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Worldwide Pollution Control Association
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A Bi-Annual Technical Journal Sponsored by the WPCA Fall - 2018

Executive Summary

Wet Flue Gas Desulfurization System Enhancements to Operate at Low Load

Written by Terence Ake and Suzette Puski, Babcock Power Environmental, Inc.

The first article describes enhancements to a common wet scrubber on three coal-fired units in the Midwest. These enhancements were needed for current, variable operating conditions compared to when the WFGD was commissioned with all three units operating at full load. Two of the units will retire next year requiring further performance monitoring of the WFGD as it operates at an expected extended load range for the remaining unit.

Full Story….

It's Time To Re-Think Flare Velocity Limits

Written by Scott Evans, Clean Air Engineering

Current flare velocity limits restrict flare operation above 60 fps and prohibit operation entirely above 400 fps. This article shows that high velocity flames result in better air entrainment and mixing and so result in higher combustion efficiency. Limits on high velocity flaring are unnecessary and, in fact, counter-productive resulting in lower combustion efficiency. Therefore the EPA should consider either eliminating velocity limits for flares completely or at least expanding the range beyond the current limits

Full Story….

SCR Catalyst Management Implications Resulting From Load Cycling and Reserve Shutdowns

Written by Jared Koliha, P.E. and John R. Cochran, P.E. of IBIDEN CERAM Environmental, Inc.

Case studies for the three units discussed in this article reflect the impact of increased pluggage and increased catalyst deactivation rates on SCR performance for increasingly prevalent load cycling and reserve outages. Proactive catalyst management and dynamic catalyst management modeling can identify operational trends and assess the long-term catalyst management risks associated with load cycling and increased outage frequency all while limiting cost.

Full Story….

Evaluating Technologies for Unique Trace Metals Contamination Related to Coal Pile Runoff

Written by Max Swoboda, Evoqua

The treatment of coal pile runoff is a corollary effect of the CCR rule and the closure of coal ash ponds. While not a coal residual, the stream will require scrutiny if its path to the outfall was through the ash pond. The optimal treatment method is sufficient removal of trace metals at the same time as the TSS is removed.

Full Story….

An Historic Outline of Electrical Control Systems Used in The Process of Electrostatic Precipitation

Written by Paul Ford and Hank Del Gatto, REDKOH INDUSTRIES

For over 130 years the design and development of electrostatic precipitator controls has been a continuously evolving phenomenon. To continue this growth, it is important to look into its history, where it is clear to see the technological advancements the industry has made today go hand in hand with the basic fundamentals our colleagues first patented in the 1800's.

Full Story….

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Executive Summary (cont.)

Enhanced Low Load SCR Operation

Written by Christopher Bertole, Cormetech

Due to the current economic environment, utilities are looking to push unit loads to levels well below historical values and go even below design low load for extended periods. To accomplish this goal, it is important to balance the Plant's operating needs, the severity of low load condition (i.e., temperature, length of time, extent of ABS-induced deactivation), and the capability for performance recovery upon return to full load (i.e., the achievable temperature, the rate of activity recovery, and the transient SO_3 and NH_3 emissions). This article takes a look at CORMETECH's experience to give plants flexibility for meeting NOx reduction requirements

Full Story….

Choosing the Right SOLUTION

Written by John Rennocki and Mike Allen, Parker Hannifin Corp.

The fabric filter systems is an important part of a boiler application and maintaining the right dust cake and pressure drop across the system is a must if you are going to have success. That was a lot easier when you ran at full load for long periods of time. With today's energy demands, the load swing can make the fabric filter operations a potential problem or bottleneck, if you don't understand how load affects the fabric filter operation.

Full Story….

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Wet Flue Gas Desulfurization System Enhancements to Operate at Low Load

Written by Terence Ake and Suzette Puski, Babcock Power Environmental, Inc.

ABSTRACT

Three midwestern coal-fired units have operated at about half load since a common Babcock Power Wet Flue Gas Desulfurization system was commissioned in 2011. The system removes 98% of the SO_2 from the combined flue gas from all three units. At full load, hydrocyclone performance sometimes deteriorated when the absorber liquid level dropped below the overflow line in the absorber and flue gas flowed back up the line. At low load, absorber level and bleed solids density control were difficult due to reduction of water evaporation and excess water to the absorber from the mist eliminator wash system. To address these problems, we extended the internal hydrocyclone overflow line to ensure that it was covered, and we recommended improved mist wash and reduced absorber level at low loads to improve bleed density control. Reduced absorber level will decrease the L/G ratio due to reduced head from the recycle sprays. Further tests of the proposed reduced absorber level control will ensure continued good WFGD performance for current and future load conditions.

INTRODUCTION

Coal fired generation is decreasing in the U.S. due to low natural gas prices, customer demand for renewable energy, and the coal fleet age. Coal fired units are often operated at lower loads and variable loads. Air pollution control systems were mainly designed for operating at

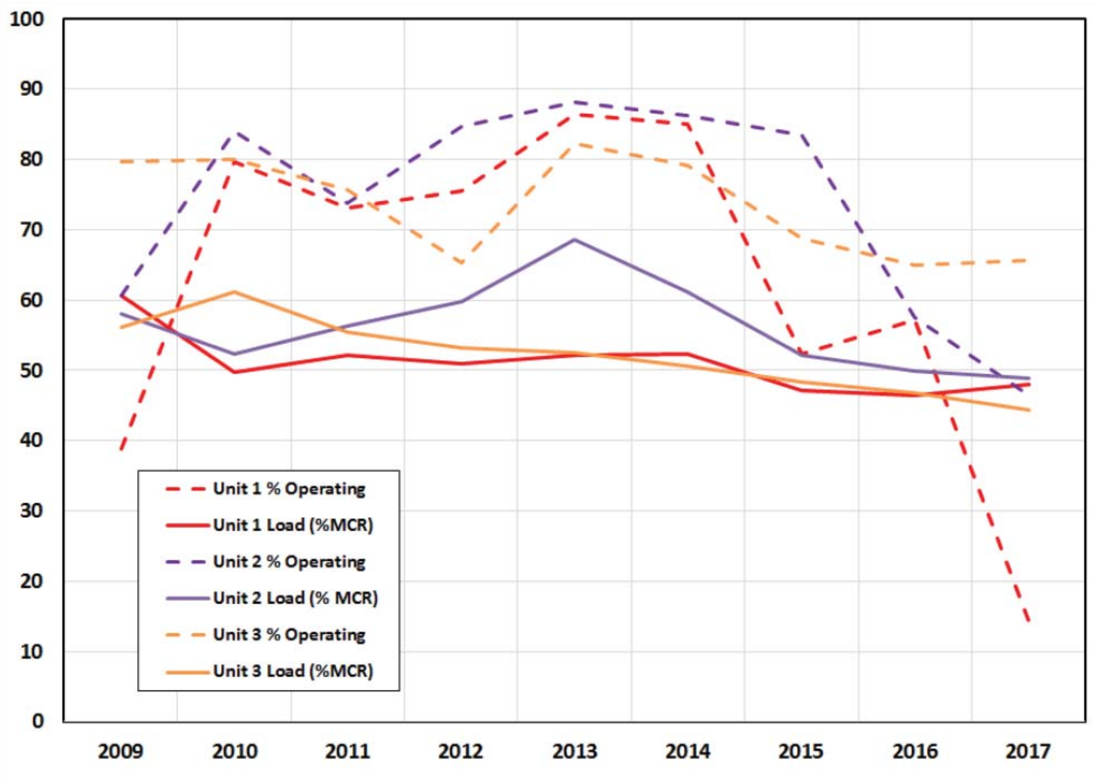

Figure 1: Load and Operating Hours History for Three Coal-fired Units.

full load with limited turndown typically around 50% MCR (Multi-Pollutant Catalytic Reactor) conditions. Original equipment manufacturers are now often called upon to optimize the equipment and operation to extend the load range of the systems. These include operating the equipment at higher loads due to boiler efficiency improvements in the remaining coal fleet and, at the same time, much lower turndown due to periods of lower demand.

MIDWESTERN GENERATION STATION

The Wet Flue Gas Desulfurization System supplied by Babcock Power to a utility for a power generating station with three units is a case in point. The WFGD removes 98% of the SO_2 for the combined flue gas from the three units at the station. Two smaller units started operating in the 1950s and 1960s, and the largest unit started in the 1970s. The three units have operated at about half load since the WFGD met performance guarantees in 2011. There are plans to decommission the two older units in 2019.

Figure 1 (on page 1) shows the operating history of the three units based on the U.S. EPA Air Markets Program website [1]. This website allows users to download load and emissions data from power generating sites in the U.S. Monthly, daily, or hourly data can be downloaded on a unit basis or an aggregate basis based on several air pollution control programs maintained by the EPA.

As shown in the figure, the three units have operated at about half of each unit's nameplate since 2009. The three units operated about 80% of the year until 2014 when unit 3 operating hours decreased to 65% and units 1 and 2 decreased below 50%.

Figure 2 plots the total load history and stack SO_2 emissions for 2013 as an example to show the load variation to the WFGD. The average SO_2 emission for 2013 (0.07 lb/MilBtu) was about 97% SO_2 removal based on average emissions before the WFGD in 2009.

In 2012, Babcock Power installed an SCR on the largest unit to control NOx emissions. In 2013, the stack NOx was maintained at an average 0.22 lb/MilBtu for all three units after the SCR was in-place. These emissions were typical in subsequent years based on the U.S. EPA database.

WATER BALANCE

In September 2015, the U.S. EPA finalized a rule for steam electric power generation that set more stringent effluent limits for arsenic, mercury, selenium, and nitrogen in the wastewater stream from WFGD systems and zero discharge of these pollutants in transport waters from fly ash, bottom ash, and flue gas mercury control. The utility conducted test programs to reduce wastewater from the WFGDs at four power stations to be ready for the updated rule. These tests were conducted at full and low load and included fuel, limestone slurry, absorber bleed slurry samples analyzed for

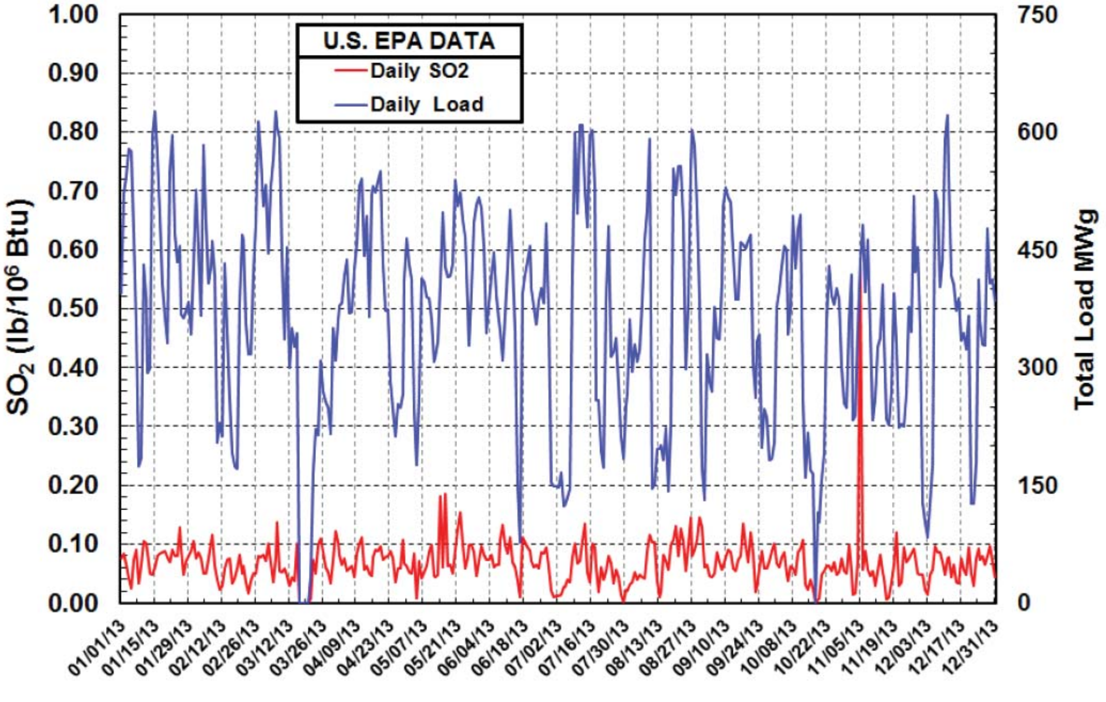

Figure 2: Total Load and SO_2 Emissions for 2013

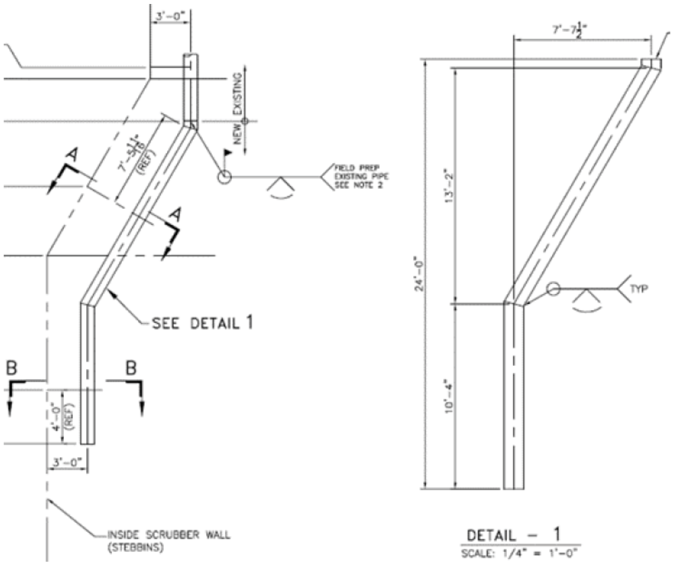

Figure 3: Hydrocyclone Overflow Internal Extension

chemical makeup and density.

Babcock Power evaluated methods to reduce wastewater from the WFGD systems based on the 2015 data. In the evaluation, we calculated the major input and output water streams for the WFGD (a water balance). Overall findings for the fleet included creating a realistic design basis for actual conditions, identifying an acceptable wastewater rate, and determining the best wastewater treatment option for that rate. These wastewater treatment options included physical/chemical/biologic wastewater treatment for large purge rates or applying sorbent injection to reduce chlorides for a smaller purge rate that can be treated less expensively.

Site-specific recommendations for the subject power station included rerouting flush, cooling, and seal water to the mist eliminator wash tank, adding a reclaim tank and pump to the secondary dewatering system to send reclaim water back to the absorber. Erratic mist eliminator dwell times at low loads and leaky ME wash valves resulted in higher time weighted ME wash rates than intended. We recommended improving the ME wash cycle at low loads including replacing leaking ME wash valves.

The largest unit includes dry sorbent injection for SO_3 control and powdered activated carbon injection for mercury control in a pulse jet fabric filter upstream of the WFGD. The DSI is good for the future because it can be optimized to remove chlorides reducing the waste water that will be treated by a future waste water treatment plant. An ESP upstream of the DSI system collects marketable fly ash.

ABSORBER LEVEL ANALYSIS

Another recommendation from the water balance was to reduce the absorber liquid level at low loads to allow surges in make-up water flow to the absorber. The surges caused high liquid level and poor bleed solids density control to dewatering at low loads. Most nozzles to the absorber are not rated for hot flue gas if they become uncovered. There is a permit to start the ID fan when liquid level is 84% of normal liquid level (NLL) to protect from uncovering nozzles and ensure a good operating L/G ratio during startup.

After reviewing operating data from 2015, additional data from 2017, and lower level limits, we recommended changing absorber liquid level control based on the total operating load to the WFGD, as follows:

- 100% NLL at > 50% Load, and
- 89% NLL at < 50% Load.

These values will counter the trends in absorber liquid level that showed increased liquid levels at lower load at constant NLL set point. To check that the recorded absorber liquid level was actual, we used the recycle pump discharge pressures and the total discharge head recycle pump curves supplied by the pump manufacturer to back-calculate the recycle flows and absorber levels. The recycle pump analysis liquid levels averaged 6% lower than the recorded indicating good agreement between an analyzed level and recorded level.

Operating at reduced absorber level will decrease the L/G ratio due to reduced TDH from the recycle sprays, and it will require improved mist eliminator wash control to obtain a lower set point. We do not expect that there will be performance deficits when operating at lower liquid level. Nevertheless, we recommended further tests with the recommended liquid level control to ensure good WFGD performance throughout current and future load ranges.

HYDROCYCLONE INTERNAL RETURN LINE EXTENSION

The primary WFGD solids dewatering system at the subject power station includes bleed pumps that remove gypsum slurry from the reaction tank at a solids density set point (15%) and hydrocyclones that separate gypsum solids for further dewatering with return of the overflow back to the reaction tank. The hydrocyclone overflow return line includes an internal pipe in the reaction vessel exiting at about 14% below normal liquid level (NLL).

Flue gas sometimes flowed up the overflow pipe affecting the ability of the hydrocyclone to discharge the concentrated bleed stream to the secondary dewatering system. The up-flow also caused corrosion in the pipe and escaping flue gas was a safety concern. The absorber liquid level analysis showed that the level sometimes dropped below overflow pipe outlet at high load. Without a physical change, the recommended lower liquid level set point will increase the chance that the existing hydrocyclone outlet will be uncovered at low load as well as high load.

Before the absorber liquid level analysis, the utility contracted Babcock Power to supply an overflow pipe extension as shown in Figure 3 on page 3. As shown, the extension lowered the existing outlet by 24 feet following the contour of the Stebbins reaction vessel. The extended outlet is now about 28% below the normal liquid level below the LLL trip point for the recycle pumps, bleed pumps, and agitators. Therefore, the extension is now continuously below the current and recommended NLL set points.

CONCLUSIONS

As coal-fired power generation has diminished, it has become necessary to evaluate pollution control equipment performance at increasingly variable operating load for soon to be retired units and extended high load for units remaining in the fleet. Based on recent reduced load performance tests conducted by a utility at a three-unit power station, a change was recommended to the absorber liquid level control to reduce the normal liquid level set point at low loads to provide a surge capacity and improve solids density control. A physical extension of the internal hydrocyclone outlet was installed to prevent flue gas backflow at low liquid level. It allowed for us to recommend a low load liquid level set point below the normal liquid level that was originally set mainly for high load. It will be necessary to improve mist eliminator wash to reduce water input at low loads and maintain a lower set point. The operating history from the U.S. EPA Air Markets program showed that the power station kept its SO_2 emission set point for 98% SO_2 removal of the combined flue gas from the three units as the operating hours and loads decreased for each coal-fired unit. The recommended absorber level control will allow continued good WFGD performance for current loads and when two smaller, older units retire in 2019 and the remaining unit is expected to increase operating hours and load depending upon future demand.

