

Executive Summary

In-Situ Particle Size Distribution Sampling Using Cascade Impactors: What Can It Tell Us?

Written by James A. Guenthoer, Clean Air Technologies

This article shows various types of data that can be obtained from an in-situ cascade impactor particle size distribution test run. It shows the classical gravimetric data graphs along with size specific chemical speciation data using ICP-MS and XRF. An SEM photograph is also presented. It also shows the possibility of doing “wet” and dry in-situ distributions to understand the effect of water droplets in a gas stream.

Full Story....

Dry Scrubber Byproduct for Disposal or Use

Written by Terence Ake, Babcock Power

Typically in the U.S. at least 91% of the byproduct from dry scrubbers has been disposed in a landfill as compared to Europe where 91% is utilized in reclamation, structural or reagent applications. This article discusses the barriers to higher use in the U.S. and incentives to reduce plant operating costs and reduce the volume of wastes which may make future dry scrubber byproduct use economically viable.

Full Story....

Air Preheater Upgrade for Wastewater Evaporation for ELG Compliance Without Heat Rate Penalty

Written by Blake Stapper and Steven Kosler, LJUNGSTRÖM

Many utilities are looking for cost-effective compliance options for their FGD wastewater. An alternative solution to bio-treatment is the elimination of wastewater by evaporation which avoids the uncertainty of future discharge limits. However, a key issue with evaporative processes being economically feasible is the large cost of energy required to vaporize the wastewater. This article discusses how an APH upgrade utilizing new high-efficiency heating elements can recover additional energy, maintaining the original amount of heat transfer to the combustion air while allowing a fraction of the flue gas to bypass the APH for use in evaporating the FGD wastewater stream.

Full Story....

Helpful Hints from Hanby

Written by Darren Hanby, AEP

The largest hurdles in diagnosing and correcting challenges are not always technical in nature. The relationship that you as an engineer or supplier has with the end user are at times the most challenging and rewarding aspect of solving problems. The following quick four points serves as a guideline I have used over the last 30 years. Maybe it will be helpful for you.

Full Story....

A Focused Look at the Proposed ELG Rule Changes for Flue Gas Desulfurization

Written by Max Swoboda, Evoqua Water Technologies

This article discusses the rule changes to the 2015 Effluent Limitation Guidelines (ELG) and the possibilities of reducing compliance costs by using the newly approved Low Hydraulic Residence Time Biological Reduction (LRTR) Treatment Technology.

Full Story....

In-Situ Particle Size Distribution Sampling Using Cascade Impactors: What Can It Tell Us?

Written by James A. Guenthoer, Clean Air Technologies

Accurate particle size distribution (PSD) data can provide a significant amount of information about the nature of a particulate emissions source. One means of collecting accurate PSD data uses an in-situ cascade impactor.

Figure 1 shows the actual samples from a well-performed in-situ cascade impactor test. Each photo shows particulate matter (the tiny dark spots) deposited on ultra-pure quartz substrates that occupy each of the stages of a cascade impactor. The particle size of the particulate collected in each stage gets successively smaller moving from the left to the right in the top photo (Photo 1) and continuing from left to right in the bottom left photo (Photo 2). The lower right photo (Photo 3) is the final backup filter and contains the smallest particles.

The initial information obtained from analyzing the samples in these photos is a gravimetrically determined set of particle size cuts (D50) called a particle size dis-

tribution. When sampled from an industrial process, the distribution can be used to determine how much particulate matter of each particle size cut that a new piece of air pollution control (APC) equipment would need to remove from the gas stream to meet a target emissions value. For a controlled process, the distribution can tell us how efficiently an existing APC device is operating.

Figure 2 (on page 2) shows a cumulative mass plot of a spline-fitted PSD data set. Note the X-axis title of "Aerodynamic Diameter." PSD data are presented in terms of either the aerodynamic or the Stokes diameter of the particles. The aerodynamic diameter is a mathematically derived parameter that allows the irregularly shaped particles to be represented as idealized spheres of unit density. The Stokes diameter is a similar construct that represents the particles as spheres having the same density and settling velocity as the actual particles. It is important to know which diameter basis is being represented when evaluating PSD data.

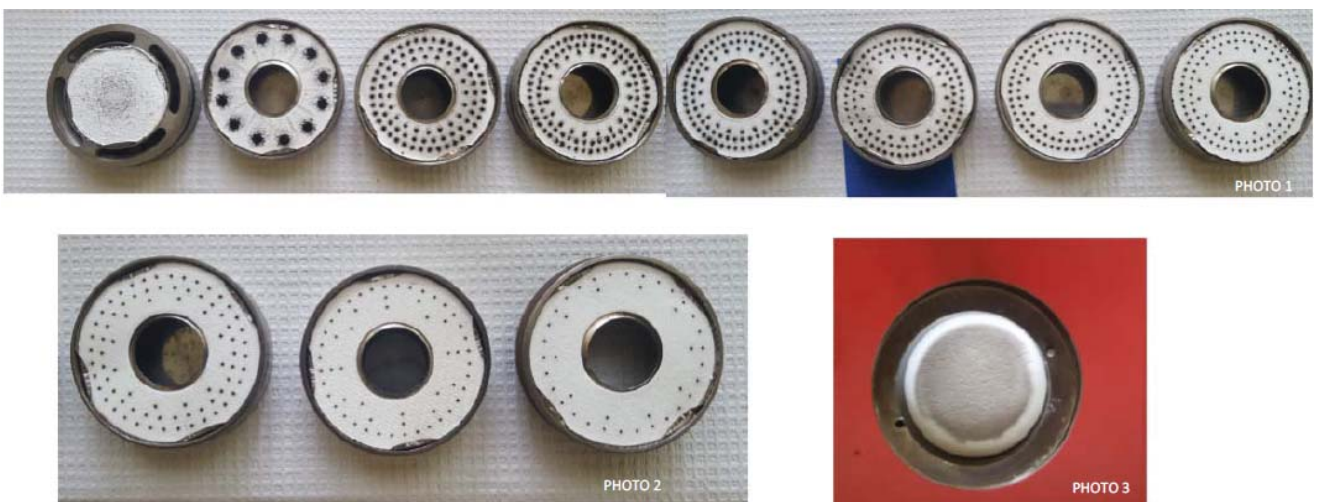


Figure 1: A University of Washington Mark V Cascade Impactor Collected Sample

The “mass mean diameter (MMD)” is another parameter typically used to evaluate PSD data. The MMD is the particle diameter at which half of the sample mass is comprised of particles with smaller diameters. In the case represented in Figure 2, the MMD is approximately 2.5 microns. The smaller the MMD, the more difficult it is for an APC system to remove the particles from the gas stream. This trend tends to go up exponentially as particle size decreases. Once the MMD is below about 5 μm, a significant investment of money and energy will be required to remove a substantial fraction of the entrained particulate matter.

Another common way to represent PSD data is the use of a dM/dLogD graph. The dM/dLogD plot presents the mass concentration on a linear Y-axis versus particle size on a logarithmic X-axis. By using a linear scale for the Y-axis, the area under the curve between any two particle sizes equals the total concentration of particulate existing between the diameters.

This type of plot is particularly useful because it provides insight into the type and prominence of formation mechanisms of the captured particulate matter. Figure 3 (on page 3) is a dM/dLogD plot that shows a trimodal distribution, with the three distinct peaks reflecting the three modes of particle formation from a combustion process.

The peak on the far-right side centered at 20 μm is typical of “mechanically” generated particles. These are usually caused by processes such as grinding or crushing. In the combustion case, they are the larger pieces of material that have not fully combusted and still retain a significant portion of combustible content. The peak can also represent agglomerations of finer particles that act aerodynamically as larger particles.

