WPCA NEWS

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Executive Summary

Circulating Dry Scrubber for Mercury Control in PRB Coal-Fired Power Plants

By Terence Ake and Roderick Beittel, Babcock Power Environmental, Inc.

This paper presents results from two recently commissioned Babcock Power Environmental, Inc. (BPE) Circulating Dry Scrubbers (CDS) installed on Powder River Basin coal-fired boilers to control emissions to levels required by the U.S. EPA Mercury and Air Toxic Standards (MATS).

Full Story….

The Care and Feeding of Your Hydrated Lime Conveying System / Part I: Controlling Flow from the Storage Silo

By Randy Griffard, Mississippi Lime R&D Department

Dry Sorbent Injection (DSI) systems need to run reliably in order for end users to maximize their value from use of the sorbent. For DSI systems feeding hydrated lime, efficiency begins by controlling flow from the hydrate storage silo into the rotary feeder leading into the conveying air. This paper shares Mississippi Lime's experiences with manufacturing and conveying hydrate and from working with the Air Pollution Control industry to resolve challenging areas of DSI systems.

Full Story….

Air Preheater Performance Enhancement to Increase Efficiency

By Sterling Gray and Blake Stapper, AECOM Process Technologies; Jonas Klingspor, LJUNGSTRÖM

This article describes how AECOM and ARVOS are working together to apply SO_3 control in combination with an air preheater upgrade to recover additional heat from the flue gas. It presents the resulting efficiency improvement that was achieved on a 500 MW coal-fired unit, along with the ancillary benefits for the operation of the existing emission control equipment.

Full Story….

Overview of Mercury Control Approaches Used by U.S. Plants

By Sharon Sjostrom and Connie Senior, ADA-ES, Inc.

In this article a summary of the analysis for bituminous-fired plants will be provided. This information provides insights into which technologies are being relied upon, and the efficacy of different control strategies as a function of both Hg control strategy and type of coal being combusted.

Full Story….

The Hidden Liability of the Transformer/Rectifier

By Dan Holt, KraftPowercon, Inc.

Transformer/Rectifiers (T/R) have earned a reputation as a long performing, reliable precipitator power supply. Eventually the transformer coils age and extensive repairs become necessary. Many T/Rs are rebuilt. However, replacement may offer cost savings and process improvements opportunities over rebuilding.

Full Story….

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Circulating Dry Scrubber for Mercury Control in PRB Coal-Fired Power Plants

Written by Terence Ake and Roderick Beittel, Babcock Power Environmental, Inc.

ABSTRACT

This paper presents results from two recently commissioned Babcock Power Environmental, Inc. (BPE) Circulating Dry Scrubbers (CDS) installed on Powder River Basin coal-fired boilers to control emissions to levels required by the U.S. EPA Mercury and Air Toxic Standards (MATS).

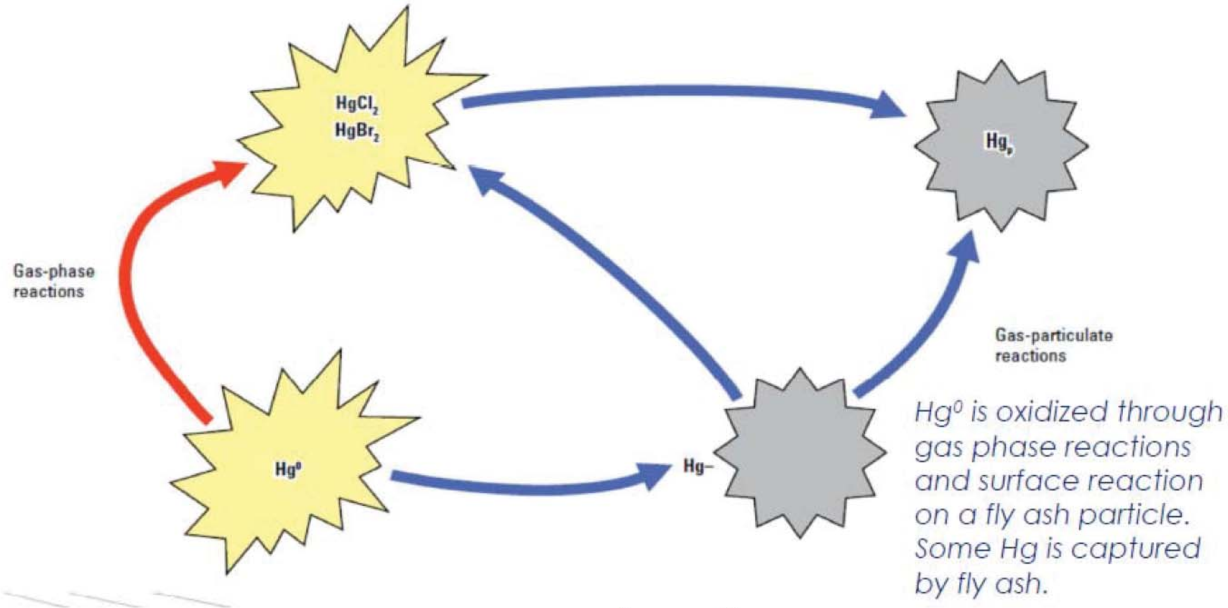
INTRODUCTION

The U.S. EPA Mercury and Air Toxics Standard (MATS) requires coal-fired boilers to emit mercury at less than 1.2 lb/TBtu (1.5 ug/Nm^3 at 6% O$_2$). Figure 1 shows the mechanism for capturing mercury in a coal-fired boiler. Elemental mercury is oxidized through gas phase reactions with halogens (Cl, Br) that originate in the coal or from coal additives, and are captured by surface reactions on the fly ash.

Sub-bituminous Power River Basin (PRB) coal has low concentrations of halogens and burns with less unburned carbon in the fly ash than bituminous coal. Therefore, it is more challenging to remove mercury in PRB than in bituminous coal-fired power plants. To enhance removal of Hg in a PRB coal fired power plant, a mercury removal reagent such as a halogen solution is added to the coal and/or Powdered Activated Carbon (PAC) is injected into the flue gas to capture mercury in particulate removal devices such as an electrostatic precipitator or fabric filter [2]. A Selective Catalytic Reduction (SCR) system for NOx emission control also enhances the mercury removal efficiency by oxidizing elemental mercury.

CIRCULATING DRY SCRUBBERS OVERVIEW

There are three main absorber technologies for flue gas acid gas control; 1.CDS; 2.Spray Dryer Absorber (SDA) and 3.Wet Flue Glue Desulfurization (WFGD) scrubber.



Hg^0 is oxidized through gas phase reactions and surface reaction on a fly ash particle. Some Hg is captured by fly ash.

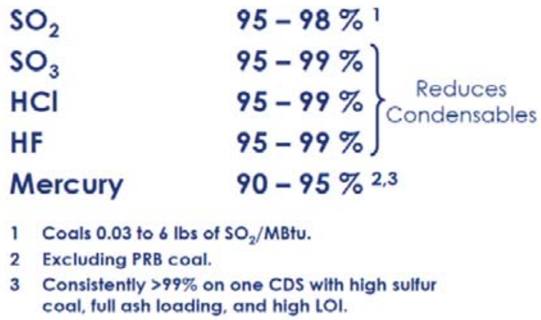
Figure 1: Mercury oxidation (Hg0 -> Hg+2) and particle capture [1].

Figure 2 shows a CDS for SO_2 and acid gas control. A CDS works by circulating dry solids consisting of hydrated lime, reaction products, and fly ash through a reactor, fabric filter and air slides that control the circulation rate. It is akin to a SDA because it operates at a similar temperature and uses hydrated lime as an absorbent; however, a CDS can achieve a higher level of acid gas removal than a SDA.

The CDS injects dry hydrated lime and water separately rather than a lime slurry used in a SDA. Therefore, all solids are dry in a CDS and water is injected through high pressure lances rather than lime slurry atomizers. For both systems, a dry reaction byproduct is removed from the system to maintain solids inventory. The CDS differs from a WFGD scrubber that saturates the flue gas with water and lime or limestone slurry to remove SO_2 and includes dewatering equipment to produce a dry byproduct. A SDA or CDS byproduct is not as marketable as a gypsum byproduct that can be produced from a WFGD, but the dry scrubber byproduct is a stable mine or landfill material.

The CDS completely vaporizes the injected water and a dry flue gas exits the stack while the fabric filter controls particulate emissions. Therefore, there are no wet or secondary plumes, less makeup water, and no wastewater as with a WFGD.

Figure 3 summarizes typical SO_2 and acid gas removals with a CDS. The CDS removes 95 to 99% of HCl and SO_3 compared to a WFGD that removes > 98% HCl and about 50% of the SO_3. In bituminous coal-fired power plants, > 90% of mercury is removed with help from halogens in the coal that oxide the mercury and unburned carbon in the fly ash for easy capture on the CDS fabric filter bags.



SO_2	95 – 98 % [1]	
SO_3	95 – 99 %	Reduces Condensables
HCl	95 – 99 %	
HF	95 – 99 %	
Mercury	90 – 95 % [2,3]	

1 Coals 0.03 to 6 lbs of SO_2/MBtu.
2 Excluding PRB coal.
3 Consistently >99% on one CDS with high sulfur coal, full ash loading, and high LOI.

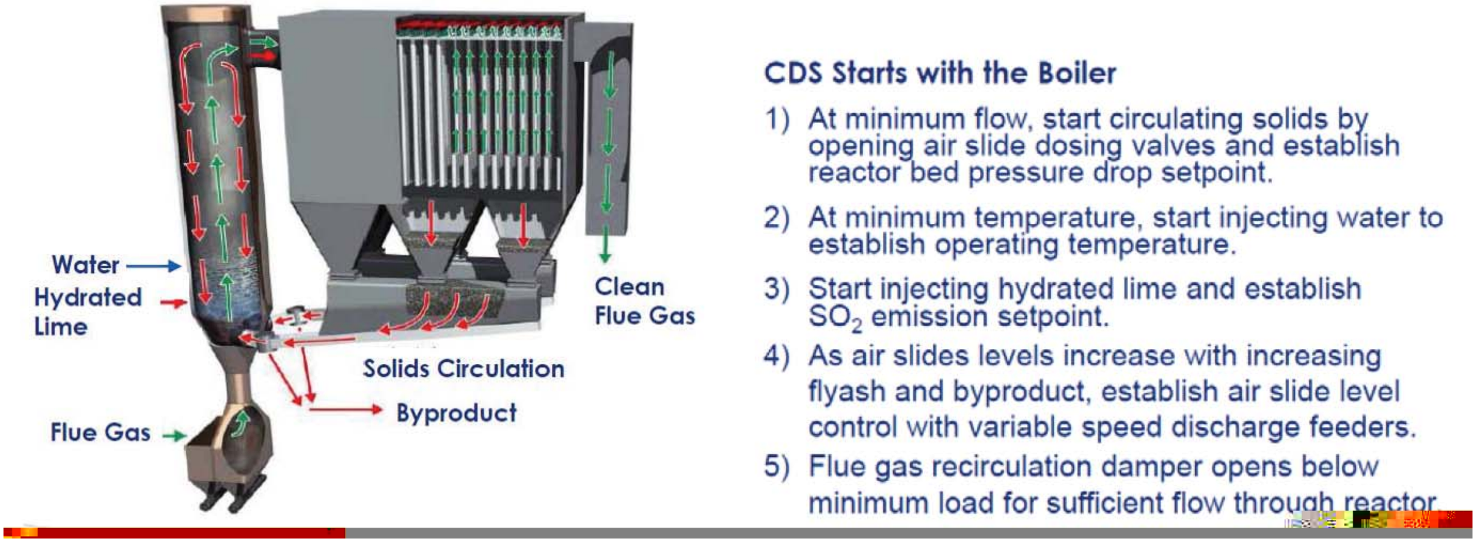
Figure 3: Typical CDS removals without additives or PAC

BITUMINOUS COAL EXPERIENCE

BPE has installed CDS systems at four bituminous coal fired utilities ranging from 90 to 240 MWg from 2006 to 2010 for SO_2 and acid gas control. The bituminous coal utilities included PAC or provisions for PAC for Hg control, but PAC was either added at low rates or not at all. The Hg removal obtained was adequate to achieve emission requirements with the CDS alone.

