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### *Don't overlook the indiscernable*

# Dealing with Non-Detects in Air Emissions Testing *(Part 1)*

**By Scott Evans, Clean Air Engineering**

## Introduction

When the U.S. Environmental Protection Agency (EPA) originally developed Reference Methods for measuring emissions from stationary sources in the early to mid 1970's, emission levels were much higher than they are today – sometimes by an order of magnitude or more. These Reference Methods may have been acceptable for these higher emission levels, but today, many of these methods are proving problematic or even inadequate for accurate determination of low-level emissions. Inherent biases in these methods that were insignificant when measuring emissions of 1000 ppm become unacceptable when measuring at 10 ppm. Even more important, state and local regulatory agencies are driving emission limits ever lower through permit limitations. In some cases, these regulatory limits are set lower than the capability of the Reference Method to accurately measure them; that is, they are set below the detection limit of the method.

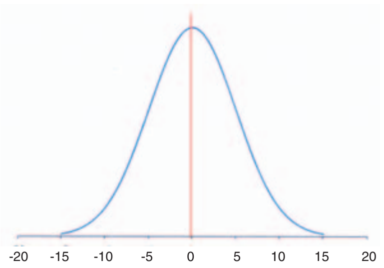

Figure 1: Example of Blank Probability Distribution Function

## What is a Detection Limit?

While this may seem at first a simple question, the concept of detection limit is one of the most controversial in analytical chemistry. It has undergone much change over the past 40 years and is still an unsettled issue. Debates on this topic at analytical chemistry conferences are passionate with two or more sides each vigorously defending their point of view. Until recently, the subject of detection limits was rarely considered in the field of air emissions testing. Most Reference Methods specify detection or "sensitivity" limits and not much was thought about them. However, over the past few years, the drive to lower NOx emissions and to an even greater extent, $SO_3$ emissions, has fueled an intense interest in air measurement detection limits. Vendors of air pollution control equipment, in particular, are struggling how best to insure they can meet performance guarantees for emission concentrations in the sub-ppm range. *Continued on page 12*

### *Mercury capture: Not as easy as 1,2,3*

# Cost Effective Integrated Approach to Mercury Removal

**By Albert L. Moretti, John L. David, Ashley N. Krout, and Tim G. Ruppelli,**
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## Background

Mercury, present in only trace amounts in coal, is released during the coal combustion process, and can appear in several forms in the flue gas. In the solid phase, it is referred to as particulate mercury, and in the gaseous phase it is referred to as vapor-phase mercury. Due to the high volatility of mercury and many of its compounds, most of the mercury produced by coal combustion is found in the gas phase. Vapor-phase mercury from coal-fired power plants is considered a hazardous air pollutant by the EPA. Regulations are in place in many states and are being reworked at the Federal level to regulate gaseous mercury emissions. The concentration of mercury in the coal is primarily dependant on the coal type. Bituminous and lignite coals have the highest concentration of mercury, while subbituminous coal contains less. The form of mercury present in the flue gas (oxidized or elemental), commonly referred to as speciation, is a key factor in the development of emissions control strategies. *Continued on page 14*

## Inside

### *Is there a simple solution?*

# Acid Mist Formation

**By Wayne Buckley & James "Buzz" Reynolds, Siemens Environmental Systems & Services**

***Depending upon the type of FGD technology installed, a considerable portion of ammonia salts and sulfuric acid may exit the stack as respirable sub-micron fine particle emissions.***

Sulfur trioxide ($SO_3$), when hydrated with moisture in the gas stream or in the atmosphere, forms sulfuric acid ($H_2SO_4$), which contributes to visible plume and may violate local opacity regulations. Control of sulfuric acid mist presents an extremely difficult air pollution control problem due to its uniform 0.3-0.5 sub-micron size.

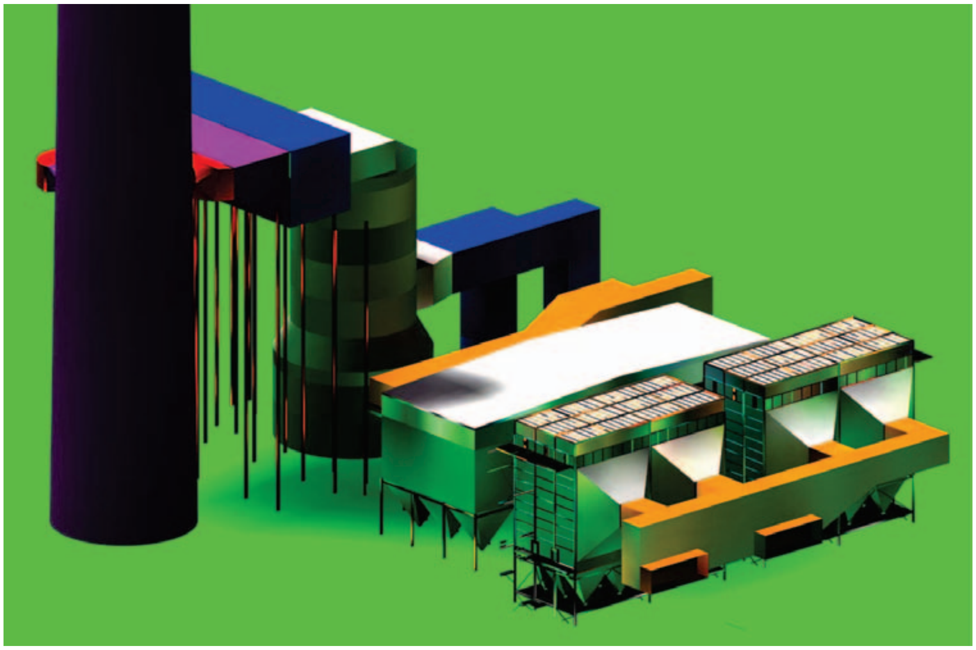

Figure 2: New Coal Fired APC System with WESP

***Sulfuric acid emissions are problematic in both wet and dry FGD processes***

In wet processes, where the flue gas leaving the absorber is saturated with moisture, sulfuric acid mist forms instantly after the flue gas is saturated and creates a stack opacity problem. Dry processes, where the flue gas is not saturated with moisture, typically remove fine particles such as $(NH_4)_2SO_4$. However, dry processes typically have lower removal efficiency for $SO_3$ vapors. Upon exit from the stack, these vapors convert to sulfuric acid mist and produce significant visible emissions.

***Sulfuric acid formation takes place through the oxidation of $SO_2$ to $SO_3$, followed by reaction with $H_2O$ to form $H_2SO_4$.***

During the combustion process, the sulfur in the fossil fuel reacts to form about 95-97 percent sulfur dioxide ($SO_2$) and the remainder sulfur trioxide ($SO_3$). Most of the $SO_3$ in boiler flue gas likely forms during the several seconds when the combustion gas cools from 2900-3100° F to about 1830° F. SCR technologies will generate an additional quantity of $SO_3$ through catalytic conversion of $SO_2$ to $SO_3$ even at low temperatures.

***There are two primary mechanisms for sulfuric acid mist formation.***

The first mechanism is the reaction between $H_2O$ vapors and $SO_3$ vapors that form liquid droplets. The second mechanism is sulfuric acid vapor condensation in the bulk gas phase when the gas stream temperature is lowered below the $H_2SO_4$ dew point. While an FGD system will remove some $H_2SO_4$, the majority will exit the stack.

***If reductions of mass emissions, stack opacity, or both are required, it is necessary to use a technology that will simultaneously remove both sulfuric acid mist and solid particulate material from the flue gas.***

Wet electrostatic precipitation (WESP) technology can satisfy this requirement and has the added potential for abatement of heavy metals (including mercury), as well as water mist carryover from an FGD scrubber system.

***Future PM2.5 and Regional Haze regulations will require control of $SO_3$ and sub-micron particulate.***

Any plant planning to install an FGD system for $SO_2$ control should consider leaving room for the future addition of a WESP (Figure 2) and performing preliminary engineering design concurrently with the FGD to minimize future outage time and cost.

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### *Is what you see, what you get?*

# Application Calculations on the Impact of High Frequency T-Rs on Electrostatic Precipitator Performance

**by Robert Mastropietro / Clive Cottingham / K. S. Park, Lodge-Cottrell / KC Cottrell**

## Summary

Electrostatic precipitator (ESP) mathematical models can be used to calculate the ESP size increase that would cause an equivalent performance enhancement to that observed by adding high frequency transformer-rectifiers (T-Rs). This information can be used to predict performance enhancements on existing ESPs when adding high frequency T-Rs.

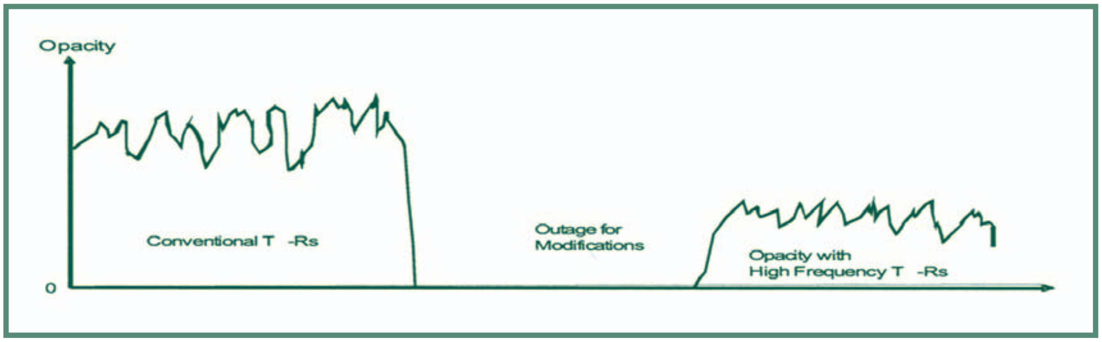


Figure 3: Opacity Based Performance Demonstrations

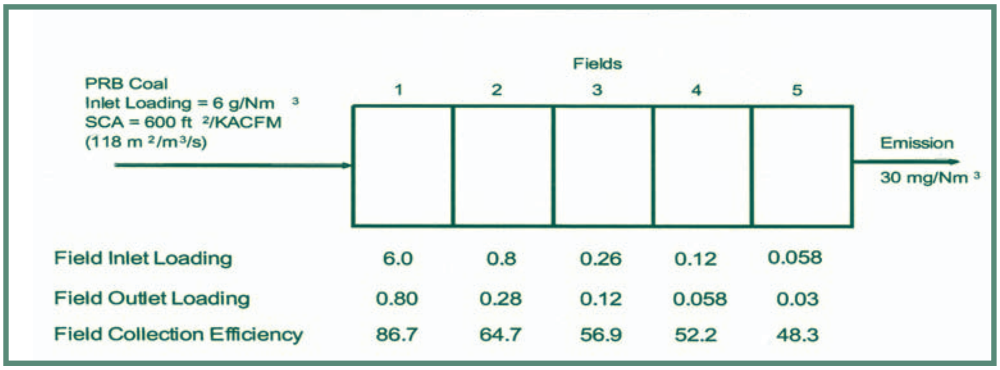
## Discussion

In recent years, many papers have been presented by transformer-rectifier manufacturers that show performance enhancements caused by adding high frequency T-Rs. Typically these opacity based performance demonstrations take the form show on Figure 3.

