Executive Summary

Natural Gas Conversions of Existing Coal-Fired Boilers
By F.J. Binkiewicz Jr., R.J. Kleisley, McMahon, J.E. Monacelli, D.A. Roth, D.K. Wong, Babcock & Wilcox, Power Generation Group

This article will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision. Full Story....

Real World Performance Results of Fabric Filters on Utility Coal Fired Boilers
By Tim Stark, GE Power and Water Air Filtration

This article examines how fabric filters behave in real-world environments, taking into account differential pressure changes, emissions levels and scrubbing results. It will address the effects that fabric finish and pressure drop have on scrubbing results and will show that the key to obtaining the scrubbing performance out of the dust-cake on the filter bag is the maintenance of that dust-cake by controlling pressure drop across the baghouse. In addition, this article will identify the effects that the other gas stream treatment equipment in line with the baghouse have on the dust-cake, and the system’s ability to manage the pressure drop. The baghouses used in these case histories include both pulse-jet and reverse-air-style cleaning methods. Full Story....

Dry Sorbent Injection Impacts on Hazardous Air Pollutant Metals
By Dr. Connie Senior, ADA-ES

In this article, the chemistry of DSI and of certain hazardous air pollutant (HAP) metals in coal combustion flue gas will be presented, followed by a discussion of the currents understanding of leaching from mixtures of alkaline sorbents and fly ash. Full Story....

Comparison of Wet and Dry Electrostatic Precipitator (ESP) Technologies
By Aaron Benedict, James “Buzz” Reynolds, Sankar Seetharama, Siemens Energy Inc., Environmental Systems & Services

This article compares the two technologies and Siemens’ experience with the technologies. To gain a better understanding of each technology a discussion of particle size is first required. Full Story....

Can Dry Sorbent Injection Technology Really Work for HCl for MATS Compliance?
By Michael Thiel, Nol-Tec Systems

The focus of this article is HCl and SO₂. The specific limit for HCl is 0.0020 lbs/MMBtu. For SO₂, the limit is 0.20 lbs/MMBtu. Dry Sorbent Injection (DSI) has been proven to meet these standards in real world tests and permanent installations. Before we examine those test results, we’ll discuss the basics of DSI. Full Story....
Abstract

Electric utilities are always searching for ways to minimize costs, improve availability and reduce emissions. Recent changes in the price of natural gas have made that fuel economically attractive, with the added benefit of reduced emissions of sulfur dioxide (SO₂), nitrogen oxides (NOx) and carbon dioxide (CO₂). For those utilities with existing coal-fired units, conversion from coal firing to natural gas firing might be an option worth considering.

This article will consider the rationale for fuel switching, some of the options available for conversion of coal-fired units, technical considerations related to conversion, and some of the financial considerations that will impact the final decision.

Rationale for Considering Fuel Switching

The first step in the process is to identify the forces that drive the decision to convert from coal to gas. The key forces are regulatory (both in terms of emissions and as an offset for a new unit), fuel costs, the age of the plant and the need for plant output.

Regulatory forces are currently in a state of flux, with a wide range of proposed rules and legislative efforts that

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<th>Location</th>
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<tr>
<td>Existing Unit Information</td>
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<td></td>
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<tr>
<td>Year built</td>
<td>1954</td>
<td>1955</td>
<td>1961</td>
</tr>
<tr>
<td>Original megawatts</td>
<td>152</td>
<td>103</td>
<td>390</td>
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<tr>
<td>Operating pressure (PSI)</td>
<td>2,950</td>
<td>1,480</td>
<td>2,640</td>
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<tr>
<td>-- Main steam temperature (°F)</td>
<td>1,050</td>
<td>1,000</td>
<td>1,005</td>
</tr>
<tr>
<td>-- Reheat outlet temperature (°F)</td>
<td>1,000</td>
<td>1,000</td>
<td>1,005</td>
</tr>
<tr>
<td>-- Original fuel</td>
<td>Pulverized bituminous coal</td>
<td>Pulverized coal</td>
<td>Pulverized coal</td>
</tr>
<tr>
<td>Target Performance Basis</td>
<td>100% NG with no pressure part changes</td>
<td>Minimize pressure part changes</td>
<td>Maintain 1000°F air minus 87% MCR</td>
</tr>
<tr>
<td>Results and Limitations</td>
<td>Original maximum continuous rating; MCR (no limitations)</td>
<td>Maximum resultant SH temp = 950°F, and higher excess air for steam temperature control at lower loads</td>
<td>Cannot maintain steam temperature above 87% MCR without modifications; and unable to fire 1000°F air without pressure part modifications</td>
</tr>
<tr>
<td>Recommended Burner Modifications</td>
<td>Add gas elements</td>
<td>New low NOₓ burners + OFA ports</td>
<td>New burners + NOₓ ports</td>
</tr>
<tr>
<td>Recommended Pressure Part Modifications</td>
<td>Minimal to none required</td>
<td>Minimal to none required</td>
<td>Minimal to none required</td>
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<tr>
<td>Attemperator Recommendations</td>
<td>No changes required</td>
<td>No changes required</td>
<td>SH changes required</td>
</tr>
<tr>
<td>Fan Recommendations</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>-- Forced draft</td>
<td>Appears OK, evaluation by others</td>
<td>No changes required</td>
<td>Static capacity deficient</td>
</tr>
<tr>
<td>-- Induced draft</td>
<td>Appears OK, evaluation by others</td>
<td>No changes required</td>
<td>No changes required</td>
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<tr>
<td>-- Gas recirculation</td>
<td>Replace FGR fan and drive</td>
<td>No recommendations made</td>
<td>Removed from service</td>
</tr>
<tr>
<td>Air Heater Recommendations</td>
<td>No changes required</td>
<td>No changes required</td>
<td>Design static pressure deficient</td>
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</table>

Figure 1: Comparison Table - Study results of Typical Pulverized Coal to Natural Gas Conversion
What appears likely is that some form of CO$_2$ controls will be enacted in the near future. These controls could be part of a cap-and-trade system (similar to previous allowance programs for SO$_2$ and NO$_x$) or they might take the form of gradual reductions to meet increasingly stricter goals. Regardless of the final form, the industry is reasonably certain that there will be some additional controls placed on power plant owners. Utilities must also factor in the future need for electrical power generation – either because of market demand projections or to replace a unit that might be approaching the limit of its useful service. There also may be regulatory issues to evaluate, such as New Source Review and offsets for other emissions regulated by state and federal laws.

The price of natural gas has recently become more attractive as a baseload fuel due to additional supply and reduced demand from general industry. There are many different projections of where gas prices might be in the near future, all of which are based on the forces of supply and demand. The current price of natural gas is relatively low and stable compared to previous years. Utilities should be aware that natural gas prices are much more sensitive than coal prices to short term changes in supply and demand. While current economic conditions favor natural gas usage, Babcock & Wilcox Power Generation Group, Inc. (B&W PGG) strongly advises its customers to evaluate potential price volatility as a key component in the decision making process.

A plant may be considered for fuel switching based on its age and how close it would be to a possible retirement or major rebuild. The timing for fuel switching may be ideal if the boiler in question is already under consideration for major projects like superheater replacement, burner modifications, air system changes and/or the addition of back-end emissions control equipment. Consultants can assist in comparing the costs and benefits of different scenarios to help make the best decision based on the specific needs of the plant.

One of the other key factors to consider is the need for plant output, including a potential for de-rate and/or increased turn-down capability. A unit’s continued usefulness might involve its ability to operate or be on standby during periods of low load.

As utilities look at their long-term forecasts, plants that operate efficiently and with high availability will play a key role in meeting future demand. As such, these plants will need to be evaluated for projects that will extend their useful life. Those projects might be targeted for efficiency improvements with coal as a fuel (burner upgrades, emissions control equipment, etc.) or as fuel-switch projects that take advantage of the benefits of natural gas.