The SCRs in the bituminous and the PRB coal applications discussed next did not include a mercury oxidizing catalyst that can be used to enhance mercury removal.

A mercury oxidizing catalyst in an SCR is likely to convert more SO_2 to SO_3 than standard NOx removal catalyst. Therefore, a CDS and an SCR with mercury oxidizing catalyst is a good AQCS complement because the CDS removes almost all of the SO_3.



CDS Starts with the Boiler

1) At minimum flow, start circulating solids by opening air slide dosing valves and establish reactor bed pressure drop setpoint.
2) At minimum temperature, start injecting water to establish operating temperature.
3) Start injecting hydrated lime and establish SO_2 emission setpoint.
4) As air slides levels increase with increasing flyash and byproduct, establish air slide level control with variable speed discharge feeders.
5) Flue gas recirculation damper opens below minimum load for sufficient flow through reactor

Figure 2: Circulating Dry Scrubber and startup procedure

POWDER RIVER BASIN COAL EXPERIENCE

If there is no mercury removal reagent, a SDA in a PRB coal-fired power plant removes only about 25% of the Hg compared to 95% Hg removal for bituminous coal. The low Hg removal is due to the SDA reactor removing the little chlorine available from the coal that would oxidize mercury before it reaches the fabric filter. In fact, a fabric filter alone without a SDA reactor can remove 75% of the Hg in a PRB coal-fired power plant. [3]

In 2016, BPE commissioned and installed a CDS for a 240 MWg 100% PRB coal fired utility boiler that required stack Hg emissions below MATS. BPE also supplied a SCR for NOx control. The SCR/CDS were arranged in two parallel flue gas trains before and after the boiler air heaters. BPE supplied a PAC injection system, and there were plans to use halogenated PAC for Hg removal which would provide a greater oxidation of mercury than a non-halogenated PAC. However, the client did not want to use halogenated PAC due to an equipment corrosion concern. Therefore, Hg removal performance tests were completed with non-halogenated PAC.

Also in 2016, BPE supplied a CDS to a 495 MWg utility boiler firing a PRB/IL coal blend. The CDS included two reactors on two fabric filters. The utility had an existing SCR by another supplier. While an SCR is generally a help to control Hg from enhanced Hg oxidation over the catalyst, the SCR can also hinder Hg control if there is excess SO_3 and NH_3 slip from the SCR interfering with Hg capture. The 495 MWg utility planned for PAC injection, but also had a provision to add a halogen solution to the coal belt for enhanced mercury control.

PROBLEM STATEMENTS

The following mercury control problem statements were developed during commissioning and performance tests for the PRB coal fired CDS systems supplied by BPE in 2016.

To maintain stack Hg emissions below U.S. EPA MATS:

- Was a non-halogenated PAC sufficient for the 100% PRB coal fired in the 240 MWg utility boiler or was halogenated PAC required?
- Was a halogenated fuel additive sufficient for the PRB/IL coal blend fired in the 495 MWg utility boiler or was PAC injection required?

RESULTS

Non-halogenated PAC for a 240 MWg Utility Firing 100% PRB Coal

Figure 4 shows stack Hg emissions measured by EPA method 30B (sorbent trap) versus the concentration of PAC injected upstream of the CDS at the 240 MWg 100% PRB coal-fired utility boiler. The data is plotted in terms of a per-

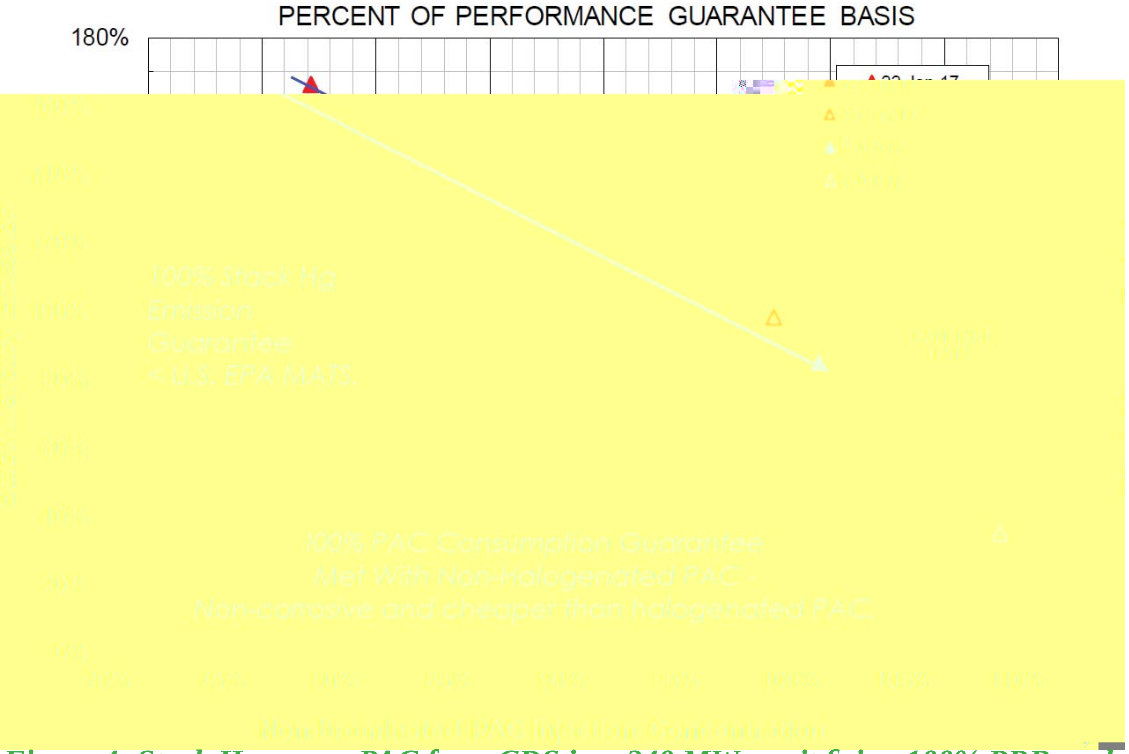


Figure 4: Stack Hg versus PAC for a CDS in a 240 MWg unit firing 100% PRB coal.

cent guarantee for stack Hg emission that is less than MATS versus the percent of the guarantee PAC injection concentration. As shown in the figure, when PAC was injected at 77% of its guarantee concentration, the stack Hg emission was above guarantee, but when PAC was increased to 100%, the stack Hg emission guarantee was met. The plot includes subsequent transient tests when the unit was ramped from 150 MWg to full load with PAC injection in AUTO to maintain 100% concentration showing stack emissions was maintained at or below the guarantee emission.

Figure 5 shows the unburned carbon as a percentage of the 240 MWg unit's design unburned carbon based on fly ash samples taken during the SCR and CDS performance tests. As shown, the measured unburned carbon was well below the expected unburned carbon for the unit's design. Therefore, the Hg removal was especially challenging due to the low unburned carbon.

The figure includes PAC injection and stack emissions guarantee percentages during the CDS performance test. At the beginning of the CDS performance test, the stack Hg emission was at guarantee with PAC injection 77% of its guarantee. The next day, the boiler O_2 control was changed that significantly decreased the unit's unburned carbon. The effect was a large increase in stack Hg emissions while PAC injection was constant. As shown, when PAC injection was increased to its guarantee value and unburned carbon was at a higher value (but still well below the unit's design unburned carbon), the stack Hg decreased to its guarantee. Therefore, we confirmed that there is strong effect of unburned carbon on meeting stack Hg emissions and the required PAC concentration, as we had found elsewhere.

Figure 6 (on next page) shows CDS trends of load, temperature, and PAC injection during transient load tests when PAC control was first put into automatic showing good PAC injection concentration control over unit load ramps. PAC injection was subsequently optimized for continuous stack mercury emission lower than required by MATS. Given optimized PAC injection for the unit, we believe that EPA MATS Hg emissions can be maintained with PAC injection for PRB units with low unburned carbon.

Halogen Additive for a 495 MWg Utility Firing a PRB/IL Coal Blend

Figure 7 (on next page) lists measured CDS inlet and stack Hg in the flue gas for the large utility PRB/IL coal blend application by EPA method 30B paired with speciation to measure the elemental and oxidized Hg removals. The results were without halogen solution coal additive or PAC injection. These results show significant removal of both elemental and oxidized mercury across the CDS without additives. The coal to stack removal was 85% for the 7 lb Hg/TBtu in the PRB/IL coal blend.

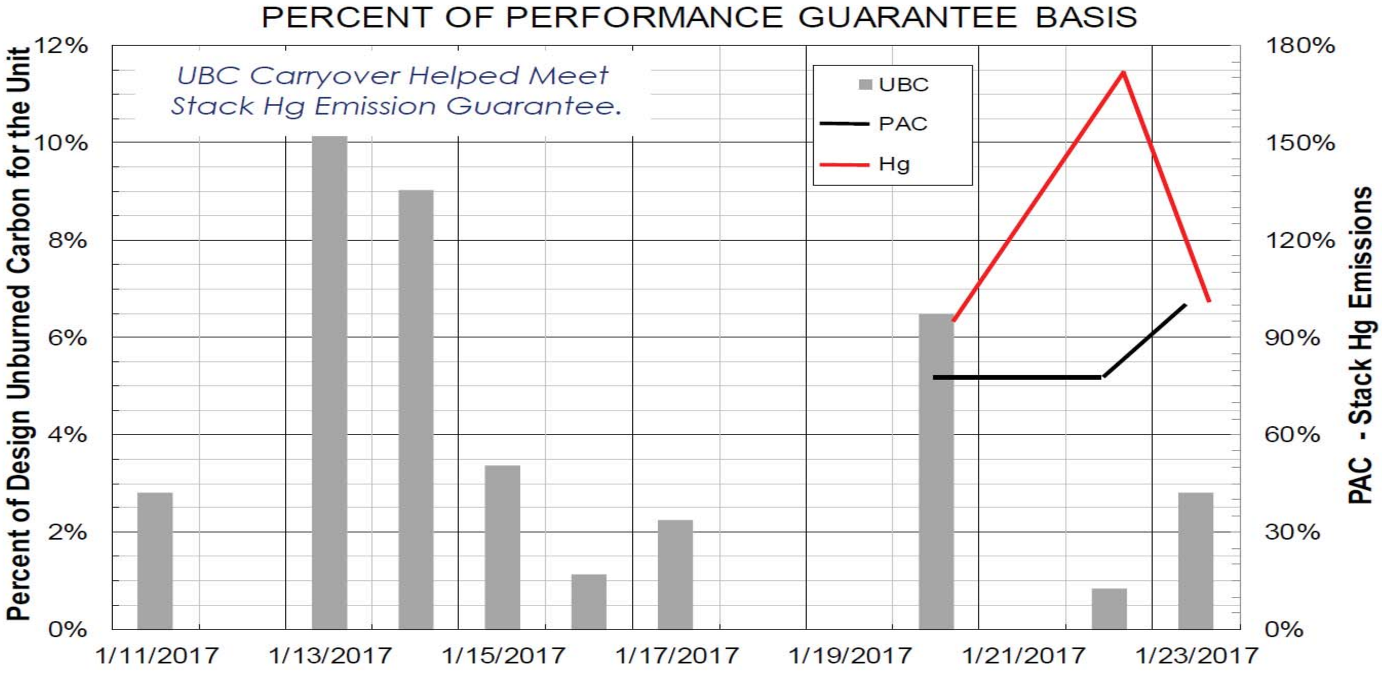


Figure 5: Fly Ash unburned carbon, PAC concentration, and stack Hg.