The large center peak of approximately 1 μm that dominates the size distribution is that of the inert products of combustion. This mass of material is approximately 3½ times as

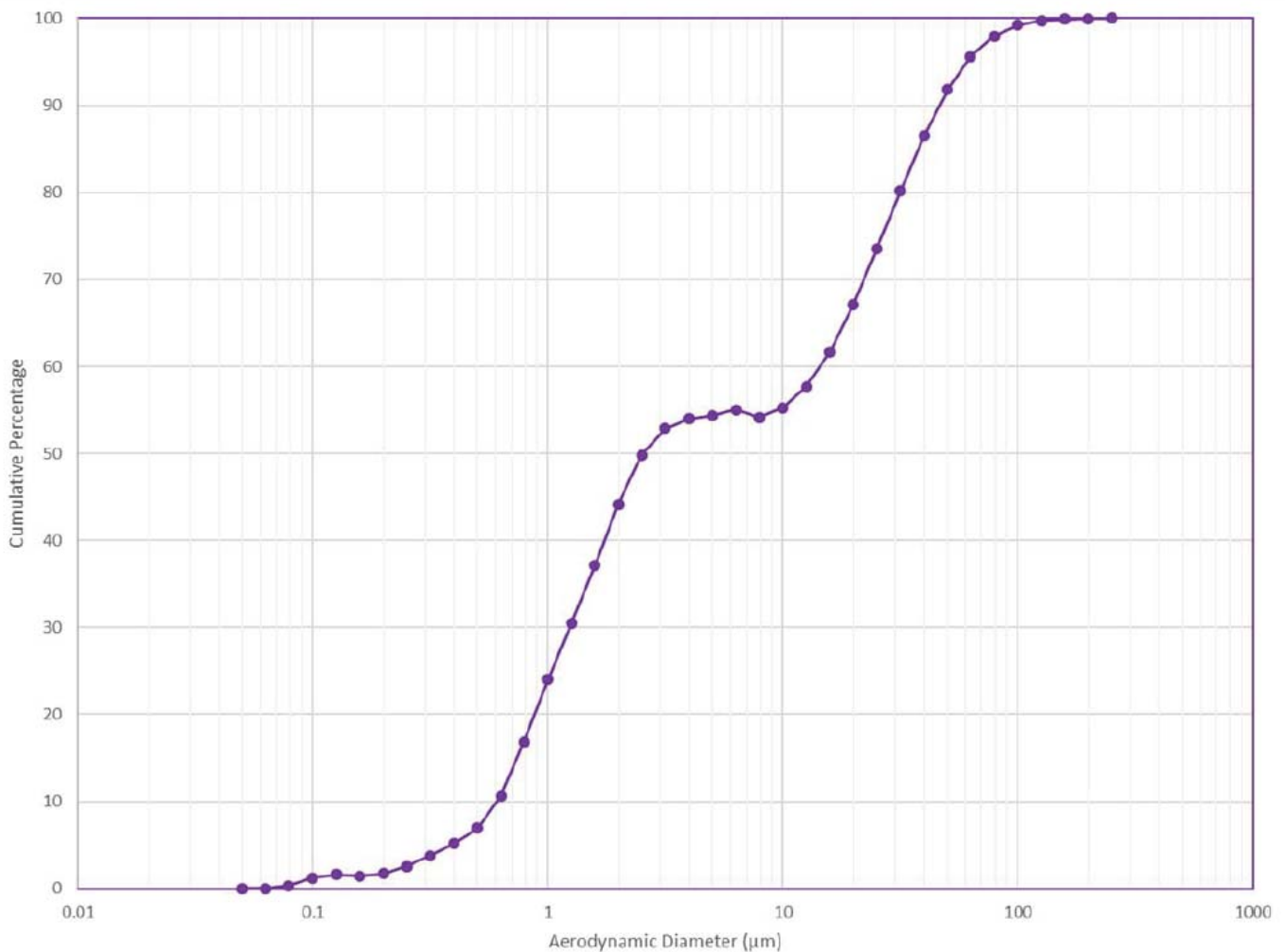


Figure 2: Cumulative Mass Percentage PSD Data Plot

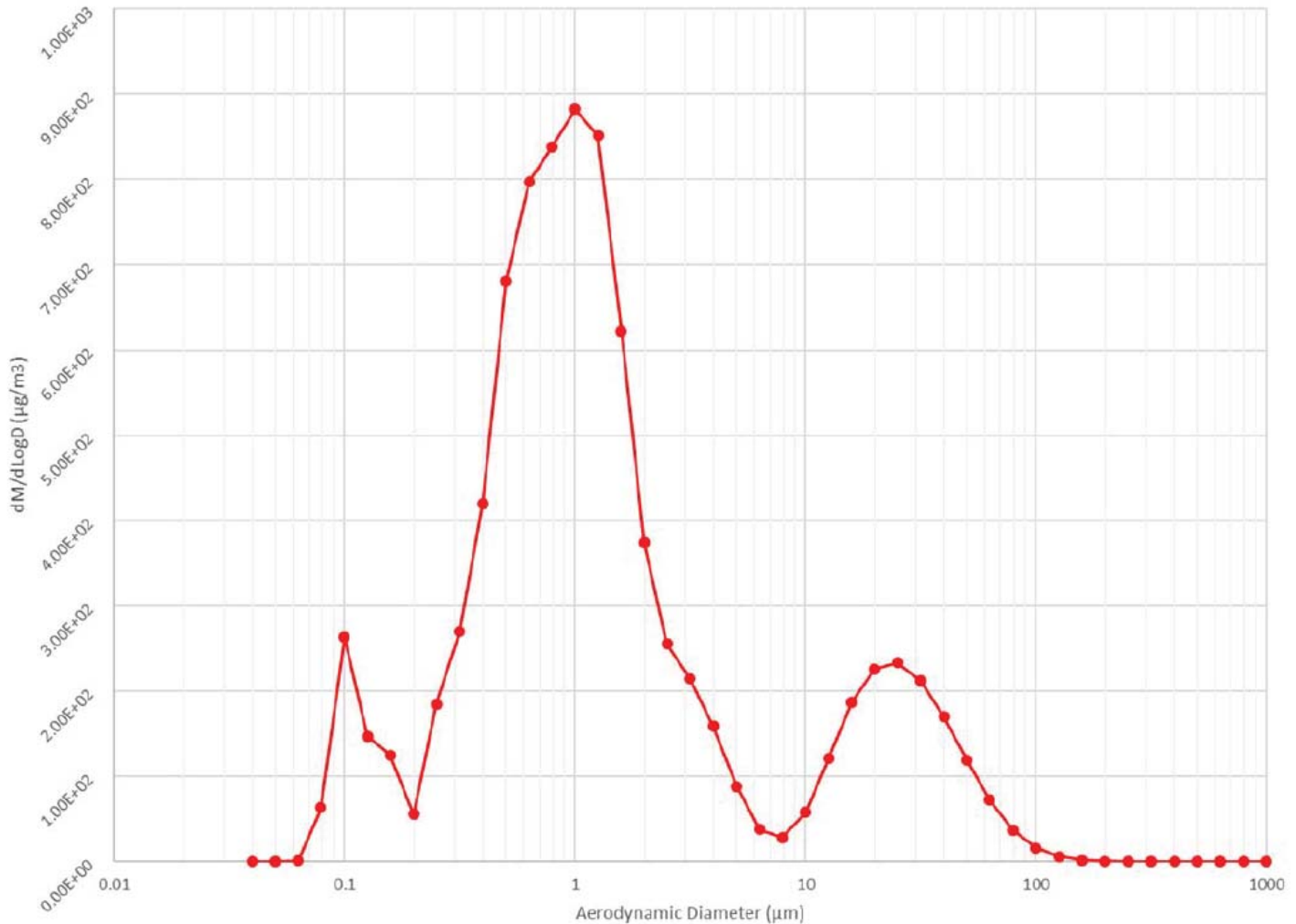


Figure 3: dM/dLogD PSD Data Plot

prevalent in the gas stream as that represented by the other two peaks. A substantial portion of this material would need to be removed to effectively “control” particulate emissions from this source.

The third, leftmost, peak centered at 0.1 µm is generated by particles that have been formed by vapor phase condensation. Gas phase compounds have cooled enough to form solid material in the gas stream. It is typical for these to form in the sub-micron size range. These particles, if present in a large quantity, present a significant APC challenge.

Multiple dM/dLogD plots taken at different times can present a picture of the particle size evolution during a process. Figure 4 (on page 4) shows the graph of two data sets from the same process. Run 1 was collected during the initial few minutes of combustion while Run 2 was collected after the combustion had fully developed. The shifts in the sizes and relative magnitudes of the peaks discussed above are mark-

edly apparent and are indicative of changes in the particle size generation mechanisms as the combustion advances.

In addition to regular gravimetric analysis of cascade impactor samples, another analytical tool that can be employed is scanning electron microscopy (SEM). SEM analyses can provide information about the specific morphology and actual size of the collected particulate matter. This tool provides a visual means to distinguish between individual particles and agglomerations of smaller particles acting like a larger particle in the gas stream. Figure 5 (on page 4) shows an SEM photograph of a collected sample of coal fly ash.

In addition to SEM analysis, a variety of other analytical protocols can be applied to the individual recovered substrates to get size-specific chemical speciation. This can be used to correlate one or more specific compounds in the gas stream to each particle size cut-point. This can then be related back to the particle generation mechanism for each cut-point.