### Options

An engineering study can be performed to help determine the best options for your specific application. Among the many options to consider are:

1. **Fuel switch with modifications to the existing boiler**
2. **Fuel switch for the existing boiler and the addition of a gas turbine to the existing boiler cycle**
   - addition of simple cycle to the existing system
   - hot windbox repowering
   - combined cycle repowering
3. **New combined cycle plant (elemental review) with retirement of the existing coal plant**

Each option has advantages and disadvantages, including cost and operational considerations, including:

- comparison of modification costs vs. capital cost of a new gas turbine
- impact of future changes in fuel prices and the potential risk associated with natural gas price volatility
- life expectancy of gas turbines and heat recovery
- steam generators (HRSG) compared to steam boilers
- amount of acceptable de-rate

Since no two plants are identical, it is important that utilities work with an experienced supplier to evaluate the best solutions for their needs.

### 1. Fuel Switch with Modifications to the Existing Boiler

The most obvious change to a power plant that switches from coal to gas will be the modifications to the fuel handling, storage and distribution equipment. The plant must receive natural gas via a pipeline spur from the local main transmission line. If a spur does not currently exist, the plant will need to evaluate the costs and activities (permits, land rights, etc.) associated with constructing a new spur. Once inside the plant perimeter, the gas must be metered and piped to the boilers, where new gas burners will be required (or to a new gas turbine if applicable).

If the existing boiler is modified for gas-firing, the convection pass, ducting and windbox will likely need modifica-
tions. The extent of the modifications will be determined by an engineering study that will look at overall furnace absorption, furnace exit gas temperature, and tube bank arrangement/material changes (superheater, re heater and economizer). Other operational changes like sootblowing schedules, attenuator spray flows, air heater operation and operation of any back-end emissions control equipment will need to be adjusted for the switch from coal to gas.

**Technical Considerations**
As the engineers study your plant, they will evaluate the impact of the following technical considerations:
- characteristics of natural gas vs. original or current fuel
- impact on boiler design and capacity
- impact on cycle efficiency
- boiler and environmental equipment modifications
- burner modifications
- convection pass modifications
- changes to fans, ductwork, fluwork, etc.
- amount of acceptable de-rate

**Financial Considerations**
Any modification to an existing plant carries considerable cost implications. This is true when upgrading a coal plant with new components for higher efficiency and/or lower emissions. Likewise, there are financial considerations for switching fuel from coal to natural gas. Cost ranges for modifications for the units shown in the comparison table on page 1 are estimated to be in the range of $50 to $75/kW.

The unique conditions of each plant will necessitate a detailed study of the potential operational options and their corresponding costs. These costs include only modifications to the boiler island. Excluded are costs related to bringing natural gas supply to the boiler.

2. Fuel Switch for the Existing Boiler with Addition of a Gas Turbine

**Technical Considerations**
The concept of repowering existing power plants is currently viewed as an option to economically meet new demands for improved efficiency, power growth and stricter environmental regulations. Partial repowering is the conversion of an existing site to combined cycle where the boiler and steam cycle are retained to the greatest extent possible. There are several major partial repowering alternatives. Many of these alternatives have multiple possible equip-ment configurations that can be considered depending on the option. Low gas turbine exhaust oxygen concentrations (as low as 12%), and high exhaust temperatures (exceeding 1100F) can provide design challenges depending on the combustion turbine used for this configuration.

2a. Addition of Simple Cycle to the Existing System
This technology uses the existing boiler and steam turbine equipment in essentially its original configuration. In this design, a gas turbine and feedwater heater are added in parallel to the existing boiler. Figure 2 provides a bullet summary and illustrates a typical equipment arrangement for this option. Depending on the specific plant configuration, balance-of-plant (BOP) material and erection services are required to complete this retrofit.

2b. Hot Windbox Repowering
In this configuration, a gas turbine is added to an existing plant and the exhaust from the turbine is ducted directly to the boiler windbox where it is used as combustion air for the boiler. The existing air heaters are typically retired with new stack gas coolers (or partial HRSG) added in parallel to the feedwater heaters to maximize cycle efficiency. Figure 3 (see on page 4) provides a bullet summary and illustrates a typical equipment configuration for this technology.

![Figure 2: Addition of simple cycle](image-url)

- **New gas turbine**
- **New recuperative feedwater heater(s)**
- **Retains steam system**
  - closes some extractions and feedwater heaters
- **Advantages**
  - low additional capital cost
- **Disadvantages**
  - small efficiency gain - 2% to 3%
Depending on the specific plant configuration, significant boiler and BOP material and erection services are required to complete these retrofits. This has been the repowering configuration of choice outside of the U.S. with Holland having more than 12 plants designed in this configuration (both retrofit and original). B&W PGG designed two new plants based on this cycle configuration in the early 1960s. Recent improvements in gas turbine technology have made integration of these machines with boilers more challenging than in the past.

2c. Combined Cycle Repowering

In this configuration, a gas turbine is added to an existing plant and the exhaust from the turbine is ducted to the boiler windbox where it is used as combustion air for the boiler. This configuration uses a supplemental heat exchanger (or partial HRSG) or mixes ambient air upstream of the boiler to cool the exhaust temperature to levels acceptable to existing windbox materials. The existing air heaters are typically retired with new stack gas coolers (or partial HRSG) added in parallel to the feedwater heaters to maximize cycle efficiency.

Figure 4 provides a bullet summary and illustrates a typical equipment configuration for this technology. Depending on the specific plant configuration, significant boiler and BOP material and erection services are required to complete this retrofit.

**Financial Considerations**

As the repowering configuration can vary significantly depending on the goals and constraints of a given system, cost for such a conversion can span a broad range. The combustion turbine will likely be the largest single component and cost. Estimates on retrofit costs range from $180 to $1,025 per unit kW increase in power.
3. New Combined Cycle Plant with Retirement of the Existing Coal Plant
A modern, highly efficient combined cycle plant is always a consideration when evaluating a fuel switch from coal to gas, especially when a considerable increase in power generation is needed. The higher capital cost of this option requires a careful analysis of its suitability to the unique needs of each utility.

This report is not intended to review every factor related to switching from coal to natural gas, but it is important for each prospective utility to consider the hidden costs associated with the retirement of a coal plant, including the cost of decommissioning or mothballing, as well as any site remediation costs. It is only when all the true costs are identified that the real savings from a fuel switch can be fully and properly evaluated.

For further information contact Don Ryan at deryan@babcock.com

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Real World Performance Results of Fabric Filters on Utility Coal Fired Boilers

By: Tim Stark, GE Power and Water Air Filtration

Abstract
This article examines how fabric filters behave in real-world environments, taking into account differential pressure changes, emissions levels and scrubbing results. It will address the effects that fabric finish and pressure drop have on scrubbing results and will show that the key to obtaining the scrubbing performance out of the dust-cake on the filter bag is the maintenance of that dust-cake by controlling pressure drop across the baghouse. In addition, this article will identify the effects that the other gas stream treatment equipment in line with the baghouse have on the dust-cake, and the system’s ability to manage the pressure drop. The baghouses used in these case histories include both pulse-jet and reverse-air-style cleaning methods.

Introduction to Fabric Filters
Fabric filters, or baghouses, have been used to capture particulate from combustion processes for more than 50 years. They grew popular in the power generation industry in the 1970s after the first installation of a reverse-air-style fabric filter. Pulse-jet, another type of fabric filter, was also implemented on coal-fired power generation applications in the early 1970s, with the first actual utility installation taking place in the early 1990s.

Reverse-Air Style Fabric Filter
Reverse-air was the original style of choice for dust collection in utility applications. In the 1970s, this style of collector was more suited for utility applications than pulse-jet because of the proven relatively low air-to-cloth/offline cleaning technology.