The best performance enhancements reported in these "sales oriented" papers show opacities to be cut in half (i.e. approximately, the ESP is making an additional 50% collection of outlet particulate). Let's suppose for calculation of the upper end of our ESP enhancement range that this performance enhancement was solely due to the high frequency T-Rs. What does an additional 50 % collection mean in terms of ESP sizing? This can be calculated using the modified Deutsch equation;

$$\text{Efficiency} = 1 - e^{-(A/V*wk)^{y}}$$

As shown on Figure 4 , the collection efficiency of an ESP drops from inlet to outlet fields due to particle size effects. Also, collection efficiency of the outlet field of the ESP approaches 50%. This is approximately the same collection efficiency as the most optimistic claims for high frequency T-Rs.



| | | | | | |
|---|---|---|---|---|---|
| Field Inlet Loading | 6.0 | 0.8 | 0.26 | 0.12 | 0.058 |
| Field Outlet Loading | 0.80 | 0.28 | 0.12 | 0.058 | 0.03 |
| Field Collection Efficiency | 86.7 | 64.7 | 56.9 | 52.2 | 48.3 |

Figure 4: ESP Performance Calculations as Predicted by the Modified Deutsch Equation with 0.6 Exponent

Note that the outlet field of this ESP comprises 20% of the total ESP treatment time. If high frequency T-Rs truly reduced particulate emissions by about one half, this would correspond to a required ESP size decrease of 20% (i.e. since the outlet field of the ESP reduces emissions by one-half). However, the observations of performance improvement levels are not solely caused by the use of high frequency waveforms alone. Sales people tend to only publish the best cases. They tend to avoid mention of less successful improvements in performance. They also fail to mention that when ESPs are refurbished, there are a number of other improvements that occur. Some examples would be;

- ✔ Electrodes cleaned by rapping and thermal effects.
- ✔ Electrodes realigned and broken electrodes taken out.
- ✔ Insulators cleaned and broken insulators replaced.
- ✔ Replace weighted wires with rigid mast type designs.

✔ Collecting plates that "ring" better with rapping.
✔ Adding rappers to reduce electrode buildup & reentrainment.
✔ Adding T-Rs reduces % of surface affected by each spark.

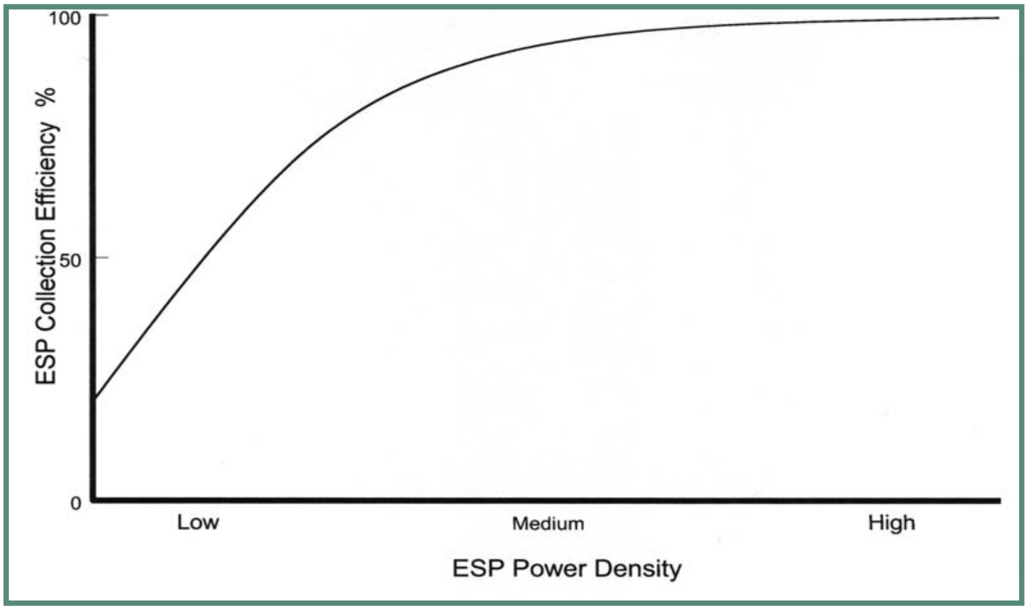


Figure 5: Typical ESP Power vs. Performance

✔ Gas flow modifications and hopper baffling.
✔ High frequency T-Rs maximize power/minimize sparking.

So very often, other factors serve to reduce opacity in combination with the change to high frequency T-Rs. Therefore, a conservative approach to our upper bound for performance enhancement on ESP size, solely from the T-R change alone, must be reduced from the optimistic 20% value.

Additionally, the concept of performance enhancement from adding high frequency T-Rs results from the capability to get more power into the ESP. It is a well known fact in the ESP industry that the collection efficiency of ESPs behave as follows in Figure 5.

So for high frequency T-Rs to make the ESP benefit from higher power, the ESP should have low power before the addition. If the ESP has high power already, adding high frequency T-Rs would have very little effect. Note that this gives us a lower bound on our range of enhancements near 0%. This also means that one should assume greater enhancements if the ESP is electrically sick, than if it is electrically healthy.

## Conclusion

**1.** If the ESP has properly designed electrode geometry and is getting high power levels with conventional 60 Hz T-Rs, then the ESP size enhancement from changing to high frequency T-Rs should be estimated in the 0-10% range.

**2.** If the ESP has poor power levels, and the only change being made to the ESP is changing from conventional to high frequency T-Rs, then the ESP size enhancement should be estimated in the 5-10% range.

**3.** If the ESP has poor power levels, and the ESP is being refurbished at the same time that the T-Rs are converted to high frequency, then the ESP size enhancement should be estimated in the 10-20% range.

## Sample Calculations

***How are these conclusions useful?*** Suppose, for example, that an existing ESP had 10 seconds of treatment time and conventional T-Rs. ESP sizing models are then used to analyze the coal and ash chemistry and these indicate that the minimum treatment time (with conventional T-Rs) to get the required outlet particulate emission is say, 18 seconds. This information tells you that changing the T-Rs to high frequency is not going to get you where you need to be. This is because at best, enhancements in ESP performance would make a 10 second treatment time ESP work like a 10 x 1.2 = 12 second treatment time ESP (i.e., 20 % enhancement if the ESP is electrically sick, we add high frequency T-Rs, and refurbish the ESP). It would only be possible to get the performance you need if your models indicate required treatment times in the range of 12 seconds.

In simple terms, adding high frequency T-Rs and refurbishment is making the ESPs act like they have one more field. Simply adding high frequency T-Rs without refurbishment is making the ESPs act like they have another half field.

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### *It's not old hat!*

# Cliffside 6 Integrated Emissions Control System

**By D. Gregory McGinnis, Duke Energy; Philip C. Rader and Raymond R. Gansley, Alstom Power Inc.;**
**and Wuyin Wang, Alstom Power Sweden AB**

With approval of the final air permit in January 2008, Duke Energy has begun construction of a new nominal 800 MW unit as part of an overall modernization of their existing Cliffside, NC facility. This paper will focus on the advanced Integrated Emissions Control System (IECS) that will be supplied by Alstom. The IECS combines Alstom's dry and wet flue gas desulfurization systems in an innovative way. In the IECS process, sulfuric acid mist, hydrogen chloride, mercury, and particulate are removed by the DFGD stage with $SO_2$ and additional HCl and mercury removal occurring in the downstream WFGD. The WFGD purge stream is sent to the DFGD where it is spray dried and collected in the fabric filter thus avoiding the need for wastewater treatment and discharge.

Major cost savings are achieved by employing the spray dryer in place of a wet electrostatic precipitator to control acid mist emissions. Further savings are accomplished by eliminating the need for wastewater treatment equipment for the WFGD system. Other advantages of the IECS process include improved fuel flexibility, reduced water consumption, and the ability to employ low cost materials for construction for the WFGD absorber. This article will describe the IECS process planned for Cliffside as well as present a lifecycle cost analysis comparing Alstom's IECS to conventional technologies.

## Introduction

In response to the anticipated base electrical load growth and the need for clean energy solutions, Duke Energy is constructing a new nominal 800 MW unit as part of an overall modernization of their existing Cliffside, NC facility. The complete project involves the retirement of four 1940s vintage units, the addition of a WFGD system on Unit 5, and the construction of a new super-critical coal-fired generating facility (Unit 6). Unit 6 is currently under construction and expected to be in commercial service in 2012.

Like all new generating facilities, Cliffside Unit 6 is subject to strict emission limits for sulfur dioxide ($SO_2$), sulfuric acid mist, mercury, and total and filterable particulate. In addition, effective control of other acid gases, including HCl and HF, is an important consideration from both an environmental standpoint as well as impacts on equipment operation and maintenance. After extensive review, Duke determined that the Integrated AQCS was the most cost-effective approach to meet all these limts for Cliffside.

## System Design

Alstom's Integrated Air Quality Control System (IAQCS) combines two proven technologies – dry (DFGD) and wet (WFGD) flue gas desulfurization systems – in an innovative way that reliably achieves stringent emission requirements at a lifecycle cost well below that of competing technologies. In the integrated process, sulfuric acid mist, hydrogen chloride, mercury, and particulate are removed by the DFGD stage, with $SO_2$ and additional mercury and HCl removal occurring in the downstream WFGD. The WFGD purge stream is sent to the DFGD, where it is spray dried and collected in the fabric filter, thus avoiding the need for wastewater treatment and discharge.