REFERENCES

1. *Air Markets Program Data | Clean Air Markets | US EPA. https://ampd.epa.gov.*

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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.

Suzette Puski started working in the power industry in 1991 after graduating in chemical engineering from Purdue University. She evaluated AQCS proposals, attended plant start-ups and completed optimization testing. She then transferred to R&D in manufacturing where she worked as a process engineer scaling up product from R&D to pilot-scale to the manufacturing plant. Over the last 12 years Suzette has worked for Babcock Power starting as a process engineer completing engineering, commissioning and startups, and optimization of AQCS systems. She now works in proposals where she uses her plant experience to provide practical solutions to the power industry.

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It’s Time To Re-Think Flare Velocity Limits

Written by Scott Evans, Clean Air Engineering

BACKGROUND

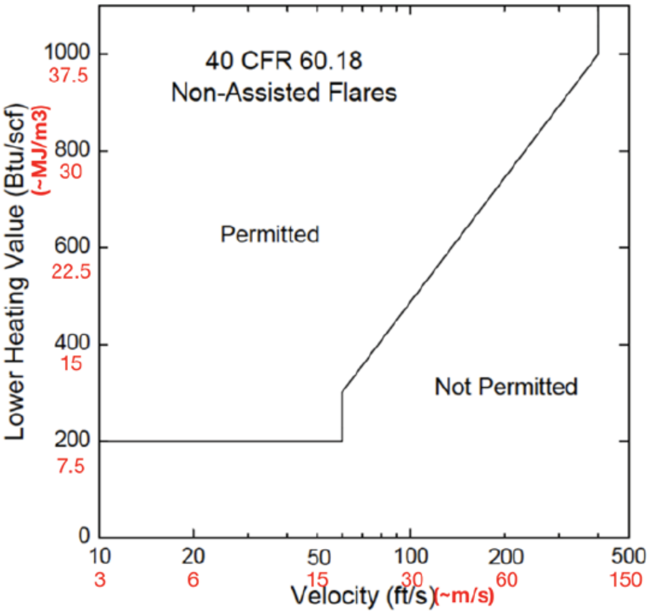


Figure 4: Current EPA Flare Velocity Limits

U.S. EPA’s flare velocity limits were originally issued in 1986. Since then, they have found their way into flare regulations around the world. These limits are shown graphically in Figure 4. The figure shows flame exit velocity along the x-axis and lower heating value of the waste gas along the y-axis. A minimum heat content is required of 200 Btu/scf (7.5 MJ/m^3) for unassisted flares or 300 Btu/scf (11.2 MJ/m^3) for assisted flares up to 60 fps (18.3 m/s), where the required heat content increases as a function of exit velocity until a maximum allowable velocity of 400 fps (121.9 m/s) is reached.

This relationship was developed following a series of EPA sponsored tests conducted in the 1980’s that examined how various flare operating parameters, including velocity, affect flare performance. The tests with relevance to the current velocity requirements are the 1983 McDaniel[1] test and the 1984 Pohl[2] test. The focus of the 1985 Pohl[3] and 1986 Pohl[4] studies was not on high velocity, but any test runs from these studies where the exit velocity of the flare was greater than 60 fps have been included in this analysis.

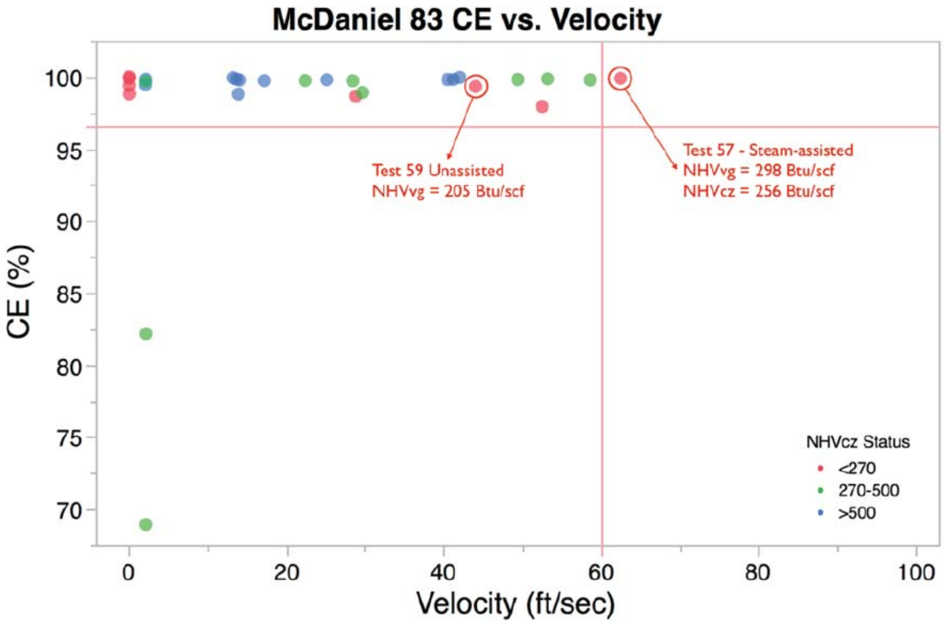


Figure 5: A Comparison of Combustion Efficiency vs Velocity for McDaniel 1983[1]

The 60 fps, 300 Btu/scf limit for steam-assisted flares was set based on a single data point -- McDaniel 1983[1] test 57. The 200 Btu/scf limit for unassisted flares was also set based on a single data point – McDaniel test 59. These tests were performed on an 8.6-inch steam-assisted flare fueled with a propylene/nitrogen mix. The data are shown in Figure 5. The data are binned by heat content, where red dots indicate test runs whose combustion zone net heating value (NHV_{VG}) is less than 270 Btu/scf, green dots indicate test runs with NHV_{VG} between 270 and 500 Btu/scf, and blue indicate test runs with NHVVG greater than 500 Btu/scf.

It is noteworthy that the concept of

heat content in the combustion zone is relatively new and the data were not presented in those units in the referenced studies, but rather as indicated by the net heat content of the vent gas (NHV_{VG}) (i.e. the gas sent to the flare, without accounting for volumetric dilution of assist gas). It is also noteworthy that for Test 57, NHVcz = 256 Btu/scf below the current regulatory limit of 270 Btu/scf. For an unassisted flare, NHV_{CZ} is the same as NHV_{VG}.

McDaniel did not collect data at velocities higher than 60 fps. At the 60 fps upper limit of the data, combustion efficiency remained very high and with no evidence of a trend toward lower combustion efficiency. These data were used to establish the 60 fps velocity limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

The 400 fps, 1,000 Btu/scf limit appears to be set based on two data points from flame stability test runs 99 and 104 from Pohl 1984.[2] That study was performed on a 3-inch steam assisted flare fueled with a propane/nitrogen mix. These data are shown in Figure 6. The data are binned by heat content, where green dots indicate test runs with NHV_{CZ} between 270 and 500 Btu/scf and blue indicate test runs with NHV_{CZ} greater than 500 Btu/scf.

Similar to the data used to establish the 60 fps limit, data collected in this study were not collected at velocities higher than the upper limit of 400 fps. As in McDaniel 83, Pohl 84 showed no evidence of a trend towards lower combustion efficiency at the upper velocity limit measured. These data were used to establish the 400 fps limit although there is no evidence that operating at higher velocities results in degraded combustion efficiency.

A REVIEW OF HIGH VELOCITY FLARE TEST DATA

Recent flare testing has revealed much regarding the relationship between flare exit velocity and combustion efficiency. Figure 7 (on page 7) shows testing conducted in 2010 on a steam-assisted flare. Vent gas composition and steam assist rates were held constant for each test run. Only exit velocity was changed.

The figure shows that combustion efficiency improves over the normal operating range as exit velocity increases. This is consistent with accepted combustion theory that higher velocities promote better air entrainment and mixing resulting in better combustion. The price paid for better efficiency at higher flows is that efficiency begins to fall off at a higher NHVcz value as velocity increases. However, as long as the flare remains in a stable operating range, higher exit velocity equates to higher combustion efficiency. The orange line shows an extrapolation of these result to the very high velocity rates required by pressure-assisted multi-point ground flares (MPGF) discussed below.

Figure 8 (on page 7) shows data from publicly available high

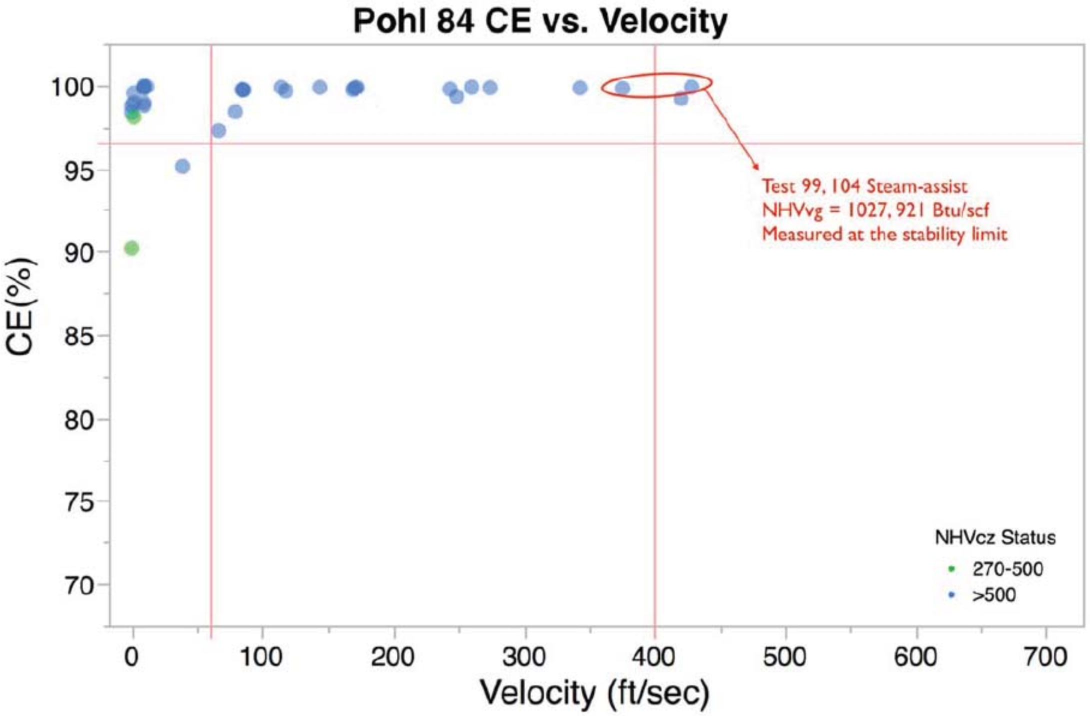
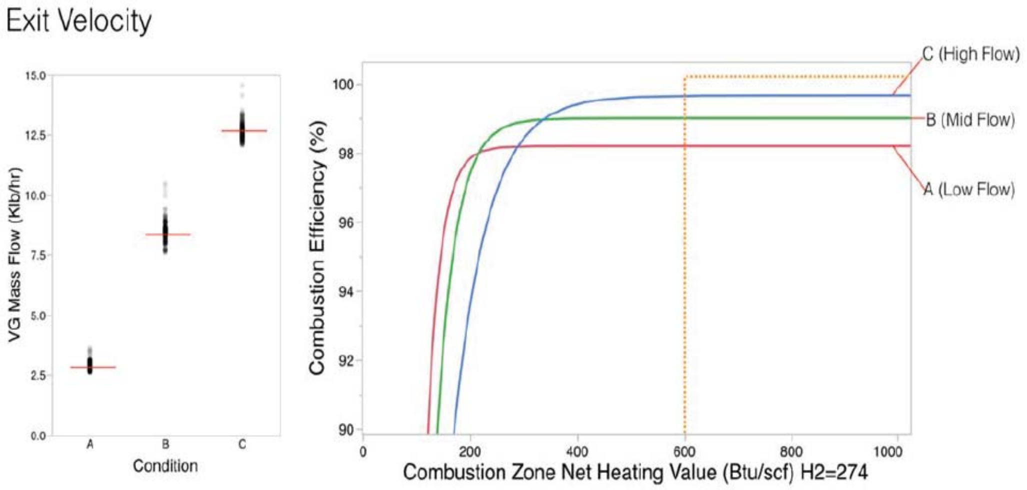


Figure 6: A Comparison of Combustion Efficiency vs Velocity for Pohl 1984[2]



Flint Hills Resources Flare Test

Figure 7: A Comparison of Combustion Efficiency vs NHVcz for steam-assisted flare at three flow levels. Orange line shows average MPGF performance for comparison.

velocity MPGF tests. Note that many tests show very high combustion efficiency at velocities well in excess of EPA's current limits.

FLAME STABILITY

The claim is often made that the reason velocity limits are necessary is to ensure "flame stability." However, flame stability has been defined differently in different studies. McDaniel did not address flame stability. Pohl defines flame stability as:

> *The term "flame stability" simply means that a flame is maintained; flame instability occurs when the jet velocity exceeds the flame velocity and the flame goes out. [Pohl 84, p2-3]*

Others[5] have defined flame stability in terms of "lift-off", a condition that occurs when the base of the flame detaches from the flare tip.

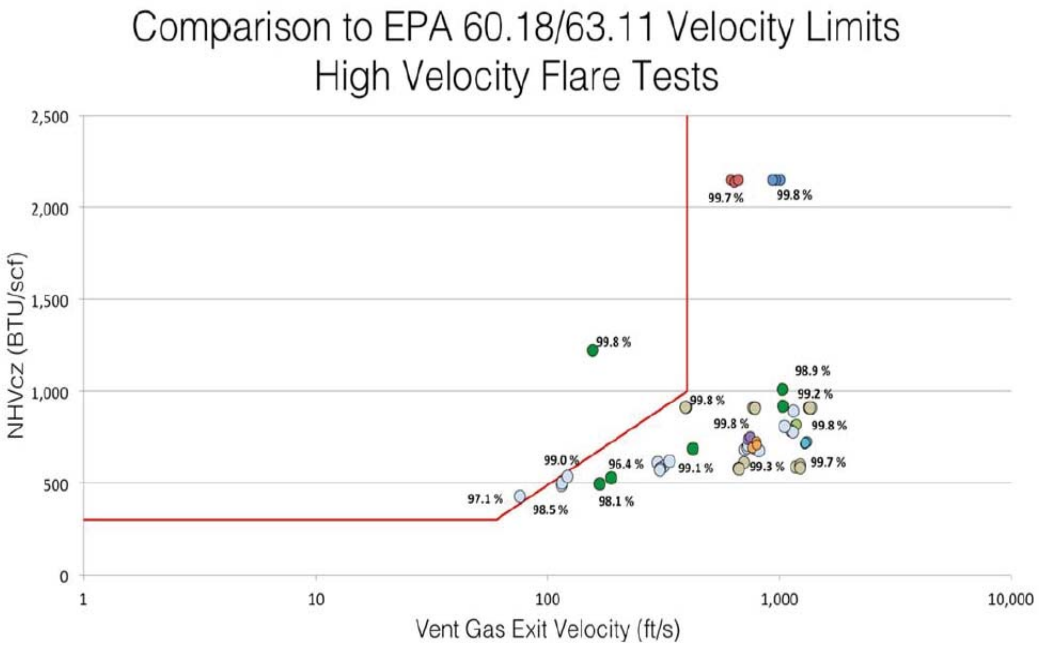


Figure 8: Test results from MPGF tests compared to EPA's current limits.

While there is no doubt that Pohl's definition results in unacceptable flare performance -- when the flame is out combustion efficiency is zero --, there is little evidence that flame lift-off has any correlation either positive or negative to combustion efficiency. Figure 8 (on page 7) shows every data point from Pohl 84 where flame lift-off was noted in the report.

27 of the 32 lifted flames showed high combustion efficiency. None of the remaining five points had measured combustion efficiency below 91%. Figure 9 clearly shows that flame lift-off does not affect combustion efficiency over a wide range of velocities and net heating values.

Concern over flame lift-off affecting combustion efficiency is not supported by the data. The only definition of flame stability with relevance to velocity limits is Pohl's definition… a high velocity flame is stable until it goes out.

In the MPGF tests, there is also no evidence of a gradual decline of combustion efficiency when approaching the point where the flame is extinguished or the "snuff point". The data for these tests were collected as near as possible to the snuff point while still maintaining a flame. No evidence of degraded combustion efficiency was noted.

CHANGE IN VELOCITY BASIS

It should be noted that U.S. EPA's recent Refinery Sector Rule (RSR) changes the basis of flare velocity calculation. Under the current rule, EPA changed the basis from standard (68 deg.F/1 atm, 20degC/101 kPA) conditions to actual conditions. In most cases, using actual conditions results in a higher calculated flow and higher velocity. For example, flow rates of 60 fps under the former rule could be 70-80 fps under the new rule. For flares operating near the current velocity/NHV limits, it may be necessary under the RSR to reduce flow to the flare by as much as 10-20% or possibly adding supplemental gas to raise the net heating value in order to remain in compliance. EPA is currently considering a proposal to return to standard conditions but this has not been finalized as of the date of publication.

It should also be noted that the McDaniel and Pohl studies used standard temperature and pressure to calculate velocity. Therefore, the current limits are based on standardized values.

FLARE VELOCITY CONCLUSIONS

Current flare velocity limits restrict flare operation above 60 fps and prohibit operation entirely above 400 fps. All of the data collected, including the data used previously to set current limits as well as recently collected data, show that high velocity flaring results in high flare combustion/destruction efficiency (>96.5%/>98%). Previous limits were based solely on lack of data at higher flare exit velocities. There is no indication either in the 1980's studies or the more recent flare studies that high velocity flaring contributes to poor combustion efficiency.