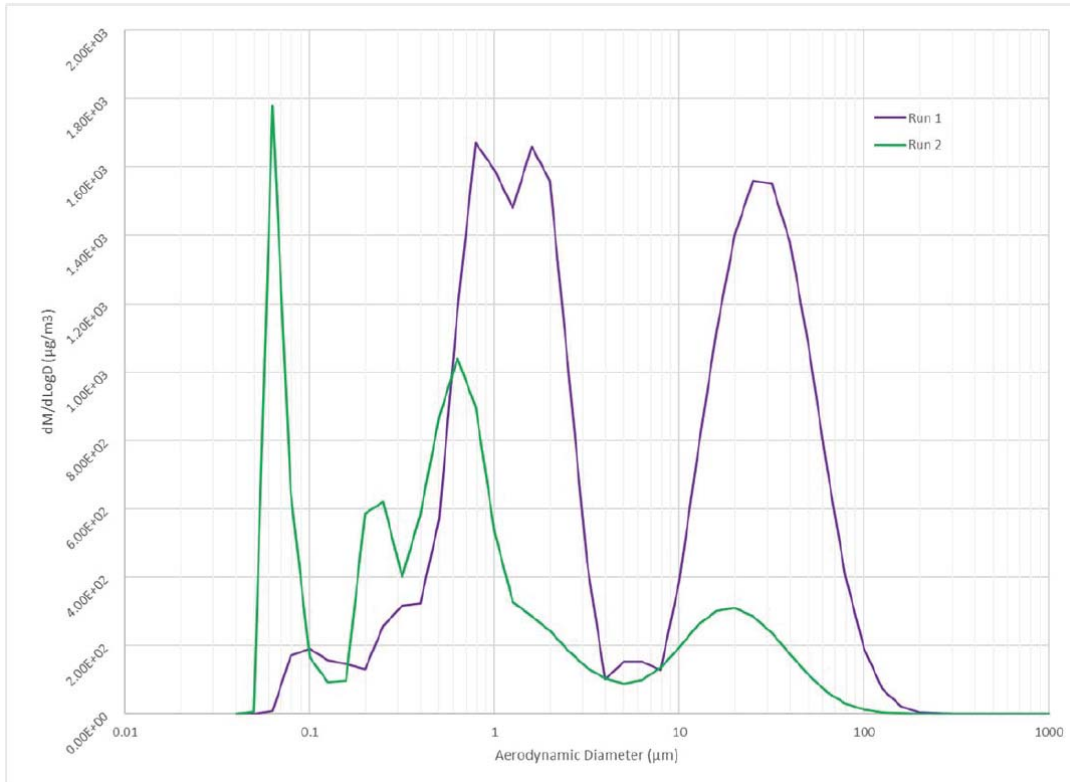


Figure 4: Comparison of Process Time Related PSD Data Set

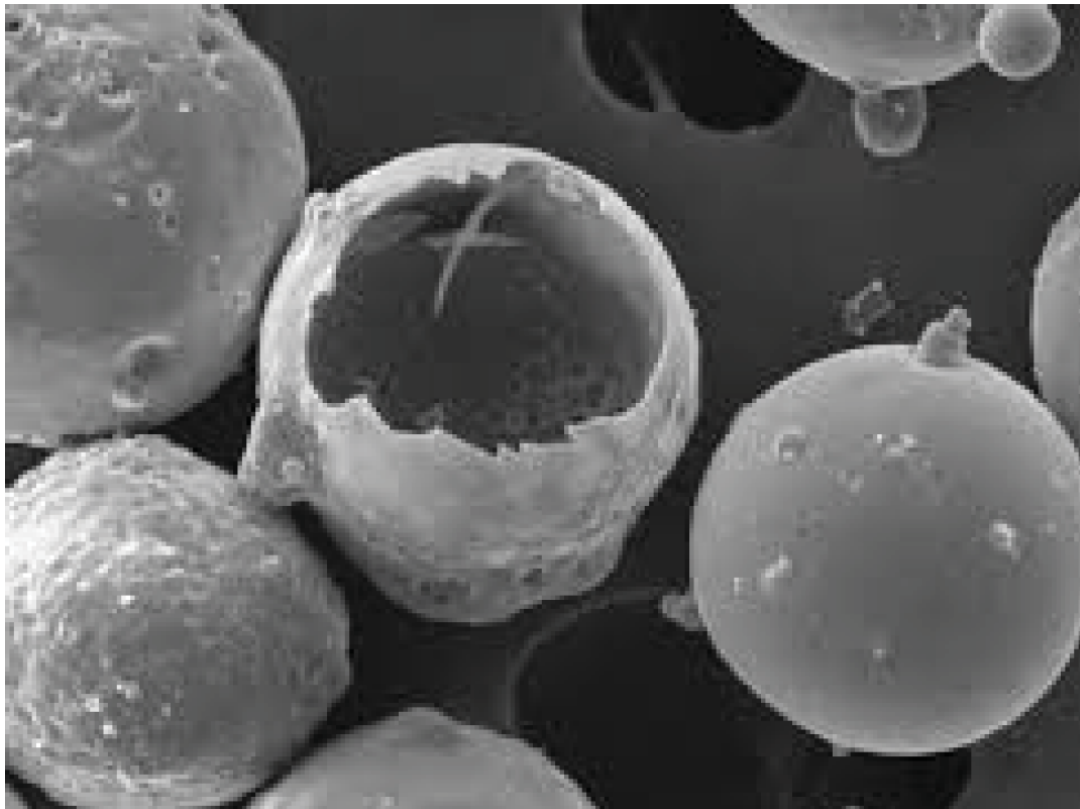


Figure 5: SEM Photo of Coal Fly Ash Cenospheres

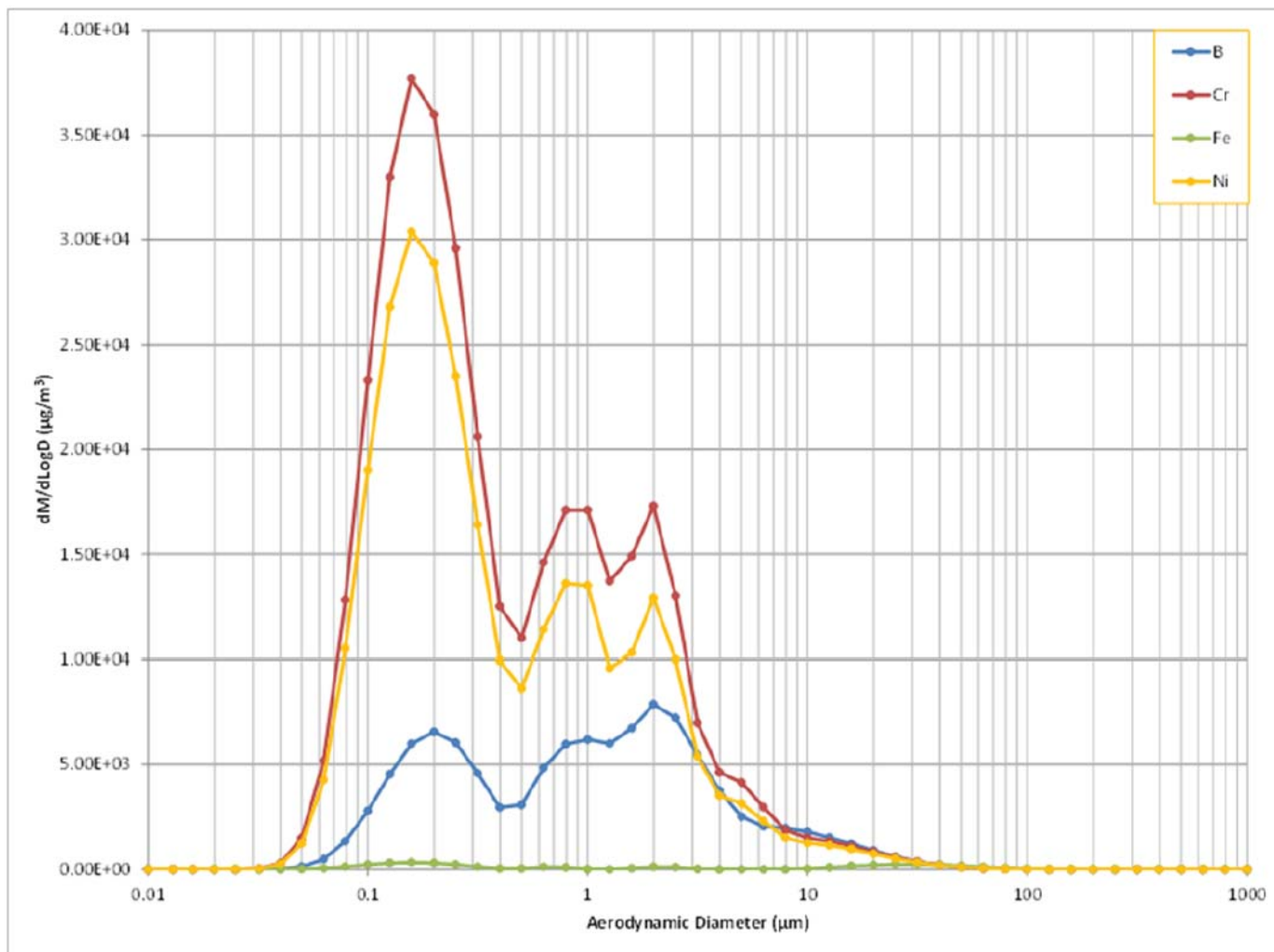


Figure 6: dM/dLogD plot Showing Size Specific Chemical Speciation using ICP-MS

Figure 6 is a dM/dLogD plot of a metal coating process. After gravimetric determinations were made, each substrate was analyzed for a selection of target metals by ion coupled plasma - mass spectroscopy (ICP-MS). The result is a separate dM/dLogD plot for each target metal. As expected, the metals in the exhaust gas stream undergo vapor phase condensation to form submicron particles. These ultrafine particles present both a potential health risk as well as a significant challenge for emissions control.