## Process Description

The principal process steps are as follows:

❶ The flue gas is cooled in the Spray Dryer Absorber (SDA) using a lean, lime slurry (see Figure 6). Since the SDA outlet temperature is well below the acid dew point, the $SO_3$ in the flue gas condenses as sulfuric acid ($H_2SO_4$) mist. The sulfuric acid mist reacts with the lime slurry and is captured in the fabric filter (FF) as calcium sulfate. Experience with DFGD systems and recent pilot testing has shown that sulfuric acid mist emissions are expected to be less than 1 ppm (~0.004 lb/MBtu).

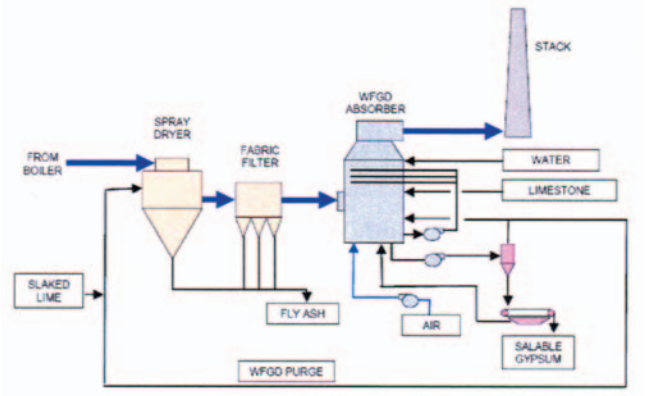


Figure 6: Integrated AQCS PFD

❷ Significant mercury capture also occurs in the DFGD. Depending on the fuel and boiler/SCR design, more than 85-90% mercury capture is expected in the DFGD stage.
❸ Significant HCl and HF capture occurs in SDA. The HCl and HF react with lime to form dry solids (i.e. calcium chloride and fluoride), which are removed in the FF.

❹ Sulfur dioxide ($SO_2$) capture in the DFGD stage is minimized by temperature control and sub-stoichiometric reagent feed in order to minimize lime usage. The small amount of $SO_2$ that is captured reacts to form a mixture of calcium sulfite and sulfate which is removed as a dry solid in the FF.

❺ $SO_2$ removal is accomplished in a conventional manner in the WFGD stage with low-cost limestone. Wallboard quality or landfill gypsum is produced. Alstom's proven open spray tower technology is capable of achieving >99% $SO_2$ removal.

❻ Additional HCl, HF, and oxidized mercury removal occurs in the spray tower as well.

❼ The purge stream that is required to control chlorides and inert fines for wallboard gypsum production is returned as a component of the lime slurry feed to the DFGD stage where it is spray dried in the SDA. Dissolved and suspended solids in the purge stream are captured in the FF and removed as dry solids with the ash.

❽ No wastewater treatment system is required to treat the purge stream from the WFGD dewatering system. In addition to the capital cost savings, the operating costs associated with this equipment (i.e. energy costs, treatment chemicals, maintenance, etc.) are avoided.

## System Benefits

The main features and benefits of the IAQCS process are discussed below.

### Sulfuric Acid Control Using Proven DFGD Technology

Like other specifications for new high-sulfur coal-fired units, the Cliffside specifications initially called for an alloy WESP (Wet Electrostatic Precipitator) as the means of controlling sulfuric acid emissions. In the IAQCS process, total particulate and sulfuric acid mist concentrations are reduced to the required permit levels through the use of DFGD technology consisting of a rotary atomizer Spray Dry Absorber (SDA) and fabric filter. Benefits of doing so include:

- Lower material costs by employing carbon steel SDA in place of an alloy WESP
- Lower construction costs due to simple SDA design (compared to WESP) and reduction in amount of alloy field welding
- Reduced exposure to alloy price volatility
- Improved O&M cost predictability with DFGD vs. WESP

### Fuel Flexibility and Lower Cost Alloy Construction for the WFGD

As a substantial quantity of the incoming HCl is removed by the DFGD stage, chloride levels in the WFGD absorber can easily be controlled to low levels (<12,000 ppm). This allows the use of lower grade stainless steel, resulting in capital cost and operating cost savings. The Cliffside project original fuel specification had fuel sulfur levels up to 5.0 lbs $SO_2$/MMBtu and up to 1,300-ppm chloride in the fuel. During further development of the project, it was decided to include fuel chloride levels up to 3,000-ppm to allow added flexibility of fuel sourcing. The integrated AQCS design was readily able to address the higher chloride condition by increasing the lime addition to the DFGD area for more HCl removal and increasing the WFGD purge rate sent to the DFGD area for evaporation. Because additional HCl could be removed in the DFGD area, the WFGD absorber operating chloride design level was maintained at 12,000-ppm, even at the highest fuel chloride condition. Thus, the material choice for the absorber remained alloy 2205 instead of a more expensive alloy needed for higher operating chloride designs.

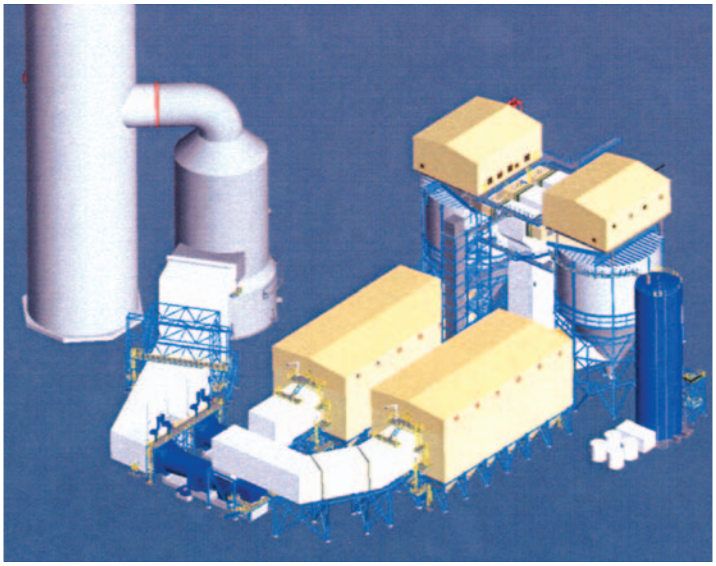
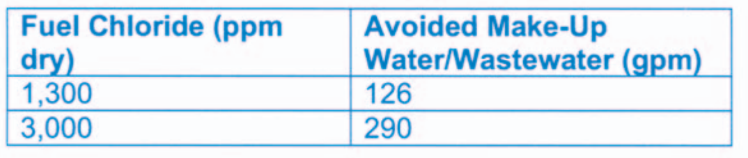


Figure 7: Cliffside 6 Integrated AQCS



| Fuel Chloride (ppm dry) | Avoided Make-Up Water/Wastewater (gpm) |
|---|---|
| 1,300 | 126 |
| 3,000 | 290 |

Figure 8: Make-up Water Savings

### No FGD Waste Water Treatment System

As noted above, a purge stream is required to control chloride and inert fines contamination in WFGD gypsum. NPDES limits on dissolved/suspended solids, heavy metals, and other constituents typically require that the purge stream be treated in multi-stage processing facilities to reduce suspended solids, heavy metals, and organic com-

| Fuel Characteristic | Minimum | Maximum |
|---|---|---|
| HHV (Btu/lb) | 9,971 | 13,256 |
| Moisture (%) | 4.57 | 19.99 |
| Ash (%) | 2.81 | 27.36 |
| Sulfur (%) | 0.52 | 3.34 |
| Sulfur Dioxide (lbs/MMBtu) | 0.9 | 5.0 |
| Chloride (ppm in fuel) | 156 | 3000 |
| Mercury (ppm in fuel) | 0.03 | 0.18 |

Figure 9: Cliffside Design Fuel Range

| Parameter | Design Value |
|---|---|
| Flue Gas Flow | 2,601,453 acfm |
| Flue Gas Temperature | 274° ± 10°F |
| $SO_3$ to AQCS | Up to 1.7% of $SO_2$ |

Figure 10: Flue Gas Design Conditions

pounds. By evaporating the purge stream in the SDA, the IAQCS process eliminates the significant capital and operating costs associated with purge stream treatment. An added benefit is that the plant owner does not have to permit, monitor, and report on the purge stream discharge. See Figure 7 on page 6.

For Cliffside, a wastewater treatment system, along with the ongoing operating and maintenance costs, is not required for the Unit 6 AQCS. Because the Unit 5 WFGD system needs to operate independently of Unit 6, a wastewater treatment system (WWTS) is planned for Unit 5. However, when Unit 6 is operating, most or all of the Unit 5 purge can be accommodated in the Unit 6 SDA, thus reducing or eliminating the O&M costs associated with the Unit 5 WWTS.

**Reduced Make-up Water Consumption**

Traditional WFGD systems remove nearly all of the HCl in the flue gas into the absorber slurry and generate a wastewater purge stream to maintain the dissolved chloride level within the design limit for the selected materials of construction and control gypsum quality. Eliminating the need for a wastewater purge stream results in a reduction in make-up water consumption for the integrated AQCS design. This is significant make-up water savings/wastewater elimination, particularly as the fuel chloride level increases, is seen in Figure 8 on page 6. Additional water conservation measures on the project are being included to allow use of cooling tower blowdown (CTB) or a blend of CTB with river water as make-up water to both the Unit 5 and Unit 6 AQCS systems.