Reverse-Air Technology
+ Air-to-cloth ratio target: 2.5:1 or lower
+ Large footprint
+ Offline cleaning
+ Woven fiberglass fabric
+ Finish options: Teflon™ B, acid resistant, expanded polytetrafluoroethylene (ePTFE) membrane
+ Dust collected on inside of filter-no support cage utilized
+ Average bag life range: 5-10 years

Pulse-Jet-Style Fabric Filter
The pulse-jet-style fabric filter, while in service since the early 1970s on coal-fired applications, was not yet cost-effective enough and did not have the performance track record nor the technology advancements required to operate at the scale of a large utility boiler application. As technology advanced and performance objectives were proven on smaller-scale industrial boiler applications, the pulse-jet technology gradually became the choice on utility installations.

Pulse Jet Technology
+ Air-to-cloth ratio target: 3.5:1 or lower
+ Smaller footprint
+ Online cleaning with ability for offline cleaning
+ Fabric options: woven fiberglass, polyphenylene sulfide (PPS) felt, acrylic felt, P84™ felt, aramid felt, fiber blends
+ Finish options: acid resistant, singe, Teflon coatings, micro-denier, ePTFE membrane
+ Dust collected on outside of filter
+ Support cage utilized
+ Average bag life range: 3-6 years

Lab vs. Real-World Conditions
While a fabric filter serves to remove particulate from the gas stream prior to the stack, it must do so while also controlling the fabric filter pressure drop so that there is proper ventilation during combustion and the cost of maintenance and fan energy consumption are minimized. This is a relatively simple task under conditions typically found in the lab.

Lab conditions
+ Constant temperature
+ Constant volume
+ Constant moisture level
+ Constant gas stream chemistry
+ Constant grain loading

Using the above criteria for a gas stream in the laboratory yields acceptable performance results for most fabric and
It is most important for the fabric filter to maintain pressure drop in an acceptable range, while also meeting emissions requirements, under all of the typical operating conditions that occur. Meeting these goals and doing it cost effectively boils down to dust-cake management.

**Dust-Cake/Emissions Management**

Over time, a dust-cake develops on the surface of the filtration media as a result of the particulate in the gas stream. In a coal-fired boiler, for example, this dust would consist of fly ash and any materials used to treat the gas stream (lime, trona, powder-activated carbon, etc.) before it collects on the fabric filter. This dust-cake is controlled by the baghouse cleaning system. The dust-cake performs two critical functions in the baghouse:

1. **Filtration efficiency:** The fabric filter acts as a support structure for a dust-cake that actually creates and controls efficiency. The fabric itself is not as efficient as the dust cake that is created on its surface, and the fabric alone cannot allow the system to meet environmental regulations. This dust-cake also provides some protection against the incoming gas stream, keeping the fabric from being directly subjected to the incoming dust load.

2. **Gas-stream contact with dust-cake:** In a coal-fired boiler that uses scrubber technology or activated-carbon injection technology before the baghouse, the dust-cake on the filter is providing some of the contact time between the gas stream and the materials injected into the gas stream for pollution control.

The key to controlling this dust-cake is monitoring the pressure drop and controlling the cleaning to maintain the dust-cake.

Over-cleaning filter bags is one of the main causes of premature bag failure. First of all, the filter has the ability to withstand a certain number of cleaning cycles over the course of its life. If we clean a filter every five minutes, it may last two years. If we clean it every 10 minutes, it may last four years. The cleaning energy will slowly degrade the filter much like cleaning fabric in a washing machine will degrade clothing over time. The less we clean, the longer the fabric should last. The other problem with over-cleaning is it does not allow a dust-cake to properly develop, leading to either dust penetrating into the depth of the fabric and becoming permanently lodged there (blinding) or the dust passing completely through the fabric and ending up as emissions (bleed-through). Most people intuitively believe that the more they clean the filters, the lower the pressure drop and the lower the potential for emissions, but the opposite is true: it is the dust-cake that provides the efficiency and protects the fabric from premature blinding and/or bleed-through.

In a *utility* baghouse, with gas stream treatment equipment upstream of the baghouse, the dust-cake has another purpose: create more contact time between the gas stream and the dust to help scrub the gas stream. This is an important variable to note. When trying to improve the filter’s ability to release dust-cake, we often consider other fabric finishes. This raises the question about degrading the scrubbing results with filters that can potentially operate at a lower overall pressure drop. Can we improve dust-cake release to the point where it adversely affects the scrubbing characteristics of the dust-cake? Real-world results show that the fabric finish does not necessarily affect the filter’s ability to create the dust-cake needed to accomplish scrubbing goals. Dust-cake management, regardless of the fabric finish used, continues to be the important factor when operating a power plant baghouse.

**Potential Effects on Dust-Cake Management of Gas Stream Treatment**

The air pollution control equipment used in today’s coal-fired utility plants will almost always consist of more than just a fabric filter. Various different gas stream treatment technologies are used either before or after the fabric filter to treat the gas stream before it leaves the stack. Not only does...
<table>
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<tr>
<th></th>
<th>Acrylic</th>
<th>PPS</th>
<th>Aramide</th>
<th>Fiberglass</th>
<th>P84</th>
<th>Pleated elements</th>
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<tr>
<td>Max Operating Temp</td>
<td>265 F, 130 C</td>
<td>375 F, 190 C</td>
<td>400 F, 204 C</td>
<td>500 F, 260 C</td>
<td>500 F, 260 C</td>
<td>Dependent on base fabric</td>
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<td>Concerns in coal fired boiler applications</td>
<td>Lowest maximum operating temperature.</td>
<td>Susceptible to degradation at elevated temperatures coupled with oxygen levels over 12%.</td>
<td>Not as capable as PPS in chemically active gas stream environment.</td>
<td>Woven style fabric that is more fragile than other options. Requires tight tolerance to be maintained on bag-to-cage fit in pulse jet applications.</td>
<td>Dimensional stability at higher temps over 400 F. Requires oversizing of filter to maintain proper bag-to-cage fit.</td>
<td>Air to cloth ratio must be below 3.5 to 1. Applicable only when additional cloth area is needed to lower air to cloth ratio and eliminate inlet abrasion.</td>
</tr>
<tr>
<td>Relative Cost</td>
<td>$</td>
<td>$$$</td>
<td>$$$</td>
<td>$</td>
<td>$$$</td>
<td>$$$$$</td>
</tr>
<tr>
<td>Fabric treatments to improve performance</td>
<td><strong>ePTFE Membrane</strong>: Laminated to collection surface-most efficient option, enables fabric to handle system upsets reviewed in paper at more consistent airflow/less cleaning frequency.</td>
<td><strong>Micro-denier fibers/Tri-lobal fibers</strong>: Creates improved efficiency over standard fibers by increasing total fiber surface area. Limited improvement over ability to handle upset conditions reviewed.</td>
<td><strong>PTFE Coating</strong>: Non-membrane surface coating used to improve dust cake release-sacrifices ability to maintain consistent airflow leading to increased cleaning frequency/high differential pressure.</td>
<td><strong>Singe</strong>: Removes some of the fabric surface area, creating an improved ability of the fabric to release dust cake. Limited improvement over ability to handle upset conditions reviewed.</td>
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*Figure 5: Standard Fabrics Used in Utility Coal Fired Applications*
this equipment have the potential to affect the performance of the fabric filter, the fabric filter can also affect this equipment.

To maintain a lower pressure drop for a longer period of time with the lowest cleaning frequency possible, end users have chosen different fabric types and fabric finishes. The gas stream treatment equipment used in conjunction with fabric filters can create conditions that make it more challenging for the cleaning system to maintain pressure drop. There are several instances where the fabric style or finish has been successfully changed in order to improve a system’s ability to maintain pressure drop in the correct range with the lowest cleaning frequency possible.

**Scrubbers**

Scrubbers are used for flue gas desulfurization (FGD) and acid gas control. There are several different technologies used.