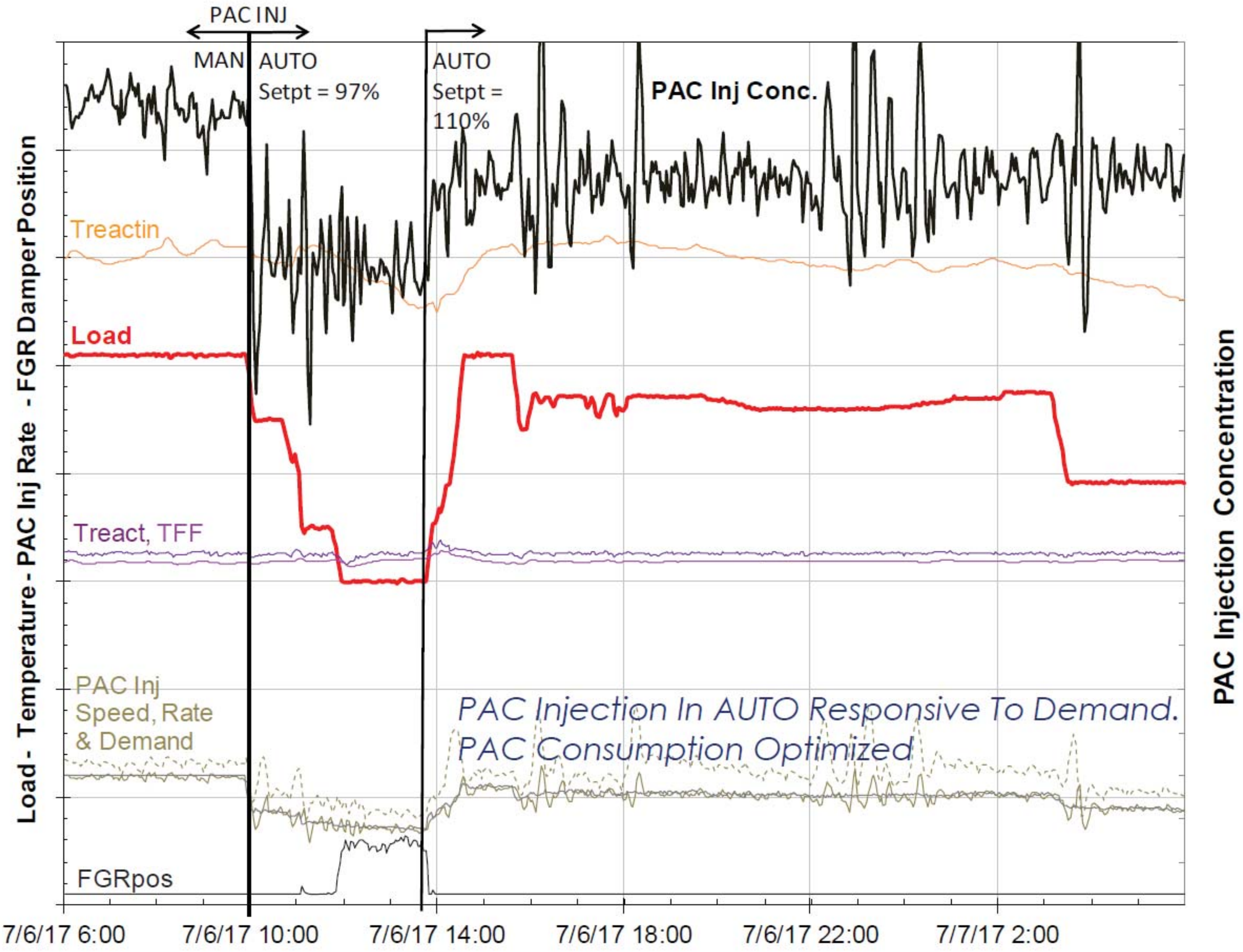
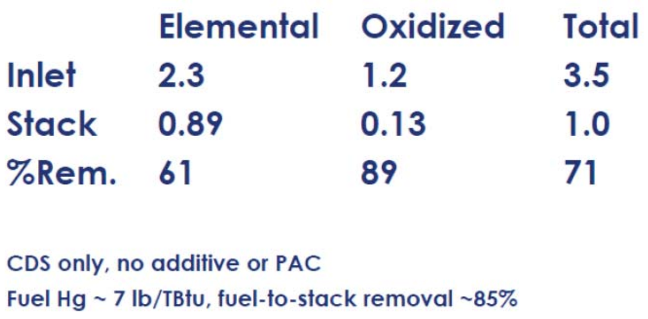


Figure 6: Load, Temperature, and PAC injection trends



	Elemental	Oxidized	Total
Inlet	2.3	1.2	3.5
Stack	0.89	0.13	1.0
%Rem.	61	89	71

CDS only, no additive or PAC
Fuel Hg ~ 7 lb/TBtu, fuel-to-stack removal ~85%

Figure 7: Hg test measurements without fuel additive.

Further sorbent trap tests over several months without fuel additive showed the CDS inlet Hg ranging from 3.2 to 7.2 lb/TBtu at 75 to 100% unit load. The corresponding stack Hg from the Continuous Emission Monitor System (CEMS) was typically about 1 lb/TBtu, with three values from 1.6 to 2.2 lb/TBtu. There was no clear correspondence of stack Hg emissions to inlet Hg or load. However, there was inadequate information about boiler or SCR operation or unburned carbon in the fly ash at the time precluding any analysis of how it could affect the Hg capture. During these months, the CDS inlet to stack Hg removal ranged from 59 to 84% with an average of 72%.

Figure 8 (on next page) shows the effect on stack Hg CEMS when a halogen based fuel additive was applied to the coal. Before the additive, the stack Hg was 2.1 lb/TBtu for a 5.3 lb/TBtu Hg concentration at the CDS inlet and 7.4 lb/TBtu from the coal. After the additive flow was established, the stack Hg decreased to 0.25 lb/TBtu resulting in over 95% Hg removal (as compared to the Hg in the coal). The stack Hg CEMS showed that before additive, all the Hg emission was elemental that could not be captured. When the additive started, the elemental Hg dramatically decreased while the oxidized increased showing conversion of mercury to

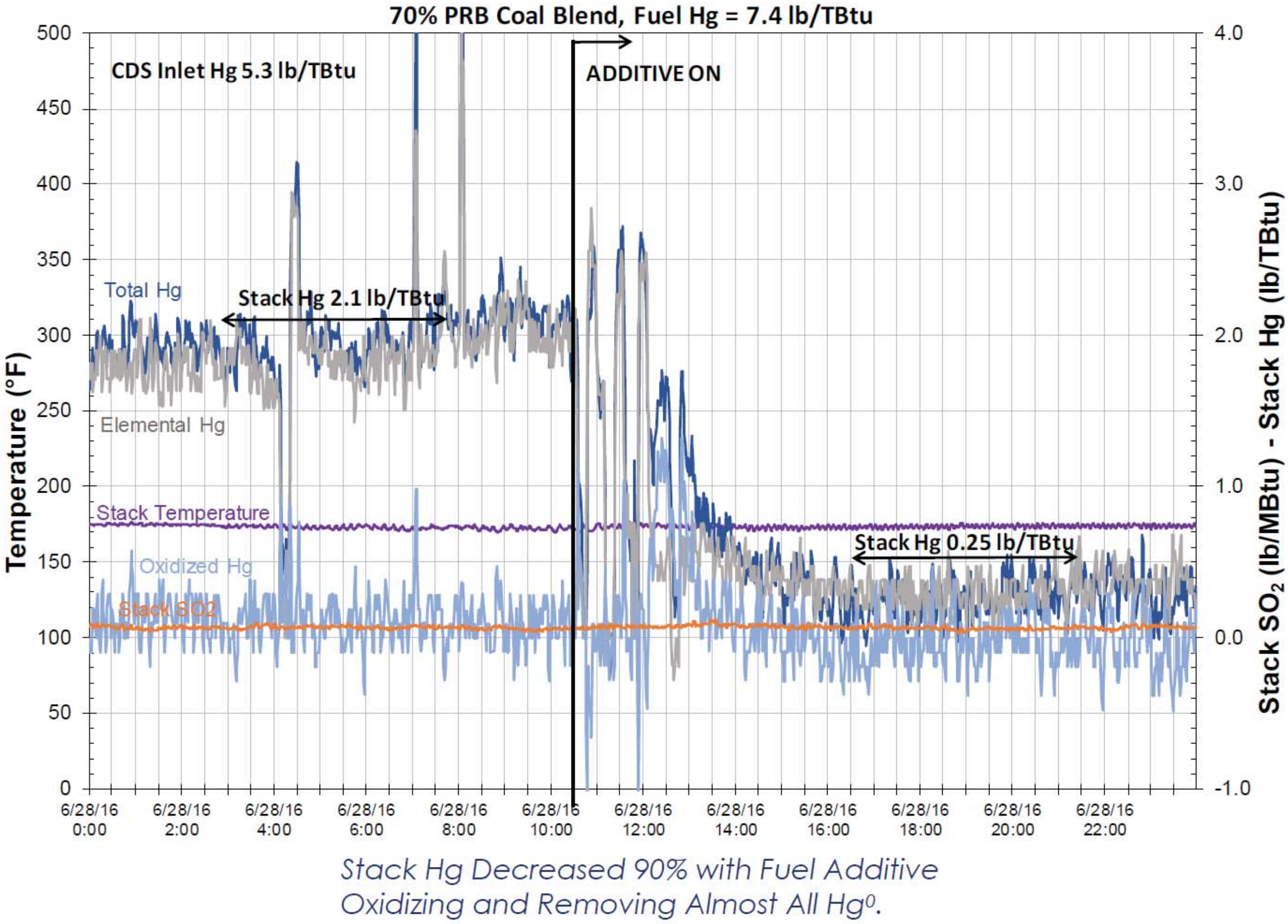


Figure 8: Stack Hg change with fuel additive

its oxidized form. The oxidized mercury was subsequently captured and the total mercury reduced to less than MATS levels. These results show the strong effect of the additive (as well as good information from a mercury continuous emissions monitor capable of showing both elemental and oxides forms).

CONCLUSIONS

Stack mercury emissions were controlled at less than 1.2 lb/TBtu required by US EPA MATS at two PRB coal-fired utility boilers with BPE Circulating Dry Scrubbers using:

- Non halogenated PAC injection at a 240 MWg 100% PRB coal fired boiler,
- Halogenated fuel additive at a 495 MWg PRB/IL coal fired boiler.

Typical Hg removals without fuel additive or PAC were:

- ~ 85% Coal to stack,
- ~ 70% CDS inlet to stack.

Typical Hg removals with fuel additive or PAC were:

- ~ 95% Coal to stack,
- ~ 90% CDS inlet to stack.