**Mercury Capture Capability**

Based on the fuel chloride levels and the presence of an SCR, a high degree of mercury oxidation is expected at Cliffside. Based on testing, high levels of oxidation are conducive to mercury capture in both wet and dry FGD systems.[1] Since the integrated AQCS design includes DFGD and WFGD systems in series, the majority of the mercury will be expected to be removed in the DFGD area, which includes a fabric filter, and the WFGD absorber is expected to act more as a polishing stage for oxidized mercury that is not captured by the DFGD. Since only a small portion of the total mercury removed is projected in the WFGD, the potential for mercury re-emission from the WFGD is reasoned to be low relative to a design where the WFGD removes the majority of the mercury. The mercury content in the gypsum is also expected to be lower than in a conventional WFGD-only system.

| Parameter | Emission |
|---|---|
| $SO_2$ Removal | 0.12 lbs $SO_2$/MMBtu (99% Removal*) |
| Filterable Particulate ($PM_{10}$) | 0.012 lbs/MMBtu |
| Total Particulate ($PM_{10}$) | 0.018 lbs/MMBtu |
| Sulfuric Acid ($H_2SO_4$) | 0.005 lbs/MMBtu |
| Mercury | 0.019 lbs/GWh gross energy output |
| Opacity | 20% |
| Lead | 0.000022 lbs/MMBtu |

* AQCS design value

Figure 11: Emission Requirements

**Potential Fly Ash Resale**

Since a lean feed of lime slurry is used in the DFGD area to remove sulfuric acid and a portion of the HCl, the impact on the ash composition is small as compared to a conventional DFGD application. There is also a small contribution of solids, mainly gypsum solids from the WFGD purge stream that is added to the ash. For the Cliffside performance basis fuel (17.96 wt.% ash, 3.55 lbs $SO_2$/MMBtu, 531 ppm Cl in fuel), the total addition of solids to the fly ash collected is expected to be less than 5%. The impact on ash composition increases for high flue gas sulfuric acid and HCl levels and for lower fuel fly ash content.

Analysis of representative ash samples from the pilot plant study by a firm that re-sells power plant ash to the cement industry has been completed. No problematic issues for cement use were identified with the pilot samples. Chemical composition and mix testing provided positive results. It is expected that final determination of suitability for cement use will not be determined until actual plant operation, and it will then depend on the characteristics (sulfur, chloride and ash levels) of the fuels burned due to the wide range of fuels specified.


Figure 12: Spray Tower Absorber

## Specific Details for Clifffside Unit 6

### Design Requirements

Duke Energy's new Cliffside Unit 6 will include a pulverized coal-fired supercritical boiler equipped with selective catalytic NOx reduction (SCR). The plant is located near Cliffside, North Carolina at an existing power plant site. The plant is nominally sized at 800 MW and is permitted to fire up to 7,850 MMBtu/hr.

The design of the AQCS considers a wide range of fuels including both eastern bituminous and western sub-bituminous coals. Design includes fuel blends with sulfur levels up to 5.0 lbs $SO_2$ per MMBtu, and chloride levels up to 3,000 ppm on a weight basis. Figure 9 on page 7 presents design ranges for the fuel blends. Design conditions for the flue gas leaving the air heaters and entering the AQCS scope are shown in Figure 10 on page 7. In Figure 11 on page 7, system emission requirements are stringent to meet permit requirements for this new coal-fired power plant.


Figure 13: Rotary Atomizer

### Flue Gas Path

The flue gas leaves the two air heater outlets (by others) and is combined into a common duct that rises vertically to the inlet of two 50% Spray Dryer Absorbers (SDA). Separate gas paths are maintained through the fabric filters.

Gas leaves the fabric filter to the two axial flow ID fans. The gas is combined in a common duct and enters the single Open Spray Tower (OST) absorber. A new two-flue stack will serve both Units 5 and 6.

### Common Systems

The WFGD portion of the Unit 6 AQCS shares common equipment with the new WFGD system for the existing Cliffside Unit 5. The limestone preparation system has two (one operating and one redundant) horizontal ball mills, each rated at 48 tph. Redundant reagent slurry storage tanks, pumps and feed loops to both absorbers are included. Hydrocyclones are used for the primary dewatering step with the underflow collected in filter feed tanks (two provided). Two horizontal belt filters are provided to produce wallboard-quality gypsum.

### DFGD Area

Two 68 ft diameter SDAs are provided to intimately contact the flue gas with the lime reagent, and partially quench the flue gas while evaporating the purge flow from the WFGD system. The capacity of the SDAs to evaporate water not only allows for all of the purge from Unit 6 to be evaporated, but also allows for the complete WFGD purge stream from Unit 5 to be evaporated in the SDAs under most scenarios when Unit 6 is operating. The SDA is a standard Alstom design employing three top-entry gas inlets per vessel, each equipped with a rotary atomizer.

The lime preparation system includes three detention type slakers. Each slaker is sized for 50% of the maximum demand condition. Since the plant had a wide range in lime demand due largely to the wide range in fuel chloride level (up to 3000 ppm Cl in fuel), the choice of 50% slakers allows for the operation of one slaker only under lower chloride operating scenarios and avoids turndown issues on the slaker for these conditions.

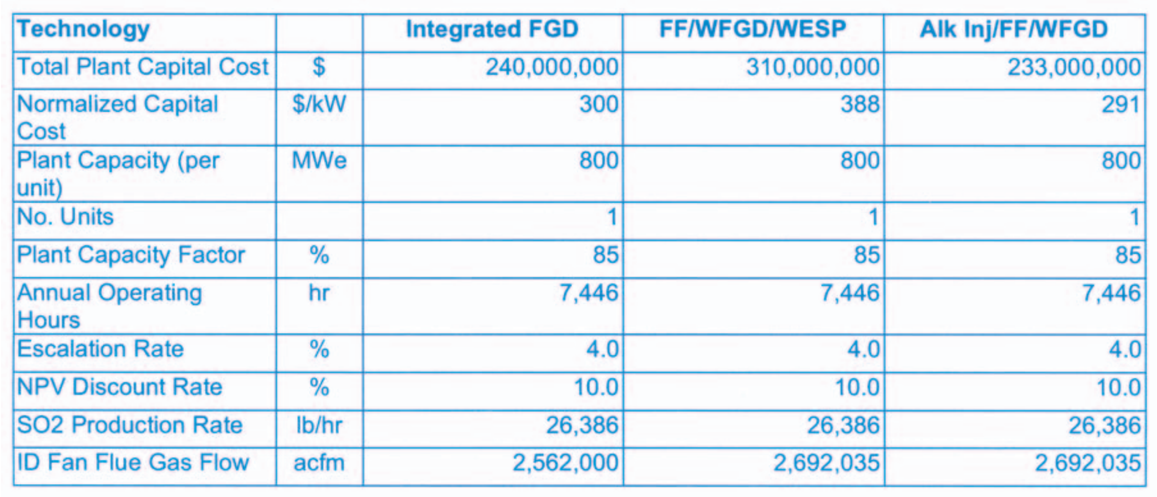
Slaked lime slurry is combined with the purge from the WFGD absorbers in a pre-mix tank. (See Figure 12.) The pre-mix tank overflows to an SDA feed tank, which provides suction to an SDA feed pump that delivers the slurry to the atomizers. Any additional make-up water needed to quench the flue gas is added to these tanks. A redundant set of tanks, feed pump and feed line to the SDAs is included for reliability.

The fabric filter is Alstom's LKP intermediate pressure, pulse jet design. Two casings are provided, each with 12 compartments with a 3.6-ft/min net-1 air-to-cloth ratio. The bags are 26.5 ft. long of a blended PPS/P84 material with an intrinsic coating.

**WFGD Area**
The spray tower absorber is designed for 99% $SO_2$ removal over the range of fuel sulfur levels. See Figure 13 on page 8. The absorber is Alloy 2205 construction designed for continuous operation with dissolved chloride levels of up to 12,000 ppm. The design includes five normally operating spray levels for the maximum sulfur condition, with each spray level fed by a single slurry pump. The absorber is designed for up to 13 ft/sec saturated flue gas velocity. The reaction tank diameter is expanded relative to the absorption section to allow for adequate gypsum residence time. Absorber design features include dual orifice spray nozzles on the bottom four spray levels with a high degree of spray overlap and wall ring technology. An organic acid additive system is included (shared with Unit 5 absorber); its intended use is to maintain $SO_2$ removal in the event of an unplanned spray pump outage.

## Lifecycle Cost Analysis

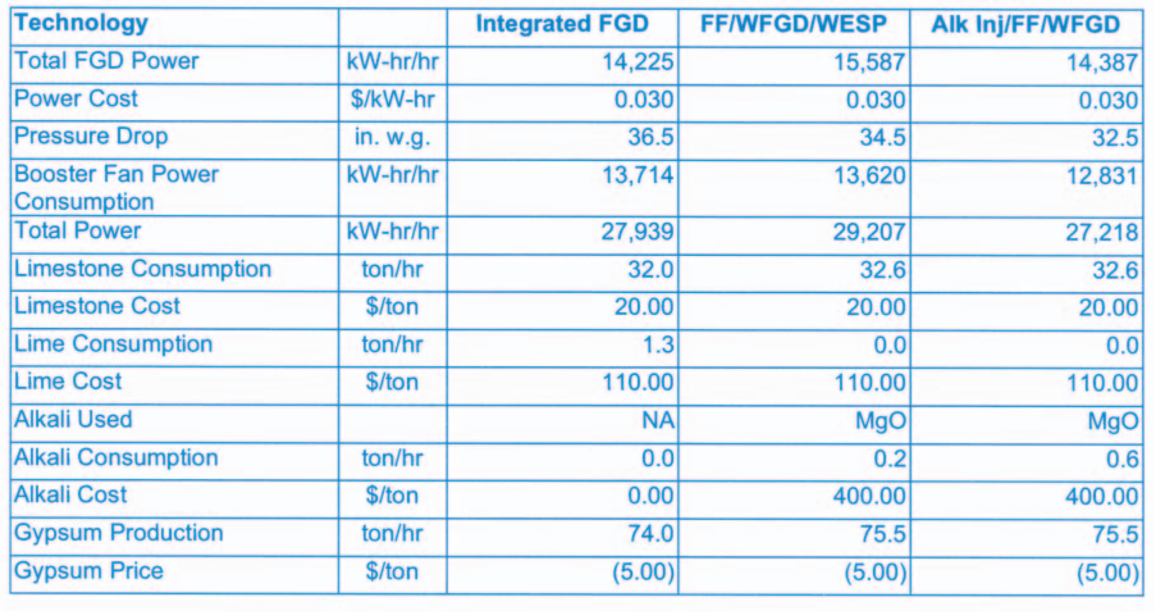
The principle quantitative benefit of the Integrated Air Quality Control System is a savings in lifecycle costs. The following paragraphs present a lifecycle cost comparison of the IAQCS to conventional solutions as follows:



| Technology | | Integrated FGD | FF/WFGD/WESP | Alk Inj/FF/WFGD |
|---|---|---|---|---|
| Total Plant Capital Cost | $ | 240,000,000 | 310,000,000 | 233,000,000 |
| Normalized Capital Cost | $/kW | 300 | 388 | 291 |
| Plant Capacity (per unit) | MWe | 800 | 800 | 800 |
| No. Units | | 1 | 1 | 1 |
| Plant Capacity Factor | % | 85 | 85 | 85 |
| Annual Operating Hours | hr | 7,446 | 7,446 | 7,446 |
| Escalation Rate | % | 4.0 | 4.0 | 4.0 |
| NPV Discount Rate | % | 10.0 | 10.0 | 10.0 |
| SO2 Production Rate | lb/hr | 26,386 | 26,386 | 26,386 |
| ID Fan Flue Gas Flow | acfm | 2,562,000 | 2,692,035 | 2,692,035 |

Figure 14: Lifecycle Cost Inputs (5)

***Integrated AQCS***
Alstom Integrated AQCS as described in this paper (spray dryer, fabric filter, spray tower absorber).