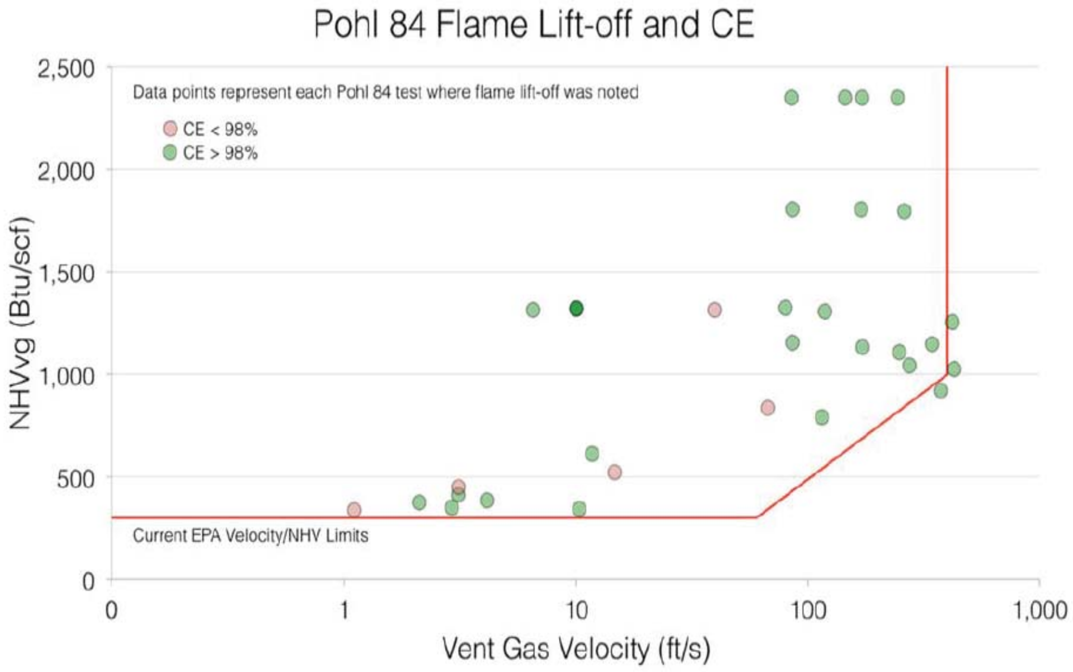


Figure 9: A Comparison of Flame Lift-off and Combustion Efficiency from Pohl 84

The data on high velocity flaring is consistent with combustion theory, which shows that high velocity flames result in better air entrainment and mixing and so result in higher combustion efficiency. Limits on high velocity flaring are unnecessary and, in fact, counter-productive resulting in lower combustion efficiency and the installation of un-necessarily large flares designed to keep exit velocities low.

EPA should consider either eliminating velocity limits for flares completely or at least expanding the range beyond the current limits.

Reference

1. McDaniel, M.; "Flare Efficiency Study," EPA-600/2-83-052, July 1983
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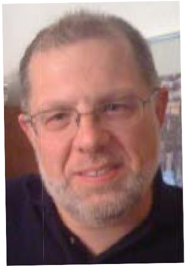
BIOGRAPHY



Mr. Evans has over 30 years of experience in the air pollution field. As Technical Leader of the Consulting Services Team, his responsibilities include tracking U.S. and international legislation and regulations affecting Clean Air clients and advising clients on the impact of new and existing regulations. Mr. Evans has been heavily involved in refinery flare testing and management having served as an industry consultant on flare measurement and performance issues. Recently, Mr. Evans has been involved with real-time small sensor networks and Internet of Things (IoT) infrastructure development. Mr. Evans is also a primary contributor to the CleanAir blog (www.cleanair.com/info) and hosts the Hot Air by CleanAir podcast available on iTunes, GooglePlay, or anywhere podcasts are available.

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WPCA

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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.

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SCR Catalyst Management Implications Resulting From Load Cycling and Reserve Shutdowns

Written by Jared Koliha, P.E. and John R. Cochran, P.E. of IBIDEN CERAM Environmental, Inc.

ABSTRACT

A major shift has occurred for coal plant operations due to reduced demand, low natural gas prices, and increases in wind and solar generation. These developments have resulted in frequent coal plant load cycling and reserve outages. This article's objective is to assess trends and impacts of this operations shift on SCR system operation and catalyst management.

INTRODUCTION

Changing power market demands have created scenarios where load cycling and reserve outages are becoming more common for previously base loaded coal-fired power plants. Additionally, numerous plants look to increase the stable load range to increase revenue opportunities. The shift to cycling operation presents significant boiler and balance-of-plant system operation impacts. Selective catalytic reduction (SCR) systems utilized for controlling boiler NOx emissions experience unique challenges associated with deeper and more frequent load cycling and increased outages.

The predominant challenges to assuring reliable SCR system operation for this coal plant operation paradigm shift include:

- Accommodate increased possibility for catalyst pluggage. Lowering minimum stable low load reduces flue gas flow rates and thereby changes the velocity distribution to the catalyst. This change possibly increases ash dropout rates.

- Extend the permitted range for ammonia injection below original minimum operating temperature requirements while preserving catalyst performance.

- Increase ammonia supply system turndown to accommodate new minimum stable load limits.

- Identify and accommodate new and increased catalyst deactivation trends resulting from more frequent exposure to moisture and acid dew point temperatures. These new trends are apparent for both bituminous and PRB fired units. Increased catalyst deactivation results in significant implications to consider during catalyst management modeling and can have substantial economic impacts.

Accurate assessment of these challenges results in significant implications to consider during catalyst management modeling to best avoid substantial economic impacts. As such, recent experience and results will be presented in this article to assist owners with reducing risk and cost as well as assuring accurate SCR system budget planning efforts. Additionally, the long-term SCR catalyst management impacts resulting from these changes will be assessed. The case studies presented herein are specific to individual SCRs; however, the information and results presented appear to be consistent with observations for other systems.

CASE STUDY APPROACH

Since 2003 CERAM has performed comprehensive catalyst management services for more than 50 coal-fired units. The catalyst management services have included SCRs designed by all predominant SCR system suppliers including catalyst not only from CERAM, but also from all other major catalyst suppliers. The following catalyst management affecting developments have been observed coincidental to increased dispatch with wider load fluctuations:

1. Increased catalyst pluggage;
2. Different deactivation trend characteristics as compared to historical observations.

This article will focus on examining three units and the effect that increased load cycling has on SCR operations and catalyst management. The coal-fired SCR plants were selected because of their substantial departure from historic circumstances. Active mitigation of performance problems experienced due to increased low load operation and proactive planning were assessed for each plant and are key in assessing the dynamic modeling necessary to predict the timing of future catalyst events.

1. Plant A – Plant A is a 360 MW midwestern cyclone fired boiler that operates on high sulfur bituminous coal. The SCR consists of 4 layers of honeycomb catalyst.

2. Plant B – Plant B is an 80 MW midwestern cyclone fired boiler that operates on high sulfur bituminous coal. The SCR comprises a combination of 3 layers of new and regenerated honeycomb catalyst.

3. Plant C – Plant C is a 700 MW midwestern pulverized coal fired boiler that operates on powder river basin (PRB) coal. The SCR is split into two reactors and each reactor has 3 layers of honeycomb catalyst.

Plant A was selected for evaluation based on the availability of long-term reactor inspection results and low load computational fluid dynamic (CFD) modeling information performed by Fuel Tech. Plant B and Plant C were selected for the evaluation based on the long term operating and catalyst test data associated with chemical composition and catalyst activity.

All catalyst samples evaluated were of honeycomb design with varying geometry and manufacture. Based on previous work performed by Hartenstein and Healy[1] and substantiated separately by CERAM experience[2], it has been demonstrated that plate, honeycomb, and corrugated catalyst exhibit similar poisoning and catalyst deactivation rates. All three catalyst types (honeycomb, plate, and corrugated) have similar composition (Ti-V-W or Mo) and consistently effective tri-modal pore structures; similiar rates of catalyst deactivation are expected.

The effects of more frequent outages and reserve shutdowns are discussed in terms of the chemical relationship between moisture condensation and fly ash with the primary focus of analysis being the qualitative relationship between the calcium concentrations in the fly ash and the presence of moisture within the system. Field observations of fly ash quality were correlated with selected research of the calcium chemistry. The chemical deactivation effects of outage and load cycling on the catalyst was analyzed as a series of reactor inspections and catalyst test results for each plant.

The chemical composition of the aged catalyst samples was tested using X-Ray Fluorescence (XRF) on isolated samples from the catalyst surface and from the bulk of the catalytic material. XRF analysis samples were taken from a consistent location within each test element to obtain a representative average of the chemical constituents on the surface and bulk catalytic material. The measured catalyst constituents are reported as weight distribution percentages.

Catalyst activity testing was performed in a semi-bench scale reactor. The semi-bench scale reactor tests a section of catalyst that is cut to an appropriate size and subsequently exposed to a simulated flue gas with the conditions noted in Figure 10. After achieving equilibrium, the NO inlet and outlet concentrations were measured in parts per million (ppm).

Parameter	Unit	Semi-Bench
Temperature	°F	716 (380°C)
Area Velocity	Nm^3/m^2h	25
H_2O	%	10
NO	ppmvd	200
Molar Ratio	NH_3/NOx	1.2
SO_2	ppmvd	500
O_2	%	2
N_2	%	Balance

Figure 10: Semi-Bench Scale Reactor Test conditions

The NOx removal efficiency was calculated using Equation 1:

$$n = (NO_{inlet} - NO_{outlet}) / NO_{inlet}$$

Where:
NO_{inlet}= inlet NOx concentration in ppmvd;
NO_{outlet}= outlet NOx concentration in ppmvd;

Area velocity was calculated as shown in Equation 2:

$$AV = Q/ (V * SSA)$$

Where:
Q= the volumetric flow of flue gas through the catalyst in Nm/h;
V= the catalyst volume in the reactor in m^3;
SSA= the specfic surface area of the catalyst in m^2/m^3;

From the NOx removal efficiency and area velocity, the activity (K) was calculated as shown in Equation 3:

$$K = -AV * \ln(1 - n)$$

Where:
AV= area velocity expressed in units of Nm/h;

The catalyst activity reported herein is the relative activity ratio of the aged catalyst activity (K) to original catalyst activity (Ko).

RESULTS AND DISCUSSION

Catalyst Pluggage Resulting from Load Cycling and Increased Outage Frequency

Historically, the original design basis and flow model associated with SCR reactors on coal-fired plants was considering base-loaded (maximum flow) with an associated minimum load (flow) condition. Many efforts have been exerted at plants to further increase turndown and further reduce stable minimum load operation. Consequently, the original flow modeling (with narrower load range) is no longer representative and pluggage risk has increased. Reduced flow conditions associated with current practices for load cycling and further reduced low load operation have increased the influence of localized flue gas flow problems otherwise not typically problematic under base-loaded operation thereby increasing catalyst pluggage.

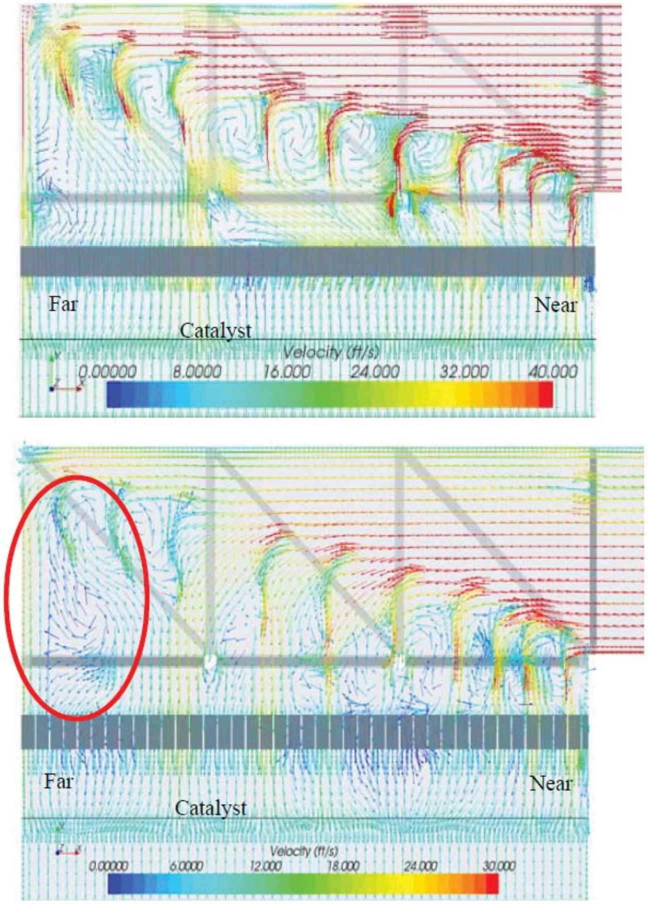
Figure 11-A and Figure 11-B depict the CFD velocity vector output data for the full load operating conditions and the minimum load operating conditions, respectively, associated with Plant A. CFD modeling was performed on Plant A as a means of confirming and then correcting the extensive catalyst pluggage on the near side (AIG/boiler side) historically observed in the reactor. The depicted CFD model outputs reflect field-modifications that were ultimately made to the reactor hood turning vanes.

Flow modifications associated with the CFD modeling remedied the near wall pluggage observed under normal operation. Some changes in flow characteristics resulting from flow modifications were observed at reduced load. Of particular interest on Figure 11-B is the flue gas flow recirculation zone located on the far side of the reactor (circled) which illustrates how low load and low flow conditions can exacerbate flow problems.

Some flow disturbances within this area are present in the full load CFD modeling; however, the extent of recirculation appears much more prevalent in the reduced flow operating case. Inspections of the reactor did not immediately indicate the presence of fly ash piling or significant catalyst pluggage adjacent to the far wall of the reactor. Ash accumulation and pluggage was noted in these areas after multiple years of increasing periods of low load operation.

Figure 12 (on page 13) depicts an alpha-numeric grid associated with the first layer of catalyst at Plant A where module rows “K” and “L” are the module rows directly adjacent to the far wall of the SCR reactor. The first catalyst layer at Plant A is 9.2 mm pitch honeycomb catalyst installed one year prior to the reactor hood modifications associated with the CFD modeling. Trends of the yearly pluggage levels in module rows “K” and “L” are presented on Figure 13 (on page 13) alongside the trend of the Plant A monthly average load.

As confirmed by the decrease in monthly average load, the



(A)- Plant A CFD Modeling at Full Load Operating Conditions

(B)- Plant A CFD Modeling at Low Load Operating Conditions; note flow recirculation zone present directly above the “egg-crate” flow-rectification device (circled).

**Images courtesy of Fuel Tech, Inc.*

Figure 11: Plant A CFD Modeling of Reactor Hood Field Modifications Performed in 2010.

frequency of load cycling at Plant A increases by year. As low load operation becomes more prevalent, the far wall catalyst pluggage rates increase substantially, with the location of the most significant pluggage being module row "K", which is directly beneath the flow recirculation zone observed in the low load CFD model.

The catalyst pluggage observed at Plant A was largely a consequence of ash sloughing from overhead guide vanes and flow rectifying grid onto the catalyst face. Localized pluggage of the rectifier grid resulting in flow shadowing unto the catalyst beneath was also observed. Increased time at low load operation may have facilitated the accumulation of fly ash on the rectifying grid in the locations of flow recirculation, and changes in flow characteristics resulting from unit load cycling up or down can result in ash shear onto the catalyst surface below.

The affinity of PRB fly ash to collect ambient moisture is well documented[3]. Field observations of fly ash quality note the tendency for this fly ash to "set" or solidify with cooling and coincidental moisture absorption, rendering catalyst pluggage difficult to remediate once established. The potential risk for fly ash solidification increases with the level of moisture condensation within the SCR. Frequent outages or exposure to dew point conditions can increase the severity of catalyst pluggage by creating conditions that favor the solidification of ash.

Figure 14 depicts fly ash that had accumulated upon a turning vane and subsequently sloughed down on the catalyst surfaces below. The fly ash sample depicted on Figure 14 was taken from a PRB unit with a high frequency of reserve shutdowns. As such, the hardened fly ash accumulation appears to have stratifications that may represent specific instances of moisture adsorption by an accumulated layer of fly ash.

The beneficial use of fly ash in cement manufacturing processes as a pozzolan has been documented for both bituminous and PRB fuels[4]. Within the cement manufacturing process, the aluminosilicates common to fly ash react with calcium hydroxide to form cementitious material. High concentrations of calcium oxide typical to PRB ash can create conditions necessary for cementation reactions provided sufficient moisture[5]. Limiting the fly ash constituents necessary for producing cementitious reactions is infeasible upstream of an SCR system unless the SCR is located in a low dust arrangement. However, limiting the amount of moisture available for this lime slaking process may be possible by

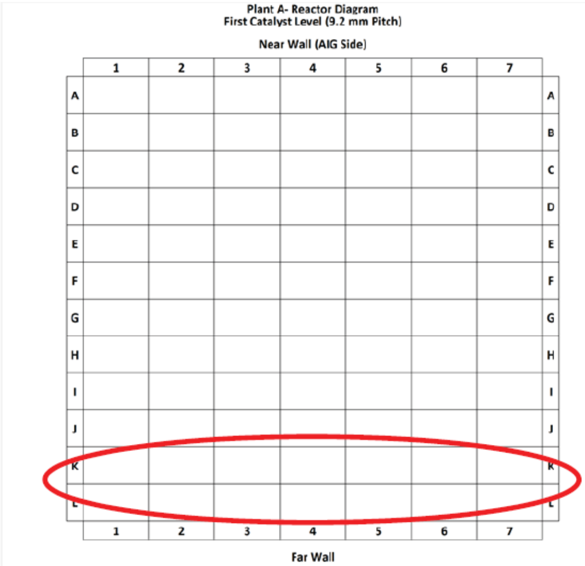


Figure 12: Plant A Reactor diagram.

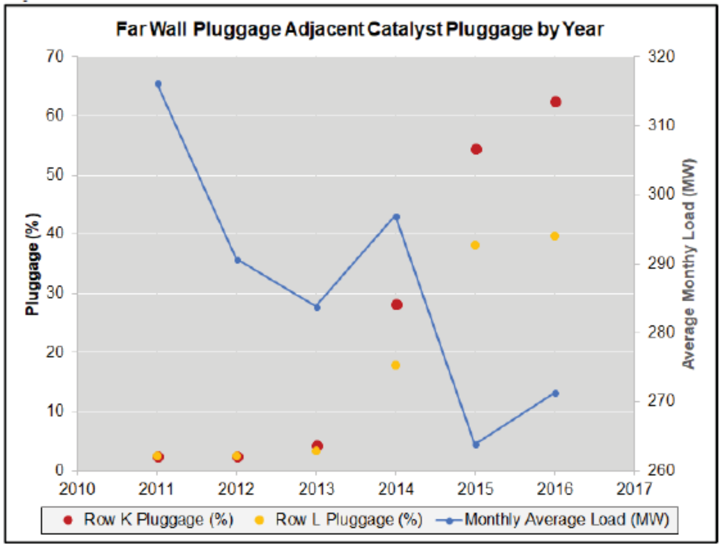


Figure 13: Plant A catalyst pluggage in Rows K and L and monthly average load by year.

Figure 14: Hardened PRB fly ash accumulation fallen from SCR turning vane.

limiting the potential for condensation through reactor temperature control and outage best practices

Water Soluble Catalyst Poisons Influence and Mobility

The elements classified as Group 1 alkaline metals in the periodic table are known SCR catalyst poisons that can alter catalytic active site acidity with accumulation[6]. Of these Group 1 metals, sodium and potassium are typically present in coal; the relative amounts and native mineral speciation of these elements vary with coal rank and source. The severity of catalyst poisoning because of sodium and potassium depends on combustion practices and flue gas chemistry as well as the quantities and speciation of the alkaline material within the fuel source. Ultimate deposition of sodium and potassium onto the catalytic surface is dependent on the basic sequence of steps depicted on Figure 15.