PROBLEM RESOLUTIONS

To maintain stack Hg emissions below US EPA MATS:

- A non-halogenated PAC was sufficient for a 240 MWg boiler firing 100% PRB coal at lower than design unburned carbon in the fly ash (halogenated PAC was not required).
- A halogenated fuel additive was sufficient for a PRB/IL coal blend fired in a 495 MWg utility boiler (PAC injection was not required).

While resolved for these units, the resolutions may not be true for every PRB coal-fired unit.

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[1]Mercury and Halogens in Coal – Their Role in Determining Mercury Emissions from Coal Combustion USGS Fact Sheet 2012-3122 November 2012.

[2]Reisch, M. Bromine Comes to the Rescue for Mercury Power Plant Emissions Chemical & Engineering News Vol 93. Issue 11 March 15, 2015.

[3]Control of Mercury Emissions from Coal Fired Electric Utility Boilers: An Update U.S. EPA, Research Triangle Park, NC February 18, 2005.

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BIOGRAPHY

Terence Ake is a principal engineer at Babcock Power, Inc. He has 33 years of experience in clean power including burners and combustion systems, selective catalytic reduction systems for NOx emission control, and wet and dry scrubbers for sulfur dioxide, acid gas, and particulate control. A large part of his experience includes combustion research and development, flow model studies, and commissioning, optimizing and evaluating performance of clean power installations. Terry has a Bachelor of Science degree in Chemical Engineering from the University of Illinois and a Master of Science Degrees in Chemical Engineering from Iowa State University.

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The Care and Feeding of Your Hydrated Lime Conveying System

Part I: Controlling Flow from the Storage Silo

Written by Randy Griffard, Mississippi Lime R&D Department

Dry Sorbent Injection (DSI) systems are prevalent on Utility and Industrial boilers. These systems feed powdered alkali, typically hydrated lime, into the flue gas to neutralize acid gases such as sulfuric acid/sulfur trioxide, hydrochloric acid, and sulfur dioxide. DSI equipment consists of a silo, rotary feeder(s), convey piping, feed splitters, and injection lances. Blower air is used to convey hydrated lime through the system in a very dilute phase form and usually the air is conditioned to control temperature, moisture content, and/or carbon dioxide content.

A lot is demanded from DSI. End users need the systems to operate effectively to maintain regulatory compliance. As cost pressures continue for coal-fired boilers, there are limited resources for Operations and Maintenance costs, so DSI systems need high operating times. Additionally, the cost benefits from air preheater protection and low load operation demand that hydrate DSI feeds reliably to protect equipment and preserve the savings from things such as lower SCR Minimum Operating Temperature and better heat capture in the air preheater. Simply stated, a DSI system must effectively and consistently control SO_3 levels at these points in order to capture savings. For those reasons, it is important to have reliable hydrated lime feed rates in your DSI system.

While Mississippi Lime does not supply conveying systems for hydrated lime, the company has developed practical material handling expertise through a history of manufacturing various grades of high quality refined hydrate dating back to the early 1920's. (For a historical reference, this pre-dates the introduction of talking movies.) In that over 95 years we have been successfully storing and extracting hydrate from various sized and shaped storage bins and silos. Mississippi Lime feels it is important to support the DSI industry by sharing our experiences and thoughts on best practices. There are several established vendors supplying DSI systems –fellow WPCA members United Conveyor Corporation and Nol-Tec Systems are two examples – and our information in this article is intended to help support and guide vendors and end users with our experiences conveying hydrate.

CONTROLLED MATERIAL FLOW FROM SILO

Those experienced with hydrated lime know the product has two basic flow conditions. In its normal state of storage, the material does not want to flow and can bridge, arch, rathole, or cling to the side wall of the storage container. When aerated the material flows readily.

While there are a multitude of definitions to describe the range of various material flow characteristics, (free flowing, friable, adhesive, cohesive, fibrous, aeratable, hygroscopic, etc.) hydrated lime is best described as having a combination of cohesive and aeratable properties. A cohesive material is defined as a product with a high angle of repose that tends

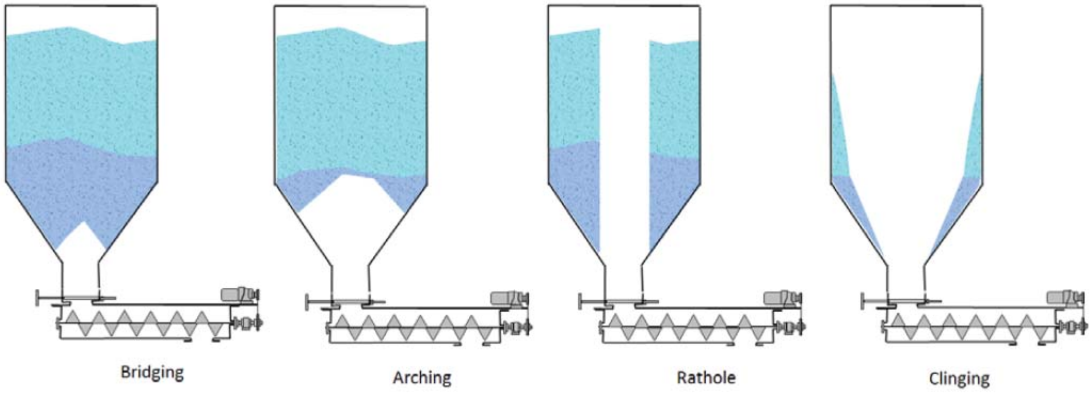

Figure 9: Problematic flow conditions for silos.

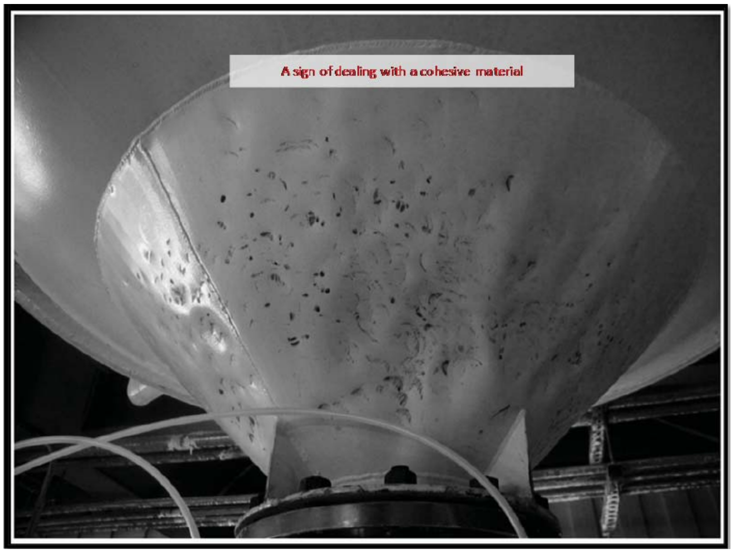

Figure 10: A sign of dealing with a cohesive material

to pack or clump rather than flow easily; typical properties of a very fine powder. However, an aeratable material is one that behaves like a fluid when excess air is trapped in the voids between the individual powder particles (air entrainment). This entrained air can cause the material to flood in an uncontrolled flow from a silo, depending upon the type of discharge device used.

The following are the primary causes of uncontrolled air entrainment (fluidization):

- Failure of an arch or bridge (during the free fall voids between the particles become entrained with air.) It should be noted that an arch or bridge failure could result in damage to a storage silo.
- A rathole caves in when the hopper is partially or completely emptied
- Fresh material is introduced into a hopper with a rathole

When handling a hydrate that has the combined properties of being a cohesive material and an aeratable fine powder, getting the material out of the storage bin or silo through a relatively small opening can create problems. hose problems often mask the hydrate's performance due to the material's tendency to either hang up in the silo or develop uncontrolled flushing, depending directly upon the amount of air entrainment.

We have found the key to controlling hydrated lime's flow properties resulting when the powder is de-aerated is to first apply intermittent high pressure air pulse sweeps to prevent the formation of bridges, arches and ratholes and then inject low-pressure air through properly placed aeration pads to fluidize the hydrate. This type of product conditioning has the added advantage of minimizing variations in the bulk density of the hydrated lime.

A refined hydrate can have a bulk density of 32-35 lbs/ft^3 when de-aerated, yet will become 22-25 lbs/ft^3 when fully aerated. Through proper conditioning, the hydrate discharging the silo will have much less bulk density variability, averaging around 28 -30 lbs/ft3 (depending upon the amount of fluidization air used). As a word of caution, when using this fluidization method to condition the hydrate, a rotary feeder may be required below the transition section under the silo discharge cone. A standard rotary feeder can be used as a

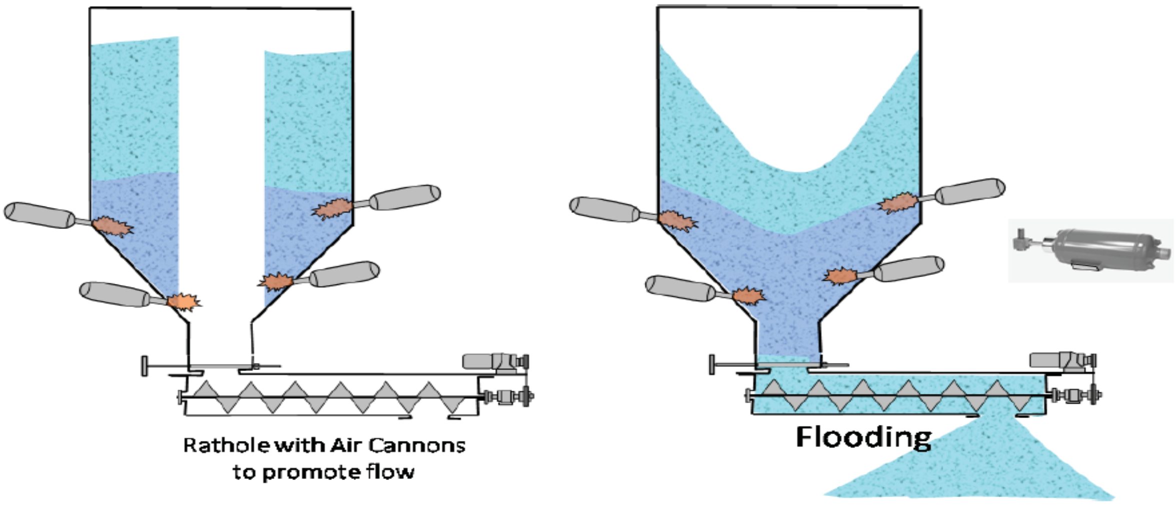

Figure 11: Potential for flooding a screw conveyor.

volumetric pre-feeder ahead of a rotary airlock for pneumatic conveying or ahead of a screw feeder to prevent flooding through the screw discharge. We have found this approach to be a valuable key for solving hydrate flow problems, variation in bulk density issues, and all without compromising the chemical quality of the hydrate, or the material's dispersion and absorption properties.

SUMMARY

Our experience is that the ideal method to maintain a uniform discharge from any bin or silo is to adopt the following material conditioning methods:

1. Fluidize the hydrate using low pressure aeration pads and preconditioned fluidizing air
2. Apply intermittent high pressure pulse sweeps to prevent the formation of bridges, arches, ratholes, etc.
3. Use a rotary discharge valve to control discharge flow rates.

Hopefully this report shows that the two main issues related to handling and pneumatically conveying hydrated lime can be resolved. The first issue is achieving a consistent and uniform flow of material from a storage bin or silo. This is possible by the proper placement and operation of:

1. Air sweeps – to prevent the formation of ratholes and bridging
2. Aeration pads – with controlled aeration of the hydrate, both the flow properties and material bulk density become more uniform
3. Rotary feeder – the rotary feeder is necessary to prevent flooding of the hydrate out of the storage vessel. (Fluidized hydrate will flood past downstream equipment like screw conveyors, weigh belts, etc.)