- Spray dry FGD-typically upstream of the fabric filter
- Wet dry FGD-typically downstream of the fabric filter
- Circulating dry scrubber
- Dry sorbent injection

Potential fabric filter effects:

- Increase in grain loading
- Potential for moisture introduction into fly ash, leading to high pressure-drop/increased cleaning requirements
- Potential for decreased inlet temperature, increasing the risk of the gas stream dropping below the acid dew point before or inside of the fabric filter
- When scrubber is downstream of fabric filter, inefficient operation can lead to increased cleaning requirements for downstream technology

**Selective Catalytic Reduction (SCR)**

SCRs are used to convert nitrogen oxides (NOx) with the aid of a catalyst into diatomic nitrogen (N₂) and water. Typically ammonia is added into the flue gas stream and is absorbed onto a catalyst.

Potential fabric-filter effects: Sticky dust created by ammonium bisulfate that leads to higher pressure-drop/increased cleaning frequency

**Electrostatic Precipitators (ESPs)**

ESPs remove particulate from the flue gas by using electrical forces. The dirty gas stream is passed through an electrical field set up between electrodes of opposite polarity. In the utility industry, where ESPs were originally installed as the primary Air Pollution Control device, they sometimes are left in service after the addition of a fabric filter downstream from the ESP.

Potential fabric filter effects:

- Lower grain loading -- a good thing -- leads to potentially lower cleaning frequency
- Potential for applying fabric filter at a higher A/C ratio based on lower grain loading
- Can change the particle size distribution going to the fabric filter, removing the larger particulate

Figure 6: The microporous structure of the membrane

The most successful example in recent years has been the treatment of the base fabric with an expanded polytetrafluoroethylene (ePTFE) membrane. In brief, the membrane creates a very slick and highly efficient surface that allows the dust-cake to be maintained with less cleaning energy. This helps the system not only handle a sticky, difficult-to-clean dust-cake, it decreases cleaning frequency (leading to longer filter life). The gas stream treatment options listed below all have an effect on the dust-cake that the fabric filter handles.

While ePTFE filters enable the fabric filter to run at a lower pressure drop regardless of the changes in gas stream, the real-world results show that they do not adversely affect the scrubbing results from the potential decrease in contact between the gas stream and the dust-cake.
and allowing mostly the finer particulate to pass through. This can create a more challenging dust-cake for the baghouse.

**Carbon Injection**

One method to help control mercury emissions is the injection of activated carbon into the flue gas to adsorb mercury before it exits the stack. This is typically done upstream of the fabric filter.

Potential fabric filter effects:
- Increased grain loading
- Fire potential
- Inability to sell fly ash from baghouse

**Real-World Upset Conditions Affecting Fabric Filters**

The fabric filter has several jobs to perform in a coal-fired boiler application. It needs to maintain pressure drop while meeting all environmental regulations in conjunction with the other pieces of environmental equipment in the system. On top of that, upset conditions in the real world can present challenges to the fabric filter. If the fabric filter can’t handle the upsets, the result could lead to the plant not being able to run at the required load demand or being forced to shut down because of an inability to meet environmental regulations. The other issue is if the upset conditions require continuous cleaning for prolonged periods of time, leading to premature bag failures and shorter bag life than the budget anticipates.

**Conclusions**

Fabric filters utilized on coal-fired boilers face real-world environments that make their primary goals of managing pressure-drop, efficiency and a percentage of the systems scrubbing performance a challenge. Dust-cake management is critical in ensuring these goals are met. Multiple factors can have an impact on a system’s dust-cake:

- Low inlet temperatures
- High moisture levels
- Challenging dust-cake created when using scrubbers/SCRs/activated carbon injection
- Longer-than-normal filter bags requiring aggressive cleaning to maintain pressure drop

Managing the dust cake requires controlling the filter differential pressure and is critical in ensuring:

- Required particulate removal efficiency
- Plant load requirements
- Necessary scrubbing by dust-cake on filter media
- Minimized energy cost for operating fabric filter
- Maximized filter life with minimized maintenance costs

<table>
<thead>
<tr>
<th>Upset Condition</th>
<th>Fabric Filter Effects</th>
</tr>
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<tbody>
<tr>
<td>Tube leaks</td>
<td>High pressure drop from moisture carry-over, leading to constant cleaning</td>
</tr>
<tr>
<td>Material handling system failure</td>
<td>High hopper levels leading to high pressure drop from re-entrainment and filter abrasion/failure—also potential for heat excursion from hopper fires</td>
</tr>
<tr>
<td>Cleaning system failure</td>
<td>High pressure drop</td>
</tr>
<tr>
<td>Dew point excursions from pre-fabric filter equipment failure</td>
<td>High pressure drop from moisture condensation and chemical degradation of fabric/premature corrosion of support cages in pulse-jet-style units</td>
</tr>
<tr>
<td>SCR system upsets leading to high ammonia slip</td>
<td>High pressure drop from sticky dust created by ammonia levels, leading to constant cleaning</td>
</tr>
<tr>
<td>Fire suppression system failure</td>
<td>High pressure drop from moisture carry-over, leading to constant cleaning</td>
</tr>
</tbody>
</table>

**Figure 7: Common Upsets Causing Fabric Filter Issues**
Filter media technology exists that improves the ability of the fabric filter to operate under real-world conditions. The use of ePTFE membrane laminated filters improves the performance of the fabric filter by allowing it to operate at a lower pressure drop and recover from common upset conditions. This style of filter shows no change in the scrubbing performed by the dust-cake and no increase in the use of adsorbents as long as pressure drop is managed.

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Dry sorbent injection (DSI) is intended to remove acid gases from the flue gas via the injection of sorbents. However, there are other chemical reactions that happen in the flue gas and in the fly ash-sorbent mixture that should be considered when contemplating using dry sorbent injection. Specifically, the sodium-based or calcium-based sorbents can shift certain metals (Hg, Se, As) from the vapor phase to the solid phase. Furthermore, the characteristic leaching of these metals from fly ash can be altered when alkaline sorbent is present in the fly ash.

In this article, the chemistry of DSI and of certain hazardous air pollutant (HAP) metals in coal combustion flue gas will be presented, followed by a discussion of the currents understanding of leaching from mixtures of alkaline sorbents and fly ash.

**What is Dry Sorbent Injection?**

A DSI system is designed to inject of dry alkaline sorbents directly into combustion flue gas and collect of the sorbents, typically in the particulate control device or, less commonly, in the wet flue gas desulfurization scrubber. DSI systems were originally developed to reduce SO₂ emissions or SO₃ emissions. DSI chemicals can also remove HCl from flue gas, thus providing a low-cost alternative to traditional flue gas desulfurization scrubbers to some plants in order to meet HCl emission limits under the Mercury and Air Toxics Standards (MATS). The DSI systems are tailored to each location, plant and unit, to assure optimized mitigation of targeted air pollutions.

In the Mercury and Air Toxics Standards (MATS) rule for electric utility boilers, HCl was identified as a surrogate for a group of acid-gas HAPs; hence there are emission limits for HCl. Sulfur dioxide emissions are regulated by both the state and federal government. Emissions of SO₃ are regulated at the state level in some states via a restriction on condensable particulate matter. Even if SO₃ emissions are not regulated, there are compelling reasons to reduce concentrations in combustion flue gas:

1. Prevention of formation of ammonium bisulfate in air preheaters;
2. Ability to lower cold end air temperatures in the air preheater and increase boiler efficiency;
4. Reduction in corrosion in the air preheater or downstream of air preheater; and
5. Reduction of sulfuric acid mist in the stack, which can manifest as a persistent plume (“blue plume”) in the atmosphere.