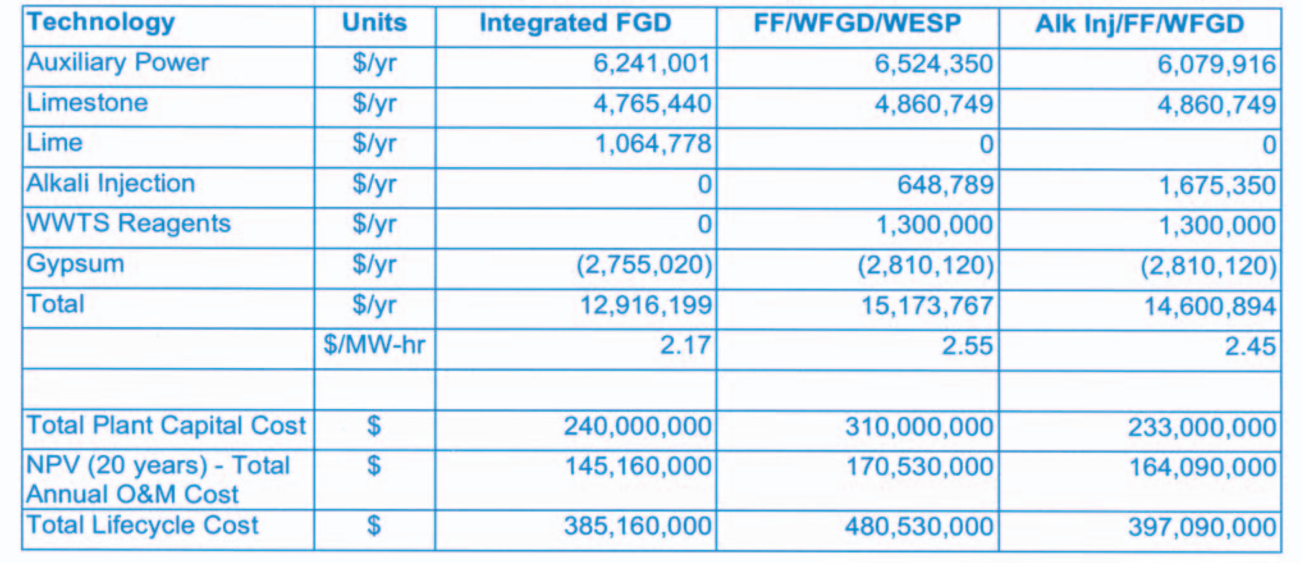


| Technology | | Integrated FGD | FF/WFGD/WESP | Alk Inj/FF/WFGD |
|---|---|---|---|---|
| Total FGD Power | kW-hr/hr | 14,225 | 15,587 | 14,387 |
| Power Cost | $/kW-hr | 0.030 | 0.030 | 0.030 |
| Pressure Drop | in. w.g. | 36.5 | 34.5 | 32.5 |
| Booster Fan Power Consumption | kW-hr/hr | 13,714 | 13,620 | 12,831 |
| Total Power | kW-hr/hr | 27,939 | 29,207 | 27,218 |
| Limestone Consumption | ton/hr | 32.0 | 32.6 | 32.6 |
| Limestone Cost | $/ton | 20.00 | 20.00 | 20.00 |
| Lime Consumption | ton/hr | 1.3 | 0.0 | 0.0 |
| Lime Cost | $/ton | 110.00 | 110.00 | 110.00 |
| Alkali Used | | NA | MgO | MgO |
| Alkali Consumption | ton/hr | 0.0 | 0.2 | 0.6 |
| Alkali Cost | $/ton | 0.00 | 400.00 | 400.00 |
| Gypsum Production | ton/hr | 74.0 | 75.5 | 75.5 |
| Gypsum Price | $/ton | (5.00) | (5.00) | (5.00) |

Figure15: Operating Cost Inputs

***FF/WFGD/WESP***
Fabric filter with WFGD system followed by WESP for $SO_3$/total particulate control.

***Alk Inj/FF/WFGD***
Dry alkali injection (MgO) for $SO_3$ control followed by fabric filter and WFGD system. (Note that this configuration is included for illustrative purposes only as alkali injection has not been proven to consistently achieve the modern $SO_3$ permit limits for Cliffside.)



| Technology | Units | Integrated FGD | FF/WFGD/WESP | Alk Inj/FF/WFGD |
|---|---|---|---|---|
| Auxiliary Power | $/yr | 6,241,001 | 6,524,350 | 6,079,916 |
| Limestone | $/yr | 4,765,440 | 4,860,749 | 4,860,749 |
| Lime | $/yr | 1,064,778 | 0 | 0 |
| Alkali Injection | $/yr | 0 | 648,789 | 1,675,350 |
| WWTS Reagents | $/yr | 0 | 1,300,000 | 1,300,000 |
| Gypsum | $/yr | (2,755,020) | (2,810,120) | (2,810,120) |
| Total | $/yr | 12,916,199 | 15,173,767 | 14,600,894 |
|  | $/MW-hr | 2.17 | 2.55 | 2.45 |
|  |  |  |  |  |
| Total Plant Capital Cost | $ | 240,000,000 | 310,000,000 | 233,000,000 |
| NPV (20 years) - Total Annual O&M Cost | $ | 145,160,000 | 170,530,000 | 164,090,000 |
| Total Lifecycle Cost | $ | 385,160,000 | 480,530,000 | 397,090,000 |

Figure 16: Lifestyle Cost Comparison

## Methodology

The capital and operating costs were compared by combining the sum of the present day capital cost and the discounted value of future operating costs over the period of concern. The Net Present Value (NPV) method is commonly used in the engineering project business to compare the economic merits and viability of alternative scenarios in which expenditures are made and the economic impact is felt over a period of time. In this method, the annual O&M costs were calculated based on the plant/unit capacity factor and AQCS system operating performance (e.g. power consumption, reagent consumption, etc.). The long-term impact of each O&M cost component was evaluated using the net present value method.

The NPV of a series of future payments is defined as:
where, NPV = Net Present Value of future payments, $

$$NPV = \sum_{i=1}^{n} \frac{P}{(1+R)^i}$$

n = Number of equally-spaced payments
P = Value of individual payment, $
R = Discount rate, %

The Net Present Value can be thought of as the amount of money that, if in the possession of the owner at the beginning of the lifecycle and used to pay for future operating expenses, would be exhausted at the end of the period. The time-value of money is incorporated in the analysis by assuming a certain discount rate. The sum of the capital cost and the NPV of the O&M costs is a reasonable representation of the total lifecycle cost.

## Capital Cost

Figure 14 on page 9 presents the capital costs and financial assumptions used to calculate the lifecycle costs. The Total Plant Capital Costs are indicative estimates for a plant like Cliffside. The capital costs include the major process equipment (i.e. absorbers, fabric filters, WESP, reagent handling/feed systems, byproduct handling systems, etc.), balance of plant (i.e. foundations, electrical, plant services, etc.), construction, and commissioning.

## Operating and Maintenance Costs

The following O&M costs were considered in the analysis:

➜ Power – The power consumed by both the AQCS system and ID fans is considered and are shown separately. Power consumption was calculated by summing the individual electrical loads for the major components.

➜ Reagent – The following reagents are considered in the lifecycle cost analysis:

- ♦ Limestone – Used in all cases for removal of $SO_2$ and other acid gases (e.g. HCl, HF).
- ♦ Lime – Used in the Integrated AQCS to react with $SO_3$ and other acid gases (e.g. HCl, HF).
- ♦ Magnesium hydroxide – Used in the FF/WFGD/WESP to neutralize the $SO_3$ collected in the WESP and in the Alk Inj/FF/WFGD for $SO_3$ control.
- ♦ WWTS (Waste Water Treatment) chemicals – Used in the FF/WFGD/WESP and Alk Inj/FF/WFGD cases to treat the WFGD purge stream. These chemicals are used to remove heavy metals and suspend ed solids prior to discharge.

➜ Byproduct – The revenue from gypsum sale was considered. Ash disposal/sales were not considered in this analysis as the costs/revenues are considered to be equivalent for all cases.

Quantities and unit costs/credits for major O&M items are indicated in Figure 15 on page 9.

**Lifecycle Cost Comparison**

Figure 16 on page 10 indicates the annual O&M costs and lifecycle cost for the Conventional and Integrated AQCS options.

Based on the analysis in Figure 16, the Integrated AQCS approach is clearly preferred. Contributing factors include:

➜ The use of relatively low-cost lime reagent for $SO_3$ in the Integrated AQCS control results in a substantial operating cost savings compared the use of MgO in the FF/WFGD/WESP and Alk Inj/FF/WFGD cases.

➜ Eliminating the need for WWTS (Waste Water Treatment System) chemicals in the Integrated AQCS results in a $1.3 M per year O&M cost savings.

➜ The AQCS capital costs for the Integrated AQCS are significantly less than the FF/WFGD/WESP approach due to:

- ♦ Material cost savings due to the elimination of the WWTS
- ♦ Material cost saving associated with replacing the WESP with a spray dryer
- ♦ Corresponding lower erection costs

➜ Although the capital cost of the Integrated AQCS is slightly higher than the Alk Inj/FF/WFGD approach, the operating costs are lower, making the IAQCS the better choice on an overall lifecycle cost basis. Also, the IAQCS can reliably achieve the proposed permit limits for sulfuric acid mist emissions.