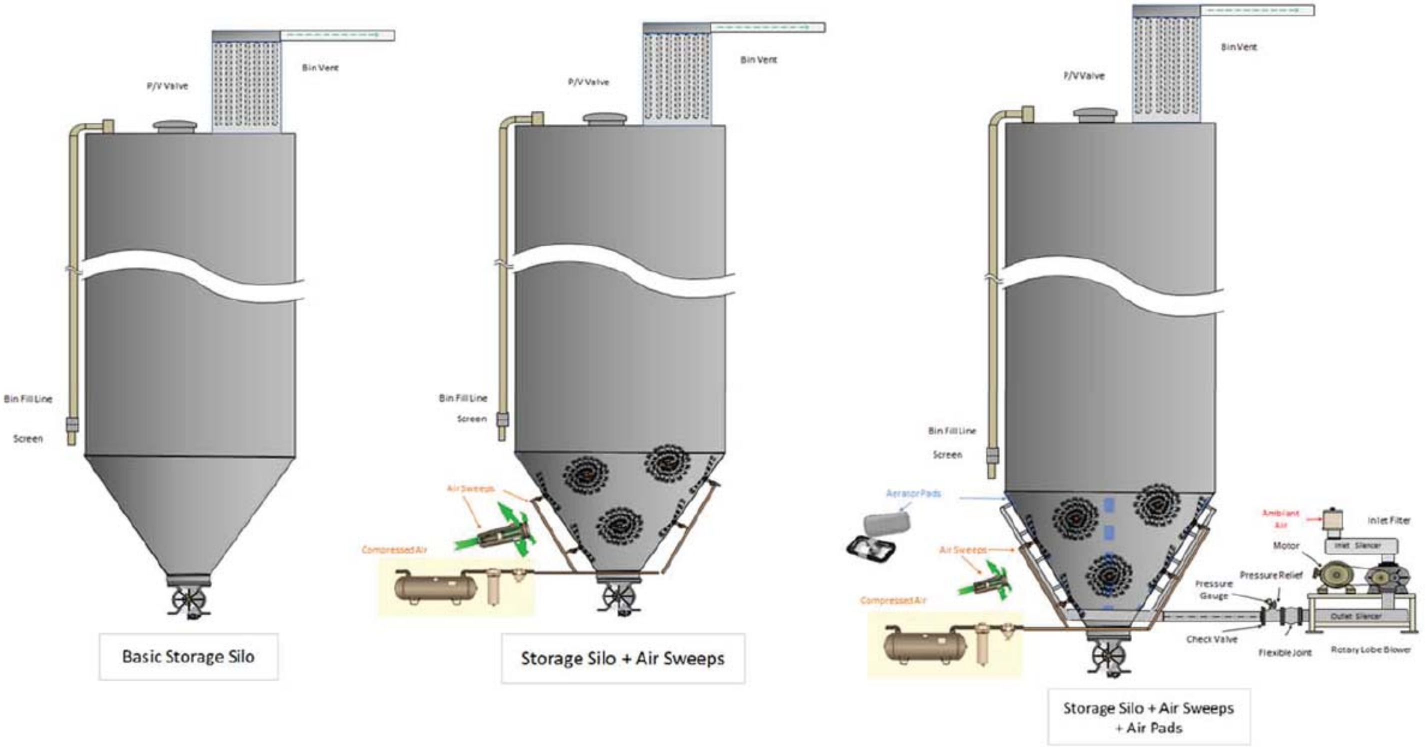

Figure 12: Method of fluidizing hydrate in a silo.

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BIOGRAPHY

Randy J. Griffard is a 35 year employee at Mississippi Lime Company. During his tenure he served as a Supervisor over the Electrical & Instrumentation Departments, Process Engineer, Plant Manager in charge of Specialty Products Production (Hydrated Lime and Precipitated Calcium Carbonate), Research and Development Department Manager, and is presently the Director of Research and Development.

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Who We Are

The Worldwide Pollution Control Association (WPCA) has assembled a group of people and companies who are experts at some aspect of pollution control. In addition, the WPCA has organized a user advisory board who can give this group direction and assistance in performing service to pollution control business throughout the world.

Our Mission

The mission of the WPCA is to enhance technical communication through seminars, technical journals and a website. The WPCA is a non-profit organization and our members and advisors need to be motivated by a desire to see the pollution control community make world wide technical progress through improved technical communication.

Who Directs the WPCA?

The WPCA is a partnership which includes system/equipment/services suppliers, consultants and users. The WPCA President, Vice President and Advisory Committee are equipment users. The Corporate Sponsors and Board of Directors are suppliers. Together they develop annual seminars and events to achieve their goal of better technical communication for users of air pollution control systems.

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Air Preheater Performance Enhancement to Increase Efficiency

Written by Sterling Gray and Blake Stapper, AECOM Process Technologies
Jonas Klingspor, LJUNGSTRÖM

INTRODUCTION

AECOM's SBS Injection™ technology was originally developed to eliminate the visible "blue" plume that was often generated by units firing high-sulfur coal that had implemented selective catalytic reduction (SCR) for NOx control. The process utilizes the injection of sodium carbonate, and has been applied to over 30 boilers, representing nearly 18,000 MW of generating capacity and over 10 years of commercial operating experience. Over time, additional benefits of SO_3 removal have been identified, and a number of enhancements have been developed. The latest of these involves a partnership between AECOM and LJUNGSTRÖM to take full advantage of lowering the acid dew point of the flue gas.

LJUNGSTRÖM has developed a new technology, AdvX™ Heat Recovery Technology that can extract a significant amount of additional energy from existing air preheaters (APH). The system consists of an upgrade of the air preheater and control of the SO_3 concentration ahead of the air heater to minimal levels. The additional energy can be used in several beneficial ways including improving the boiler heat rate, evaporation of waste water and stack gas reheat. By removing SO_3 and lowering the flue gas temperature, a number of environmental benefits may be realized. These include reductions in NOx, PM, and Hg emissions, and a decrease in fresh water consumption and WWT demand. This solution also provides new operating flexibility for SCRs by making it possible to operate at low loads without any adverse impact on the SCR catalyst.

AIR PREHEATER UPGRADE

The upgrade of the air preheater consists of three components including use of high efficiency and low pressure drop heating elements, additional heating element surface in the air preheater baskets, and a shift in the "x-ratio" or air to flue gas ratio. The shift in "X-ratio" can be accomplished by increasing the secondary air flow rate by up to 20 percent or bypassing up to 20 percent flue gas around the air preheater. In either case, the boiler efficiency is not impacted.

Pushing additional air through the cold side of the air preheater is typically associated with a slight increase in pressure drop and the capability of the existing primary and secondary forced draft fans will have to be evaluated. The flue gas option does not require a dedicated fan or a fan upgrade.

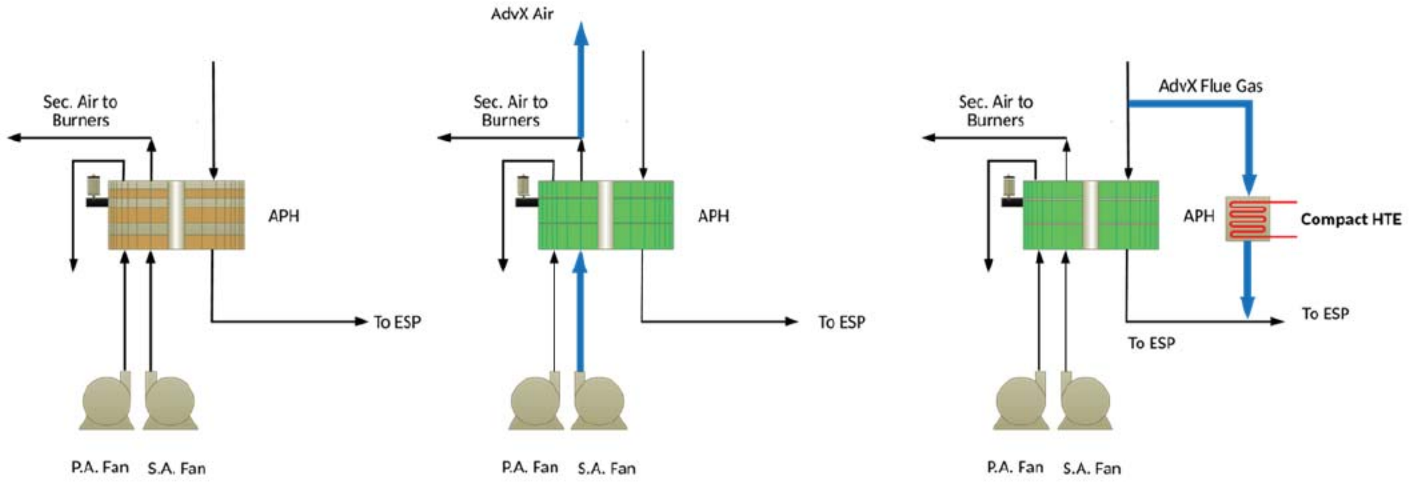

Figure 13:

Current ***Option 1*** ***Option 2***

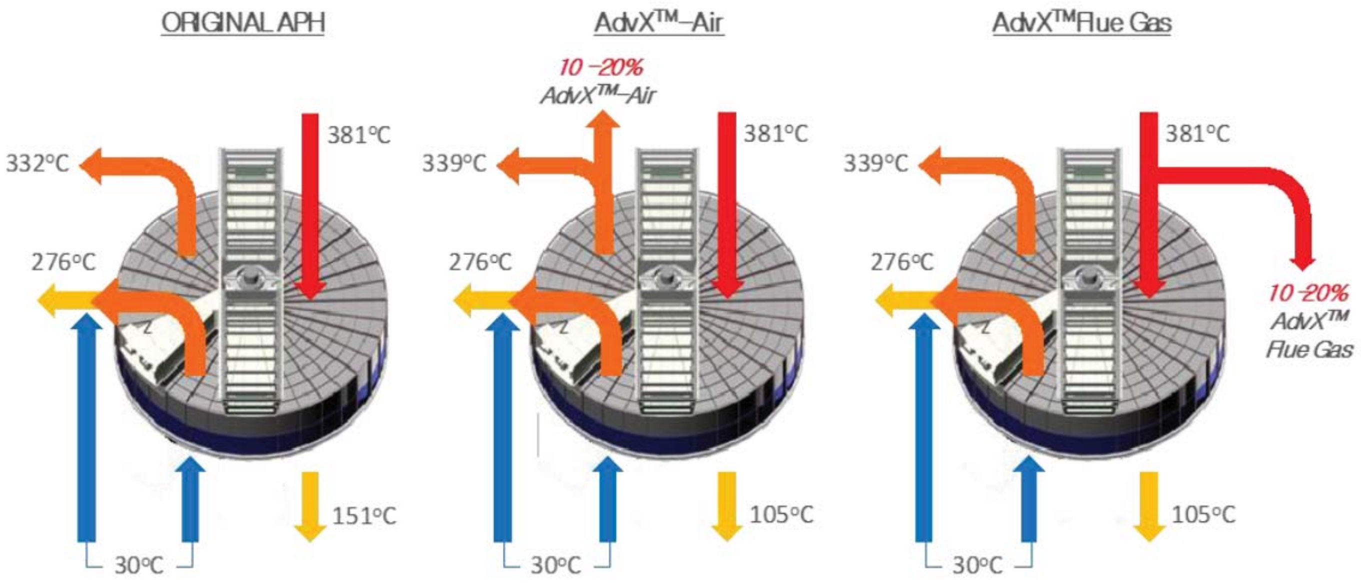

Figure 14:

Current *Option 1* *Option 2*

A typical example of the modified air preheater temperature profile is shown below. As shown, the primary and secondary air temperature will increase slightly which will result in a modest increase in boiler efficiency. The flue gas temperature ahead of the air preheater will stay the same while the flue gas temperature after the air heater will drop. The reduction in flue gas temperature after the air preheater will increase the performance of the ESP, and a reduction in fly ash emissions of 50 to 70 percent is expected.