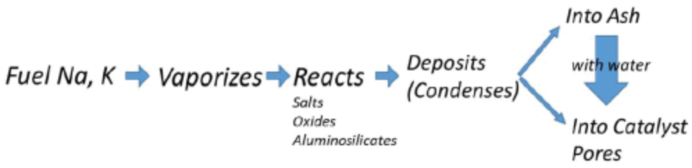


Figure 15: SCR catalyst sodium and potassium deposition sequence.

Levels of volatilization of alkaline material from the fuel source is heavily dependent on the mineral speciation of the sodium and potassium bound in the coal. Sodium is typically more volatile in coal given the common associations of sodium with organic material or simple salts such as sodium chloride. Potassium is often associated with non-volatile illite in coal which typically is partitioned with bottom ash in the combustion process. Organically associated potassium species more prevalent in low rank fuels are volatile in lower furnace conditions[7]. Information regarding the mineral species of fuel alkaline and the associated volatility is frequently available as part of backpass fouling and fouling mitigation studies for particular coals. Assessment of problematic alkaline specie volatility can thus be helpful to evaluate catalyst poisoning risk.

Once in the flue gas stream, sodium and potassium can be bound in fly ash as a fully oxidized species or as part of an aluminosilicate or ash absorbed ionic species. Aerosol and vapor alkaline species such as oxides, sulfates, and chlorides can additionally be absorbed onto fly ash in the flue gas stream. In a dry, high temperature environment, the degree of catalyst poisoning attributable to sodium and potassium is limited by the quantity of aerosol and vapor species condensing directly onto the catalyst, which can limit the relative severity of alkaline associated catalyst poisoning. However, the soluble alkaline species can readily transfer from fly ash into catalyst pores in the presence of moisture, resulting in catalyst poisoning.

Of particular importance on Figure 15, is the mechanism by which water soluble sodium and potassium species can be transferred from the fly ash to the catalyst by way of condensation. Condensation during outage periods presents a difficult challenge to coal-fired units in current market conditions, where the frequency and the duration of unit downtime can be unpredictable.

The high solubility of common sodium and potassium species is conducive to alkaline mobility under a wide range of solvent pH. Prior to year round SCR operation in 2009, SCR systems were designed with full or partial bypass dampers that were used to layup or isolate the catalyst to keep it warm and dry to prevent accelerated deactivation due to alkaline poisoning. Plants were designed to be base loaded and load cycling was not prevalent. The approach for mitigating catalyst poisoning from mobile compounds of sodium and potassium agents was to try and maintain the reactor temperature greater than water and acid dew point condensation temperatures.

Transient or inconsistent rates of catalyst deactivation may be partially attributable to the water dependent rates for sodium and potassium deposition during outage periods. Figure 16 (on page 15) depicts the recent catalyst test history associated with Plant B. Figure 16 depicts the average test history deactivation curve as the red line comprising the average of thirty-two test results. The catalyst test results for catalyst currently occupying each layer appear as individual sample points. A testing anomaly associated with a low relative activity ratio on the third catalyst level is observed at operating time 17,500 hours. This data point is a departure from typical deactivation trending observed as the relative distance increased between the data point at time 17,500 to the red deactivation curve. Previous test history over 15 years has not shown such a large difference in relative activity for the bottom layer of catalyst.

Figure 17 (on page 15) depicts the Plant B catalyst surface XRF chemical catalyst surface chemistry. Within this data, a stepwise change in sodium, potassium, and sulfur trioxide levels is observed within the third level catalyst sample from 2015 to 2017. Plant B operated in more of a reserve capacity in 2017 than in previous years. It is believed that the 2017 low activity data point observed on Figure 17 correlates to the stepwise increase in sodium and potassium levels which

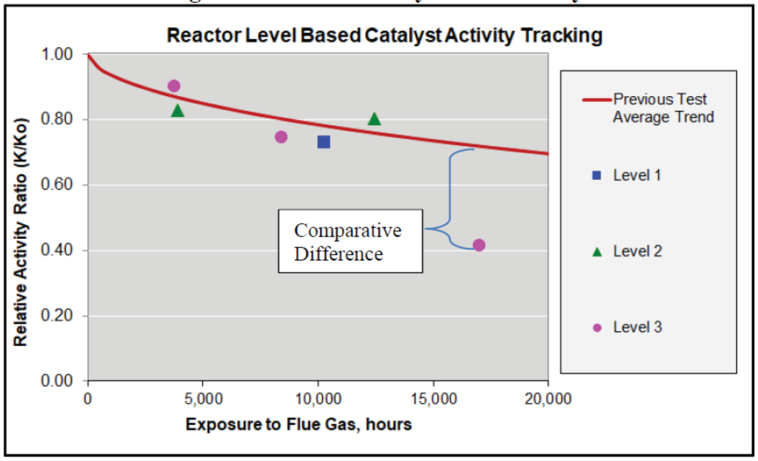


Figure 16: Plant B Catalyst Test history.

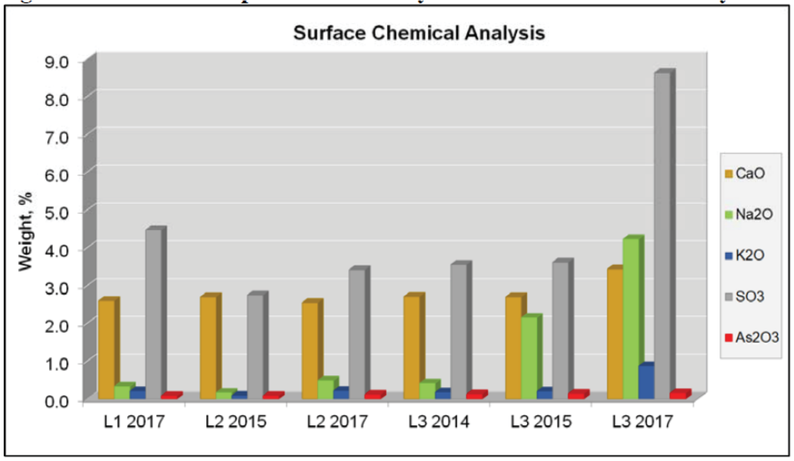


Figure 17: Surface composition of catalyst removed from Plant B by year.

Figure 18: Moisture observed on the third level catalyst sample removed in 2017.

have resulted in an increase in catalyst poisoning. Incremental increases in other catalyst poison concentrations appear to be moderate or typical from 2014 to 2017.

A SCR inspection of Plant B in 2017 noted high ambient moisture at the inspection time which is apparent by the water marks observed on the catalyst sample on Figure 18. Discussions with station personnel suggested that unit operation between 2015 and 2017 was less frequent (< 6,000 accumulated hours of generation), and that increasing SCR temperature or measures to reduce condensation within the SCR during outages were not typically pursued.

The condensation dependence of alkaline mobility can skew catalyst test results based on temperature gradients inside the SCR during the outage periods. One explanation for the bottom or third level having a greater impact by alkali metals is due to the bottom layer being the coolest, as the latent heat or heated air stored within the SCR reactor during outages rises and maintains the upper layers warmer for a longer period than the bottom layer. Ambient air intrusion or the presence of heat retaining fly ash piles can create a thermal profile within the SCR that favors moisture condensation in specific areas. In the case of the high sodium and potassium excursion observed at Plant B, localized condensation contributing to high alkaline poisoning rates is a potential cause for the atypical catalyst activity test result. As such, test results validated through multiple catalyst test samples can provide a more accurate representation of the catalyst performance.

Figure 19 (on page 16) depicts Plant C's recent catalyst test history. Collected data for Plant C spans over ten years and through multiple catalyst management events. Plant C has consistently fired PRB fuel containing up to 1.5% sodium in the fly ash. As such some indication of sodium poisoning has been noted throughout the catalyst test history.

The test results of the three most recently installed catalyst layers are depicted as individual data points on Figure 19; the first and second catalyst levels were replaced during the same outage (2013), and the third catalyst level was replaced during the next planned outage (2014). The total catalyst test history accounts for over ten years of catalyst testing inclusive of testing conducted prior to 2017 and totals fifty-two catalyst activity tests. Figure 19 depicts the complete Plant C test history as the red deactivation curve.

Similar to the Plant B catalyst test result observations, a departure from the typical exponential catalyst deactivation curve (redline) is noted within the Plant C test results. Deviations between the historical deactivation curve and the test data appear most predominantly at the first and second

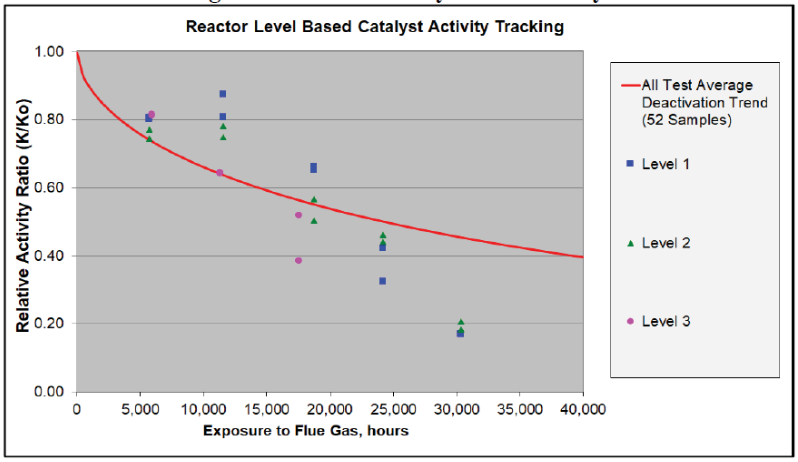


Figure 19: Plant C catalyst test history.

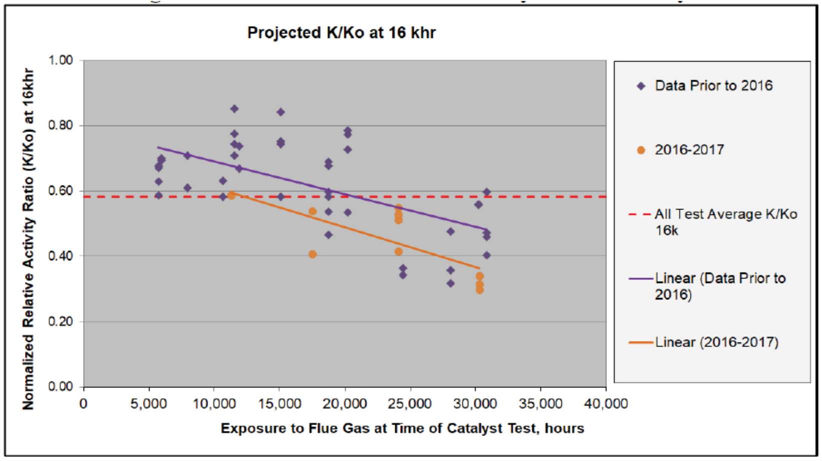


Figure 20: Plant C normalized catalyst test history.

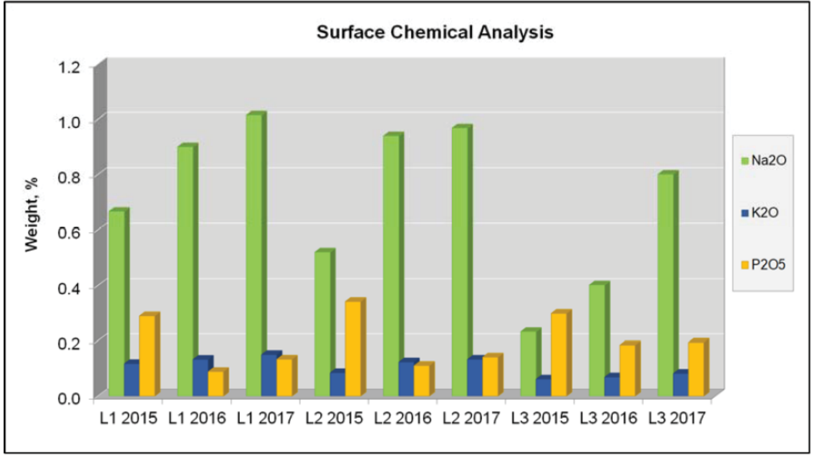


Figure 21: Surface composition of catalyst removed from Plant C by year.

layer test points after accumulating more than 24,000 hours of flue gas exposure (samples taken in years 2016 through 2017), likewise a similar deviation in the third layer test data is noted at the test points that had accumulated 18,000 hours of flue gas exposure (samples taken in 2017).

Figure 20 depicts the time-normalized test result history for Plant C. Relative catalyst activity (K/Ko) ratios were normalized to 16,000 operating hours considering a consistent exponential deactivation decay basis. For example, a sample taken at 8,000 hours with a K/Ko of 0.70 would have a projected K/Ko at 16,000 hours of 0.59 based on the assumed exponential deactivation decay model. Please note that the catalyst test results collected prior to 2016 are depicted in purple, and test samples collected from 2016 and 2017 are depicted in orange. The average historical deactivation rate for Plant C is depicted as a horizontal dashed red line. Analysis of the normalized deactivation rates allows for the direct comparison of catalyst samples of differing age for the consistency of the deactivation rate. As such, one would expect the normalized activity ratio evaluation as a function of time to yield a constant relative activity ratio under a consistent uniform deactivation rate (slope equal to zero). The non-zero linear regression slopes of the normalized test data prior to and after 2016 depicted on Figure 20 emphasize that the typical Plant C deactivation rate curve may not accurately describe the system performance. The current trends have shifted from historical trends. Likewise, the larger discrepancy between the normalized average data and the linear regression for more recent data suggest a stepwise catalyst deactivation change at or immediately prior to 2016.

Figure 21 (on page 16) depicts evaluation of Plant C catalyst chemical composition data for test years 2015 through 2017. Comparison of catalyst sodium concentrations over time suggest stepwise changes in sodium amounts on the first and second catalyst levels between years 2016 and 2017, coincidental to the disparity between the catalyst test results and historical deactivation rates shown on Figure 18 (on page 15); likewise, a stepwise change in sodium concentration is observed in the third level in 2017, coincidental to the change in the third level catalyst deactivation rate depicted on Figure 19 (on page 17).

Additional analysis of historical and more recent catalyst test results for Plant C is depicted on Figure 22 as a comparison between recent and historical aged catalyst test data with approximately 30,000 hours of flue gas exposure. Evaluation of station operating data suggests that operation between testing intervals in 2015 and 2016 was limited, and that the typically base-loaded unit had operated for less than

7,000 hours over the calendar year as a result of forced outages and dispatch related changes in load profile. The local conditions of the SCR during more frequent outage periods (relative humidity, temperature, presence of ash, etc.), likely have a strong impact on alkaline catalyst poison mobility. Previous catalyst test results prior to 2016 did not show the same magnitude in increased deactivation rates and alkaline poisoning during outages. However, it stands to reason that an increased outage frequency and duration will increase the likelihood of the reactor conditions to be conducive to offline catalyst poisoning.

It is important to note that the catalyst samples studied herein are field samples whose activity and poisoning rates are dependent on multiple factors. The deposition of other catalyst poisons (calcium sulfate, phosphorus, etc.) was still observed during the evaluation periods at all studied facilities. Sodium and potassium poisoning are not believed to be the primary means of catalyst deactivation at these locations; however, extended and more frequent outages can increase the presence of transient sources of catalyst deactivation which can have dramatic impacts on long-term catalyst management planning.

Catalyst Life Predictive Assessments Utilizing Field Data and Observations

Flue gas flow maldistributions and fly ash drop-out conditions created during low load can increase pluggage which affects full load (limiting case) operating cases critical to catalyst management considerations. The pluggage related impacts noted within the Plant A load cycling study reflect conditions that are widely applicable throughout the industry. As noted in the discussions of cementitious fly ash chemistry, moisture condensation in high calcium oxide environments can further propagate catalyst pluggage during reserve outage periods. Likewise, outage related moisture condensation can facilitate the transfer of alkaline poisons into the catalyst pore structure causing transient changes in catalyst deactivation.

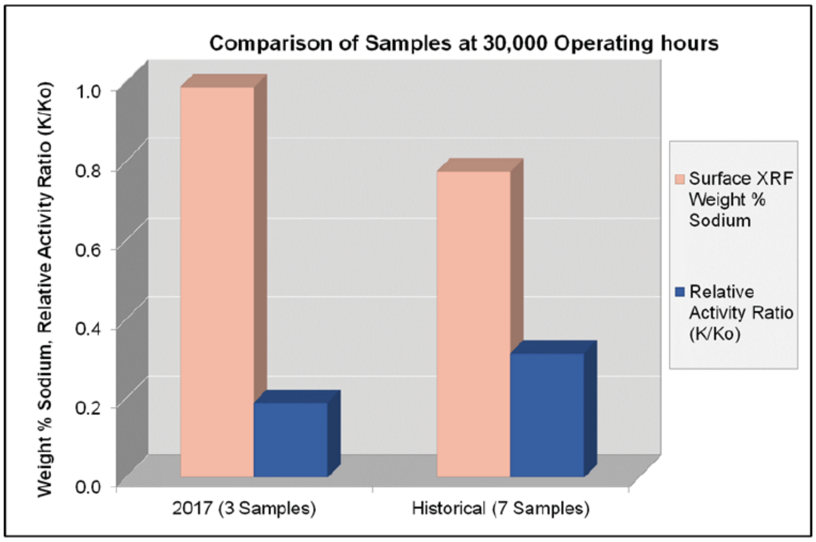


Figure 22: Comparison of recent and historical Catalyst Test Samples from Plant C accumulating approximately 30,000 operating hours.

A two-step approach can be taken for minimizing the long-term catalyst management impact of load cycling and outages on SCR's:

- Active mitigation - Active Mitigation of SCR performance problems resulting from outage and low load operation requires addressing the root cause of the catalyst pluggage and poisoning problems discussed herein; mitigation measures would include CFD modeling and flow correction device modifications to reduce low load flow abnormalities, utilizing catalyst cleaning devices such as sonic horns or ash sweepers, or utilizing offline heating mechanisms to minimize condensation within the SCR during outages.
- Proactive Planning - Proactive planning predicated on the accounting for the impacts of outages and load cycling within a flexible catalyst management planning strategy, both in operations and SCR related costs.

Active mitigation strategies may or may not be feasible and should be studied on a case by case basis for cost effectiveness. CFD modeling can provide beneficial low load operating information as well as effective strategies for modifying flow profiles to account for low load operation. Correcting flow problems may be cost intensive or may adversely affect flue gas flow characteristics at full load operation. Similarly, the implementation of offline/lay-up heating mechanisms may not be economically feasible or possible during all outages.