Another tool is the use of X-ray diffraction (XRD) analysis of the collected sample on each substrate. XRD provides information about the crystallographic structure and chemical composition of the sample. Figure 7 (on page 6) is an XRD analysis of a substrate that was part of an impactor sample collected downstream of a venturi scrubber demister. This information was used to determine how much gypsum from

the scrubber liquor was being lost because of subpar demister performance.

The examples presented herein demonstrate some of the information that can be generated from in-situ cascade impactor sampling. This information can help end-users assess the efficacy of their APC equipment or specify new equipment in a more informed and capital sensitive way.



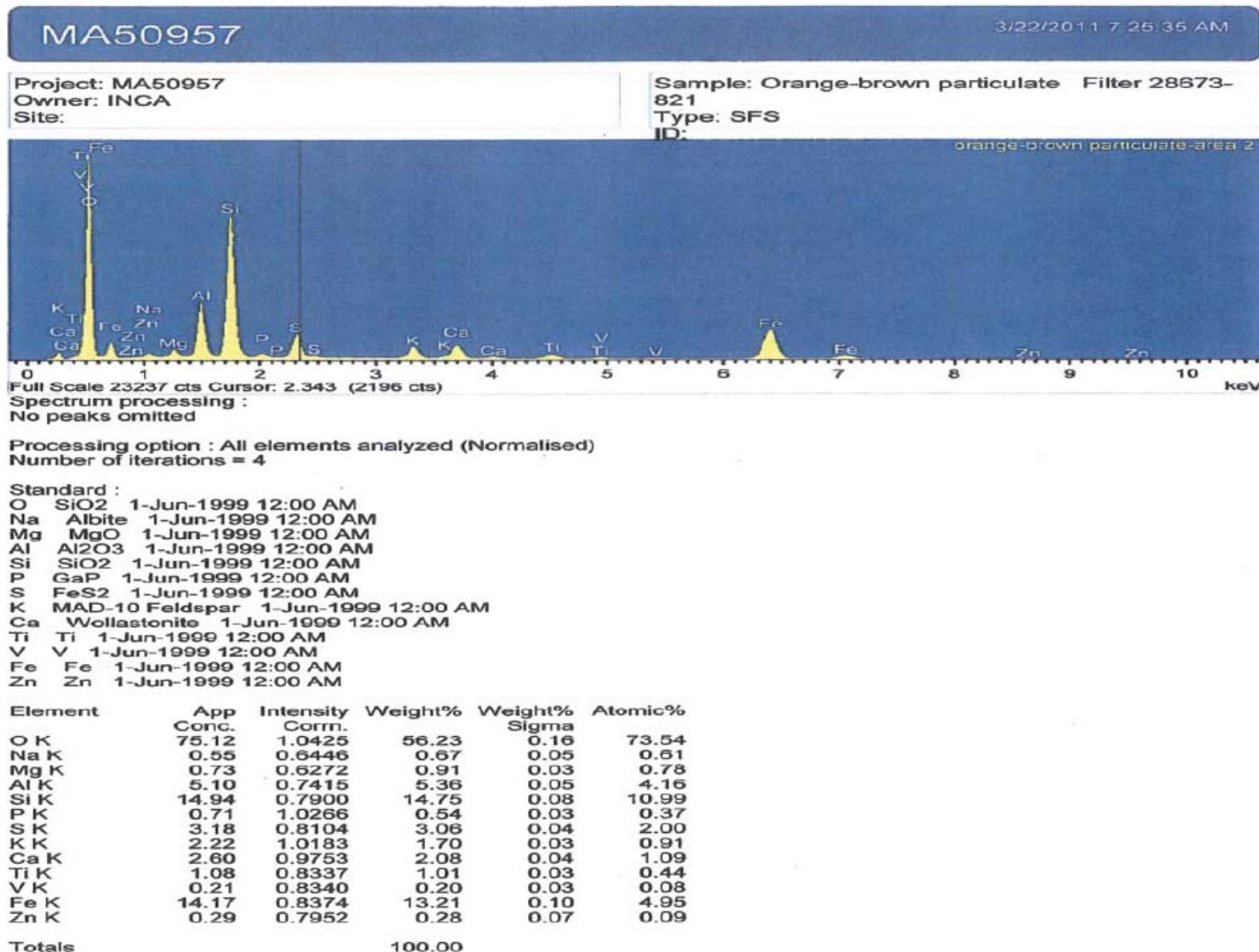


Figure 7: XRD Analysis of a Single Impactor Substrate

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BIOGRAPHY



James A. Guenthoer has over 40 years of experience in the field of air emissions testing and consulting. Prior to joining Clean Air Engineering he was involved with the development of the Pilat, University of Washington impactor and held positions at several other engineering consulting firms, air pollution control and source testing equipment manufacturers.

While at those firms his roles included project management and field testing, as well as design, manufacture, technical service, and sales of in-situ cascade impactor particle sizing devices. While at one firm he was involved with research and development studies of novel particulate control technologies using enhanced electrostatics. He earned his BS Degree from Juniata College and an M.S.E. in Environmental Engineering from the University of Washington.

Dry Scrubber Byproduct for Disposal or Use

Written by Terence Ake, Babcock Power

INTRODUCTION

Spray Dryer Absorbers (SDA) and Circulating Dry Scrubbers (CDS) have operated since the 1970s to remove SO₂, HCl, and other acid gases from the flue gas from coal-fired power stations. The solid byproduct from the SDA is a mixture of coal flyash, lime, and reaction products. Due to calcium sulfite in the reaction products, the byproduct is not suitable for making gypsum (CaSO₄•2H₂O) - as is done with forced oxidized Wet Flue Gas Desulfurization (WFGD) scrubbers that convert the sulfite to sulfate. Although the SDA byproduct has cementitious properties, over time, the calcium sulfite may oxidize to sulfate causing expansion reducing the structural integrity of concrete. As a result, most SDA byproduct is disposed in a landfill. As plants look to reduce O&M cost and waste disposal there may be more incentive in the United States to avoid disposal by finding alternative end uses.

COAL FLY ASH

Dry Scrubbers are usually retrofitted onto coal-fired boilers with an existing Electrostatic Precipitator for particulate removal. The dry scrubber includes its own particulate removal device to circulate and remove the reaction byproduct. If the boiler operator sells the flyash collected by an existing ESP, then often, the ESP will be kept in service removing coal flyash upstream of the scrubber. With an operating upstream ESP, the dry scrubber byproduct is reaction products with a little flyash carryover.

If flyash sales are not an important practice for the boiler operator, then when a dry scrubber is installed, the existing ESP may be detuned, not energized, or demolished resulting in a dry scrubber byproduct containing a significant proportion of fly ash. In general, flyash stabilizes the byproduct by diluting the reactive products. When there is flyash in the dry scrubber byproduct, it is important to know about the flyash when considering its disposal or use.

TREATING FOR LANDFILL OR USE

At a coal-fired power station, the dry scrubber byproduct is mixed with water to suppress dust for consistent handling before it discharges from a storage silo into a truck. If the byproduct is transported to a landfill, there is usually no other treatment. It is typically safe for landfill. For example, Figure 8 lists the Toxic Leachability Characteristic Procedure (TCLP) results for a power station with a CDS showing very low leachate concentrations of heavy metals.

As uses have developed for the byproduct, solids handling equipment suppliers have offered material processing to make the byproduct a lightweight aggregate for fill or pelletizing it for other uses [1]. The purpose of added mixing equipment is to make an end-product that can be easily transported and used as feed material for further processing.