The AdvX - air flow rate or the AdvX - flue gas bypass flow rate is typically limited to about 10 to 20 percent for existing units. In order to further increase the energy capture across the air preheater, LJUNGSTRÖM has developed a new DN8™ heating element that exhibits superior heat transfer capabilities while providing an open profile that can accommodate additional gas capacities without an appreciable increase in pressure drop.

BENEFITS

There are a number of options for use of the additional energy that can be extracted from the upgraded air heater including:

- Stack gas reheat
- Evaporation of waste water to allow zero liquid discharge operation;
- Boiler efficiency increase through preheating the boiler feed water;
- Production of hot water or low-pressure steam; or
- Coal drying.

The additional heat energy from an air preheater upgrade can be used to eliminate the waste water treatment system, associated operating and maintenance costs as well as future requirements to upgrade the waste water treatment system to meet new more stringent emission limits. An overview of the AdvX™ Waste Water Evaporation system is shown below and accomplishes zero liquid discharge (ZLD).

IMPROVED PERFORMANCE

The AdvX™ Heat Recovery Technology provides numerous benefits including:

- SO_3: Reduction of SO_3 both upstream of and formed in the SCR, ahead of the air preheater, and ultra-low stack emissions provides substantial benefits and a completely clear plume.
- Corrosion: Sulfuric acid condensation and subsequent corrosion in vessels and ductwork is avoided reducing maintenance costs.
- Hg: Mercury oxidation and removal across the ESP and wet FGD system is enhanced leading to ultra-low Hg emissions. Hg control may require use of the complementary HBS Injection™ system which co-injects sodium bromide with the sodium carbonate solution.
- APH: Condensation of sulfuric acid, ammonium bisulfate and subsequent fouling of the air preheater is avoided. Reduced soot blowing will increase heating element life. Additional energy can safely be extracted.

- ESP: Reduced temperature across the ESP will substantially reduce fly ash emissions.
- Efficiency: Extracting additional heat across the air preheater will improve plant efficiency
- CO_2: Increasing the plant efficiency will reduce CO_2 emissions.
- NOx: improved SCR performance is possible when SO_3 is reduced to low levels. Reduced SCR minimum operating temperature allows the SCR and plant to operate at lower loads.

FULL-SCALE RESULTS

Full-scale results are shown in the exhibit below. This particular plant has 500MW coal-fired boilers burning high sulfur coal. It is equipped with an AdvX™ system comprising of an air preheater upgrade and a SBS Injection™ system. The plant also has a SCR, an ESP, and a wet FGD system for control of NOx, Hg, PM, and SO_2 emissions. The plant achieved a 2 percent improvement in boiler heat rate and a substantial reduction in emissions of SO_3, NOx, Hg, and PM. Other benefits include a reduction in water consumption due to the lower temperature at the FGD, and in FGD chloride levels due to removal of HCl across the ESP which also has the potential to decrease wastewater production. The results also allow the plant to remove one catalyst layer while still achieving reduced NOx emissions. One less layer translates to reduced SO_3 generation, and less pressure drop. In addition, the minimum load at which the plant is to operate without damaging the SCR is significantly lower.

ECONOMICS

The return on investment varies depending on the extent of the benefits that can be applied at each particular plant. Typically, the return of investment is around 2 years if all benefits can be realized.

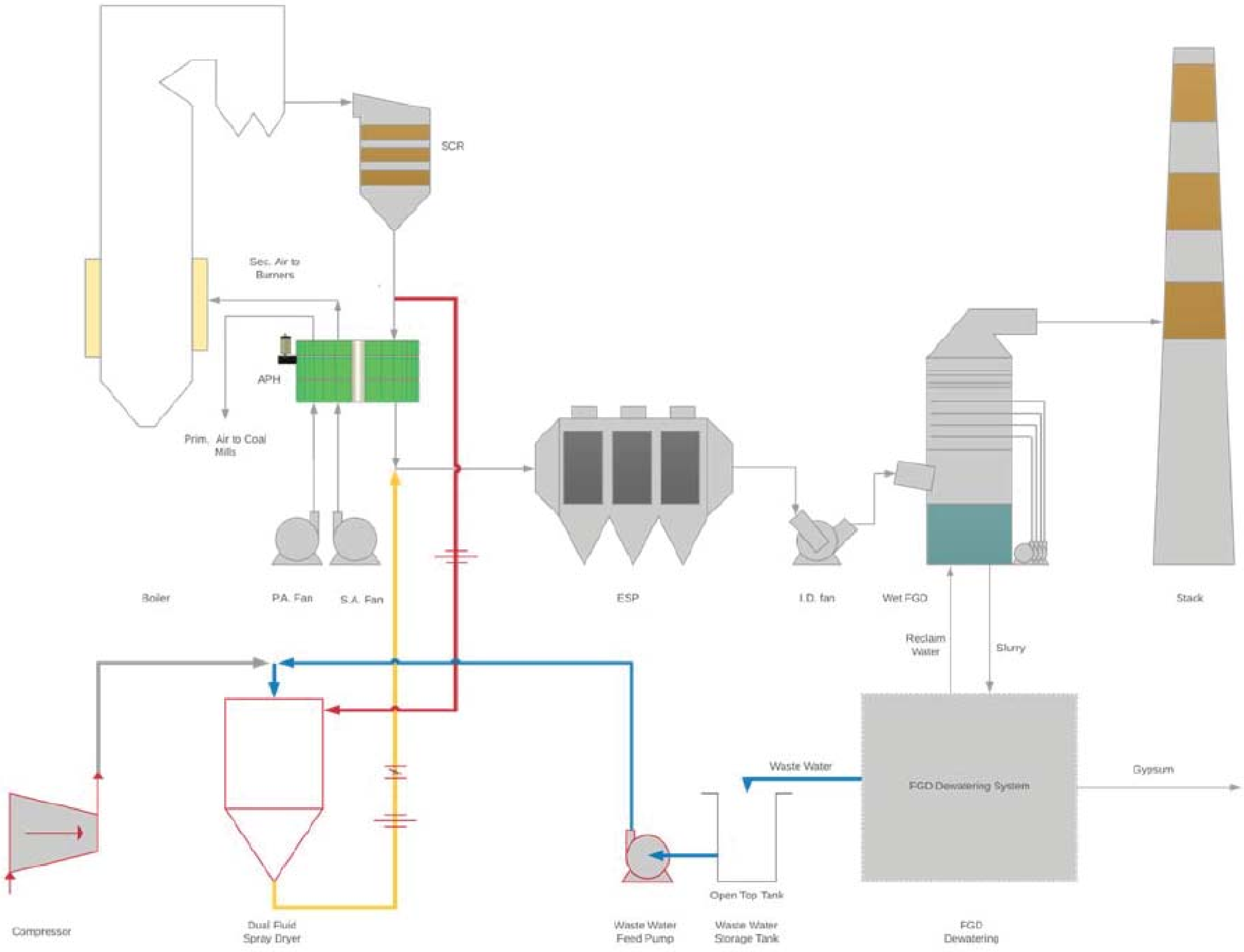

Figure 15: AdvX™ Waste Water Evaporation (WWE) accomplishing Zero Liquid Discharge

AdvX™ OPERATING TUNING		
Temp.	AH Outlet Temperature	Reduced from 171°C to 125°C
SO_3	SO_3 Removal	Up to 99 percent
	Stack SO_3 Emissions	Decreased to <1.0 ppm
HEAT RECOVERY		
Boiler	Coal consumption	Reduced by 2 percent
	CO_2 Reduction	2 percent
EMISSION COMPLIANCE		
NOx	Stack NO_x Removal	Increased
	Allowable Ammonia Slip	Increased to >3 ppm
	SCR MOT	Decreased from 325°C to 300°C
	SCR Flexible Operation	Minimum load reduced
PM	ESP Temperature	Reduced from 171°C to 125°C
	ESP Residence Time	Increased by 10%
Hg	Hg Removal	Increased to >90 percent
	Stack Hg Emissions	Reduced from 2 $\mu g/m^3$ to <0.5 $\mu g/m^3$
OTHER BENEFITS		
HCl & HF	Removal Ahead of FGD	Increased 40 percent ahead of FGD
WWT	Waste Water Production	Potential reduction in blowdown rate
Water	FGD Water Consumption	Reduced up to 35 percent

Figure 16: Table of results for 500 MW coal-fired unit

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Jonas Klingspor has spent his entire career in the coal-fired power industry, and currently manages LJUNGSTRÖM's new AdvX(TM) technology. His expertise is in modifying existing power plant systems to improve performance and accomplish multi-pollutant emission control, while reducing the cost of implementation.

AECOM

Overview of Mercury Control Approaches Used by U.S. Plants

Written by Sharon Sjostrom and Connie Senior, ADA-ES, Inc.

INTRODUCTION

Development and implementation of mercury controls for coal-fired power plants in the U.S. has a relatively long history. Pilot testing at operating power plants to determine the effectiveness of activated carbon injection to limit mercury emissions began in the early 1990s. Hundreds of full-scale demonstrations of mercury control technologies have taken place since DOE began providing funding in 2001. On December 16, 2011, the EPA issued the final Mercury and Air Toxics Standards (MATS) rule, which took effect on April 16, 2012. Almost all affected units had to be in compliance by April 16, 2016. Most units now have at least one year of experience managing plant operations to meet compliance limits.

As part of the Mercury and Air Toxics Standard (MATS), affected coal-fired power plants must report their hourly mercury emissions to the U.S. Environmental Protection Agency (EPA). Plants employ a variety of strategies to reduce mercury air emissions. Eleven months of U.S. mercury emissions data, May 1, 2017 through March 31, 2018, for all coal-fired power plants reporting emissions with information on the control technologies employed at specific plants have been reviewed for this analysis. In this edition of the newsletter, a summary of the analysis for bituminous-fired plants will be provided. This information provides insights into which technologies are being relied upon, and the efficacy of different control strategies as a function of both Hg control strategy and type of coal being combusted.

CURRENT COAL USE BY U.S. EGUS

One of the primary identifying characteristics for mercury control technology choice is the coal being fired at the plant. The coal type incorporates several important parameters associated with mercury emissions and control effectiveness including the inherent mercury, sulfur, and halogen contents in the coal.

At the end of 2017, 643 electric generating units (EGUs) were identified as “operating” by the Energy Information Administration (EIA). Ninety-two percent of these were evenly split between units identifying bituminous and subbituminous units as their primary coal type. Less than 5% of EGUs reported using lignite as their primary fuel source. The average capacity factor of subbituminous plants was higher than bituminous plants (55% compared to 43%, on average), and 54% of the fuel fired by EGUs was subbituminous coal, as shown in Figure 17 and 18.