Proactive catalyst management is a critical and cost-effective tool for SCR capital project planning and is an important consideration for flexible operation when used with or without any active mitigation strategy. The inherent value of a robust catalyst management strategy is the ability to evaluate a diversity of SCR operating and management scenarios on a sensitivity basis as a means of best minimizing the likelihood of non-compliance while also minimizing long-term operating costs. Effective catalyst management depends on the assessment of actual operating conditions which can deviate substantially from the original design. Evaluation of operating data, flue gas characteristics, catalyst pluggage, and catalyst test data are critical to the development of dynamic catalyst management models that depict accurate field conditions.

The catalyst pluggage analysis depicted within the Plant A load cycling discussion emphasizes the importance of accurately assessing the root causes of reactor pluggage. Catalyst plugged as a result of increased low load operation is unavailable for NOx reduction at higher load conditions and limits the overall operating reactor potential. Comprehensive catalyst management models should account for catalyst pluggage such that the impacts of variable pluggage rates can be readily identified and accounted for accurately. Likewise, comprehensive catalyst management planning should address the potential variability in catalyst deactivation rates whether observed within the historical test data or if evaluated as a future risk.

One dynamic catalyst management scenario for Plant A is presented on Figure 23. The minimum reactor potential required to achieve operating goals (full load NOx reduction and ammonia slip limits) is presented as the red line and the operating reactor potential “saw-tooth” curve is presented as a blue line. Examples of the noted variations in the operating and minimum reactor potential lines are circled. The circled points reflect time dependent changes in reactor potential and DeNOx demand as a result of observed changes in deactivation rate and operating conditions. Without dynamic modeling future event timing would be incorrect and could result in either unplanned outages or the addition of catalyst that is not needed, both resulting in increased cost to the utility.

A 10-year catalyst management plan associated with Plant A and the events shown in Figure 23 result in one less catalyst management event than a catalyst management plan considering only original design conditions for Plant A, resulting in approximately $1M in avoided costs. Unnecessary catalyst management events can drastically increase unit operating costs. Likewise, the failure to account for changing operating scenarios can result in emissions exceedances and curtailed operation. Dynamic modeling of Plant C predicts five catalyst management events would now be required over a 10-year period whereas modeling to original design conditions predicted that only three events would be necessary. The dynamic catalyst model comparison for Plant C suggests that the unit would have increased operating risk or significant emissions exceedances if original design conditions were used as the primary catalyst management modeling means.

Similar modeling assessments are likewise pertinent in the study of Plant B where the impacts of the observed variability in catalyst deactivation rate can be accurately assessed via dynamic catalyst management modeling. The evaluation of multiple catalyst management scenarios can provide the most complete depiction of the most cost-effective catalyst management strategies while still managing operating risk.

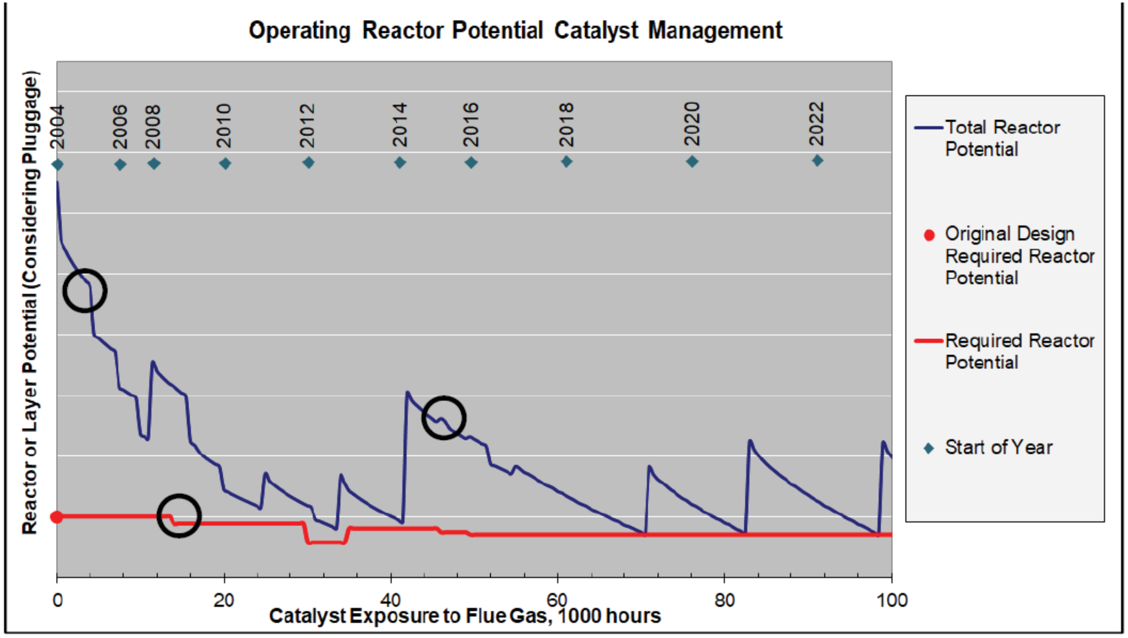


Figure 23: Plant A Dynamic Catalyst Management Modeling.

SUMMARY

Current power market conditions necessitate operational flexibility for traditionally base loaded coal-fired generating facilities. The cases discussed herein reflect the impact of increased pluggage and increased catalyst deactivation rates for increasingly prevalent load cycling and reserve outages on SCR performance. The observations and analyses presented may be pertinent for other SCR equipped generating facilities. Reduced load flue gas flow maldistributions can facilitate rapid increases in catalyst pluggage. Extended outage durations and increases in outage frequency can result in moisture and acid condensation and create necessary circumstances to solidify fly ash in/on the catalyst or mobilize soluble catalyst poisons resulting in increased deactivation rates. These circumstances can create transient variations in operating reactor potential that can have dramatic effects on long-term catalyst management strategies for coal-fired facilities. Proactive catalyst management and dynamic catalyst management modeling can identify operational trends and assess the long-term catalyst management risks associated with load cycling and increased outage frequency all while limiting cost. In the circumstance presented for Plant A (360 MW), the cost impact for neglecting these new operations paradigm effects could exceed $1 million over a ten-year period.

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BIOGRAPHY

Jared Koliha joined CERAM in 2016, where he currently specializes in SCR catalyst design, optimization, and system management. Jared has six years of experience in the power generation field with a background in plant engineering and chemical processes. As a former utility engineer, he has extensive experience in air quality control system operation and project implementation, SCR system management, MATS compliance strategies, and general power plant operation. Jared is a licensed professional chemical engineer with a bachelor's degree from Iowa State University.

John Cochran founded Ibiden Ceram Environmental in 2000. John specializes in SCR catalyst design, system design, optimization, and catalyst management. He also has extensive experience with other air quality control systems including FGD, particulate removal, and CEM. His work in the SCR field began in 1992 with the design of OUC Stanton Unit 2 which was the 2nd coal plant equipped with SCR in the U.S. Prior to founding the company, John was Black & Veatch's SCR Program Director and Air Quality Control Business Area Manager. John is a licensed professional mechanical engineer with a bachelor's degree from the University of Missouri.

CERAM

Evaluating Technologies for Unique Trace Metals Contamination Related to Coal Pile Runoff

Written by Max Swoboda, Evoqua

With the implementation of the Coal Combustion Residual regulations, the focus has been on the treatment requirements of residuals created after the coal is used and converted to ash. The ash pond dewatering for both cap and close, and closure by removal has garnered the bulk of the attention related to treatment systems. Since many streams within the plant ultimately passed through the ash pond before reaching an outfall, without an ash pond for final treatment these streams now require alternate treatment to meet NPDES compliance. One stream that can require an alternate treatment solution is the runoff created by rainfall on the coal pile.

While not a combustion residual, coal pile runoff may be covered under the CCR rule. If the impoundment used to hold coal pile runoff meets the following two criteria:

1. The impoundment was designed to hold an accumulation of CCR and liquid, and
2. It treats, stores, or disposes of CCR,

it is covered by the CCR rule.

Before the implementation of CCR regulations, coal pile runoff was typically transferred to the ash pond by a ring of drainage channels around the outside base of the coal pile. Since the ash pond meets both criteria, this would be an instance where the coal pile runoff is covered by the CCR rule. A separate and unique impoundment for coal pile runoff generally would not meet both criteria and would be exempt from the CCR rule as its design is not to hold the accumulation of residuals. These simple examples are just to illustrate the importance of an accurate understanding of the rule, and the design and function of a plant's impoundments. Careful evaluation of each impoundment is needed to understand how they meet the definition of a CCR impoundment and how the rule applies to each one.

In the event coal pile runoff requires treatment, an understanding of the water characteristics is needed. A coal pile of course is the reserve fuel source for a coal burning power plant. Most power plants tend to hold large reserves, up to 90 days of coal on site to prevent power production interruptions related to coal deliveries. Since the coal pile typically resides outside exposed to the forces of nature, it therefore receives rainfall, which generates the runoff water. The amount of runoff is proportional to the area of the pile and the local weather circumstances. Evaluation of these factors will yield an understanding of the required treatment volume. As the rain contacts the coal, it collects coal fines and other dissolved elements contained in the coal. These elements can include, high concentrations of iron, manganese, and sulfate, and trace concentrations of aluminum, arsenic, cadmium, copper, chromium, lead, mercury, nickel, selenium, vanadium, and zinc. Runoff with high concentrations of sulfate may depress the pH to less than 3.0. The contaminants collected in the runoff from the coal pile can require treatment to meet outfall limits. The minimum standards under any NPDES permit are TSS, pH and oil and grease. The other trace elements can be included in the permit limits, but are not uniformly consistent, as the requirements vary greatly from state to state based on the regulatory needs of each outfall.

Thus, of chief concern for any coal pile runoff treatment system is TSS removal and pH correction. Oil and grease could be present as heavy equipment is used to move the coal pile and hydraulic fluid, diesel fuel and other hydrocarbons could find their way on to the coal pile, but typically they are not largely present.

A collection sump or tank is sized based on the expected volume of water created by the rainfall. The design criteria include the collection area of the coal pile and the expected rainfall event data for the geographic area of the plant. Correct sizing is key for operating the treatment system within its designed flow rate. The retention time in this part of the system also helps equalize the runoff, since rainfall is not uniform. During lighter rainfall at the start of a storm, TSS level could be lower and increase quickly as heavier rain falls. The retention time of the sump reduces the variability caused by changing rainfall, making the downstream treatment easier to manage.

The treatment for TSS can easily be performed by clarification. A traditional clarification system is configured in a circular structure that is divided into a mixing zone/flocculation chamber, separation zone, sludge blowdown system and

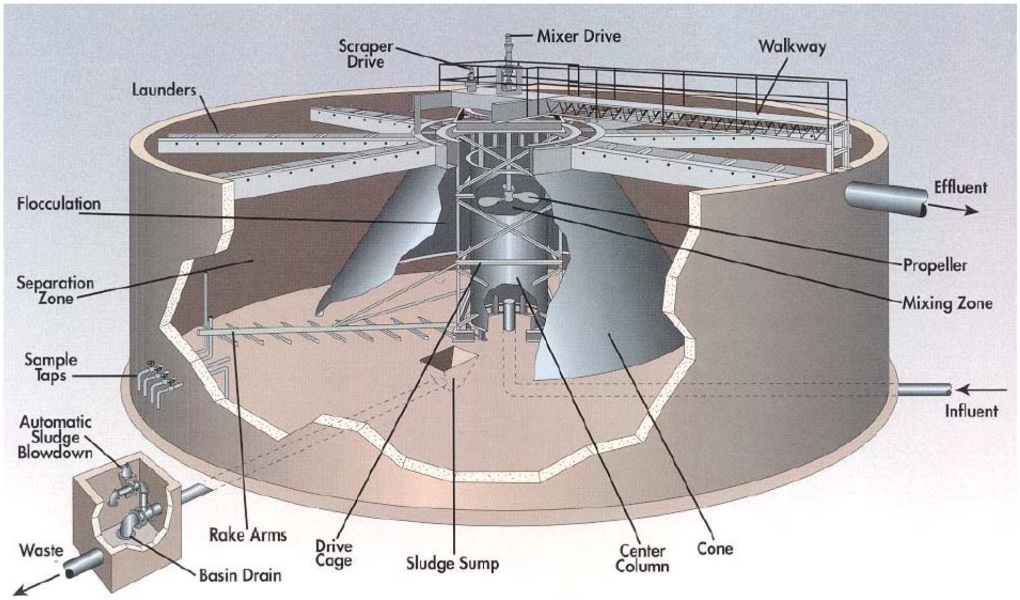

Figure 24: Circular clarifier major components

an effluent weir. The mixing zone has a paddlewheel slow mixer fixed in the flocculation chamber that is gear driven by an electric motor. The chemical metering pumps feed chemical to the mixing zone. The chemical addition system and mixing zone speed are based on the characteristic's collected from runoff samples and jar testing to determine optimal dosing. The recipe is selected based on the cost of chemical dosage, the constituents to be removed, and to a lesser extent the sludge production. The chemical system adds the proper chemical recipe to coagulate suspended solids for settling in the clarifier. If the optimal coagulation reaction coincides with the outfall pH range limit, the pH adjustment can occur during this step.

A walkway platform is provided and attached to the top of the clarifier. The clarifier portion of the unit has an inverted cone that reduces the velocity of the particles to assist in the settling as water enters the separation zone. Sludge withdrawal laterals in the bottom of the clarifier are used to withdraw sludge from the bottom of the clarifier. An air-operated diaphragm pump transfers the solids to a sludge tank. The sludge transfer is controlled by the system PLC and the transfer time and duration is based on the solids loading. The sludge tanks store the sludge which is eventually pumped to a sludge dewatering device via an air-operated diaphragm pump. The effluent from the clarifier flows over the weir via gravity to the next treatment step.

An improvement to traditional clarification is the ballasted flocculation clarifier. Ballasted flocculation is the process of adding a heavy material, to floc particles in order to increase the settling speed. Somewhat like high molecular weight polymers, that are added to grow the floc mass and increase settling, the ballast material greatly increases the specific gravity of the floc. The heaviest ballast material is magnetite. It has three characteristics that make it an excellent choice as a ballast material. First it is very heavy thus, high raise rates can be achieved. Next, it is magnetic, so after it has helped settle the floc, it can be easily separated by a magnet and recycled back to the front of the process. Over 95% recovery has been observed. Lastly it is not expensive. Ballasted flocculation can be added to traditional clarifiers to increase the operational flowrate or be provided as packaged systems with a 75% smaller footprint than a tradition clarifier.

The ballasted flocculation process includes three key components,

A – Multi-stage reaction tanks for coagulation, magnetite and polymer addition to ensure proper solids floc-

Figure 25: CoMag Ballasted Flocculation Clarifier Skid.

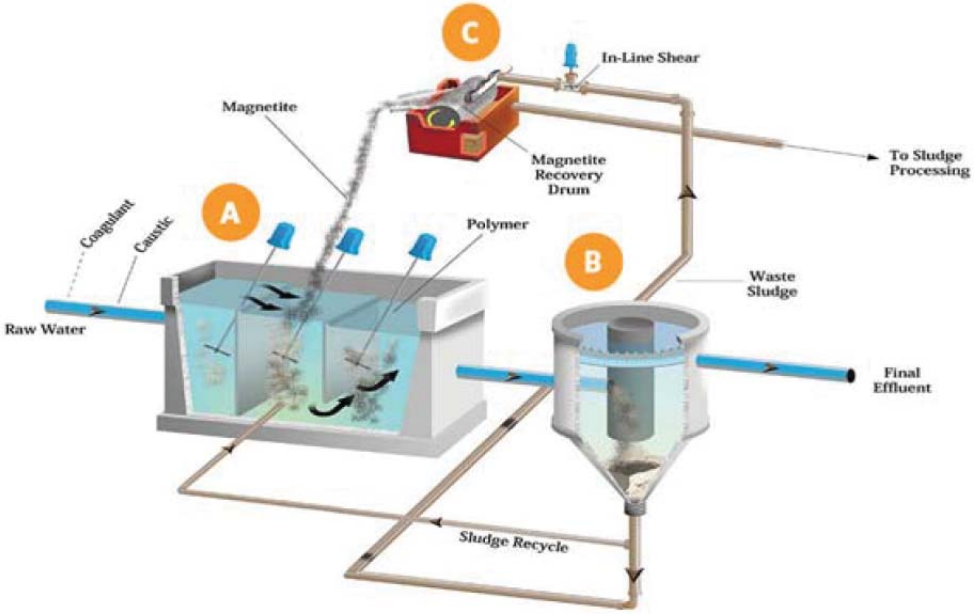

Figure 26: CoMag ballasted flocculation clarifier

culation. Sludge recycle reduces chemical usage and promotes nucleation.

B – The settling area where solids are separated by gravity is a compact, high rate clarifier used due to the fast settling magnetite impregnated floc particles producing a superior effluent.

C – Magnetite is sheared from the floc and recovered on the magnetic drum and the recovered magnetite is feed back to the reaction tanks. Sludge is removed here for dewatering and solids disposal.

The clarification equipment whether traditional or ballasted primarily addresses TSS, but other constituents can be reduced by co-precipitation. When selecting the chemical recipe, it can be adjusted to target a specific constituent that might be over the outfall limit. Coal pile runoff can include high amounts of iron and manganese, both of which are effectively removed with oxidation and pH adjustment. If the runoff pH is low, adjusting it with an inexpensive base like caustic soda is necessary. Iron will start to form iron hydroxide above 5.5 pH. Aeration or oxidation with chlorine or other oxidant can be added before the addition of a coagulant to increase the effectiveness of the coagulant. Aluminum and ferric based coagulant typically produce good removal rates in a pH range of 5-8. If a ferric based coagulant is selected better co-precipitation of arsenic can be expected.

Cadmium, lead, selenium and zinc all react well with ferric salts in a pH range of 6-9. Cadmium removal is optimum above pH 8. Also lime softening or caustic addition are effective for removing these dissolved metals from the stream.

The use of organo-sulfide precipitants produces metal sulfide compounds which have a much lower solubility than metal hydroxide compounds (created by ferric and aluminum-based coagulants), resulting in maximum heavy metal removal. Organo-sulfide coagulants can be used to target most heavy metals, including cadmium, chromium, copper, mercury, nickel, and zinc. The optimal pH is 6.5-8.5 and mercury removal tends to work best towards the lower end of the range.

If attempts to use co-precipitation methods do not yield an acceptable outfall result, another treatment technology that can achieve sub part per billion limits for most of the metals found in coal pile runoff is ion exchange or selective absorption media. This service is known as wastewater ion exchange (WWIX) (see figure 28 on page 23). The service is an incorporation of equipment and specialty resins delivered to a treatment location for metals removal. When the resin in the vessels reaches capacity, the local service branch is notified and delivers fresh tanks containing new resin to the site. Exhausted tanks are shipped to a RCRA-permitted treatment facility where the contaminants are removed from the resin and recycled into a reusable raw material. Recycling of the spent resins at the treatment facility effectively reduces the customer's liability associated discharge and handling.