EXPERIENCES USING BYPRODUCT FROM DRY SCRUBBERS

European.....

Bengtsson has described the European experience using the byproduct from SDA dry scrubbers [2]. In general, Europe has led recycling of all types of coal combustion products. "Governments are increasingly favoring the use of secondary raw materials. They use incentives such as legislation and taxes to increase [its] use." According to Bengtsson, 91% of dry scrubber byproduct is utilized, which is higher than the utilization of WFGD-gypsum (87%).

Examples of dry scrubber byproducts uses mentioned in the reference include:

- Filling of mine shafts
- Reclamation/restoration of land
- Structural embankment fill
- Synthetic aggregate
- Soil amendment and plant nutrition (Ca/S fertilizer)
- Civil works (sealing, capping material, sub-base for

CDS Byproduct	Ag	As	Ba	Cd	Cr	Hg	Pb	Se
Dry Concentration, mg/kg	0.532	18.9	270	0.273	70.3	0.63	21.1	9.79
TCLP Leachate (mg/L)	0.00058	0.003	0.288	0.00022	0.0298	0.00025	0.00072	0.0236

Figure 8: Example TCLP analysis of a CDS Byproduct

parking lots and storage areas, road banks, noise protection walls, fill behind a new harbour quay)

- Reagent in WFGD
- Thermal oxidation into technical anhydrite

Some of these applications benefit from the fact that many European dry scrubbers have a pre-collector for coal ash before the scrubber.

Figure 9 shows an example dry scrubber byproduct processing method in Europe called Cefill (or Cefyll). The Cefill product is a thick slurry/paste consisting of coal ash, spray dryer byproduct product, water and additives. It is manufactured in different grades, and the different grades harden to different compressive strengths to match an end use. The technology is fully commercial including automated mixing stations and truck transportation and delivery systems. The properties of the Cefill product have been a focus for several academic research papers.

United States....

EERC, University of North Dakota in cooperation with EPRI completed a literature search on the use of spray dryer absorber material [3]. They report that only approximately 9% of the dry scrubber byproduct was beneficially used in

the United States. Other sources mention down to 1.5-2%, but the discrepancy lies most likely in terminology and definitions. The report ranks SDA byproduct use as follows:

- High potential: cementitious products (such as masonry, flowable fill and synthetic aggregate) and mining applications
- Moderate potential: cement replacement in concrete, engineering applications, agriculture, soil stabilization and wet FGD sorbent
- Low potential: binder material, cement manufacture, hazardous waste fixation, marine applications, mineral wool, sulfuric acid production and wall-board

The report lists the following barriers inhibiting the use of dry scrubber byproduct in the U.S.:

- Inconsistent terminology used to define the material
- Lack of understanding of the material
- Limited data on environmental and health effects
- Inconsistent guidelines on beneficial use
- Economics

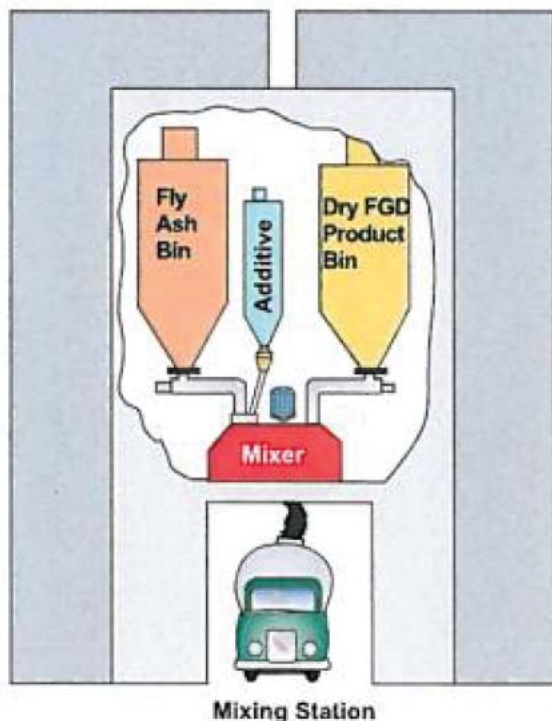


Figure 9: Cefill Technology

Figure 10 shows a full-scale demonstration of manufactured aggregates utilizing spray dryer byproduct [4]. The project was co-funded by Universal Aggregates LLC and Department of Energy. The production plant was built in Birchwood, Virginia, and it was designed to produce 167,000 tons of product annually. Production tests were made in 2004-2006 and during the same time period several modifications were made to improve the plant operation. After completion of the test program, Universal Aggregates continued to improve the commercial operation of the plant.

An article in the publication “Ash at Work” describes replacing cement with spray dryer byproduct to produce architectural blocks [5]. Tests at the 274 MW Rawhide power station firing Powder River Basin Coal showed that the byproduct from its SDA units had excellent pozzolanic properties. Extensive testing on long-term performance and shrinkage also gave good results. The byproduct was successfully tested in concrete block production at Valley Block of Loveland, CO. The concrete block manufacturer typically uses a 35% ash-for-cement substitution rate and has noted positive effects in their product as compared to using only cement.

CONSIDERATIONS FOR USING DRY SCRUBBER BYPRODUCT

To be economically viable, a dry scrubber byproduct process has to be a high-volume technology producing a low cost end product. Due to the cost of transportation, the end product needs to be locally produced and consumed. The properties of the end product will vary between one power station and another. For an individual power station, the properties will also vary due to operating changes and fuel variations. A dry scrubber byproduct use technology needs to be forgiving for such variations. Also, to be successful, the responsibility for marketing and sales has to be with a company with local presence and customer network. A good example would be aggregate and building materials suppliers.

CONCLUSIONS

The byproduct from a dry scrubber, either a SDA or CDS, is typically disposed in a landfill because it is safe and there is not usually a large economic incentive to use it. However, as plants strive to reduce costs and produce less waste, the economics may be viable to use it. There has been much experience in Europe using the byproduct for fill and civil works. There has been work in the U.S. to use the byproduct



Figure 10: Synthetic Aggregate Full Scale Product (Courtesy Universal Aggregates, LLC)

for synthetic aggregate and various cementitious products. A byproduct use technology needs to process a high-volume near the source and end user to be economically viable.

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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 scrub-

bers for sulfur dioxide, acid gas, and particulate control. A large part of his experience includes combustion research and development, flow model studies, and commissioning, optimizing and evaluating performance of clean power installations. Terry has a Bachelor of Science degree in Chemical Engineering from the University of Illinois and a Master of Science Degrees in Chemical Engineering from Iowa State University.



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Air Preheater Upgrade for Wastewater Evaporation for ELG compliance without Heat Rate Penalty

Written by Blake Stapper and Steven Kosler, LJUNGSTRÖM

INTRODUCTION

On November 4, 2019, the EPA proposed revisions to the Effluent Limitations Guidelines (ELG) that were promulgated in 2015 (40 CFR Part 423) and updated the federal limits on the levels of toxic metals in wastewater that can be discharged from power plants. With the revisions, many utilities are again looking at options for ELG compliance, with an eye to the limits set on flue gas desulfurization (FGD) wastewater. EPA maintained the Best Available Technology (BAT) as chemical precipitation followed by biological treatment. However, there continues to be concern that the performance of biological systems is unpredictable and sensitive to FGD process changes that can reduce the effectiveness of the microorganisms in the bioreactor.

An alternative solution to bio-treatment is the elimination of wastewater by evaporation. EPA maintained a voluntary incentive program on FGD wastewater; however, changed the program to also include membrane filtration. Facilities that chose to implement treatment strategies based on the voluntary incentive program will be afforded an additional delay in compliance.

As noted in the proposed revisions, a main issue with evaporative processes being economically feasible is the large cost of energy required to vaporize the wastewater. A traditional brine concentrator crystallizer uses energy from the power plant for heat of evaporation, typically at low efficiencies. Alternatively, using flue gas heat for spray dryer evaporation requires a slipstream around the air preheater (APH) which increases heat rate as the flue gas no longer is passing through the APH.

The AdvX™ technology has been developed for recovering additional heat from the APH for use elsewhere in power plants. This approach includes an upgrade of the APH to extract energy more efficiently, and management of the SO₃ concentration ahead of the APH to allow for lower flue gas outlet temperatures. This article describes how the additional energy that is recovered can be used to supply heat to a spray dryer to evaporate wastewater and accomplish zero liquid discharge without incurring a heat rate penalty.