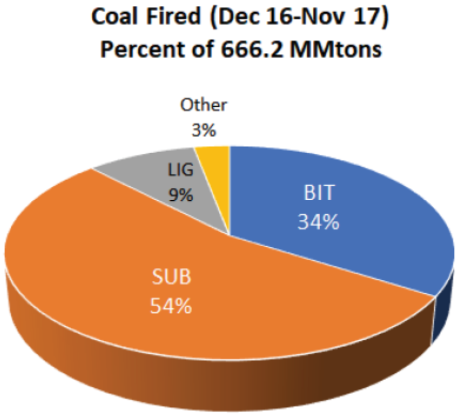

Figure 17: Distribution of coal fired for power generation in US, 2017 [Source: EIA]

For coal-fired boilers firing bituminous or subbituminous coal, the MATS emission limit for mercury is 1.2 lb/TBtu, computed on a 30-day rolling average basis. For coal-fired boilers firing lignite coal, the MATS emission limit for mercury is 4 lb/TBtu, computed on a 30-day rolling average

Coal	Generating Capacity (MW)	Coal Fired (MMtpy)	Avg Capacity Factor (%)	Number of EGUs
BIT	125,481	226.5	43%	294
SUB	119,888	358.5	55%	294
LIG	12,928	61.3	69%	29
Other	3,944	19.9	71%	26

Figure 18: Coal use and generation, U.S. electric generating units, 2017 [Source: EIA]

basis. This is a multi-pollutant rule, which can increase the complexity of finding a compliance solution. The control of particulate matter (PM) must be accomplished while controlling both acid gases and mercury (Hg).

AIR POLLUTION CONTROLS

There are only two pathways by which mercury can be removed from coal-fired boilers:

1. Collection of mercury that has been adsorbed on surfaces (e.g., fly ash, sorbents) and subsequently removed by particulate control devices, and
2. Absorption of oxidized gaseous mercury species (collectively, Hg^{2+}) in aqueous media such as in a flue gas desulfurization (FGD) scrubber.

The common mercury control strategies applied to U.S. plants fit the two pathways described above and include the following:

1. <u>Co-Benefits</u>: Use the existing air pollution control devices for NOx, SOx and particulate matter with no mercury-specific controls
    - More common on scrubbed plants firing higher halogen coal where sufficient mercury oxidation can be achieved resulting in sufficient removal in a scrubber
2. <u>Coal additives (CA)</u>: Increase halogen content in coal to increase the fraction of oxidized mercury in the flue gas
    - More common as a stand-alone option on scrubbed plants
1. <u>Powdered activated carbon (PAC) injection</u>: Increase the amount of particles that can adsorb mercury
    - Common on plants firing low-halogen fuel
    - Often used in conjunction with coal additives or halogen-treated PAC

An overview of air pollution controls installed on all units firing bituminous coals is shown in Figure 19 as a function of the amount of coal fired. The perspective using the metric of coal fired provides insights into the relative operating experience with the different control technologies. Another common population metric is the controls installed by EGU, which does not provide insights into the relative size or operating capacity factor for each unit. The population distributions for the most common configurations are shown in Figure 20 (on next page), calculated by the amount of coal fired. As indicated, the most prevalent configuration, representing 53% of coal used at bituminous-fired units, includes an SCR, cold-side ESP and wet FGD. The average generating capacity of these units is 555 MW, compared to an average of 415 MW for all bituminous-fired units. The population distribution for the next most popular configuration, a cold-side ESP followed by a wet FGD, represents 7% of coal used at bituminous-fired units. For comparison, the combination of an SCR, cold-side ESP and wet FGD is installed at only 40% of the EGUs, due to the relatively larger size of the plants that have installed this suite of pollution controls.

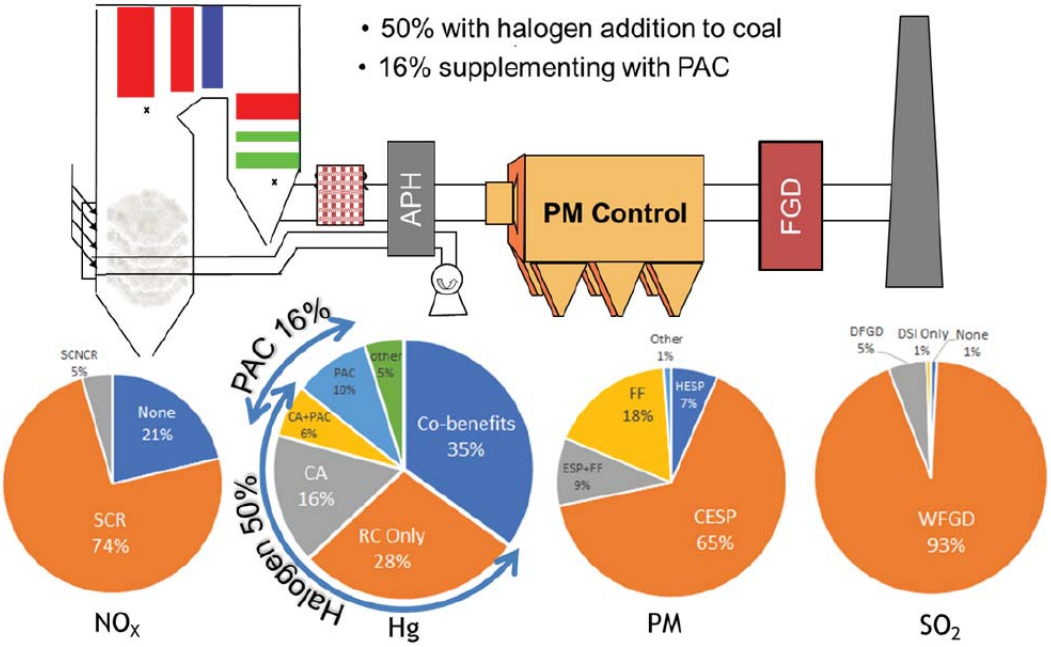

Figure 19: Distribution of air pollution controls on U.S. bituminous-fired EGUs by amount of coal fired. [Source EPA AMPD and EIA] (CA: Coal Additives, PAC: Powdered Activated Carbon, RC: Refined Coal)

NOx Controls	PM Controls	SOx Controls	Percent of Population	Average Size (MW)
SCR	ESP	WFGD	53%	555
SCR	ESP+FF	WFGD	6%	575
SCR	FF	WFGD	5%	514
	ESP	WFGD	7%	304
	FF	WFGD	5%	426
Other Combinations (each < 4% of total)			24%	

Figure 20: Distribution of air pollution controls and average generating capacity, bituminous-fired EGUs as function of amount of coal consumed, 2017
[Source EPA AMPD]

In many instances, sufficient mercury control can be achieved in bituminous-fired plants through "co-benefits", that is, by relying on a combination of properties inherent in the coal fired and the air pollution controls installed at the plant without the use of mercury-specific controls. As shown in Figure 19, thirty-five percent (35%) of bituminous-fired EGUs rely solely on co-benefits when calculated by the amount of coal fired.

It is interesting to note that, although to average generating capacity for all bituminous plants is 415 MW, the average generating capacity for the subset of plants represented in Figure 19 that report no mercury-specific controls are in use is 324 MW. This group of "co-benefit" plants represents the lowest average generating capacity for any mercury control configuration subset. This population subset also has the lowest average capacity factor, 38%. Thus, although 35% of all bituminous-fired EGUs report no mercury-specific controls when calculated by the coal-fired, this represents 48% of all bituminous-fired EGUs measured by the number of EGUs in operation. The combined factors of relatively low average generating capacity and relatively low capacity factor for this population subset must be considered when assessing the predominance of relying on co-benefits to achieve mercury compliance. Furthermore, when considering the subset of bituminous plants that have invested the capital to install an SCR + ESP + WFGD (555MW average generating capacity from Figure 20), less than 50% of these EGUs have chosen to rely solely on co-benefits without installing mercury-specific controls. Note that, although it is required to report installed controls such as coal additive injection systems or activated carbon injection systems, EGUs are not required to report how often the systems are operating or how much reagent or sorbent is being applied. Therefore, many of the larger plants may also be using co-benefits as their predominant mercury-control strategy, but they have installed mercury-specific controls that are therefore available for use on an as-needed basis to mitigate risk of non-compliance.

Fifty percent of bituminous-fired EGUs, by the annual amount of coal-fired, report use of a halogen added to their coal or introduced into their boiler. Many of these plants report using refined coal, which is a category of coal that, for the plants included here, includes the addition of a halogen prior to combustion. It should be noted that the use of refined coal is not contingent on meeting mercury emissions compliance and some plants that use refined coal may be exceeding MATS or other mercury emissions limits. It should also be noted that, for this analysis, if additional coal additives are reported by the plant in addition to refined coal, the plant was considered a "CA" or coal additive plant.

Only 16% of bituminous-fired plants report the use of PAC. The majority of bituminous-fired plants consume Eastern bituminous coal, which has relative high sulfur contents in the range of 1 wt% to 4 wt%. While most of the input sulfur is converted to SO_2, typically one to three percent is converted to sulfur trioxide (SO_3) in the flue gas. The effectiveness of activated carbon for mercury control is impacted by the presence of SO_3 in the flue gas, limiting its effectiveness for many units in this category.

An example of the impact of SO_3 on PAC effectiveness is shown in Figure 21. In this example, sodium sesquicarbonate, or trona was injected with the PAC upstream of a fabric

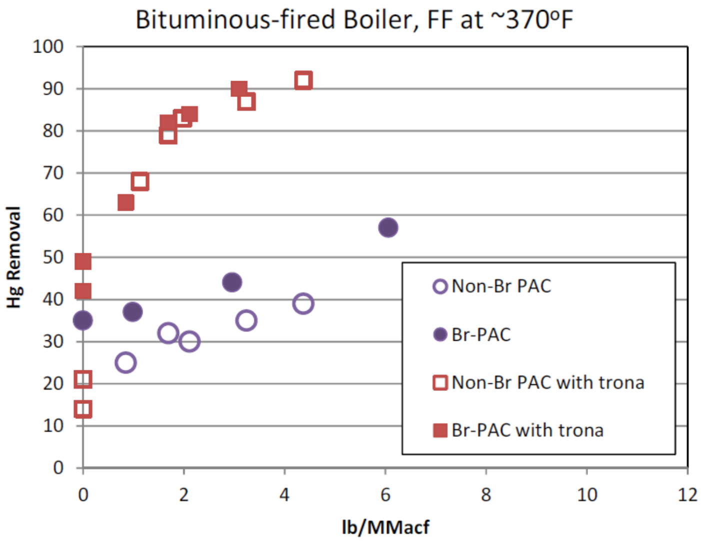

Figure 21: Improved PAC effectiveness by co-injecting with DSI

	CA + PAC	CA	PAC	Co-Benefits	RC
Sample Size (Units)	6	20	10	53	35
Avg. Hg (lb/TBtu)	0.51	0.62	0.31	0.44	0.51
Average Coal Sulfur (%)	2.5	2.4	2.7	2.9	2.6

Figure 22: Mercury emissions. bituminous coal, SCR+ESP+WFGD [Source: EPA AMPD and EIA 923]

filter to lower the SO_3 concentration in the flue gas. The uncontrolled SO_3 at this site was nominally 20 ppm. Both sodium and calcium-based alkaline dry sorbent injection (DSI) are utilized to manage SO_3 concentrations. As shown in the figure, there was a significant reduction in the PAC required when trona was used to manage SO_3 concentrations. With this fabric filter, only a marginal improvement was noted by using bromine-treated PAC (Br-PAC) compared to non bromine-treated PAC. This suggests that sufficient halogen was present in the flue gas to enhance the effectiveness of the PAC.

The mercury emissions for all plants reporting emissions from May 1, 2017 through March 31, 2018 (11 months) to assess the effectiveness of various mercury control approaches. The data included in Figure 22 is limited to bituminous plants that are configured with an SCR+ESP+WFGD. As shown, the average mercury emissions for all compliance approaches during this 11-month period were well below the 30-day average compliance limit of 1.2 lb/TBtu.