**Sorbents Used in DSI Technology**

The primary DSI sorbents used in today’s market for acid gas control are calcium-based (hydrated lime) or sodium-based (trona, sodium bicarbonate) sorbents. The applications of these sorbents are shown in Figure 8.
scribe the ratio of moles of active sorbent element (Na, Ca) to moles of acid gases present in the duct. NSR should be calculated based on total acid gases (SO$_2$+HCl+HF+SO$_3$), because all will react with DSI chemicals to some extent. Unfortunately, NSR reporting is inconsistent; in some cases, the NSR of sorbent to a specific acid gas or sorbent usage as mass ratio (e.g., lb sorbent/lb acid gas) is reported. To compare the effectiveness of various sorbents, the flow rate of acid gases in the flue gas of interest must be calculated to estimate site specific sorbent usage.

Hydrated lime has been used to remove SO$_3$ and/or HCl from flue gas. Efficient removal requires a high surface area (greater than 20 m$^2$/g) and a small particle size (2-5 microns).

Trona typically has mean particle size between 30 and 35 μm, while sodium bicarbonate (SBC) is coarser (~50 μm). Both trona and SBC may benefit from being milled before injection. Trona and SBC decompose at about 275°F (135°C) to form sodium bicarbonate. The decomposition reaction that occurs when the sodium sorbents are injected into the flue gas produces a high surface area, allowing an efficient reaction with acid gases.

Generally the removal of acid gases follows this trend:

$$\text{SO}_3 \gg \text{HCl} >> \text{SO}_2$$

Sodium sorbents are more reactive with SO$_2$ than calcium sorbents when injection occurs post-economizer. When DSI is used to remove SO$_3$ or HCl from the flue gas, some SO$_2$ may also be removed and must be taken into account when calculating the sorbent flow rate that is needed.

Arsenic remains in the vapor phase until the inlet of the air preheater, at temperatures above about 650°F (300°C). The presence of vapor-phase arsenic at these temperatures has caused deactivation of the catalysts in selective catalytic reduction (SCR) units. Gaseous arsenic reacts with calcium oxide, which can be seen in the data in Figure 9 showing results from three full-scale power plants where gaseous arsenic concentration was measured at the SCR inlet, with and without addition of limestone to the fuel [1]. Laboratory experiments on the reaction between arsenic oxide and lime showed the highest reactivity at about 1000°F (600°C) [2]. Thus, if hydrated lime were injected upstream of the air preheater, it could react with gaseous arsenic oxide. However, injection of hydrated lime downstream of the air preheater would not result in reaction between vapor-phase arsenic and calcium, because arsenic does not typically exist in the

![Figure 9. Gas-phase arsenic at SCR inlet temperature in three bituminous-fired boilers, with and without limestone addition to the boiler [1].](image-url)
gas phase after the air preheater. Theoretically speaking, gaseous arsenic could react with sodium compounds at pre-air preheater temperatures in the flue gas, although this has not been documented as yet.

Selenium, like arsenic, vaporizes almost completely in the combustion zone, forming a stable gaseous oxide that can react with surfaces as the flue gas cools. Selenium oxide reacts with calcium and iron in the fly ash [3]. Selenium also reacts with sodium sorbents, as illustrated in Figure 10, in which experiments with sorbent injection in a quenched off-gas stream from an industrial glass furnace showed that hydrated lime was a more effective sorbent for selenium than sodium carbonate when injected at temperatures between 625°F and 735°F (330°C and 390°C) [4]. In contrast to arsenic, however, selenium forms a stable gaseous oxide down to temperatures as low as 140°F (60°C) [5]. Gaseous selenium has been shown to react with hydrated lime injected into downstream of the air preheater. These sorbents will reduce the gas-phase concentration of the metals and, in the case of selenium, shift selenium from the gas phase to the fly ash that is collected in the particulate control device.

**How Does DSI Affect Metals Leaching from Fly Ash?**

Dry sorbent injection may increase the concentration of mercury, arsenic and selenium in the fly ash collected by the plant’s particulate collection device. Fly ash may be sold, mixed with water and sent to settling pond, or sent to a landfill. In all these cases, the amount of metals leached from the fly ash is an important characteristic in determining the disposition of the material.

Without the addition of alkaline sorbents, bituminous fly ash has been shown to leach more As and Se than subbituminous ash. In subbituminous fly ash, little As is leached. The high calcium content of subbituminous fly ash plays a role in minimizing leaching of As and Se in subbituminous ash. When hydrated lime was added to the flue gas in a pilot-scale combustor burning bituminous coal [7], selenium concentration increased in the fly ash, relative to the baseline, and TCLP leaching tests showed that selenium was the only RCRA metal to substantially increase in the leachate in the fly ash sample containing hydrated lime.

Mixtures of bituminous fly ash and sodium- or calcium-based sorbents were exposed to simulated flue gas [8] at 399°F (204°C) and the mixtures were then leached using SPLP. Leaching of arsenic, selenium and chromium increased in the mixtures containing Na₂CO₃ more than in the mixtures containing Ca(OH)₂ (relative to baseline). None of the other RCRA metals, including mercury, showed evidence of increased leaching as a result of the presence of either sorbent.

Fly ash has been analyzed for leaching characteristics from plants burning bituminous and subbituminous coal in which trona was injected [9,10]. Trona injection resulted in significantly more leaching of As and Se, as well as Mo and V, relative to the baseline. Similar full-scale fly ash samples containing calcium-based sorbents have not been studied to date. However, laboratory and pilot-scale testing suggests that leaching of As and Se will not increase as much when calcium sorbents are used for DSI as compared to sodium sorbents.
Conclusion

Dry sorbent injection is a low-capital cost method for compliance with emission limits on acid gases and mercury from coal-fired boilers, with operation co-benefits such as eliminating corrosion issues and blue plume. Of the metals of interest in combustion systems, some mercury, arsenic and selenium are expected to be in the vapor-phase at temperatures downstream of the economizer. Mercury removal can be enhanced by removing SO$_3$ from the flue gas, which competes with mercury capture by carbon. Arsenic and selenium can be removed from the flue gas directly with sodium- or calcium-based DSI sorbents, depending on the injection location. Leaching of arsenic and selenium from the fly ash increases with the addition of DSI sorbents; addition of sodium-based sorbents results in much higher leaching of these metals compared to addition of calcium-based sorbents. The addition of DSI sorbents to fly ash has not shown any increase in the leaching of mercury from fly ash. When considering the application of DSI on a particular boiler, the fate of the fly ash must be given consideration.

References

Abstract
With the recent surge in Electrostatic Precipitator (ESP) installations and future predictions of continued growth, ESP technology has been and will continue to be utilized for many applications. Wet and dry ESP technologies are similar but many questions arise as to the applicability of each technology as well as the advantages and limitations of each technology.

Siemens Environmental Systems & Services provides both wet and dry ESP technology for the utility power, cement and refinery industries as well as other industrial applications. While wet and dry ESPs retain similar high voltage and collection systems and share similar physical characteristics, many differences exist, attributable mainly to the inherent design of the technology to address various size particles. Dry ESPs are used to capture coarse, filterable particulate matter (PM10) such as flyash. PM10 is defined by the U.S. Environmental Protection Agency (EPA) as particles smaller than 10 microns (a micron is one millionth of a meter). Wet ESPs capture sub-micron particulate matter, condensables and water mist commonly referred to as PM2.5 (defined by the EPA as particles less than 2.5 microns). Whereas dust or flyash characteristics play a large role in the sizing of dry ESPs, this is not the case with wet ESPs as they are not dependent upon particulate resistivity.

This article compares the two technologies and Siemens’ experience with the technologies. To gain a better understanding of each technology a discussion of particle size is first required.

1. Particle Size and Surface Area
As seen in Figure 11, there is a significant difference between a 1 micron particle and a 10 micron particle.

As expected, not only are smaller particles harder to capture because of their small size but there are significantly more particles to capture when dealing with fine particulate. The table in Figure 12 compares the relative number of particles that can fit within one cubic meter of gas. For the same cubic meter of gas there can be 1000 times more 1 micron particles than 10 micron particles with 10 times more total surface area!