A WWIX system is designed based on the capacity and flow rate required. Tanks of the selected resins are installed in series with sampling ports after each vessel. Three products are available to treat the elements typically found in coal pile runoff. Figure 27 below shows the effectiveness of each product.

As CCR impoundments close and the plant water balances change within the coal plant, remember to address the treatment needs related to coal pile runoff. Since the runoff is not directly regulated by the CCR rule, it is a stream that may get overlooked. Early planning and sampling can make the design process smooth and easy.

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1. *Evoqua's Mobile Clarification Provides Rapid Response to Ensure Coal-Pile Runoff Discharge Compliance https://www.evoqua.com/en/brands/IPS/productinformationlibrary/MOSSSECOALPP.pdf*

2. *Coal-Fired Power Plant in Northeast Uses Ion Exchange Service for Metals Removal https://www.evoqua.com/en/brands/IPS/productinformationlibrary/ESNEPWRPP.pdf*

Element	Product	Expected Effluent
Arsenic	ASG	<10 ppb
Cadmium	SCU	<10 ppb
Chromium	SCU or AGW	<10 ppb
Copper	SCU	<10 ppb
Lead	SCU	<10 ppb
Mercury	SCU	<12 ppt
Nickel	SCU	<10 ppb
Vanadium	SCU	<10 ppb
Zinc	SCU	<10 ppb

Figure 27: Effectiveness of each product.

Figure 28: WWIX Exchangeable Resin Bed

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BIOGRAPHY

Max Swoboda has 25 years of experience providing technical and water treatment solutions to power plants. His experience includes developing water solutions for many industries, ranging from ultrapure water production to providing water treatment services for fossil and nuclear facilities. Swoboda joined Evoqua in 2016, focusing on the wastewater needs of power plants, particularly coal-fired plants needing to stay in compliance with CCR and ELG regulations. He holds a Bachelor of Science in Civil Engineering from the Virginia Military Institute, where he focused on the environmental/water treatment track.

An Historic Outline of Electrical Control Systems Used in The Process of Electrostatic Precipitation

Written by Paul Ford and Hank Del Gatto, REDKOH INDUSTRIES

SOME IMPORTANT EVENTS DATES

1886: Electrostatic phenomena apparatus patent by A. O. Walter

Alfred Osten Walker, of England, a subject of the Queen of Great Britain, invented a process of Depositing Solid Particles Suspended in Air or Gas such as particles of metal or of metallic compounds applicable for condensing fumes from smelting furnaces and for other purposes;

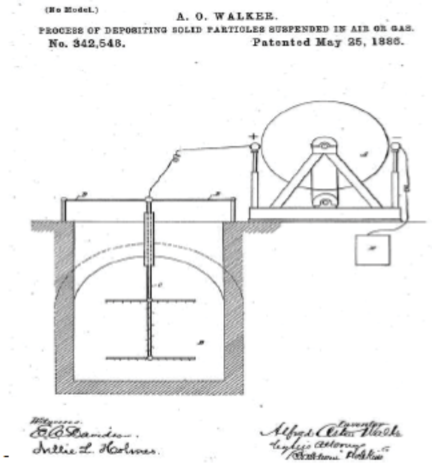

Figure 29: Patent diagram from first precipitator patent G. Walker 1885

This first patent was essentially a theoretic work that established a general description of electrostatic phenomena. Mr. Walker recognized the effect of electrostatics on suspended particles without making reference to voltage levels, voltage polarity nor a method of generation of the required voltage. The Patent diagram shown above depicts what looks to be a friction type static generator with the connection to the center 'electrode' being positive.

1903: Mercury Arc Rectifier first used by Sir Oliver Lodge on ESP

The mercury arc rectifier consisted of a glass tube with three or more electrodes. When a given amount of current would heat up and vaporize the mercury in the tube, the full power level could travel through the vapor to the other side.

Figure 30: Mercury arc rectifier

The effect on the AC power waveform is that it would chop off the beginning and end of the wave, and prevent current from traveling back through, effectively acting similar to a diode

1906: Commercial ESP installed at Pinole CA (near Berkley) by Fredrick Gardner Cottrell. ESP for H_2SO_4 collection of gas flow of 5,000 CFM. Used pipe type ESP.

1908: F. G. Cottrell Patent 895729 "Art of Separating Suspended Particles From Gaseous Bodies"

Here Mr. Cottrell provides detail on the construction of a commercial precipitator. Brush type apparatus is used for the emitting electrode while the collecting electrode uses a smooth surface. This patent makes reference to' glow discharge' around the emitting electrode but does not mention polarity. A synchronous transformer and a synchronous motor driven rectifier system is employed. This type of rectifier did provide a primarily DC voltage but the output polarity could not be predicted.

1910: 1,000,000 CFM ESP/100 tons per day on Smelter by W. A. Schmidt (Student of Cottrell) Riverside Smelter

1912: P. G. Fayer Patent 1,048,819 "Alternating Current Rectifier"

Patent defining a synchronous motor driven contacts for conversion of AC current to DC current.

1913: F.G. Cottrell Patent 11,067,774 "Method Of Discharge of Electricity Into Gases"

Here Mr. Cottrell specifies the use of negative potential on the emitting electrode having complex points on surface. The patent explains the phenomena that the negative potential permitted higher 'stable' voltage. The patent also states the concept of "electric flow" through the gas and the charging of the particles. Up until around 1914 the concept of electrons and atomic structure first became known. Early experimenters assumed electricity 'flowed' from the positive to negative. It later became known that electricity was actually electrons moving from negative to positive.

By 1914, experiments by physicists Ernest Rutherford, Henry Moseley, James Franck and Gustav Hertz had largely established the structure of an atom as a dense nucleus of positive charge surrounded by lower-mass electrons.

1919: Anaconda smelter site 2,000,000 CFM ESP

1944: 2,000 KW, 60 KV application of the Mercury Valve on Electric transmission application. Mr Uno Lamm ASEA, Sweden.

1920's to 1950: ESP primarily lab and experimental use with limited commercial application as pollution control remained a local issue.

1947: Junction Transistor invented by Shockley

1975: Large scale use of Silicon Controlled Rectifiers (SCR's) on many industrial applications

1975 to 1980's: Microprocessors Intel 8080, Motorola 6800 and Zilog Z80 Wide acceptance and application

1970's: Design and application of transistor circuitry for ESP controls

1970: USA Clean Air Act (CAA) passed defining "National Ambient Air Quality Standards.

1977 & 1990: CAA amendments re-establishing compliance date as almost none of original dates were met.

HIGH VOLTAGE GENERATION

Early commercial ESP's used Line frequency (60 Hz USA) and step up transformers and achieved voltage above 50,000 Volts DC (50 KVDC). This approach continues in use for most modern systems, though higher frequency approaches are gaining increased acceptance and application.

NEGATIVE POLARITY ELECTRODES

Negative ESP high voltage was largely applied to the emitting electrodes as been demonstrated as better efficiency than 'Positive' corona. Originally disclosed by a Patent from Cottrell in 1913 as a method of achieving higher stable voltage and improved efficiency.

SYNCHRONOUS MECHANICAL RECTIFIERS

The use of Synchronous Mechanical Rectifier was the method of choice for converting the high voltage Alternating Voltage (AC) to high voltage Direct Current (DC). This type of rectification required periodic change out of contacts as well as other maintenance of the rotating apparatus but was generally reliable. P. G. Fayer Patent 1,048,819 "Alternating Current Rectifier"

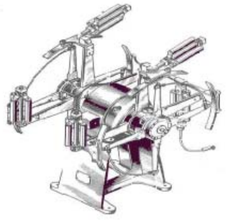

Figure 31: Synchronous mechanical rectifier

METAL OXIDE AND SELENIUM RECTIFIERS

First Metal Oxide soon followed by Selenium rectifiers became available in late 1920's and had some limited use on ESP power supplies.

SILICON RECTIFIERS

The general use of semiconductors stared in 1948 with the invention of the junction transistor by Mr. Shockley. Wide spread use of silicon semiconductors including 1000-volt diode did not occur until late 1950's. Up to about the 1970's diodes were capable of operation with reverse voltages up to about 1000 volts. In order to be used for rectification of the much higher voltages of ESP's (50,000 to 100,000 Volts) the 1000-volt diodes needed to be wired in series configuration. In addition, the diodes on the series string needed to be protected by parallel capacitors and resistors. The purpose of these extra components was to ensure that the reverse voltage would be 'shared' by each of the diodes when under high reverse voltage condition.

AVALANCHE TYPE SILICON DIODE STACKS

Around 1980 the silicon diode technology advanced to allow the production of 'controlled avalanche' devices and use in ESP power supplies. These devices were essentially the same as conventional diodes, except that under high reverse voltage they allow a level of conduction without sustaining failure. In addition, the manufacturing technology of the diode allowed the manufacture of multiple P-N junctions on a single crystal-like structure. The use of the avalanche technology along with the stacking on many P-N junctions made diodes rated at 10,000 volts and above.

Such devices having controller reverse voltage characteristics allowed the series connection without the need for compensating resistors and capacitors. With 10,000-volt capability the number of diodes was reduced by a factor of ten. This approach is used by many modern ESP Power Supply manufactures as it can result in lower cost and in lower heat loss.

LINE FREQUENCY METHODS OF POWER LEVEL CONTROL

Control of the voltage, current and resulting power that can be delivered to the ESP field is critical the ESP performance. From the very beginning, it was understood that the small voltage (KV) changes result in very large change in collection efficiency. There is evidence that as little as 3 KV differentials result in over 10% difference in ESP efficiency.

Early ESP's achieved up to 90% efficiency under controlled static conditions due to lack of automatic control while modern ESP's routinely achieve efficiencies of 99% under varied dynamic conditions.

VARIAC AND RHEOSTAT CONTROL

Prior to the availability of more modern components the High Voltage step-up transformer was controlled through use of a variable transformer (VARIAC) or variable resistor (rheostat). These control devices could also use motor drive for ease of setting. Basically, the voltage (KV) was experimentally increased until sparking occurred and then the voltage is 'backed-down' some several KV below that point. As the flue gas characteristics and flow rate changed the power supply would need to be re-tuned' by operator action.

Figure 32: Variac and rheostat control

SATURABLE CORE REACTOR CONTROL

Starting in the early 1900's Saturable Core reactors or 'Magnetic Amplifiers" were used as a means of controlling AC power to the transformer. Its use on ESP's was fairly common. The Sat Core reactor is manufactured in a similar manner as is a conventional transformer. It has an AC winding that is wired in series with the load and a DC winding that is the control winding. With zero/low current in the control winding, the magnetic core of the device operates in a linear magnetic region and offers maximum inductance to limit the current flow to the load. As current is applied to the control winding the device core is driven into saturation and the series inductance decreases and the current to the load is increased. Sat Core reactors were widely used with resistive loads such as lighting prior to the advent of SCR's and transistors. Sat Core Reactors are highly reliable control devices but do yield a highly irregular pulsing output which may not have proven acceptable for ESP's.

SILICON CONTROLLED RECTIFIER (SCR) CONTROL

In the mid 1970's the widespread of SCR's for power control occurred. SCR's are fast turn on devices that are controlled by low energy pulses on a control lead (gate). SCR's result in very low power consumption of the device as the voltage drop across it is extremely low as compared to the 380++ Volt primary line feed. An SCR can control voltage and power levels by the timing of the 'turn-on' signal with respect to the 60 Hz line cycle. For ESP use the SCR can be safely used to result in from 10% to over 90% power transfer to the transformer primary. SCR control continues to be the most used topology for ESP power.

DOUBLE HALF WAVE TR CONFIGURATION

In the early 1970s experimental data indicated that high resistivity ESP applications could sometimes benefit from the use of pulsating high voltage. At that time, a method of doing this was to configure the Transformer-Rectifier with two half wave rectifier bridges as opposed to one full wave bridge. The TR was equipped with two separate bushings, one for each half wave output. The TR bushings were then connected to power up separate field areas. The pulses were 1 to 8 msec in duration and occurred every 16.6 msec for 60 Hz feed. The single primary winding powered up both bushings, causing the KV available to be the lower operational value of the two sections. In addition, when one section was to spark then both would be set back. The use of this configuration has been essentially abandoned as new control technology has evolved.

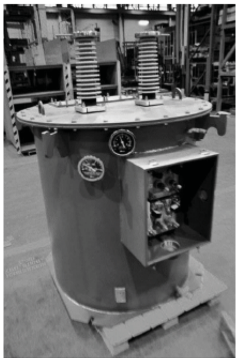

Figure 33: Double half wave tr's shown with two high voltage bushings

CURRENT LIMITING REACTORS (CLR's)

Large power inductors are used in series with the primary circuit of SCR controlled Power Supplies. The initial use for the CLR's was to limit the amount of current surge that results from an ESP arc. Once an arc is struck the KV drops to a very low value of a few KV and acts as a momentary short circuit on the transformer secondary. The amount of current that the output can rise to is a function of the parasitic impedance of the feed system which could be in the order of

10% to 20%. The low impedance is then supplemented by a series connected external reactor to bring the total impedance up. A 50% impedance will allow current spikes to twice (2X) rating where a 20% impedance will allow up to five times (5 X) rating.

The addition of the CLR can have the additional benefit of wave shaping of the SCR phase-controlled feed. As the controller is needed to phase back power, the power pulse width delivered to the ESP is decreased and results in increase of ripple. During the late 1970s and through the 1980s CLR values were increased to improve the collection efficiency of many ESP's as ripple magnitude is reduced.

Figure 34: Current Limiting Reactors (CLR's)

SEMICONDUCTOR CLOSED LOOP CONTROL THEORY AND CIRCUIT TECHNOLOGY

The basic theory or algorithm or dynamic ESP control was refined as semiconductor control circuits were available for use. Essentially the task of the controller is to maintain the highest possible voltage (KV) while allowing some acceptable frequency occurrence level of spark-over. It is desirable to sense and to extinguish spark-over by momentarily reducing voltage as quickly as possible and to then re-establish a pre-spark-over voltage as quickly as possible.

Closed loop controls use feedback signals representing ESP high voltage (KV), ESP current (ma) as well as primary voltage and current levels. Controllers use these feedback signals to cause the ESP to operate within the power supply ratings or within operator set points and for the critical function of detecting spark and arc conditions.

Control systems operate by incrementally increasing the voltage to the transformer primary until an operating limit (KV or Current) is sensed or until a spark is detected. Spark sense is accomplished by electronically monitoring the ESP current (ma) and ESP voltage (KV) for rapid change that accompanies spark and arcs in the ESP field. When such disruptions are sensed the control must rapidly reduce or remove power to extinguish the spark over ionized path and then resume high voltage by ramping up again at a controlled rate.

ANALOG CONTROL CIRCUITS

Soon after the use of transistors became available in the early 1960 various circuit designs were implemented by several commercial entities in the ESP market. The designs employed the use of available passive components such as resistors, capacitors, inductors and transistors to form amplifiers and comparator circuits. The setup of these controllers required many adjustments, using variable resistors (potentiometers or Pots) as well as variable inductors and/or capacitors. The setup of these controllers necessitated the use of an oscilloscope and that of skilled technician or engineer. Once set up these types of controllers worked very well and served the industry for many years.

DIGITAL/MICROPROCESSOR (Up) CONTROL CIRCUITS

In the late 1970's and early 1980's microprocessor technology gained wide acceptance and use in many electronic applications, both industrial and consumer. Up systems offered the possibility and the capability for a multitude of complex control sequences as well as for digital readout and for data transmission and accumulation. The use of Up continues to date with more features and capabilities being implemented every year. The relative low cost of modern Up's has allowed a multitude of products from different suppliers.

Some advanced capabilities that have been realized by Microprocessors:

1. Push button set up using buttons and alpha-numeric display to permit the operator to change control parameters. As the analog controllers necessitated the use of meters and oscilloscope and very small screwdrivers, less technical skill is needed to enter values that represent all the operating levels for the ESP.

2. Operation history recording was offered on some products so that an operator could recall historic voltage and current levels for reference.

3. Detection of adverse operation such as 'Back Corona could be automatically detected and acted upon. Back Corona condition sometimes occurs with high resistivity particle layer on the collecting surface that causes positive charged ions to be formed that effectively cancel out some of the negative corona current.

4. Communication link to central control system allows ESP operation to be recorded by central DCS as well as to be under the control of DCS.

5. Ability for semi-Pulsing operation for high resistivity conditions was/is available on many designs. This technology causes intermittent high voltage pulses of the 8 msec line to be superimposed on a base high voltage. This proved beneficial on some limited applications involving high resistivity particles.

6. Synchronization with rapper control permitted the field to be either 'turned down or to be turned off during rapping operation.

7. Various peripheral fault sensors could be wired into the controller for operator notification and/or to adjust or turn off the field as necessary.

8. Control of peripheral devices such as contactors, rapper motors and pumps could also be controlled.

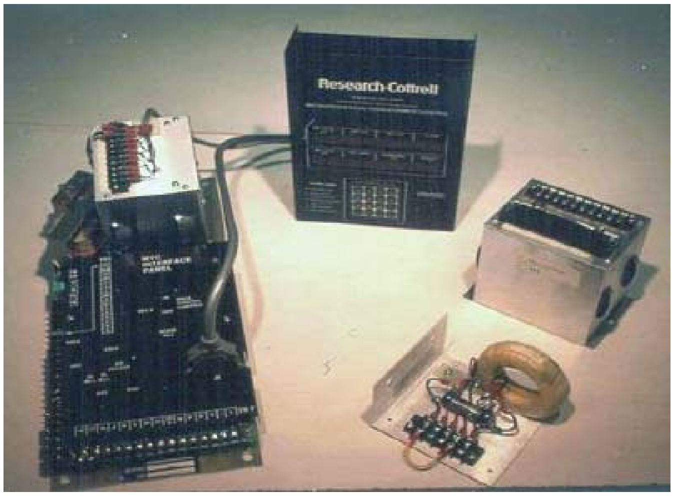

Figure 35: Research Cottrell Corp together with other supporting companies pioneered the microprocessor precipitator control technology

INVERTER METHODS OF POWER LEVEL CONTROL

In the 1980's the concept of higher frequency Power Supplies for ESP's was first developed. Such power supplies, that are referred to as Switch Mode Power Supplies had, by that time, wide acceptance in industrial and consumer products and had gained prominence of use. The development of SMPS for ESP use offered some notable advantages and notable challenges. Since the initial offering several other designs and approaches have been developed and now are gaining more acceptance in the ESP market.