A further analysis was conducted on the subset of bituminous units relying on co-benefits and configured with an SCR+ESP+WFGD to determine the potential impact of sulfur content in the coal to the mercury emissions. Figure 23 shows the relationship between coal sulfur and average mercury emissions, where each data point represents one plant's monthly coal sulfur and average monthly mercury emissions. The data is further segregated by coal region, where NAPP = northern Appalachia, CAPP = central Appalachia, and IB = Interior basin. Average mercury and chlorine for these coal regions from a 1999 EPA Information Collection Request is included in Figure 24 for reference. As shown in Figure 23, there is no correlation between coal sulfur and increased mercury emissions. As previously noted, DSI can be employed to reduce SO_3 in the flue gas. For the plants included in Figure 23, 68% report using DSI.

Coal Region	Avg Hg (ppm)	Avg Cl (ppm)
NAPP	0.18	700
CAPP	0.11	1000
IB	0.13	950

Figure 24: Average mercury and chlorine by coal region [Source: 1999 EPA ICR]

IMPACT OF SCR USE ON MERCURY CONTROL TECHNOLOGY CHOICE

In general, the presence of an SCR can improve the effectiveness of halogens for mercury oxidation. The configuration data was reviewed to determine whether the presence of an SCR impacted the fraction of units reporting that no

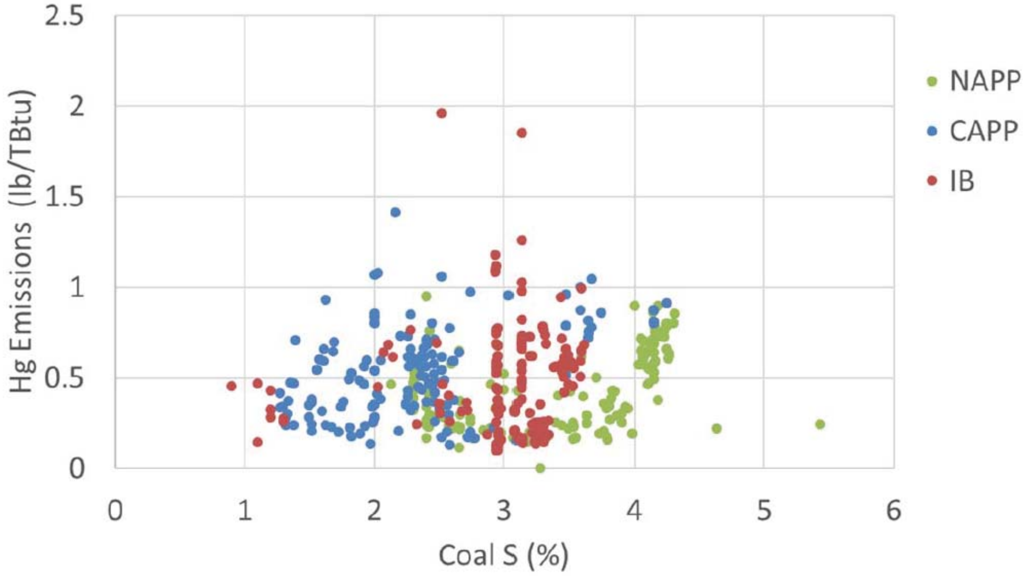

Figure 23: Influence of coal sulfur on mercury emissions. bituminous plants, SCR, ESP, WFGD, no specific Hg controls. Reported coal sulfur and Hg emissions 1 May 2017 – 31 April 2018, monthly averages. [Source: EPA AMPD]

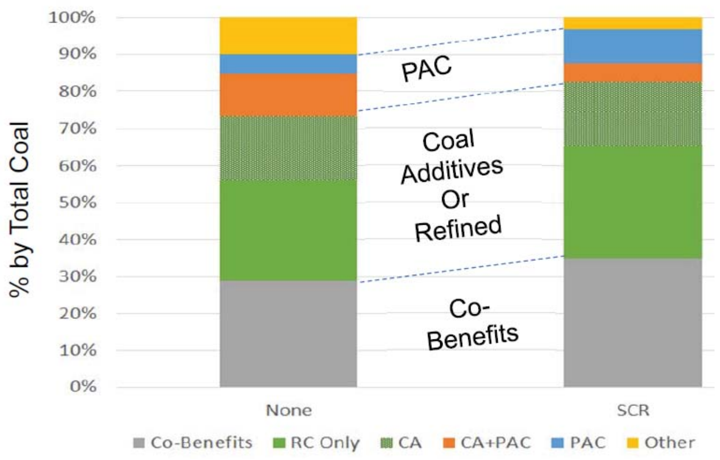

Figure 25. Comparison of mercury control technology choice for bituminous EGUs with and without SCRs.

mercury-specific controls were installed at their EGU. The data presented in Figure 25 suggests that there is a slightly larger fraction of units with SCRs that rely on co-benefits alone compared to units without SCRs. The data also indicates that, on average, an installed SCR has a minor impact on the fraction of bituminous units with SCRs reporting using PAC to supplement Hg compliance. However, as noted previously, many of the units with SCR installed are larger units, and many larger units may install supplemental controls to be available to use as needed for risk mitigation. Because the amount of reagent or sorbent is not reported, it is possible that the actual in-practice comparisons may vary from this analysis.

SUMMARY

Data reported to the Energy Information Administration and EPA can be very useful in assessing the mercury compliance choices and relative effectiveness for US EGUs. In general, the plants included in this assessment are well controlled using co-benefits, coal additives, activated carbon, or a combination of these technologies. For bituminous-fired units, the majority of plants rely on co-benefits and supplement mercury oxidation with coal additives as needed.

The relative effectiveness of coal additives and activated carbon based on the specific type and quantity used is not possible with data reported publicly. However, as EGUs gain experience and confidence, use behavior will trend towards the most economical solutions that reliably maintain compliance.

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EPA Air Markets Program Data: https://ampd.epa.gov/ampd/
1999 EPA ICR data: https://www3.epa.gov/airtoxics/combust/utiltox/utoxpg.html#DA2

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Dr. Connie Senior is Vice President of Technology at ADA-ES, Inc. She is an internationally recognized expert on mercury control from coal-fired boilers. She serves on EPA's Board of Scientific Counselors. She has worked on understanding and predicting the behavior of mercury and other hazardous air pollutants for over fifteen years and has more than ten years' experience with demonstrations of full-scale mercury emissions control.

Sharon Sjostrom is the Chief Product Officer at Advanced Emissions Solutions, Inc. where she is responsible for leading strategic product and business development for the corporation through its subsidiary ADA-ES, Inc. Sharon has over 25 years of experience developing technologies and commercializing products that reduce emissions from coal-fired power generation, with a focus on mercury controls. She has published more than fifty technical papers and is an inventor on sixteen patents.

The Hidden Liability of the Transformer/Rectifier

Written by Dan Holt, KraftPowercon, Inc.

It's difficult to determine who first said, "The squeaky wheel gets the grease." The phrase is rarely disputed and broadly applied, a modern proverb. In the industrial environment the converse is often also true. The fewer problems a machine or system causes, the less attention it receives. As if human nature was not enough to lead to a lack of upkeep, the implementation of predictive maintenance practices has, in some cases, institutionalized this behavior. Early reliability-centered maintenance techniques could provide undisputable reasons for not performing outdated time-based maintenance procedures. The longer an item performs and tests flawlessly, the longer the predictive algorithm extends service period. Everything is fine until one day.

Our example of the quietly performing wheel is the transformer/rectifier (T/R). There are thousands of T/Rs in North America currently in service for 40 years or more. In the 1970s and 80s, precipitator construction boomed as air quality standards were implemented. Most of these precipitators were equipped with single-phase T/Rs to power their fields. Many of these precipitators have undergone extensive maintenance and upgrades, but in many cases the stalwart single-phase T/R continues to serve.

Although these 40 year performers are not unusual, T/Rs do fail. Moreover, they will fail, even when the most attentive of maintenance practices are implemented. As a T/R ages, several modes of failure will emerge. Some more common failures cost can be repaired in a day and at a low cost. Oil sealing failures are more difficult, involving a shop repair in most instances. Over time the heart of the device, the transformer coil, will degrade requiring an extensive internal rebuild. Often these rebuilds can cost more than a new T/R.

The T/R is a transformer coupled to a rectifier, which are both uniquely designed for the rigors of a precipitator power supply service. This service is stressful compared to typical transformers. Most transformers are not subject to high current transients, but the precipitator power supply is continuously controlled to a voltage limit which is intended to produce sparks. The voltage level is constantly varying. This is an abusive environment for transformer coils. Furthermore, many T/Rs are in corrosive environments and sometimes subject to physical damage during precipitator repair events.

Figure 26: Physical damage to T/R cooling fins

It is likely any T/R in service more than 15 years has experienced a rectifier failure. If the correct parts are nearby, skilled electrical technicians can make rectifier repairs quickly with the T/R in place. The rectifier portion consists of a voltage divider and bridge diode boards inside the T/R. Impending failure of a rectifier board can be difficult to predict because of the cascading nature of this issue. When the failure process starts, it accelerates over time, typically inside of a testing window. Also, the voltage dividers used in the early precipitator applications were much less durable than those typically offered as replacement parts today.

Sealing failures occur with age. The older the T/R, the more likely it has a catch pan under it or oil pig near it. New seals can be put in an old T/R, but the maintenance cost and effort will increase with this type of shop repair.

Lastly is the transformer, the first component of the T/R. Transformer coils degrade over time. Coils are wound with

Figure 27: Oil pigs and catch pans near a T/R

paper used as a dielectric medium between each winding. The rate of cellulose degradation is based on the operating temperature and exposure to water and oxygen. Assuring the T/R can radiate heat and properly testing and replacing transformer oil is the means to combat aging. However, these methods will not postpone failure indefinitely. At some point coil failure will occur and the T/R will no longer provide the voltage level needed for the precipitator to operate.

Figure 28: Internal T/R corrosion indicting oxygen in the T/R

The first coil failure in a group of T/Rs may appear to be a one-off event. Often it is a surprise. It is treated like a maintenance occurrence and no consideration of obsolescence is made. But in T/Rs greater than 25 years of service, it's more often a leading indicator, given each unit has similar maintenance and service history.

At the point of first, second or third T/R coil failure the need for an extensive rebuild or replacement becomes obvious. The process owner now seeks the best path forward. The complexity of a rebuild is low, but a rebuild will forego any opportunity of improvement. A replacement opens the door for improvements such as:

- Cost savings per T/R unit
- Improve precipitator performance
- Right-size power supplies
- Lower power consumption
- Simplify unique or complicated precipitator designs

Replacement of aging T/Rs will involve some engineering, but the decision to replace is often justifiable. Power supply designs are more flexible than in years past and precipitator specialty contractors are more focused on rebuilds and upgrades. The depth of re-power project experience has grown in recent years. The current precipitator owner can take advantage of these new competencies among the contractors and manufacturers.

With some up-front effort the owner can install another set of wheels (read: power supplies) capable of squeak-lessly operating another 25 years or more. Quite wheels are the best. After all, grease is messy, and its only purpose is to make the squeaky wheel shut up for a while.

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Dan Holt is a Sales Engineer for KraftPowercon, Inc. in Pensacola, Florida. The Pensacola staff services precipitator power supply applications. Dan has 17 years of experience in the petrochemical and pulp and paper industries as a maintenance and capital project engineer. He graduated in 1989 from the University of Alabama.

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