## Pilot Plant Testing

Although the Cliffside Integrated AQCS is based on proven dry and wet FGD technologies, pilot plant testing was conducted to:

- ✲ Establish the removal efficiencies/limits of $SO_3$ and HCl
- ✲ Confirm the drying properties of scrubber bleed liquid
- ✲ Perform parametric studies related to stoichiometric ratio, temperature, and bleed flow
- ✲ Examine the impact of trace pollutants
- ✲ Collect/analyze ash samples

Pilot testing of the DFGD stage was performed on a ~1 MW equivalent slipstream at Cliffside Unit 5. The pilot plant consisted of a dual-fluid nozzle spray drying and fabric filter, along with related auxiliary equipment (e.g. ducts, fans, lime slurry and scrubber purge feed systems, etc.). Purge liquor was collected from the existing WFGD system at Duke Energy's Marshall Steam Station and transported to Cliffside for testing. Provisions were made to spike the Unit 5 slipstream with $SO_2$, $SO_3$, and HCl to simulate the range of Unit 6 operating conditions. See figure 17.

Figure 17: IAQCS Pilot Plant

Pilot plant testing at Cliffside confirmed:

- ✲ Low $SO_3$ emissions (<<1 ppm)
- ✲ Selective removal of HCl in the presence of $SO_2$
- ✲ Lime stoichiometric ratio requirements
- ✲ Effective drying of WFGD purge stream

Ash/byproduct samples were collected and submitted for analysis and testing for use in cement. Initial testing indicated that the byproduct was within the required specifications for cement manufacture.

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1) J. E. Locke, Withum, J. A., Tseng, S. C., CONSOL Energy, "Mercury Emission from Coal-Fired Facilities with SCR-FGD Systems," Proceedings of Air Quality V Conference, Sept. 2005.

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# Dealing with Non-Detects in Air Emissions Testing *(Part 1)*

continued from front page

Conceptually, the detection limit is simply the minimum amount or concentration of a substance that must be present for a measurement process (MP) to distinguish it from the background. However, any specific numerical value representing a detection limit, say 2 ppm, is not absolute. It is the result of several factors any one of which, if altered, will change the number. Some of the most important ones are:

- ▲ The risk of a false positive (deciding the substance is present, when it is not)
- ▲ The risk of a false negative (deciding the substance is not present, when it is)
- ▲ The matrix in which the substance is contained
- ▲ The skill and experience of the person taking the measurement.
- ▲ The current state of maintenance and calibration of the measuring equipment.
- ▲ Sampling error.

This last factor is of particular importance to air emissions testing and one we shall discuss in more detail below.

It's important to remember that the output of any measurement process is not a number but a range, more precisely a distribution. If, for example, measurements are taken when the substance is not present, one would hope that the MP output is close to zero. But it will rarely be exactly zero. A good MP will output tightly bunched data, both positive and negative values, centered at the zero point. These data can then be used to define a curve that represents expected data scatter (see Figure 1 on front cover). For measurements taken in the absence of the substance of interest, this curve is usually the familiar normal distribution. This distribution represents the background against which the MP must distinguish the signal from the substance of interest must be discerned.

This measurement, the matrix without the substance of interest present, is the blank and it is fundamental to the determination of the detection limit. The better the distribution of the blank measurement is known, the more confidence one has in the determination of the detection limit. This is discussed in more detail below.

What constitutes a blank for air emissions testing is worth discussing for a moment. In a perfect world, a blank would be composed of the entire matrix in which the substance of interest will be measured, but with the substance itself absent. Even in a laboratory setting, this is often difficult or impossible to achieve. For air emissions testing, it's almost always impossible. Because of this, detection limits for reference methods are often based on prepared laboratory standards or zero gases. This approach does not take into account potential matrix effects and interference.

A more fundamental issue is that these detection limits are derived solely from the analytical portion of the method. This is the most serious flaw in the determination of detection limits for air reference methods. The vast majority of variation in air reference methods does not occur in the analytical portion of the method, but rather in the sampling portion. Typically, sampling and matrix effects are completely ignored when detection limits are determined during method validation. This results in detection limits that are far lower than what is actually achieved in the field.

This can be a major problem for affected sources using the method. Permit writers may use these unrealistically low limits to set emission standards for the source. Air pollution control vendors may also rely on these detection limits when establishing performance guarantees. Problems are then encountered when compliance or guarantee tests are performed which cannot produce reliable data at these low levels.

One example of this is EPA Method 8 "Determination Of Sulfuric Acid and Sulfur Dioxide Emissions from Stationary Sources." While there are a number of problems with this method, the focus here will be only on the detection limit issue. The detection limit (referred to as "sensitivity" in the method) listed in the method is 0.05 mg/m3 or about 0.01 ppm. After some research (Evans 2007) into the validation of this method, it was determined that this limit was based upon the sensitivity of the analytical technique, in this case, titration.

To check whether this limit was realistic in the field, tests were conducted (Evans 2007) to determine the true Method Detection Limit (MDL) of Method 8. The MDL encompasses the entire measurement process including sampling uncertainty and matrix effects. The results showed that the MDL, under controlled conditions, was no better than 0.2 ppm - an order of magnitude higher than stated in the method. In the field, this number is most likely even higher. Further field studies are on-going.

## Determining Realistic Method Detection Limits for Air Methods

The MDL is fundamentally related to the variability of the MP output at or near zero. The problem comes with determining that variability in a manner that encompasses the entire method including sampling uncertainty and matrix effects. The best way to accomplish this would be in field sampling an actual source. The question, of course, is under these circumstances, how do you obtain a blank?

EPA has already addressed this issue, although not in the context of detection limits, with its Method 301 "Field Validation of Pollutant Measurement Methods from Various Waste Media." This method is used to demonstrate the equivalence of unvalidated test methods to validated reference methods. In this method, paired sampling trains (or quadruplet sampling trains) are used to determine method variability. Although the words "detection limit" are not found in Method 301, the same approach can be used to determine MDLs.

By comparing the variability in the differences between paired sampling trains, the precision of the method is determined. This is all that is required to determine the detection limit. However, since any matrix effects should be the same for both sampling trains, these would not be taken into account. Dynamic spiking can be used to determine any biases caused by matrix effects, although the details of this are a topic for another paper. This key point here is that both sampling uncertainty and matrix effects can be determined from this method.

There are a couple of considerations when using the "differences" approach. First, it is not uncommon for the absolute variability of a method to increase proportionately with concentration (although the relative variability will usually stay the same). This phenomenon is referred to as "heteroscedasticity." Therefore, when determining MDL with this technique, sampling should be performed when the amount of the substance of interest is very low, i.e. after a control device. An interesting study might be to compare method variability at the inlet and outlet of a control device.

Another issue is that of potential bias between the paired trains. Since the sampling trains employ the same method and sample at or near the same point, the distribution of the differences should be centered around zero. If this distribution is significantly shifted, this indicates a problem with one of the sampling trains causing a bias. If this is seen, it must be identified and corrected.

A minimum of seven valid paired runs should be used in determining the MDL. Of course, a larger number provides better results. Once this is done, the standard deviation can be calculated and an appropriate upper confidence level (e.g. 95%, 99%) can be determined. The calculations for this are left to the reader and are readily available. This value is then equivalent to Currie's Critical Level (LC) (Currie 1968 and IUPAC 2005) or EPA's Limit of Detection (LOD) (EPA 2007).

In Part 2 of this paper, which will appear in the Fall Issue of the WPCA Newsletter, we will discuss how to report data that is below the detection limit.

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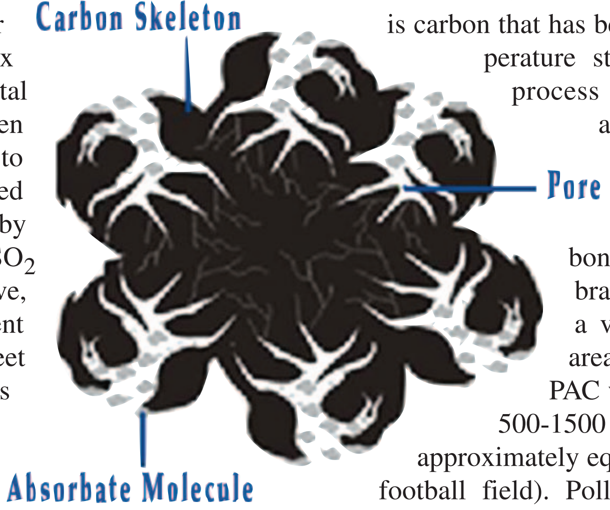
# Cost Effective Integrated Approach to Mercury Removal

continued from front page

Vapor-phase mercury, appearing in coal combustion flue gas, will be present as either elemental mercury or oxidized mercury, with proportions largely dependent on the type of coal being burned. It has been recognized by industry experts that a loose empirical positive relationship holds between the chloride content of coal and the extent to which its inherent mercury becomes oxidized. Therefore, a higher percentage of oxidized mercury is produced from high-sulfur, high-chloride coal, such as eastern U.S. bituminous coals. For low-sulfur, low-chloride coal, such as subbituminous and lignite, a higher percentage of elemental mercury is produced. Capturing oxidized mercury is easier than capturing elemental mercury.

Environmental equipment already installed at some electric generating plants can remove a portion of vapor-phase mercury, both elemental and oxidized. For example, the SCR catalyst in place for NOx removal aids in the oxidation of the elemental mercury when in the presence of a halogen such as chlorine or bromine. Then, due to oxidized mercury's water solubility, oxidized mercury is dissolved and readily removed by wet and dry FGD scrubbers during the $SO_2$ removal process. While somewhat effective, simply relying on environmental equipment already in place may not be adequate to meet current or pending mercury emissions limits set by the regulatory agencies.

Figure 18: Powdered Activated Carbon Particle[1].



Following is a discussion of general mercury technology including how it works, when and where it is used, a system overview, limitations, and potential economic savings.

## Use of Powdered Activated Carbon (PAC) for Removing Hg

Sorbent technology is the most proven method presently employed for total mercury control. Sorbents are particulate matter injected into the flue gas that provide for adsorption of chemical species from the flue gas. Of these, powdered activated carbon (PAC) is the most established technology for mercury control, and can provide up to 90% mercury capture for coals with high chorine content. By adsorbing onto the surface of the PAC, the elemental mercury converts into oxidized mercury and particulate mercury, which may be subsequently removed in particulate control devices (ESP or fabric filter). Chemical modification of the PAC, such as halogenation, can improve the ability of the sorbent to capture mercury, but can also increase material costs. Though 90% total mercury removal for PRB coal is unlikely using standard PAC, the increased reactivity provided by halogenated PAC makes this target more realistic. Due to the relative concentrations of mercury in the flue gas as compared to other reactive species, the amount of sorbent needed to achieve a target removal rate is not determined by calculations based on the amount of mercury in the flue gas. While such relations may be developed eventually, empirical correlations based on field data are currently used to guide estimation of injection rates.

