh.com

WPCA Officers

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