SMPS for ESP are currently offered in two general categories of topologies. The types are 'High Frequency" that operate above 10,000 Hz (10 KHz) and 'Mid Frequency' that operate form 100 Hz up to a few thousand Hz. Both types of topology employ a three-phase feed, a rectifier/capacitor DC Link and Transistors to form a 'H' bridge inverter circuit to convert the DC buss to a desired higher frequency. The High Frequency inverters typically use a series resonant circuit to feed the Transformer primary while the Mid Frequency inverters have the H bridge directly coupled to the transformer primary. The High Frequency inverters require that the power supply be close to the load, so they are usually mounted on the roof of the ESP. The Mid Frequency inverters can tolerate the longer feed lines between the inverter and the transformer so they can be located in a remote control room similar to those used for SCR controllers.

RIPPLE AFFECTS OF SMPS

The magnitude of the ripple on the ESP high voltage is largely affected by the parasitic capacitance of the ESP and the frequency of the energizing pulses. With typical dust resistivity the highest average voltage is obtained by having the lowest possible ripple. With frequencies above a few hundred Hz the ripple is driven down to 3 to 5% as compared to up to 40% with SCR control. The extra wide plate spacing current usage of up to 16 inches results in decreases ESP capacitance and as such the tendency for shorter electrical time constant and higher ripple. As such wide plate spacing lends increased benefit of using SMPS over the use of SCR control.

LOCATION OF CONTROL ELECTRONICS

The roof top positioning of HF Inverters imposes additional challenge for maintenance and troubleshooting activities as compared to the indoor positioning of the SCR controls and the MF Inverters. Mid Frequency controls can in most instances be retrofitted into the old SCR cabinets and use existing TR's. CLR's are not needed for HF Inverters while lower inductance value CLR's are typically retained for MF Inverters for primary wave shaping in order to use existing TR's

HEAT TRANSFER/COMPLEXITY

The tendency to make HF Inverters as small as possible results in much greater complexity of heat transfer considerations with some designs needing fans and/or oil pumps to facilitate the removal of heat from the smaller assemblies. Both HF and MF Inverters require greater number of parts and complexity of design than SCR controls. Because of this some users of these controls require to use external skilled contractors for the repair and maintenance. In general, the Higher Frequency Controls tend to be more complex and have a poor reliability history as compared to the SCR type control

SPARK RESPONSE

Both HF and MF Inverters can facilitate spark response in time order of micro-seconds as compared to SCR control needing up to 8 mill-seconds. The fast response is due to the ability of the H Bridge components (IGBT) transistors to be turned off by the removal of the gate signal. SCR's cannot be forced off, so the system must permit the continued power feed to the spark until the line feed change phase. Depending on when the spark occurs in the line cycle the feed-through current into the spark can be significant.

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Enhanced Low Load SCR Operation

Written by Christopher Bertole, Cormetech

INTRODUCTION

Selective Catalytic Reduction (SCR) is an effective process for controlling NOx emissions from coal-fired utility boilers. The NOx reduction reaction proceeds over a V_2O_5-(WO_3 or MO_3)/TiO_2 catalyst using NH_3 as the reductant according to the following two main reactions (flue gas from coal-fired boilers usually contains >90% NO):

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \quad [1]$$

$$2NO + 2NO_2 + H_3 \rightarrow 4N_2 + 6H_2O \quad [2]$$

SCR catalysts are also active for the oxidation of elemental mercury (Hg^0) present in the flue gas, which enables the capture of oxidized Hg (as water-soluble $HgCl_2$) in a downstream wet flue gas desulfurization unit:

$$2Hg^0 + 4HCl + O_2 \rightarrow 2HgCl_2 + 2H_2O \quad [3]$$

An undesirable reaction that occurs over SCR catalysts is SO_2 oxidation to SO_3 [reaction 4], the rate of which can be controlled through careful selection of catalyst formulation and monolith geometry for a given application.

$$2SO_2 + O_2 \rightarrow 2SO_3 \quad [4]$$

With NH_3 and SO_3 both present within the SCR catalyst, another reaction can occur within the catalyst pore network at low SCR operating temperatures, which is the condensation of liquid ammonium bisulfate (NH_4HSO_4, or ABS), according to reaction [5] (ABS: melting point = 147°C, bulk-phase boiling point (decomposes) > 235°C).

$$NH_3 + SO_3 + H_2O \rightarrow NH_4HSO_4 \quad [5]$$

It is the potential low temperature formation of ABS salts in the SCR catalyst that limits the SCR minimum operating temperature, and as such, the boiler's load turndown ratio.

Modern SCR systems on coal-fired boilers are being forced to maximize their operational flexibility (i.e., load cycling) due to the larger utilization of shale gas and renewables (solar and wind) in the Power industry. In addition, updated emissions regulations, such as CSAPR, MATS, and ozone NAAQS, motivates utilities to get higher performance out of existing SCRs. Lack of flexibility to operate at low loads can be a big issue affecting a Plant's operational efficiency.

Over the past 14 years, CORMETECH has developed and refined a simulation model approach, validated through lab testing, and successfully deployed on full-scale boilers, that can extend the SCR's operability at low load and enhance the boiler's turndown ratio. The first applications of this approach were completed for Duke Belews Creek Unit 2 in 2004[1] and for the TVA fleet in 2005[2], with a more recent published application at Duke Gibson Station in 2017[3]. The "Enhanced Approach", as it is referred to, is currently in use in over 39 boilers in the Power industry; broader implementation can assist utilities in meeting higher NOx reduction goals with existing assets. The current article will take a look at the Enhanced Approach.

METHOD DESCRIPTION AND APPLICATION

Figure 36 (on page 31) plots the bulk-phase ABS (ammonium bisulfate, NH_4HSO_4) dew point temperature as a function of the gas-phase SO_3 concentration under conditions of constant NH_3 and H_2O. By capillary condensation, liquid ABS can form in SCR catalyst pores above the bulk phase dew point temperature, a phenomenon governed by the Kelvin equation [equation 6]:

$$\ln (P/P_{sat\ vap}) = -(2\ \sigma\ V_1) / (r\ R\ T) \quad [6]$$

where $P_{sat\ vap}$ = saturation vapor pressure of bulk-phase ABS liquid, σ = ABS surface tension, V_1 = ABS molar volume, R = gas constant, T = temperature, and r = pore radius.

The use of the Kelvin equation in equation [6] reveals that smaller catalyst pores result in a larger vapor pressure reduction of liquid ABS, yielding a higher ABS dew point temperature, as shown in Figure 36 (on page 31).

If the SCR temperature should fall below the SCR catalyst dew point temperature, liquid ABS can start to deactivate the catalyst by filling and/or blocking pores through capillary condensation, which then inhibits the ability (i.e., lowers the diffusion rate) of the NOx and NH_3 reactants to reach the catalyst's active sites and form the N_2 and H_2O products (lowering the DeNOx activity). Figure 37 (on page 31) shows a schematic of the pore-filling process.

Thus, ABS formation in the catalyst pores is the key factor controlling the minimum operating temperature of an SCR in a coal-fired utility boiler application. While the bulk formation of ABS needs to be avoided due to its irreversible, detrimental effect when combined with fly ash, the catalyst pore filling by ABS is fortunately reversible: reheating the catalyst to a recovery temperature above the dew point will remove the deposited ABS and restore the catalyst's activity. The cyclical process of intentionally depositing a controlled amount of ABS in the catalyst, at an operating point down towards the bulk phase ABS dew point temperature, with resultant deactivation, and then following it with a heating step to a pre-determined recovery temperature to facilitate its complete removal, is the premise of the Enhanced Approach.

The Enhanced Approach (Figure 38 on page 32) increases a unit's flexibility to manage emissions at low load by enabling a much lower operating temperature than would be normally possible under continuous operation. Applying the Enhanced Approach requires a detailed understanding of ABS formation thermodynamics, details of the coal boiler unit's operation, and the SCR catalyst's transient response characteristics at both full and low load conditions. Thus, it is important to characterize the catalyst's DeNOx and ABS deposition/removal kinetics, as well as the unit's SCR temperature (average and spatial distribution), flue gas flow rate and gas composition, at both full load and the targeted part load conditions. A case specific evaluation is typically necessary, because these details vary significantly among different coal boilers and SCRs, as do the operating goals of the Plant.

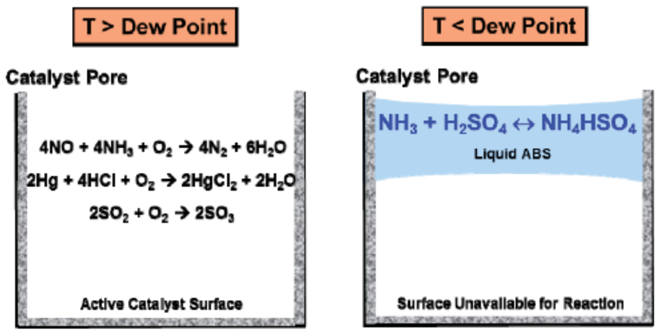

Figure 37: Schematic of Catalyst Pore Above & Below ABS Dewpoint Temperature.

CORMETECH has developed a strong toolbox for evalu-

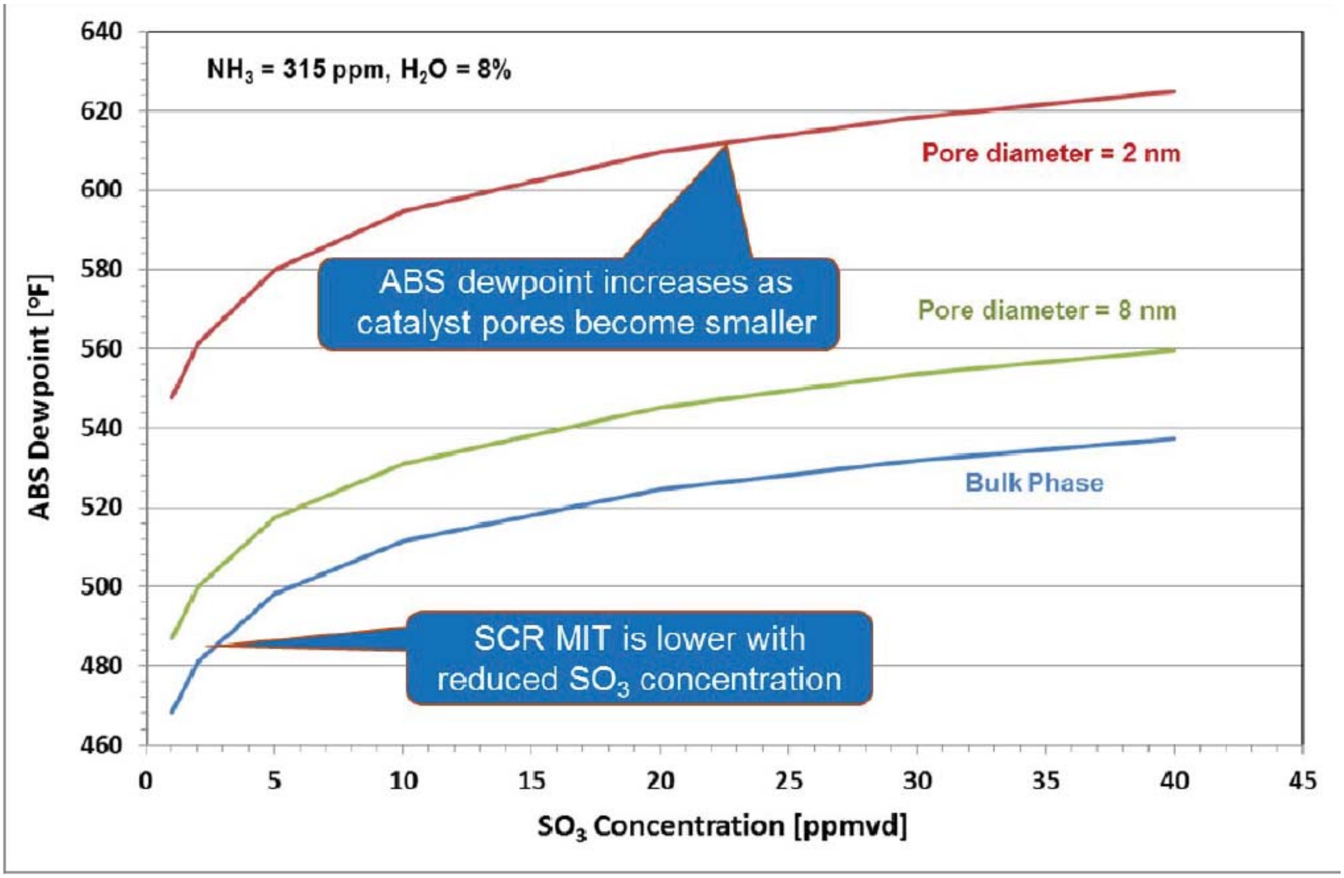

Figure 36: ABS Dewpoint Temperature as a Function of SO_3 Concentration.

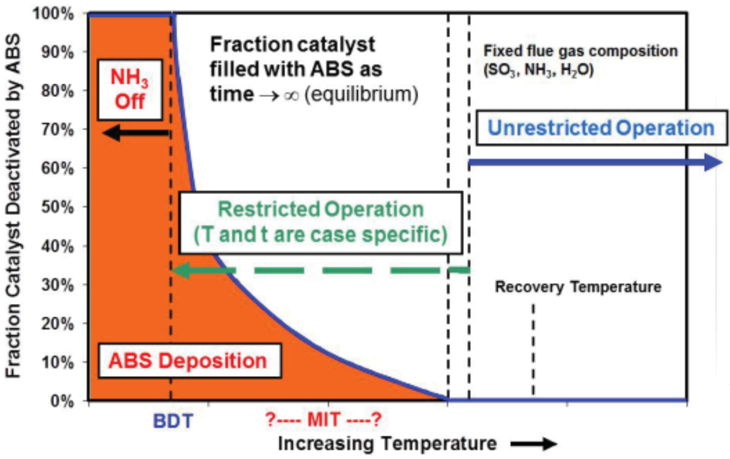

Figure 38: Enhanced Approach Operation: Managing ABS Deposition and Removal

Note: MIT = minimum NH_3 injection temperature, BDT = ABS bulk-phase dew point

ating and implementing the Enhanced Approach (see reference 3 for more information), which allows us to evaluate the feasibility of desired operating scenarios and iterate to find a good solution. The toolbox includes a large testing database and models for engineering analysis (i.e., a thermodynamic model, a kinetic model, and a transient deactivation and recovery model incorporating thermodynamics (ABS equilibrium) and kinetics into a dynamic model that can predict the DeNOx, SO_3, and NH_3 transient responses; the impact of DSI can also be included, to assess its impact on the catalyst ABS responses). Lab validation testing is a useful tool for model baselining to characterize the SCR catalyst and/or DSI material, as well as for verifying modeling output. An example of catalyst load cycle test, showing lab reactor data (relative activity: $K/K_{\text{full load}}$) and transient model simulation, is provided in Figure 39.

In the lab load cycle test in Figure 39, the flue gas composition was held constant throughout the test at NOx = 224ppmvd, molar ratio = 0.96, O_2 = 2.2%, H_2O = 9%, SO_2 = 100ppm, and SO_3 = 4ppm.

The low load temperature for this test was selected to be equivalent to the bulk phase dew point; indeed, a significant amount of ABS formed on the catalyst under the low load condition (final K after 50h at low load was ~20% of the fresh full load K). During the recovery, the activity was slowly restored; full restoration of the catalyst's activity occurred after heating for 4 hours to 750°F.

In applying the Enhanced Approach, it is important to recognize that each SCR has a specific total catalyst potential ($K/AV = -\ln(1 - \text{DeNOx})$), in X layers, that enables it to achieve

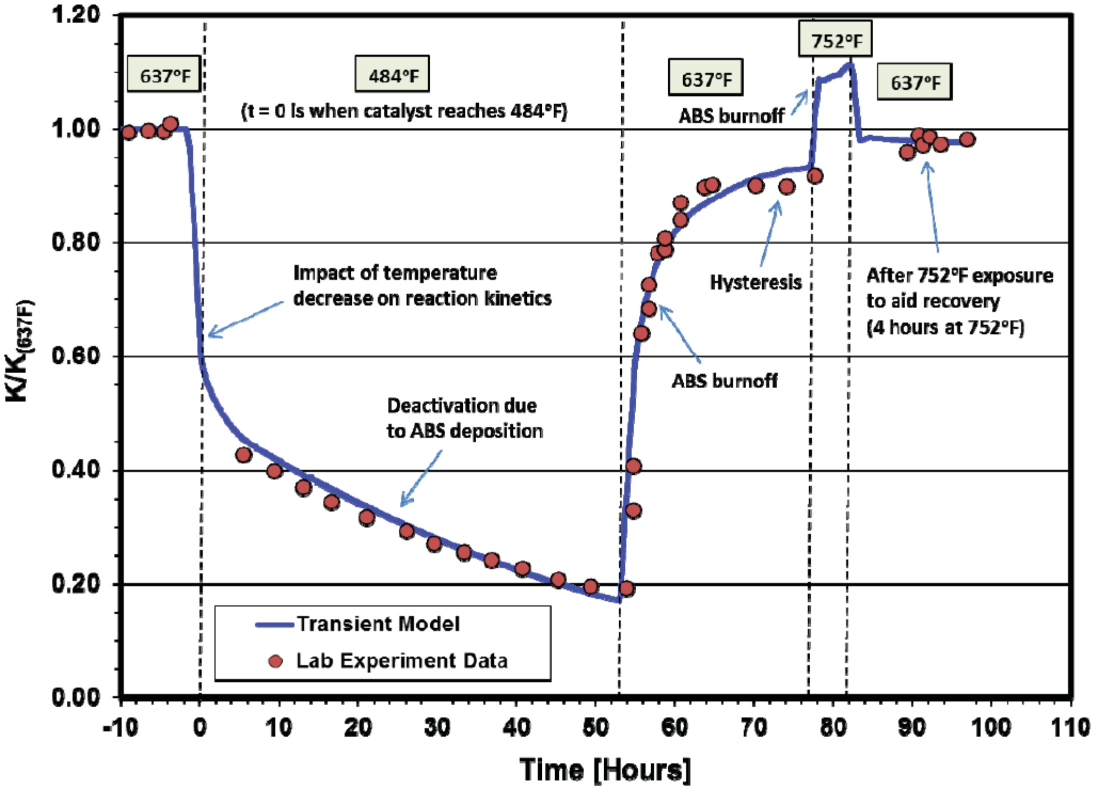

Figure 39: Enhanced Approach Operation: Load Cycle Test and Simulation

the required DeNOx and NH_3 slip targets for the unit. The total potential includes the initial K/AV that represents the minimum catalyst volume necessary to meet performance targets under ideal conditions, as well as additional potential for scale-up factors due to deactivation (from fuel poisons), NH_3/NOx maldistribution, and ash plugging (Figure 40).