To support the theoretical analysis in Figure 12 above, the charts in Figure 13 show the particle size distribution from a coal-fired utility wet scrubber on a mass basis and quantity basis (broken down by dry vs. wet for comparison). While the relative mass of “wet” particles is similar for particles sized 5 micron to 100 microns as for particles sized 0.1 to 1 micron, on a quantity basis the overwhelming number of particles are those less than 0.1 micron.

When condensable vapors cool they tend to condense on the smallest sub-micron particles because there are a greater number of small particles. The reason there has been...
increasingly more focus on capturing fine particles is that these size particles are more toxic than large particles and lodge deeper in the lungs therefore posing higher health risks. Particle toxicity increases as particle size decreases as shown in Figure 14.

2. Opacity
The most visible particles are approximately a half-micron in size due to their light extinction properties. The picture in Figure 15 shows a coal-fired power plant plume that has both a dry ESP and wet scrubber installed with high visible opacity.

Though both air pollution control devices capture coarse particulate neither is very efficient at capturing fine particulate. The visible plume seen is from light refracting off of particles 0.1 to 1 micron in size that have passed through the dry ESP and wet scrubber; with 0.5 micron particles being the most visible. The greatest contributor to this submicron particulate is sulfuric acid mist (H₂SO₄). As shown in Figure 16, opacity is directly proportional to concentration of sulfuric acid.
3. History
The first reported ESP in commercial service was a wet ESP installed in 1907 for acid mist control. The first dry ESPs followed in the 1910’s in the non-ferrous metals and cement industry. Dry ESPs in the coal-fired boiler industry went into service in 1923 at one of Detroit Edison’s power plants. While dry ESPs have been in use in many industries for decades as a primary particulate control device, wet ESPs have found their use primarily in the sulfuric acid industry as a piece of process equipment to collect sulfuric acid. Not until regulatory authorities established emission limits on fine particulate matter has there been a wider need for wet ESP emission technology.

4. Theory of Operation
Dry and wet ESPs are similar in their main purpose which is to collect non-gaseous particulate from a flue gas stream. Both technologies include a multi-stage process for removal of the particulate from the gas stream by creation of an electric field (refer to Figure 17). First, a high voltage corona discharge is emitted from the discharge electrodes, ionizing the flue gas molecules between the discharge and collecting electrodes. The particulate entering this electric field are then charged by the ionized flue gas molecules and naturally attracted to the collecting electrode of opposite polarity. And finally, the collected particulate is removed from the collecting electrode.

![Figure 17: ESP Collection Schematic](image)

All ESPs use this method of particulate charging and collection; the differences between dry and wet ESPs are in the process of removing the particulate from the electrodes. Dry ESPs allow the collected particulate to build-up in a layer on the collection surface, which is then removed via mechanical rapping or vibration. Many different rapping variations exist including tumbler hammer, gravity impact, vibrators, pneumatic and droprod rapping. The collected particulate falls into a collection hopper where it is removed from the dry ESP with an ash handling system. Similar rapping systems are used on the discharge electrodes to minimize potential build-up that could inhibit corona generation.

In a wet ESP, the collecting electrodes are cleaned via use of intermittent water sprays or an irrigation system preventing any build-up of particulate on the collecting electrode surface. If sprays are used, the affected electrical bus section must be de-energized to protect the transformer/rectifier sets whereas in an irrigation system the transformer/rectifiers may stay on as there is no interference with the electrical system. The water washes away the collected particulate on the collection surface. The difference in cleaning has a significant impact on function, location, operating temperature, materials of construction and performance.

5. Configuration
Dry ESP design configuration consists of a horizontal flow of flue gas between two vertical plates with discharge electrodes in the middle, commonly referred to as a “plate” ESP. Due to the large volume of gas and the heavy inlet loading of particulate that typically needs to be removed from a bottom hopper, the plate design has become the most common configuration.

Wet ESPs can come in a variety of configurations. They can be either plate or tubular; down-flow, up-flow or horizontal flow. Plate wet ESPs are very similar to dry ESPs with two vertical plates facing each other and discharge electrodes located between the plates. However, flue gas flow can be either horizontal or vertical.

Alternatively “tubular” wet ESPs (tubular collecting surfaces with electrodes in the middle) are always vertical but the flow can be either up-flow or down-flow. Additionally, tube configuration can be round, square or hexagonal. Tubular designs, with all four sides containing the flue gas offer higher efficiency per square foot of gas treated and smaller size. However, when multiple electrical bus sections are required to achieve high removal, cleaning of the collecting surface is more of a challenge in a tubular design to minimize impact on the lower bus sections with inter-stage drains. Consideration of available real estate, flue gas volume, inlet loading, required removal, sectionalization, water usage, cost and maintenance access are all factors that come into play when selecting the most appropriate wet ESP configuration.
6. Process Comparison

Dry and wet ESPs are utilized on coal-fired boilers as well as many similar industrial applications. The differences between ESPs become evident when looking at where the ESPs are installed in the process. Dry ESPs are typically the first control device to remove the heaviest load of particulate while wet ESPs are the last control device prior to the stack and act as a final polishing device.

Dry ESPs are most often installed in high ash and high-temperature environments. The flue gas at this stage is most often above the adiabatic saturation temperature and the acid dew point temperature. In some older utility installations, dry ESPs were installed upstream of the air heater in a “hot-side” arrangement (temperatures of 750°F / 400°C); however this arrangement has fallen out of favor due to detrimental issues such as performance degradation over time and structural problems in many installations. Modern day utility dry ESPs are installed on the “cold-side” of the air heater at temperatures of approximately 250-350°F (120-175°C) as shown in Figure 19. Some industrial applications such as rock product kilns and catalytic cracking units still successfully use dry ESPs on temperatures of 600-800°F (315-425°C).

Wet ESPs are installed in saturated flue gas streams with considerably less particulate loading than dry ESPs. Typically, a wet ESP follows a scrubber where the flue gas is saturated to the moisture dew point (typically 130°F / 55°C) and the wet ESP is used to collect PM$_{2.5}$, H$_2$SO$_4$ and liquid droplets that remain in the flue gas after the scrubber.

In a typical utility boiler, sulfur trioxide exists in the gaseous form until the air heater where the decrease in temperature converts SO$_3$ to H$_2$SO$_4$ (Figure 20). While the sulfuric acid remains in vapor form through the dry ESP (approx 300°F), in the saturated flue gas stream, all sulfuric acid previously existing as a vapor condenses into an aerosol (Figure 21).
The particulate loading to a wet ESP is typically much less than a dry ESP with PM of less than 2.5 microns and \( \text{H}_2\text{SO}_4 \) droplets of 0.1 – 0.3 microns. This creates an ultra-fine aerosol droplet and as the droplet sizes get smaller, the number of droplets generated for a given mass concentration increases dramatically as previously shown in Figures 12&13.

**Particulate Resistivity**

One of the differences between dry and wet ESPs is how the particulate resistivity affects the ESPs. In a wet ESP, as particulate is minimal and collecting electrodes are continually cleaned, particulate is immediately captured and washed from the collecting electrodes. With no particulate buildup on the collecting electrodes, potential problems with back corona are eliminated. Particulate resistivity is temperature dependent and as the temperature decreases, so does the resistivity. This makes the particulate easier to collect than with a dry ESP without the problems of particulate re-entrainment as the particulate is immediately removed when it is collected. In other words, resistivity of the particulate does not play a significant factor into the sizing of the wet ESP. Because of this, wet ESPs can be sized to higher precipitator velocities and lower specific collecting areas (SCA) than dry ESPs.

A high volume of sub-micron particulate entering the wet ESP can lead to corona or current suppression. Current suppression reduces wet ESP efficiency and can occur at particulate loadings of just 0.1 gr/acf (0.2 g/m³). Most suppliers of wet ESPs utilize a high intensity discharge electrode to combat current suppression.