PROCESS DESCRIPTION

The upgrade of the APH consists of three components including use of high efficiency and low pressure drop heating elements, additional heating element surface in the APH baskets if possible, and a management of the APH “x-ratio” or air to flue gas ratio. The additional energy that is recovered by the upgrade can then be used elsewhere in the process. For ZLD applications, this is accomplished with a flue gas bypass. Since the amount of heat recovered in the APH does not change, the boiler efficiency is not impacted, and the primary and secondary air temperatures and flow rates do not decrease.

This approach reduces the APH flue gas outlet temperature, which necessitates careful management of the SO₃ concentration to avoid acid condensation in the cold end of the APH and back-end of the power plant. Several technologies are available to reduce the SO₃ concentration to manageable levels ahead of the APH including lime, trona, and sodium carbonate injection. SO₃ control upstream of the SCR can bring additional operating and maintenance benefits. Low sulfur coals or some coals with high ash contents may not require reduction of the SO₃ concentration ahead of the APH. SO₃ controls also have the potential to capture chlorides in the ash and reduce the wastewater stream which could reduce the size and cost of the spray dryer equipment.

The wastewater evaporation system shown in Figure 11 on page 12 is specially designed as a single stage spray dryer to carry out a rapid evaporation of FGD wastewater. Flue gas from the APH bypass is used to dry the wastewater that is delivered from the FGD wastewater tank. The exhaust from the spray dryer is then returned to the flue gas duct upstream of the particulate control device.

Air Preheater Upgrade

In order to increase the energy capture across the APH, new higher efficiency heating elements have been developed, including the DN8™ for hot-end applications, and the enameled TF4™ for the cold-end. These exhibit superior heat transfer capabilities while providing an open profile that can accommodate additional gas capacities without an appre-

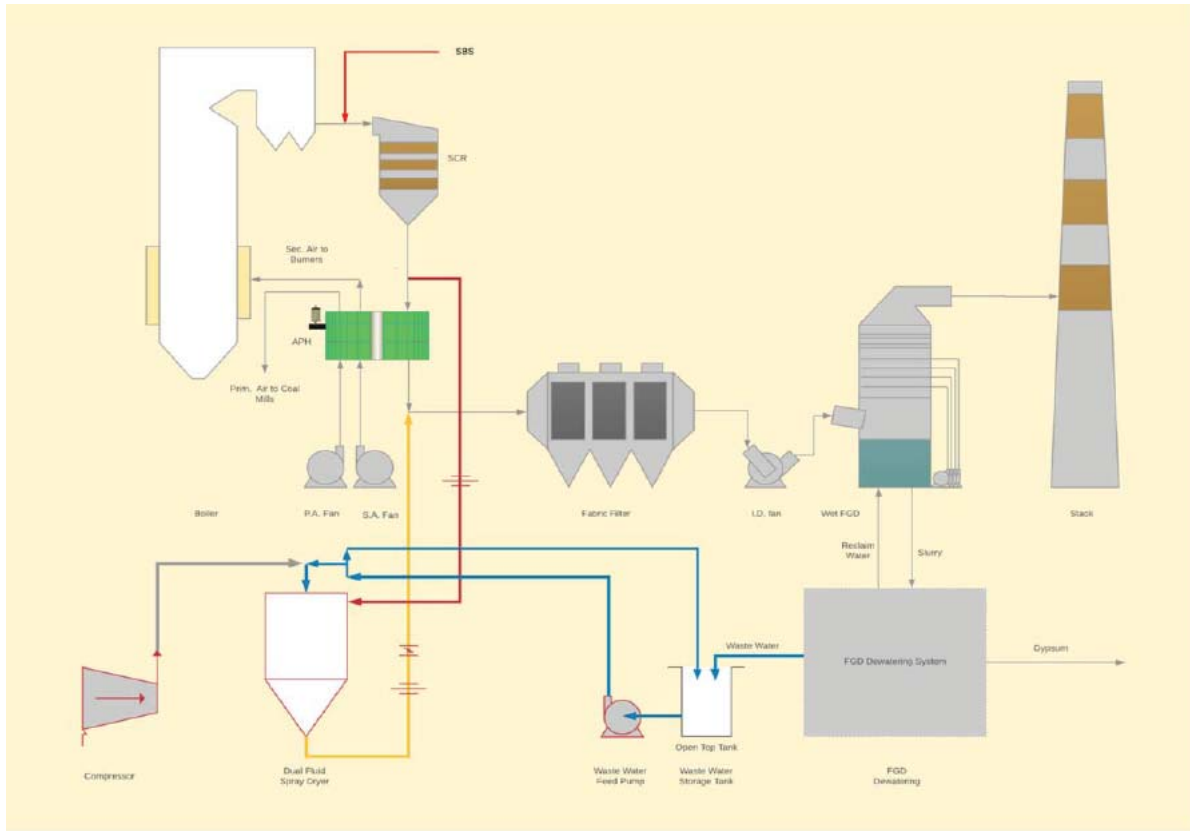


Figure 11: Typical wastewater zero liquid discharge

ciable increase in pressure drop. For APHs which are thermodynamically limited, these new heating elements unlock additional heat recovery via an x-ratio shift.

An example of an upgraded APH temperature profile is presented in Figure 12. As shown in this example, the primary and secondary air temperatures are unchanged (in some cases there is a very slight increase in one or both combustion air temperatures). The flue gas temperature ahead of the APH will stay the same while the flue gas temperature after

the APH will drop. The flue gas bypass flow rate is typically limited to about 10 to 20 percent for existing units.

There are other ancillary benefits associated with decreased flue gas temperature. The reduction will lower the ash resistivity and decrease the gas velocity through the electrostatic precipitator (ESP). As a result, the ESP performance is enhanced, and fly ash emission reductions of 50 to 70 percent are typically achieved (subject to the condition of the existing equipment). The amount of quenching that is required for the FGD is also reduced, such that FGD makeup water consumption can decrease up to 50 percent.

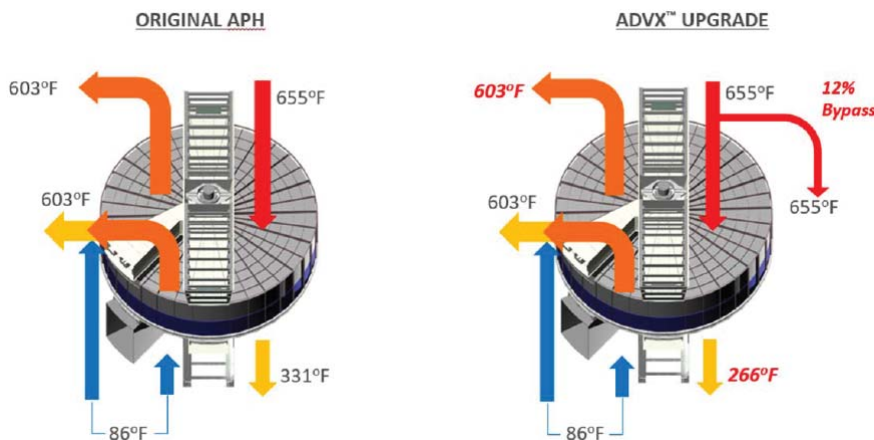


Figure 12: Possible configuration for air preheater upgrade

Spray Dryer

Hot flue gas enters the spray dryer via an air distributor at the roof level which provides a uniform distribution of the flue gas around a centrifugal rotary atomizer. Wastewater from the FGD system blowdown is delivered either by an array of dual-fluid nozzles or single rotary atomizer nozzle at the top of the evaporator. The drying chamber has a conical bottom with single outlet duct from the bottom of the cone.

The dry product may be conveyed with the exhaust gas from the bottom of the chamber and returned to the main flue gas duct just upstream of the existing particulate collection device. Alternatively, it may be managed with its own particulate control device prior to returning the flue gas if required.

The spray dryer size is primarily a function of the amount of wastewater that needs to be evaporated, the flue gas volume flow, and approach temperature. The capacity of the system to evaporate wastewater depends on the amount of additional heat that is freed up by the APH upgrade. For example, a 500-MW high-sulfur coal-fired unit with a 15 percent flue gas bypass could evaporate up to 150 gpm.

The spray dryer is controlled by a PLC using two discrete control loops, one for the wastewater feed and a second for the flue gas. The chamber outlet temperature is controlled by modulating the wastewater feed rate and the residual moisture of the dried product leaving the system. The amount of flue gas entering the drying chamber is controlled by the exit temperature of the spray dryer. When less bypass gas is needed, the APH secondary air outlet temperature will be allowed to increase, thus further improving the boiler heat rate.