As mentioned, PAC is the most widely used sorbent for mercury control in the utility industry. PAC is carbon that has been treated with high temperature steam using a proprietary process to create large surface areas. Figure 18, at left, presents a diagram of a PAC particle. Each PAC particle consists of a carbon skeleton with numerous branching pores that provide a very high ratio of surface area to volume. One gram of PAC will have a surface area of 500-1500 $m^2$ (5 grams of carbon is approximately equivalent to the area of one football field). Pollutants, such as mercury, become adsorbed in the nanopores of the PAC particles, and are effectively sequestered from the flue gas stream. The sorbent activity varies with respect to each chemical species, with oxidized mercury having a greater rate of adsorption by PAC than elemental mercury. Sorbent reactivity with respect to a given chemical species is determined by testing the sorbent with that species. Further, the reaction kinetics of PAC are temperature dependent. Standard PAC is only effective for mercury control at flue gas temperatures below about $330^{o}$F for bituminous coal and about $350^{o}$F for PRB coal. Therefore, total mercury removal of over 90% may be attained for bituminous coal using standard PAC when an SCR is part of the air pollution control system, but only about 60% removal could be expected for untreated PRB coal using standard PAC injection. However, over 90% total mercury removal when burning subbitumuous coal has been achieved using halogenated PAC. See Figure 19.

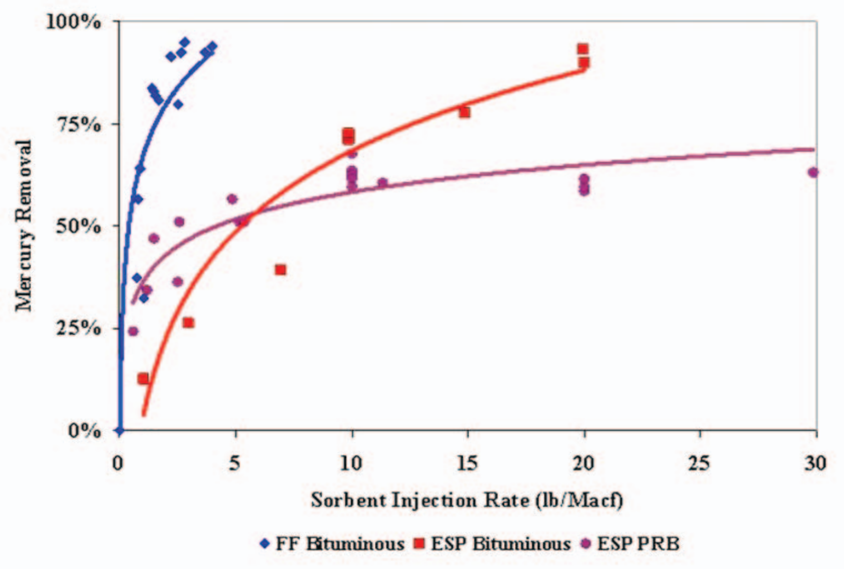


Figure 19: Mercury Removal as a Function of Sorbent Injection for Various Coal Types across a FF or ESP[2] .

A typical PAC injection system consists of the following: A storage silo, as shown in Figure 20, is used for on-site PAC storage. Air fluidization valves and nozzles at the conical discharge pulse instrument quality dry compressed air into the bulk carbon to promote mass flow. From the storage silo, the PAC is conveyed to a volumetric feed hopper for temporary storage. Screw feeders then transport the carbon into a drop tube, from which it is fed to the eductor inlet, below the feeder discharge. The carbon-in-air mixture is metered into the flue gas ductwork with an array of injection lances.

As discussed above, by halogenating the PAC, sorbent affinity for mercury capture may be increased. Therefore, lower sorbent injection rates are required to achieve the same mercury capture. Halogenated PAC is purchased from suppliers, who use proprietary methods to impregnate the carbon with the halogen species. In addition, the halogenation process alters the PAC properties such that halogenated sorbents may be effective at flue gas temperatures up to 400°F, while standard PAC decreases in usefulness as flue gas temperatures exceed 350°F when burning PRB coal. Brominated PAC is the most commonly sold carbon for Hg control, since bromine is far more reactive than chlorine. Unlike standard PAC, injection of brominated PAC alone may provide adequate mercury removal rates for many plants to meet pending State and Federal Regulations. As an example, for a cold-side ESP and a pulse-jet fabric filter (PJFF), total mercury removals would be anticipated to improve from baseline rates of 10-30% and 30-50% to 50-70% and 70-90%, respectively, with brominated PAC injection.

Another unique challenge is PAC poisoning by $SO_3$. When burning medium to high sulfur coal, $SO_2$ to $SO_3$ conversion (up to 2%) occurs in the boiler and across the SCR system. PAC consumption increases as $SO_3$ concentration increases above 5 ppm. At greater than 15 ppm, the PAC is much less effective in removing mercury. To mitigate this $SO_3$ impact, sorbent injection systems utilizing lime or trona that remove $SO_3$ before the point of PAC injection can be installed.

## Mercury Removal Optimization Using a Coal Additive - MercPlus™

As mentioned earlier, there exists a loose empirical positive relationship between the chloride content of coal and the extent to which its inherent mercury becomes oxidized. Coals with less than 100 ppmw of chlorine (Cl) have more elemental mercury at the inlet of their respective environmental control equipment while coals with greater than 500 ppmw Cl have less than 20 percent elemental mercury.

Figure 20: PAC Injection Silo [3].

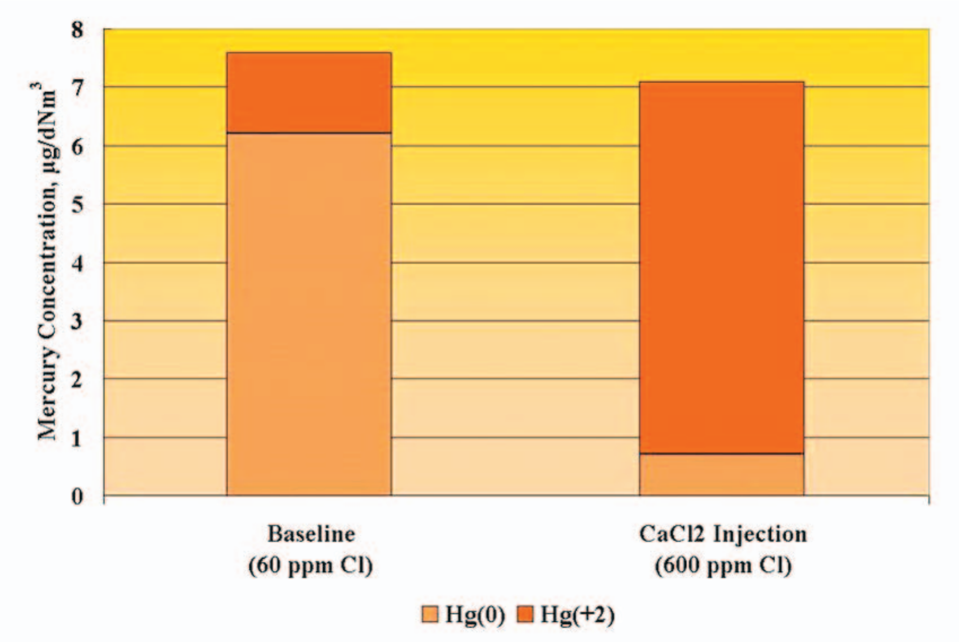
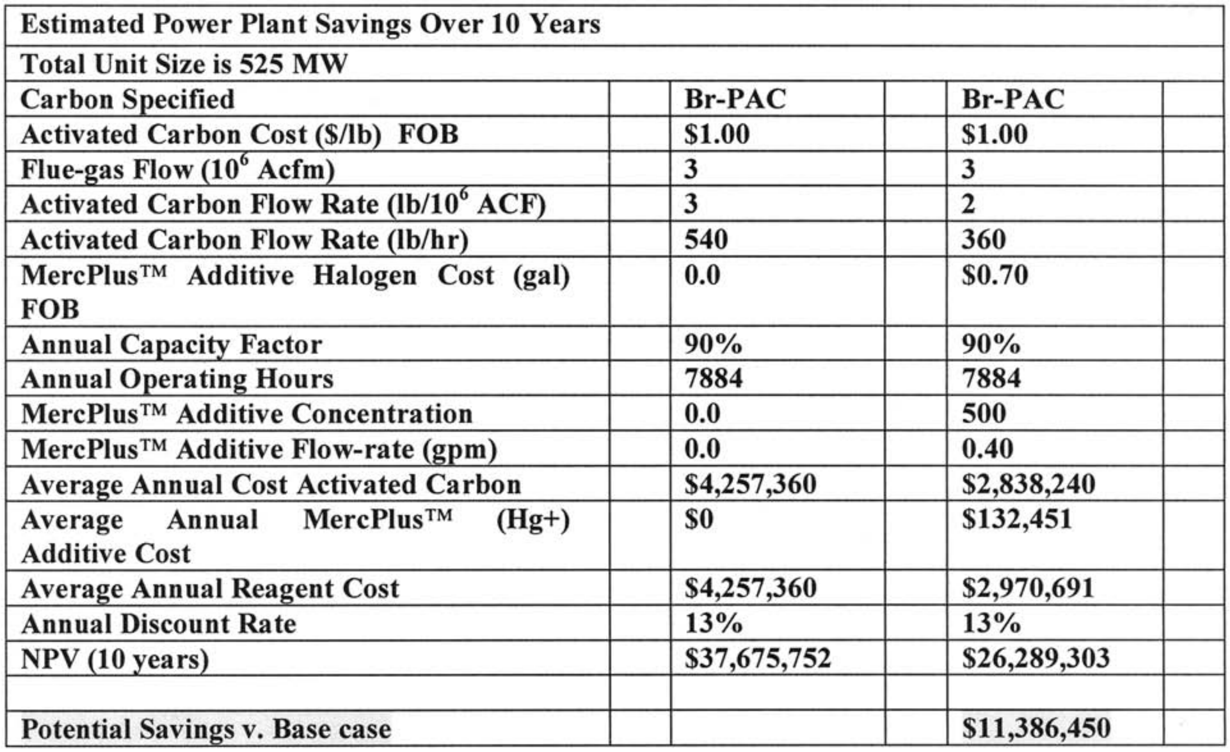