Resistivity of the particulate plays a significant role in the sizing and performance of dry ESPs. Resistivity can be broadly divided into three grades; low (<10⁹ ohm-cm), moderate (10⁹ –10¹¹ ohm-cm) and high (>10¹¹ ohm-cm). Ideally dry ESPs prefer and operate best with particulate in the moderate range. This allows the ash layer to form on the plates and mostly shear off into the hoppers when rapped. High resistivity particulate leads to back corona where the flow of positive ions from the ash layer on the collecting plate effectively hampers the precipitator process. Low resistivity particulate, though less harmful than high resistivity, results in the ash layer quickly losing its charge and having a higher propensity to re-entrain into the gas stream during rapping.

**Water Usage**

Another major difference between dry and wet ESPs is the collection and disposal of particulate. Collected flyash from dry ESPs is collected as solid waste and is typically able to be land-filled, reused in the process or sold. As wet ESPs use wash water to collect the particulate on the collecting electrodes, the water demands and effluent needs to be addressed. The wet ESP can use once-through water or a recycle system with bleed incorporated. With a scrubber, the wet ESP effluent can be pumped back into the scrubber for mist eliminator wash water and with first use of the water meant for the wet scrubber, there is no additional water burden from the wet ESP. If no scrubber is present, water treatment facilities or other modifications may be required to handle the effluent.

**Figure 22: Resistivity Curves for Low, Moderate and High Resistive Particulate**

7. **Installations**

Dry ESPs have been installed on just about every utility and industrial process that requires removing particulate from a gas stream.

Because of the conditions that they operate under (high temperature, typically above acid dew point), dry ESPs can be fabricated from mild carbon steel making them relatively inexpensive. Internal collecting electrodes are typically gauge thickness carbon steel, and recent designs utilize unbreakable, rigid frame or rigid discharge electrodes.
Wet ESP technology has become a standard component in the sulfuric acid industry to capture sub-micron H$_2$SO$_4$ aerosol. Wet ESPs have been employed in many different industrial applications for plume reduction associated with PM$_{2.5}$ and H$_2$SO$_4$ mist, as well as abatement of toxic metals.

Due to the saturated and high-corrosive environment in which they operate, wet ESPs are typically constructed of corrosion resistant materials such as alloy, FRP or plastics. The material chosen will have to withstand the concentration of acid gases and sulfur oxides in the flue gas stream as well as temperature surges. While physically smaller than a dry ESP, the materials of construction make the wet ESP more expensive.

8. Mercury Control

In recent years in the U.S., mercury emissions regulations have gone into effect throughout utility and industrial sectors. In flue gas, mercury exists as either a vapor or particulate. Vapor phase mercury is further broken down into elemental mercury (Hg$^0$) and oxidized mercury (Hg$^{2+}$), which is water soluble. Particulate mercury (Hg$^+$) exists as a solid. In dry ESPs, particulate mercury may be captured but any elemental or oxidized mercury will pass through. However, vapor phase mercury can be captured in a dry ESP with the use of an activated carbon injection system. These systems inject activated carbon into the ductwork upstream of the dry ESP which allows the activated carbon to adsorb the vapor phase mercury into its pores. These systems can achieve mercury removal efficiencies of 90%+.

There has been very limited testing of mercury removal through a wet ESP. However, the testing that has been performed has shown that a wet ESP will capture any particulate bound Hg as PM$_{2.5}$, with high efficiency as well as some oxidized mercury. Interestingly, a small fraction of elemental mercury was found to oxidize within the wet ESP, which most likely occurs from the reaction with ozone generated within the wet ESP. Therefore, a wet ESP can enhance mercury capture as a secondary free co-benefit.

9. Performance

Both wet and dry ESPs are capable of high efficiency removal. Dry ESPs have consistently demonstrated 99%+ removal efficiencies for filterable PM$_{10}$ and certainly in the 90+% range for filterable PM$_{2.5}$. However, PM$_{2.5}$ generated also contains condensables that the dry ESP cannot remove as they exist as vapor at the high temperatures that dry ESPs operate within.

Wet ESPs have demonstrated 99%+ removal of total PM$_{2.5}$ (filterable and condensable), droplets and H$_2$SO$_4$ as well as having some mercury removal as indicated in the previous section. Current-day state of the art power plants have recognized the advantages of installing both dry and wet ESPs in the air quality control system where there is a wet scrubber installed.

Siemens has provided dry ESPs and wet ESPs in series on three (3) large utility coal-fired boilers and one (1) coal-fired utility with a fabric filter and wet ESP in series. Performance results are provided below in Figure 24. Site “A” air pollution control consists of hydrated lime injection, activated carbon injection, fabric filter, wet scrubber, wet ESP. Site “B” APC consists of dry ESP, hydrated lime injection, activated carbon injection, fabric filter, wet scrubber, wet ESP. Sites “C” and “D” APC consist of hydrated lime injection, dry ESP, wet scrubber, wet ESP.

<table>
<thead>
<tr>
<th></th>
<th>Site A</th>
<th>Site B</th>
<th>Site C</th>
<th>Site D</th>
</tr>
</thead>
<tbody>
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<td>FPM*</td>
<td>0.0019</td>
<td>0.0007</td>
<td>0.007</td>
<td>0.006</td>
</tr>
<tr>
<td>TPM**</td>
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<td>0.005</td>
<td>0.020</td>
<td>0.011</td>
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<tr>
<td>H$_2$SO$_4$</td>
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<td>0.0004</td>
<td>0.0001</td>
<td>0.0033</td>
</tr>
<tr>
<td>Hg</td>
<td>6.4E-7</td>
<td>4.9E-7</td>
<td>6.7E-7</td>
<td>3.9E-7</td>
</tr>
</tbody>
</table>

*Filterable particulate  
**Total particulate (filterable and condensable)

Figure 24: Stack Emissions Results in lb/MBtu

As can be seen in the table above, the wet ESP acts as a final polishing device providing near-zero emissions. Also note that with the future possibilities of carbon dioxide regulation, sites with a wet ESP installed are “CO$_2$ ready” as CO$_2$ scrubbing requires very low inlet pollutants of particulate matter, sulfuric acid SO$_2$, etc.

Figure 23: FGD/Wet ESP Hg Removal

Figure 23: FGD/Wet ESP Hg Removal
10. Summary

Dry and wet ESPs can be utilized effectively for high efficiency removal. In order to maximize their effectiveness, it is important to understand the advantages and limitations of the technologies. The Figure 25 provides a summary of the discussion points presented above.

References


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James “Buzz” Reynolds is Vice President of Wet ESP technology at Siemens Energy Inc.’s Environmental Systems & Services Division for the past 8 years and is based in Pittsburgh, Pa. He has authored many papers, presented at numerous conferences and holds several patents on Wet ESP Technology. Prior to Siemens he was President & CEO of Croll-Reynolds Clean Air Technologies for 10 years.

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**Figure 25: Summary of the discussion points**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Dry ESP</th>
<th>Wet ESP</th>
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<td>Purpose</td>
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<td>Polishing Device</td>
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<td>Last APC Device</td>
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<td>Configuration</td>
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<td>Vertical Tubular or Horizontal / Vertical Plate</td>
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<td>High PM Loading</td>
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<td>No</td>
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<td>FPM₁₀ Removal</td>
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<td>H₂SO₄ Removal</td>
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<td>&lt; 2 in.w.c. (0.5 kPa)</td>
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<td>Re-Entrainment</td>
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<td>Carbon Steel</td>
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<tr>
<td>Cost</td>
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</table>

*Unless treated with sorbent injection
The Environmental Protection Agency (EPA) has been working for many years to develop and execute stricter standards for energy generating units’ (EGUs) pollution mitigation. Standards have finally been established and now EGUs need to find solutions that meet the mitigation standards, as well as make sense for cost effective and efficient running of their plants. Dry sorbent injection (DSI) systems are showing proven ability to meet the new EPA standards and should be considered as a means to come into compliance.