ECONOMICS COMPARED TO TRADITIONAL ELG COMPLIANCE SOLUTIONS

An ELG compliance case study was developed for a 300-MW high sulfur unit with an 80 percent capacity factor and a 50 gpm wastewater stream. Costs for three commercial treatment technologies were estimated for comparison to the AdvX™ ZLD system. They include: (1) Spray Dryer Evaporator, (2) Physical Chemical + Biological Treatment, and (3) Brine Concentrator + Crystallizer. A cost summary is shown in Figure 13.

The installed cost of the APH upgrade is lower because it benefits from the chloride removal from sorbent injection for SO₃ control. As a result, the evaporator for this system is smaller than that for the conventional SDE. The first three options in the table come with similar capital costs, but there is a significant difference in the annual cost to operate and maintain each system. For example, an 8 percent bypass is required for the SDE system, which equates to a 100 Btu/kW-hr negative heat rate impact. However, with the APH upgrade there is no heat rate impact.

SUMMARY

Many utilities are looking for cost-effective compliance options for their FGD wastewater. An alternative solution to bio-treatment is the elimination of wastewater by evaporation. However, a key issue with evaporative processes being economically feasible is the large cost of energy required to vaporize the wastewater. Traditionally, using flue gas heat for spray dryer evaporation requires a slipstream around the APH which increases heat rate as the flue gas no longer is passing through the APH.

Upgrading an APH with new high-efficiency heating elements can recover additional energy, maintaining the original amount of heat transfer to the combustion air while allowing a fraction of the flue gas to bypass the APH. The bypass stream could be up to 20 percent in order to carry enough heat to evaporate large volumes of wastewater without a decrease in the net unit heat rate for ELG compliance.

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300MW Unit 50 gpm WW	AdvX™ ZLD	SDE	PhysChem Bio	BC + Cryst
Capital Costs	\$27MM	\$30MM	\$29MM	\$43MM
Annual O&M Costs	\$110,000	\$610,000	\$1,040,000	\$1,600,000
NPV (6%, 20yr)	\$24MM	\$32MM	\$39MM	\$54MM
Total Cost @ 20 years	\$29.2MM	\$42.2MM	\$49.8MM	\$75MM

Figure 13: A cost summary

BIOGRAPHY



Blake Stapper has worked in the field of mechanical and combustion engineering for over 30 years and has played a key role in the development and commercialization of innovative emission control and efficiency improvement technologies. He currently serves as a business development manager on the global team for LJUNGSTRÖM's AdvX™ technology, which utilizes innovative, high-efficiency air pre-

heater technology and X-ratio optimization to recover additional waste heat from flue gas.



Steven Kosler is an Austinite, born and raised Texan, leader, innovator, inventor and professional chemical engineer. He has experience in power, environment, water and oil & gas industries. He has experience developing business cases and financial pro forma for technologies, capital projects and consulting services. He is a patent holder and his primary responsibility at LJUNGSTRÖM

is using innovation to help our clients solve some of their most complex problems.

LJUNGSTRÖM



Who We Are

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

Our Mission

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

Who Directs the WPCA?

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

How do I become a Member of the WPCA?

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

Helpful Hints From Hanby

Written by Darren Hanby, AEP

DEVELOP GOOD RELATIONSHIP WITH PLANT CONTACTS

This means everything when working with a plant. Get to know those working with your equipment or area of responsibility so that you're the first call they make when trouble arises or feedback is needed. When they know and trust you, frequently you get the "Paul Harvey" version.

FAVOR THE FIELD

When contacted or you find a problem, if at all possible high-tail it out to offer assistance. It is at times easier, maybe even cheaper to work remotely, but nothing makes an impression more than showing up to help.

RELATE DON'T BERATE

Upon arrival, evaluate where they are and the best path forward. Frequently it is advantageous to determine events that happened to create the situation to find that path, however, do not cast fault or blame. That is the surest way to get no cooperation.

DON'T GO LOOKING FOR FEATHERS

The final thing to remember is you are going to the plant for the plant, not for yourself. Sticking a feather in your cap by saying look what I found or presenting a solution that the plant found as your own, is the surest way to lose the trust of those you are working with. Giving credit and praise to those that provide or participate in solutions is feather enough.

Following these guidelines will enhance cooperation between the plant and those that support it remotely whether an engineer, manager, or even vendor. One final word, Let no Reese's Cup go uncaught.

*For further information contact
Darren Hanby at dchanby@gmail.com*

BIOGRAPHY



Darren Hanby has worked in power generation (American Electric Power), transportation, and agricultural industries for over 30 years. The majority of that time has been spent working in the plant or supporting them itinerantly.

Darren was instrumental in the development of an SCR testing system, NOx instrumentation, as well as procedures utilized by several companies to evaluate SCR NOx and Hg speciation. He holds a patent for a Large Particle Ash Screen and has a patent pending for the direct injection of urea solution, both for large coal fired SCR application.

Darren has a Bachelor of Science in Mechanical Engineering from Ohio Northern University. He is a two-time recipient of American Electric Power's Key Contributor award and a Roundtable Lifetime Achievement Award recipient.

**Watch for
WPCA Seminar**

***hosted by Duke, Vistra
and AEP
September 2020***

A Focused Look at the Proposed ELG Rule Changes for Flue Gas Desulfurization.

Written by Max Swoboda, Evoqua Water Technologies

On November 4, 2019 the EPA released the long-awaited rule changes for the Effluent Limitation Guidelines. The 2015 rule established new federal limitations at steam electric facilities, for the amount of toxic metals in wastewater that can be discharged. In April of 2017 the EPA postponed the 2015 rule, citing seven petitions for review of the rule. These changes are in response to the petitions and the comment period to the EPA regarding the changes is set to end on January 21, 2020.

While knowing and understanding the rule and its application is of great importance, the actual time to read and comprehend hundreds of pages of regulations is rarely available. In order to assist in that effort, one area of the rule is distilled here. The rule change recognized two additional Flue Gas Desulfurization treatment technologies, Low Hydraulic Residence Time Biological Reduction (LRTR) and membrane filtration. Both were not evaluated as options in the original 2015 rule. There are four options in the proposed changes representing incremental reductions in FGD pollutants, with option 1 being the least amount of reduction and option 4 being the greatest reduction. We will focus on LRTR which was selected as Best Available Technology (BAT) for plants that continue to operate under option 2 and 3 without a subcategory. This area should encompass the largest number of plants operating with a wet FGD system. Plants with other subcategories include the following qualifiers, plants retiring by 2028, utilization under 876,000 MW per year, and high flow FGD systems over 4 MGD.

Here is a brief word on membrane filtration as it was selected as BAT under option 4 and the Voluntary Incentives Program (VIP), which provides an extended compliance date. Membrane filtration systems for FGD wastewater are designed specifically for high dissolved and suspended solids. A pre-treatment step for removal of scaling forming ions such as calcium, magnesium, and sulfates is typical. The membrane technology (e.g., nanofiltration, or reverse osmosis) is used to remove particulate and dissolved pollutants from FGD wastewater. The membrane filtration system uses shear or vibration to create turbulence at the membrane surface in order to reduce fouling or scaling on the membrane. Since membrane filtration provides dissolved pollutant reduction, bromide and total dissolved solids are added to treatment limits in option 4 along with mercury, arsenic, selenium, and nitrate-nitrite. The EPA proposed membrane filtration as BAT under the VIP as the cost is significantly less than the previous BAT, thermal technologies.

Cost was also a primary consideration in the selection of LRTR as the BAT for biological treatment of FGD wastewater. In general, FGD wastewater treatment biological systems are primarily used for the reduction of selenate and selenite to elemental selenium. The microorganisms can also reduce other metals, including arsenic, cadmium, nickel, and mercury, by forming metal sulfides within the system¹. During the stay, the EPA collected additional information from site visits, industry and vendor data to develop the proposed rule changes. In that study the EPA identified improvements in

Proposed Limits for Option 3 and 4				
Specification Limit	Option 3		Option 4	
	Daily Maximum	30 Day Maximum	Daily Maximum	30 Day Maximum
Arsenic, total	13 ppb	9 ppb	5 ppb	N/A
Mercury, total	85 ppt	31 ppt	21 ppt	9 ppt
Selenium, total	76 ppb	31 ppb	21 ppb	11 ppb
Nitrate/Nitrite as N	4.6 ppm	3.2 ppm	1.1 ppm	0.6 ppm
Bromide	N/A	N/A	0.6 ppm	0.3 ppm
Total Dissolved Solids	N/A	N/A	351 ppm	156 ppm

Figure 14: Proposed Limits for Options 3 and 4

biological treatment technologies that reduced the residence time and cost of compliance over the previously considered biological treatments when the 2015 rule was released. These new systems are designated as Low Residence Time Reduction Biological Treatments (LRTR) and the prior treatment are labeled as High Residence Time Reduction Biological Treatment (HRTR).