Figure 21: Impact of Chloride Addition on Mercury Speciation.



| | | | | | |
|---|---|---|---|---|---|
| **Estimated Power Plant Savings Over 10 Years** | | | | | |
| **Total Unit Size is 525 MW** | | | | | |
| **Carbon Specified** | | **Br-PAC** | | **Br-PAC** | |
| **Activated Carbon Cost ($/lb) FOB** | | **$1.00** | | **$1.00** | |
| **Flue-gas Flow ($10^6$ Acfm)** | | **3** | | **3** | |
| **Activated Carbon Flow Rate (lb/$10^6$ ACF)** | | **3** | | **2** | |
| **Activated Carbon Flow Rate (lb/hr)** | | **540** | | **360** | |
| **MercPlus™ Additive Halogen Cost (gal) FOB** | | **0.0** | | **$0.70** | |
| **Annual Capacity Factor** | | **90%** | | **90%** | |
| **Annual Operating Hours** | | **7884** | | **7884** | |
| **MercPlus™ Additive Concentration** | | **0.0** | | **500** | |
| **MercPlus™ Additive Flow-rate (gpm)** | | **0.0** | | **0.40** | |
| **Average Annual Cost Activated Carbon** | | **$4,257,360** | | **$2,838,240** | |
| **Average Annual MercPlus™ (Hg+) Additive Cost** | | **$0** | | **$132,451** | |
| **Average Annual Reagent Cost** | | **$4,257,360** | | **$2,970,691** | |
| **Annual Discount Rate** | | **13%** | | **13%** | |
| **NPV (10 years)** | | **$37,675,752** | | **$26,289,303** | |
| | | | | | |
| **Potential Savings v. Base case** | | | | **$11,386,450** | |

Figure 22: Cost Savings example using MercPlus™ additive with an AQCS consisting of SCR/SDA/FF or SCR/FF.

The chlorine content of bituminous coals varies from several hundred to several thousand ppmw. Conversely, the chlorine content of low-rank coals has a much lower and a more narrow range: from 5 to 200 ppmw. In both cases, chlorine compounds in the flue gas decrease the amount of gaseous elemental mercury present at the inlet to pollution control equipment and increase the amount of oxidized mercury there. Figure 21 illustrates the impact of chloride on the speciation of mercury.

One way to improve the overall capture of mercury in the system would be to increase the fraction of mercury appearing in oxidized form. By increasing the chloride content of the coal this goal can be achieved. As an added benefit of chloride addition, the quantity of activated carbon consumed to meet mercury emissions limits can be considerably reduced. B&W PGG's MercPlus™ additive works in tandem with standard or brominated PAC to enhance the PAC adsorption capabilities. Typically, standard PAC is only used if there is an SCR system.

The equipment needed to implement a MercPlus™ additive injection system is a storage tank and a self contained pump skid which injects the MercPlus™ additive solution into the coal feeders through a single feed line for each coal feeder. The initial equipment investment is

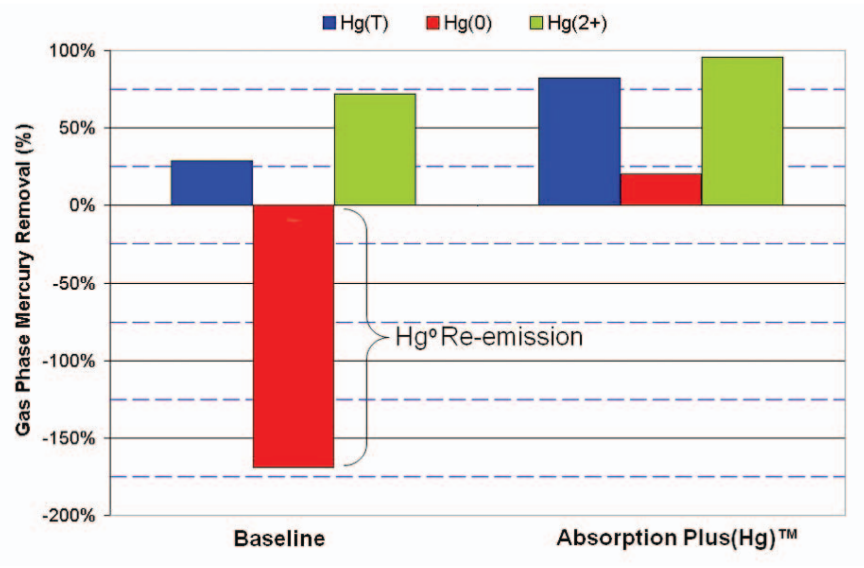


Figure 23 - The use of the Absorption Plus (Hg)™ system is designed to inhibit mercury re-emission and remove nearly all of the oxidized mercury in a Wet FGD system.

minimal when compared to the potential long term dollar savings realized in the reduced usage of activated carbon. Figure 22 on page 16 gives an example of estimated savings in carbon consumption in a plant burning a PRB coal and using a brominated PAC.

The proposed addition of chlorides to the coal to enhance mercury oxidation can raise potential concerns about the impacts of the added chlorides on boiler materials and operation, and on the downstream equipment. The target chloride content for most applications is less than 500 ppm which does not exceed the chloride concentration of bituminous coals that have been successfully fired for many years at eastern U.S. utility plants.

## Use of a WFGD Additive to Inhibit Mercury Re-emission - Absorption Plus (Hg) ™

Since oxidized mercury is soluble in water, wet flue gas desulfurization (WFGD) units have been useful as mercury control systems. In a wet scrubber, the mercury is exposed to a complex environment of gas/liquid/solid phase electrolytic chemistry. The oxidized mercury will rapidly dissolve into the WFGD slurry, but some oxidized mercury may react with dissolved constituents to be subsequently reduced to elemental mercury and then re-emitted in the vaporous, elemental form. While the exact cause of elemental Hg re-emission is being evaluated, the following parameters are important: temperature, mercuric sulfite complexes, pH, soluble chloride and the type of solid present. B&W PGG is currently offering the Absorption Plus (Hg)™ system as a patented technology for controlling re-emission of elemental mercury from WFGD units. See Figure 23. The Absorption Plus (Hg)™ system is readily utilized with B&W PGG's proprietary Absorption Plus (Hg)™ additive, thereby providing an optimal environment to react with the dissolved oxidized mercury and form an insoluble chemical species that is subsequently precipitated and removed from the WFGD.

## Conclusions

The control of mercury emissions presents several unique challenges. Variables such as mercury speciation, mercury re-emission, and $SO_2$ to $SO_3$ conversion will all have an impact on the chosen mercury reduction solution depending upon the fuel being fired and the emissions control equipment installed at the plant.

When selecting a mercury control system, a multi-faceted approach that includes many variables such as the air quality control system, fuel, flue gas composition, fly ash characteristics, stack mercury limits, and many other operational factors should be evaluated. In conclusion, an integrated approach to mercury removal can lead to the best mix of cost and effectiveness.

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### *Is it temporary or permanent?*

# Help! – I've Been Blinded!

**By Ron Richard, RE Consulting**

***Your FGD system has been running along normally when suddenly***

- The limestone feed valve is completely open
- The pH is staying the same
- The $SO_2$ removal efficiency is dropping

What has happened and what should you do?

***These are the classic symptoms of limestone blinding.*** If you are lucky, it will be a temporary phenomenon cause by an excess of dissolved sulfites in the slurry precipitating onto the surface of the limestone particles blocking the limestone dissolution.

If you have a forced oxidation system, check the air flow to the absorber. A low air flow can cause an excess of sulfites since there is not enough oxygen to convert all of them to sulfates. Once the air flow returns to normal, the sulfites will dissolve from the limestone surface and the absorber performance will return to normal.

Another mode for limestone blinding is if the absorber tower has been at low load for several days. Then if the load returns to normal rather quickly, the sudden increase in $SO_2$ can form an excess of dissolved sulfites. The best way to recover from this is to shut off the limestone feed. The pH will remain the same for some period of time. Once the pH begins to fall, return the limestone feed valve to normal control and the system will return to normal operation.

The other possibility is permanent blinding if large amounts of fly ash have entered the absorber tower. The aluminum in the fly ash reacts with the fluoride in the slurry to coat the surface of the limestone particles with aluminum fluoride. The only cure for this is to flush out the system and start with fresh slurry.

*For more information, contact Ron Richard,*
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WPCA

### The WPCA Presents Two Seminars

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and
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Don't miss out on this unique opportunity to learn all about O&M of dry scrubbers and particulate control equipment.

The two Training Seminars will be held simulateneously in adjacent rooms. Choose the one that suits you best and sign up on-line at www.reinholdenvironmental.com by selecting the "Register On-line" link on the home page.

These seminars are free of charge to all registered attendees of the 2009 APC/PCUG Conference. For complete details, go to www.reinholdenvironmental.com and scroll down to conference info on the home page. The particulars of both seminars will be posted as soon as they become available.

# Worldwide Pollution Control Association

## What is the WPCA?

*The Worldwide Pollution Control Association (WPCA) is a non-profit organization. It is comprised of a group of internationally diverse individuals and companies who are experts in various aspects of air pollution control. WPCA members and advisors are motivated by a desire to improve pollution control through better technical communication.Today, the WPCA is accomplishing this goal via its newsletters, seminars, a website and an expanding worldwide membership.*

## What are the Benefits of Joining the WPCA?

*Your membership in the WPCA includes sponsored seminars that are presented several times each year around the U.S. and the globe. As a member, you can attend these informative seminars and have access to the most up-to-date information on air pollution control from leading industry experts.*

*Your membership also includes a semi-annual free emailed copy of the WPCA newsletter. The "WPCA News" is a technical newsletter that includes current topics of interest written by corporate sponsors and members of the utility advisory committee.*

## 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.*

## How do I become a Member of the WPCA?

*In order to be a WPCA member, you must be an end user of air pollution control equipment. When you register on-line for any WPCA sponsored seminar, you automatically become a member. If you would like to join, but cannot attend a seminar at this time, please download and send in the Registration Form at the top of the members list at www.wpca.info. You will then be emailed regarding upcoming events and sent future copies of the WPCA News.*

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