**A Summary of the Standards**

The Clean Air Act, greatly expanded in the early 1990s, gave the EPA greater authority to enact and implement pollution mitigation standards throughout the United States. The EPA works closely with states, Native American tribes, local governments, and businesses to develop standards that are achievable and can be maintained over the long run.

These standards, once referred to as the application of maximum achievable control technology (MACT), are now finalized as Mercury and Air Toxics Standards (MATS). The final rule was published on December 21, 2011. EGUs have three years to comply with the final standards, with a one year extension possible for final installation of the new technology. MATS applies to EGUs larger than 25 megawatts (MW) that burn coal or oil for the purpose of generating electricity for sale and distribution through the national electric grid to the public. It establishes numerical emission limits for mercury, particulate matter (a surrogate for toxic non-mercury metals), and hydrochloric acid (HCl) (a surrogate for all toxic acid gases). It also creates alternative numeric emission standards, including SO₂ as an alternate to HCl.

The focus of this article is HCl and SO₂. The specific limit for HCl is 0.0020 lbs/MMBtu. For SO₂, the limit is 0.20 lbs/MMBtu. Dry Sorbent Injection (DSI) has been proven to meet these standards in real world tests and permanent installations. Before we examine those test results, we’ll discuss the basics of DSI.

**Basics of Dry Sorbent Injection**

DSI uses a pneumatic conveying system to inject dry sorbent materials into system ductwork in a controlled manner. The pollutants in the plant emissions interact with the sorbent material and become inert or non-polluting. Sorbents include hydrated lime, powdered activated carbon, sodium bicarbonate (SBC) and trona. The main pollutants mitigated with DSI include SO₂, SO₃, Hg, and HCl emissions.

DSI systems are designed to meet each of the power plants specific needs. The precise injection rate needed can be estimated based on unit specification, coal properties, duct work, and the desired level of removal, in conjunction with field data. Silos are sized to that injection rate and the number of days of storage a customer needs. Mills can be added, to refine the sorbent material to the most effective size to capture the emissions the plant is mitigating. Milling of the sorbent can greatly increase the removal efficiency of the pollution. And that means less sorbent is needed, decreasing costs. For example, if 10,000 lbs./hour of a rough sorbent were typi-
Why use DSI for HCl mitigation?
There are a number of reasons an EGU would want to consider utilizing DSI to meet MATS standards. One of the most attractive reasons is that DSI can be a low capital cost solution. It allows EGUs to supplement their current mitigation systems affordably – or to use DSI as an interim solution until larger, more costly solutions can be evaluated and installed, if needed.

Additionally, DSI systems can be quickly installed and started up. Often, the time frame from purchase order to commissioning is less than one year. The time frame variability is based largely on the market and amount of projects being executed by utilities. A relatively quick project execution for DSI systems can allow EGUs to quickly meet the EPA standards, even while they are seeking funding or the necessity of some additional type of solution.

DSI has been demonstrated to be effective for HCl removal. As we will see in the example results that follow, Nol-Tec Systems has proven results from real world testing of our own DSI systems.

Good candidates for DSI mitigation
There are a number of contexts that must be considered, when determining whether DSI will be effective in a power plant’s mitigation process. An EGU with an existing SO₂ wet scrubber may find that the scrubber alone is insufficient to meet the 99+% HCl removal requirement. DSI could supplement the scrubber and bring the plant into compliance.

In coal-burning units, the sulfur content of the coal and the boiler size must be considered. The amount of sulfur in the coal sulfur impacts the SO₂ levels. And SO₂ levels impact HCl removal with sodium sorbents. The combination of sulfur content in the coal and the boiler size (amount of coal being burned) sets the amount of SO₂ in the flue gas. These parameters must be considered when looking at DSI for HCl. In the case of hydrated lime, only a small amount of reagent reacts with SO₂ so the sulfur content is less of an issue.

Residence time of the emissions within the system must be considered. The longer the residence time, the more likely the air pollutants will react with the sorbent. Residence time is dependent on flow rate of the emissions and the duct configuration of the system.

The particulate control device (PCD) may also impact the decision to use DSI. A pulse jet fabric filter (PJFF) PCD allows for high residence time because of the filter cake of sorbent on the bags. This in turn increases the removal efficiency of the air pollutant. This allows for lesser amounts of sorbent to be used to achieve the desired removal of pollutant. This factor may help promote DSI technology.

Lastly, each EGU is different in how it operates in accordance with “the grid”. Some EGUs operate in a base load manner. These units desire low operating costs so they may be less apt to choose DSI, because of the ongoing cost of the sorbent. If an EGU operates in a peak load fashion, then it suffices to use a low capital cost solution and deal with the sorbent costs. Simply turn on the DSI when HCl levels rise to bring them back into compliance.

With these considerations in mind, there are a number of good candidates for DSI pollutant mitigation. Smaller, coal-fired units, or any unit that uses low sulfur coal, have achieved high success rates with DSI mitigation for HCl and SO₂. We have found that all units are good candidates for SO₂ mitigation.
Testing DSI in Your System
Dry sorbent injection is an excellent solution for many applications. It will be used by many EGUs to achieve HCl emission limits. However, the best way to determine whether it is a good solution for your plant is to test a DSI system in your plant location, mitigating your actual emissions.

It is important to work with a DSI supplier who can provide portable test systems that can be incorporated into your own EGU system. Such on-site testing can give you confidence that DSI will ensure your system will meet EPA standards in a timely and cost-effective manner.

An Example of Test Results
Nol-Tec Systems has performed a number of on-site tests for a variety of EGUs. In this example, we will examine a bituminous coal-fired unit with a boiler that is smaller than 150 MW, utilizing an economizer, air pre-heater, and electrostatic precipitator (ESP). The sulfur content in the coal is about 1.2%. Residence time of the emissions in the system is under one second, which is less than ideal.

This unit is a difficult application, for several reasons. The sulfur levels in the bituminous coal impact the mitigation. The low residence time and low mix rate the system has also present challenges. And the PCD is an ESP which does not allow further mitigation, unlike the PJFF which utilizes a filter cake for further mitigation after it reaches the PCD.

The primary objective of this test was to determine whether the new MATS HCl limit could be achieved on this boiler. With that objective and the system’s challenges in mind, Nol-Tec engineers designed a test system to meet that goal, using CFD modeling services. They determined the best location for the injections of sorbent to be made (at the economizer outlet at 600-700°F). Sorbent amounts were calculated and two types were tested. SBC and trona injection were each done for two days out of each week.

Test Results
Trona and SBC proved to mitigate HCl to MATS limit of 0.002 lbs/mmBtu. This chart, showing percent of HCl removed in relation to the amount of sorbent injection injected, is “Total Nominal Stoichiometric Ratio (NSR)” meaning both SO₂ and HCl are taken into account when calculating the NSR value. On the y-axis, we have the percent of HCl removed (please note that the y-axis starts at 86%). The level we are looking for is greater than 98%, which is shown with the solid red line. At medium load, we achieved the 98% removal more consistently, using lower injection rates. At higher load, it was more difficult. Though there may be several reasons, one may include residence time as the main contributor.

![Figure 27: HCl Removal with Trona and SBC (total NSR)](image-url)
DSI Technology Works

As we have seen with the results above, and with additional testing that Nol-Tec has done, DSI technology can indeed work to bring HCl levels into MATS compliance. It is important to note that many issues factor into a decision about using DSI for mitigation. It is important to select your mitigation partner carefully, to ensure they have the expertise or equipment to fully explore and test all the variables that can impact your decision. With due consideration to all factors, DSI technology can bring EGUs into compliance with MATS regulations in an efficient and cost effective manner.

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