It is important to note that most SCR units do not have margin specifically included in their designs for ABS deactivation at low loads. However, the Enhanced Approach is a cyclical operating method that is dynamic in nature, thus the key to continuously meeting DeNOx and NH_3 slip targets during the low load and recovery periods is to ensure that the transient K/AV is always greater than the actual K/AV required to meet the DeNOx and NH_3 slip performance targets.

During low load operation, the flue gas temperature and flow rate both experience a decrease. The lower temperature reduces the DeNOx K value (from the kinetic effect of temperature and from ABS pore plugging and deactivation), but the lower flow rate provides a benefit to K/AV by lowering AV. If $K/K_{\text{full load}}$ decreases below $AV/AV_{\text{full load}}$, the target DeNOx and NH_3 slip can no longer be achieved; alternatives to consider include increasing NH_3 slip, reducing DeNOx efficiency, settling on a higher low load temperature, or reheating catalyst above the recovery temperature to drive off the ABS. It is also important to note that the relative allowance for this deactivation will depend on the age and condition of the catalyst in the reactor; for example, a newly loaded catalyst system will have more margin for ABS deactivation than a unit close to its end of life, or just prior to an necessary action.

During recovery phase heating, there is a potential for increased SO_3 and NH_3 slip emissions due to ABS elimination from the catalyst (as well as from desorption of adsorbed SO_3 and NH_3 present on the catalyst's active sites). This desorption phenomenon is incorporated into the CORMETECH transient model, enabling simulations of the SO_3 and NH_3 spikes during recovery.

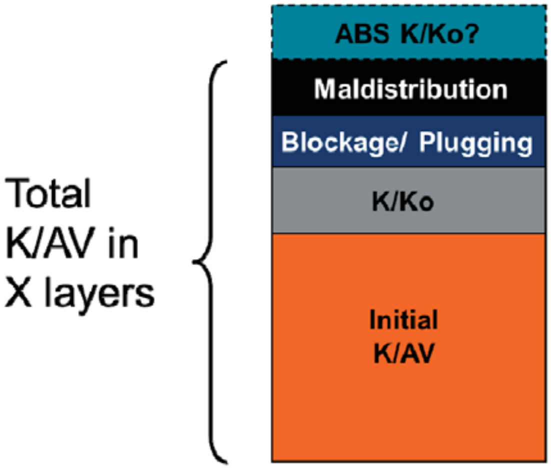

Figure 40: Catalyst Potential Breakdown for a SCR Catalyst Unit

The NH_3 slip spike, if large, will result in a temporary lower catalyst potential during the recovery phase; however, the DeNOx is still typically above target in these cases. The NH_3 slip spike can be minimized by reducing the NH_3 flow rate during the reheat step (the NH_3 from ABS and/or adsorbed onto catalyst sites can be used for DeNOx). The NH_3 and SO_3 spikes can be reduced by lowering the temperature ramp rate during recovery.

If the spikes are still too large, the amount of ABS deposited on the catalyst needs to be lowered (less to decompose during recovery), by either operating at a lower DeNOx or a somewhat higher temperature, or by shortening the time spent at the low load condition. The example in Figure 39 (on page 32) illustrates that more aggressive low load operation scenarios can lead to more stringent recovery requirements.

Thus, in the evaluation of operating scenarios for a given Plant, it is important to balance the Plant's operating needs, the severity of low load condition (i.e., temperature, length of time, extent of ABS-induced deactivation), and the capability for performance recovery upon return to full load (i.e., the achievable temperature, the rate of activity recovery, and the transient SO_3 and NH_3 emissions). Note that the long term use of this method (over a decade of experience, in over 39 boilers) has shown catalyst deactivation rates from field audits that have been consistent with fired fuels, indicating that there was no additional permanent deactivation from ABS.

SUMMARY

The Enhanced Approach, through careful engineering & modeling evaluation, lab validation testing, and field implementation monitoring, can increase a Plant's flexibility for meeting NOx reduction requirements at low load conditions and reduce operating costs.

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Choosing the Right SOLUTION

Written by John Rennocki and Mike Allen, Parker Hannifin Corp.

INTRODUCTION

Programming the cleaning system on a pulse-jet collector can be challenging. Asking for advice garners many different opinions – especially when the subject is continuous cleaning versus on-demand cleaning, a topic on which experts widely disagree. On-demand cleaning uses the signal from a differential pressure transmitter or switch to start and stop the cleaning system, whereas continuous cleaning cleans filter bags based on a fixed or variable time interval. Then there is online cleaning versus offline cleaning. What is the difference? What is the correct cleaning mode? The short and ambiguous answer is: it depends.

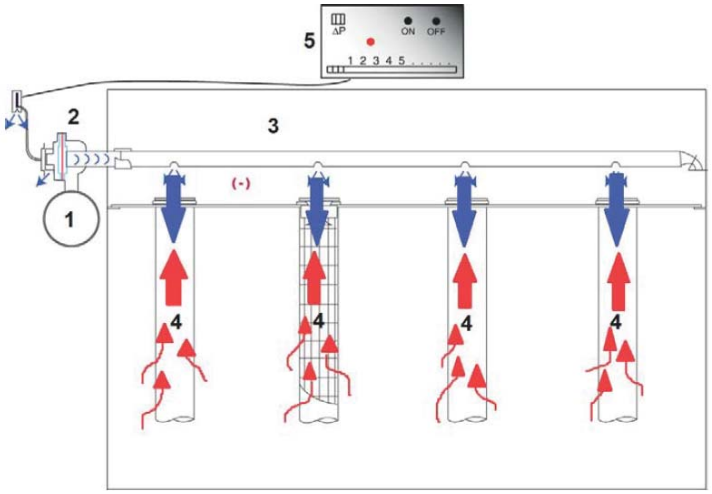

Figure 41: Pulse-jet cleaning system.

It depends on the application, on the filter media, whether it is a process collector, a nuisance collector, and whether the airflow varies or is constant. In short, evaluate every collector when setting up the cleaning system. Typically, one will configure the cleaning system according to general guidelines and then fine tune it, especially in a process collector. This article explains how operational conditions influence the setup of the cleaning system.

THE CLEANING SYSTEM

The purpose of the cleaning system is the controlled removal of accumulated material from the filter media to maintain a determined pressure drop, gas flow, and filtration efficiency across the filter media.

Common components of a pulse-jet cleaning system, sometimes referred to as a reverse pulse-jet, or simply pulse-jet, are shown in Figure 41.

Compressed air from the compressed air header (1) is released through a pulse valve (2) into a blow pipe (3). The blow pipe is centred over a row of filter bags and contains a small hole above each bag. Compressed air exits through the holes in the blow pipe (blue arrows) and shoots into the filter bags (4) below the blow pipe. The air burst injected into the filter bag shakes the bag and blows some of the dust off the outside of the filter bag. Pulse-jet systems on filter cartridges often use one pulse valve per filter cartridge to obtain higher cleaning energy. The operation of the pulse valves is controlled by the cleaning controller (5). This controller needs to be configured to meet the demands of the ventilation system. Dust collectors differ significantly, but they fall typically into two categories, the process filter, and the nuisance filter.

PRIMARY FILTER OR NUISANCE FILTER

The simple definition of a primary filter (venting boiler) is as follows; if the filter is offline, the process being vented by the filter will not function. A nuisance dust collector is used for dust control and might vent material transfer points, bins, and conveying equipment. Turning off a nuisance filter generally does not stop, for example, the conveying equipment that it is venting.

In the utility industry, primary filters typically have higher grain loading than nuisance filters, and the filtered dust is often product and returned to the process at a constant feed rate. Gas flow in primary filters often varies, whereas it is fixed in nuisance filters. Examples of primary filters are boiler baghouse.

Constant material return from the primary filter requires continuous cleaning. This does not necessarily mean frequent or over-cleaning of the bags. Continuous cleaning should ideally guarantee a continuous and controlled material discharge from the filter, while maintaining the proper operating conditions for the filter bags and the process, i.e., assuring a proper dust cake and acceptable pressure drop across the filter media. Maintaining a dust cake is important to protect the filter bags and maintain filtration efficiency on non-membrane filter bags. Most pulse-jet filters, whether primary or nuisance filters, clean online.

ONLINE CLEANING VERSUS OFFLINE CLEANING

When filter bags are cleaned online, the bags are filtering dirty gases, while a burst of compressed air is shot into the filter bags. The shot of compressed air goes against the flow of filtered air (the red arrows in Figure 41 on page 35) exiting the filter bags.

To properly clean the filter bags, the velocity of the compressed air blown into the filter bags has to be greater than the velocity of the filtered gases that exit the filter bags.

Increasing the gas flow through the dust collector increases the airflow and velocity out of the filter bags, reducing the efficiency of the cleaning system unless the volume of compressed air blown into the filter bags is increased as well. If increasing airflow through the collector reduces cleaning efficiency, decreasing airflow will increase cleaning efficiency. The operator of a dust collector often finds therefore that reducing – or even stopping – the airflow (i.e., offline cleaning) through the dust collector during bag cleaning provides better results, at least initially.

It is not recommended to clean filter bags offline since, under normal circumstances, this removes most or all of the dust cake from the filter media. However, there are dust collectors where the upward gas velocity between the filter bags on the dirty side is too high to allow the collected dust to drop off the filter bags during cleaning. In this case, the airflow through the filter has to be reduced (semi-offline cleaning) or stopped (offline cleaning). The type of filter media often determines if offline cleaning is an option.

FILTER MEDIA

Most filter media, especially non-membrane fabric, requires a dust layer or "dust cake" on the filtration side. In some applications, a minimum dust layer is required for absorption or gas scrubbing. Repeatedly removing the dust cake through over cleaning – or offline cleaning, and exposing the bare filter media of a non-membrane bag to fine dust – allows small particles to enter the filter media and obstruct the air passages (Figure 42). The result is permanently increased pressure drop across the filter bags, reduced airflow, and the need to replace the filter bags. If filter bags are used for scrubbing, losing the dust cake will reduce scrubbing efficiency.

By using filter bags with an expanded polytetrafluoroethylene (ePTFE) membrane on the filter side of the fabric, the need for a protective dust cake is greatly reduced, unless the dust cake is used for scrubbing. The membrane has a slick surface that facilitates dust release and acts a net with openings of <2 µm, and prevents most fine particles from entering into and plugging the base filter media (Figure 43). Given the requirement of a dust cake for efficient filtration, protection of the filter fabric, and for gas scrubbing, how does one maintain an adequate dust cake? The answer involves the filter cleaning system.

ON-DEMAND AND CONTINUOUS CLEANING

The consensus is that one can maintain an adequate dust cake by maintaining a constant differential pressure across the filter media; this is only true if gas flow and the dust and gas properties are constant. The pressure drop across filter media varies with changes in gas volume, gas properties, and the thickness and the consistency of the dust cake. Differential pressure by itself is, therefore, not an indicator of an adequate dust cake, if process conditions vary. Here is an example of how the different cleaning modes affect dust cake thickness.

When gas volume through a filter increases, or if moisture or other contaminants accumulate on the filter bags, differential pressure increases. In on-demand cleaning mode, the cleaning controller receives a signal from a differential pressure transmitter or switch. If differential pressure is above a

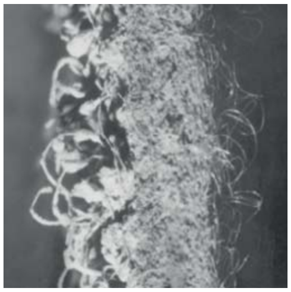

Figure 42: Conventional filter with particulate embedded into the media.

programmed set point, the system will clean the filter bags regardless of the cause for the higher differential pressure. In this situation, the increased cleaning can remove much of the protective dust cake from the filter media.

Continuous cleaning means that, regardless of differential pressure, the bags are being cleaned on a fixed time interval, while the filter is in operation. In the case of excessive gas flow or varying dust and gas properties, a system that cleans in continuous mode will better maintain the dust cake, although differential pressure will vary across the filter media.

The opposite is true, if the gas volume through the filter decreases. With lower gas flow through the filter, the differential pressure will decrease. The on-demand system will stop cleaning, and the thickness of the dust layer on the filter bags will increase. Sometimes this dust buildup can be excessive, and when the cleaning system eventually starts cleaning, the excessive dust layer on the filter bags will drop, fill the hopper of the filter and overwhelm material handling systems or cause surges and process upsets.

If airflow frequently varies significantly, differential pressure and on-demand cleaning are less effective to control the dust layer on the filter media unless one can automatically vary the differential pressure set points depending on the gas flows. Varying gas flows occur in many primary filters, boiler filters.

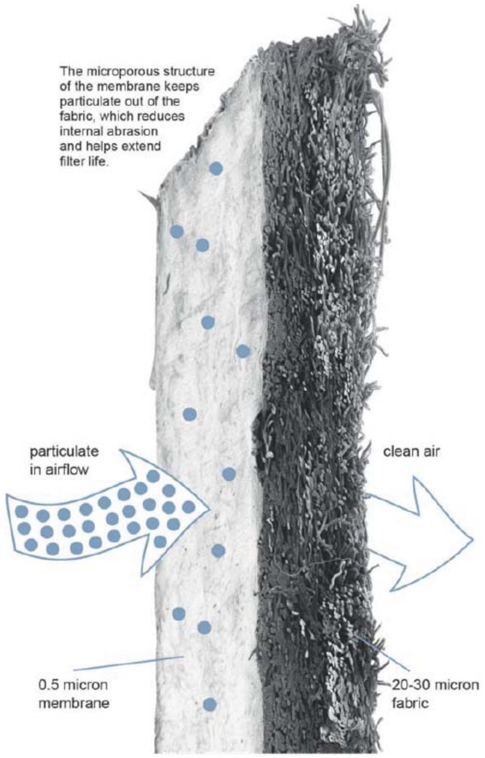

Figure 43: ePTFE membrane preventing particulate from entering the filter media.

Another filter that operates under continuously varying gas flow and differential pressure is the filter installed on the receiver bin or alleviator in a pneumatic conveying system. This filter typically has to be cleaned in continuous mode.

Most nuisance filters operate with constant gas flow and pressure drop across the filter bags. On-demand cleaning works well for these filters. On-demand cleaning also optimises compressed air consumption for the cleaning system, because the bags are typically cleaned less frequently than in the continuous cleaning mode.

In nuisance collectors, on-demand cleaning maintains a dust layer on the filter bag, and this can be a challenge when the dust cake needs to be removed after the filter shuts down. This situation can arise in applications where the dust might harden or attract moisture when the filter is not in use, or where different dusts are collected but cannot be intermixed. To address these potential problems, cleaning the filter bags offline in continuous mode for some time after the filter has stopped might be the best solution, as long as membrane bags are used. Bin vent filters on top of ash silos or lime silos might fall into this category. Some cleaning controllers have a “cycle-down” function that cleans the filter bags several times after airflow through the filter stops.

Considering that many filters have unique cleaning requirements, typical timer boards and cleaning controllers often fall short of programmable cleaning options. However, most controller boards have the choice to clean continuously and on-demand. When selecting the continuous cleaning mode, one should verify that the cleaning stops when the filter is not in use: filters that continued cleaning, even though the filter had been shut down days before, have been observed.

Controller boards for primary filters are more sophisticated but are often difficult to programme. The ideal controller would address all of the above cleaning considerations and be easy to programme. At a minimum, it should maintain a determined dust layer on the filter bags (regardless of gas flow), optimise compressed air consumption and bag life, and avoid material surges in the material handling system and filter hoppers. Some PLC-based controllers can be custom programmed to match the requirements of the filtration system, and plants often use the plant’s PLC to control primary baghouses.

CONCLUSION

After putting a dust collector with new filter bags into service, the set points in the controller should be reviewed, and it must be verified that they still meet the requirements of the filtration system and the vented process. Processes change, as do airflows, dust properties, and the permeability of the filter bags. Remember: there is no "one size fits all" solution.

UTILITY – CLEANING SYSTEM CONCLUSION

Utility energy demand with the high and lower load can have an impact on the baghouse operation and performance. When a plant goes from high to low steam production the gas velocities in the ductwork to the baghouse are low and fly ash settle out. As steam load increases, not only will the differential pressure increase rapidly because of the of the thick dust cake on the bags, but accumulated ash in the ductwork in addition to the regular ash load hits the compartments. The system starts cleaning and the thick dust cake falls into the hopper. During the cleaning lots of dust falls into the hopper and it is doubtful that all fly ash is evacuated before the compartment goes back on line. If the ash is not evacuated, the dust in the hopper can be recirculated.

The combination of high dust load and high differential pressure can cause abrasion. Then the bags are pulled against the cage wires because of high differential pressure, they form a star-shape as seen from the top. The vertical wires of the cage from a protrusion or the "points" of the star and it is in this impingement area that you can develop abrasion problems. (see Figure 44, left side shows bag with normal differential pressure, right side bag has excessive differential pressure, also not areas of turbulence)

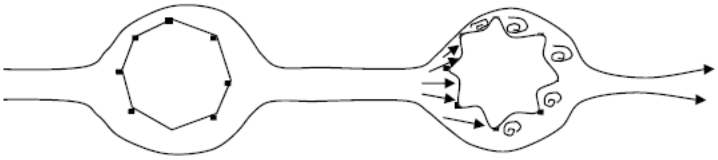

Figure 44: Normal differential pressure vs. excessive differential pressure

For these reasons we recommend reducing differential pressure excursions and dust loading by adjusting the baghouse operation as follows:

1. To avoid accumulating excessive dust on the filter bags, clean at least 1 time per hour during low load operation. The thickness of the dust cake should not be more than ¼". One can calculate the approximate thickness of the dust cake using the total filtration area, density of the flyash and quantity of flyash withdrawn from the baghouse during various load conditions. The actual thickness can be verified by taking a compartment off-line just before it would go into a cleaning cycle and inspecting a bag. Furthermore, differential pressure across the individual compartments should not be more than 6" WG during full steam load.

2. If not already programmed to do so, ash withdrawal from the hoppers should coincide with the cleaning of the compartment and ash withdrawal should continue until the hopper is completely evacuated as indicated by the line pressure in the pneumatic conveying line. Do not put the cleaned compartment online until the hopper is evacuated.

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John Rennockl is Senior Application Engineer at Parker Hannifin with 30 years of experience in industrial ventilation. He holds a B.S in Physics from The College of William and Mary and has been working in various engineering positions for most of his career. He has written several published articles on dust filtration, conducts ventilation studies and provides multilingual training courses on the design and operation of industrial dust collection systems. When not travelling at home and abroad to support customers, he can be found sailing with family and friends on the Chesapeake Bay.

Mike Allen graduated with a BS Marketing & Management @ Missouri Southern State College. Has worked for BHA a division of Parker Hannifin for 32 years. He has worked in a variety of sales and management roles over the years. He truly enjoys solving problems and servicing the market. When not working you can find in golfing, boating or running.

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