High residence time reduction (HRTR) biological treatment systems were the selected as BAT under the 2015 rule. These systems require chemical precipitation pretreatment. The biological process is an anoxic/anaerobic fixed-film bioreactor. A number of bioreactors are arranged to create the required residence time to achieve the specified removals. For the treatment of FGD wastewater, hydraulic residence times of the bioreactors is typically 10 to 16 hours. This high retention time coupled with plug flow creates an even distribution and maximum contact with the attached growth biomass. As wastewater moves through the bioreactor, the oxidation-reduction potential (ORP) is lowered by the microorganisms ultimately creating a gradient of ORP. The top part of the bioreactor has a positive ORP and is aerobic, which allows nitrification. Further down the column, the bioreactor becomes an anoxic zone with negative ORP, where denitrification and chemical reduction of selenium (both selenate and selenite) occur ^{2,3}.

The ability to lower the residence time of the system creates a smaller overall treatment system which lowers cost. Utilities and technology suppliers developed some improvements in residence time since the 2015 rule and the EPA considered those advancements in the proposed rule changes. Some of the LRTR treatment process steps are the same as the HRTR, both have anoxic/anaerobic fixed film bioreactors, but the LRTR can remove pollutants in 1 to 4 hours of residence time. Chemical precipitation is still required pretreatment. LRTR uses an anoxic, upflow bioreactor that is followed by a second-stage downflow biofilter, it is this combination that reduces the required contact time. Less contact time translates to smaller equipment that cost less to build. Much of the equipment is fabricated and delivered to the site as modular components that acts a building blocks in order to match the treatment requirements. The EPA reports, "Modular, prefabricated, skid-mounted components, coupled with the smaller physical size of the system, results in lower installation costs and shorter installation times, relative to HRTR systems, which are usually constructed on-site. At least four coal fired steam electric power plants have installed full-scale LRTR systems currently being used to treat FGD wastewater and this technology has been pilot tested using FGD wastewa-



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ter at more than a dozen steam electric power plants since 2012.”⁴ The reduction in pollutants is comparable to the performance of HRTR technology.

Cost savings were of the petitioned motives for the proposed changes to the rule, as such the EPA estimated the capital, annual O&M, and other one-time or recurring costs of rule compliance. Section 5.0 of EPA-821-R-19-009, Supplemental Technical Development Document for Proposed Revisions to the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Supplemental), compares the installation and operation cost for LRTR and HRTR systems with chemical precipitation pretreatment. The table below list cost that were considered in these estimates.

For estimation of the capital and O&M cost of these items, two flow rate cases were identified, FGD Purge flow and an Optimized FGD flow. The FGD purge flow rate is the normal

design effluent flow to the wastewater treatment system. This flow rate was used to estimate capital cost of a system. The optimized FGD flow is a reduced flow that accounts for operating the FGD at level above 80% of the maximum design concentration for chlorides. The EPA used the optimized flow rate to estimate the O&M costs. The cost estimates are provided for both the LRTR and HRTR with options of on/off site disposal of solid and low/high nitrates. Thus, the permutations of estimates are shown in Figure 16 on page 19. For clarity one option for a low nitrates case is presented here to compare each residence time.

The comparison suggests about equal O&M cost for each treatment, but the LRTR capital cost has an advantage over the HRTR. The EPA estimates the proposed rule changes result in \$175 million dollars in pre-tax compliance cost savings for all plants effected by the changes. Low Hydraulic Residence Time Biological Reduction technology is one of part of achieving those savings.

Cost Items	LRTR (Section 5.2.3)	HRTR (Section 5.2.4)
Chemical Precipitation	Included	Included
Biological treatment equipment	Anoxic/anaerobic bioreactor, flow control, backwash supply, storage tanks	Anoxic/anaerobic biological treatment system, storage tanks, and backwash system
Chemical feed system for nutrients	Included	
Nitrate/nitrite pretreatment system	Greater than 50 ppm	Greater than 100 ppm
Heat exchanger.	Included	Geographically dependent
Ultrafilter	Included	N/A
Pollutant monitoring and analysis	Included	
Transportation and disposal of solids in a landfill	Included	
Direct Cost	Freight, Installed cost of instrumentation and controls, piping, and electrical, Buildings (including services), Site preparation	
Indirect Cost	Engineering and supervision and Contingency	
O&M Costs	Operating and Maintenance labor, Chemical purchase, and Energy	
O&M Cost Other	N/A ⁵	Sludge transportation and disposal, Compliance monitoring

Figure 15: Comparison of Cost Factors for LRTR and HRTR Systems

⁵While not individual listed, it is assumed the cost for sludge transportation and disposal, as well as compliance monitoring are included as the cost chart titles include transportation and disposal. For some unknown reason they are not individually listed in the section.

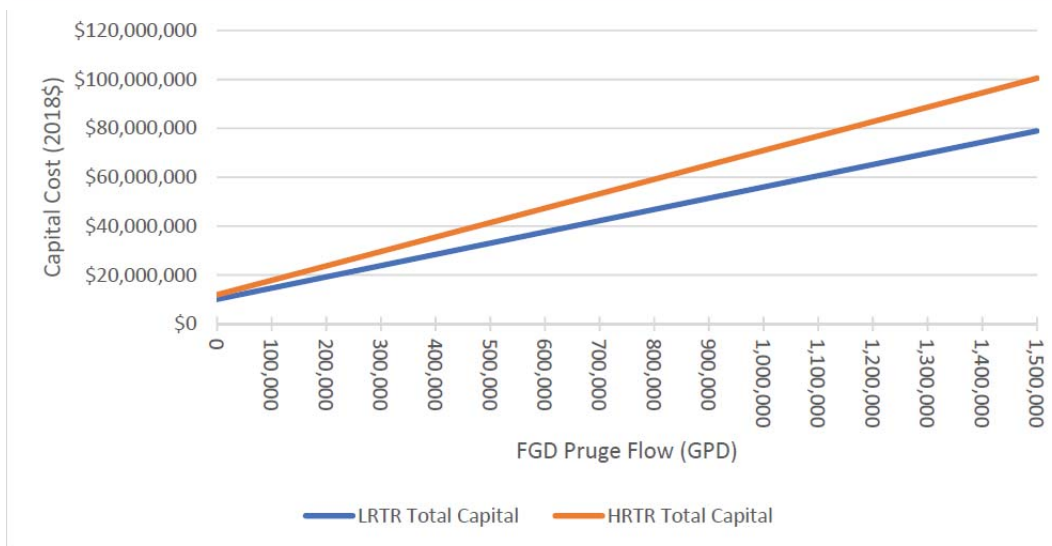


Figure 16: FGD Capital cost estimate for low nitrate case

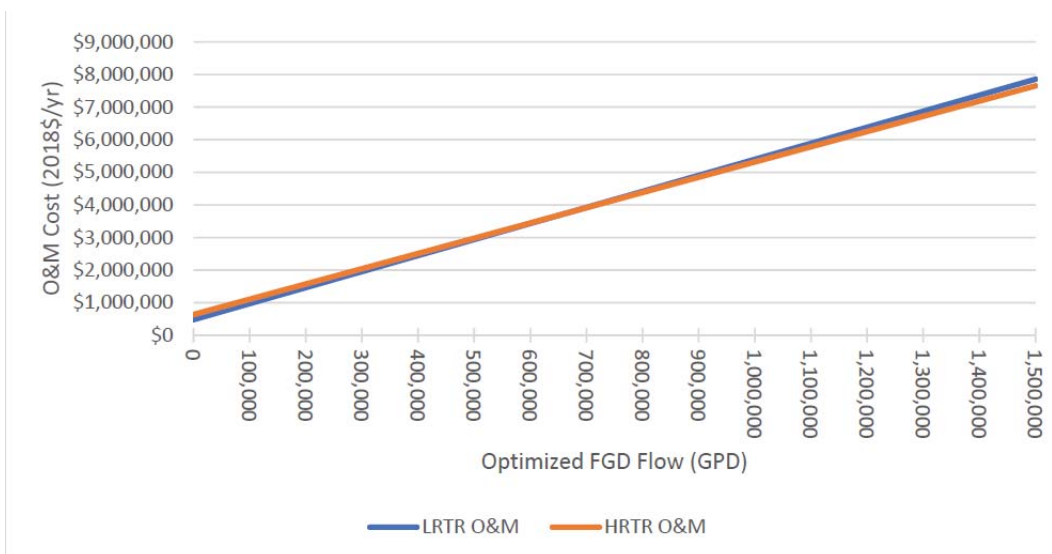


Figure 17: FGD O&M cost estimate for low nitrate case

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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.



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