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Consulting to the Air Pollution Control Industry

Opportunities for Reducing Acid Gas Emissions on Coal-Fired Power Plants

Contract Report C-21-CAELP-3

to:

Center for Applied Environmental Law and Policy

April 5, 2022

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Executive Summary

This study examined acid gas emission control methods and acid gas emission rates for the fleet of 543 coal fired units operating in 2019, with the objective of trying to identify what opportunities may exist for further reduction of acid gas emissions in the coal fleet. The study examined improvements in performance, improvements in technology, or deployment or development of new technologies in the period between 2011 and 2019. 2011 was the year that the Mercury and Air Toxics Standards (MATS) rule was developed. 2019 reflects a time after MATS was deployed and where data was collected on HCl emissions and unit characteristics in a database on NRDC's website.[1] Other sources of data used in this effort include US EPA's Air Markets Program Data (AMPD) and US EPA's National Electric Energy Database System (NEEDS). For those units where HCl data was available, it was organized into deciles to examine important trends. With this data, this study examined the improvements in the performance of acid gas control techniques over the period between 2011 and 2019.[2] It examined what the costs of these improvements are, and how widely these improvements could be deployed. It also examined what HCl emissions levels might be possible and the costs associated with achieving those emission levels.

This study finds that there are opportunities to improve acid gas emissions further, in part due to improvements in emission control technology (i.e. lower potential emission levels for any given cost), reduction in the cost of controls, and availability of ways to improve performance of existing controls. These are summarized below according to the acid gas control technology.

Methods to reduce acid gas emissions

Wet FGD – In 2019 about 160 GW of capacity (62% of coal capacity) and 300 coal units (56% of coal units) were equipped with wet flue gas desulfurization (FGD). 29 of the the 300 coal units equipped with wet FGD in 2019 systems were units with new wet FGD systems installed since 2011. Some of the new FGD systems since 2011 were installed on new generation and others were installed primarily to comply with Regional Haze plans, the Cross-State Air Pollution Rule (CSAPR), or other requirements beyond MATS. Most of the wet FGD equipped units use bituminous coal. For those wet FGD equipped units that were in operation in 2011, there have been significant improvements in emissions, with roughly 50% having an emission rate improvement of 0.03 lb/MMBtu of SO_2 or more between 2011 and 2019. About 32% of the units equipped with wet FGD in 2011 did not have an improvement in SO_2 emission rate. Therefore, a

[1] https://www.nrdc.org/resources/coal-fired-power-plant-hazardous-air-pollution-emissions-and-pollution-control-data. Because most units demonstrate compliance through other means, HCl emission rates were available for 89 units that includes both scrubbed and unscrubbed units.

[2] Bearing in mind that the facilities that did not provide HCl data were scrubbed units with sufficiently low SO2 emissions to demonstrate compliance, it is likely that the available HCl data is not reflective of the best controlled units.

significant portion of the wet-FGD equipped coal fleet deployed upgrades in wet FGD technology or improved the performance of their existing controls. New FGD systems placed in service after 2011 demonstrated significantly lower 2019 SO2 emissions than the 2019 SO2 emissions for systems that had been installed in 2011. Estimates of the cost of control improvements were made based upon the reported scope of some improvement projects,[3] which largely used improvements in absorber flow balancing and atomization methods, which was the most commonly used approach to improving wet FGD. Costs to upgrade wet FGDs were estimated to be in the range of $38/kW for a 500 MW unit. This cost estimate is significantly below what had been assumed by EPA in development of the MATS rule.

Dry FGD – In 2019 about 40 GW of capacity (15% of coal capacity) and 88 units (16% of coal units) were equipped with dry FGD. 32 of these systems were new dry FGD systems installed since 2011. Some of the new FGD systems since 2011 were installed on new generation and others were installed primarily to comply with Regional Haze plans, CSAPR, or other requirements beyond MATS. Most of the dry FGD equipped units use subbituminous coal. For those dry FGD equipped units that were in operation in 2011, there have been significant improvements in emissions, with roughly 35% experiencing an SO_2 emission rate improvement of 0.03 lb/MMBtu or more. About 33% of the units equipped with dry FGD in 2011 did not have an improvement in SO_2 emission rate. Therefore, it appears that a significant portion of the dry FGD equipped coal fleet deployed upgrades in dry FGD technology or improved the performance of their existing controls. New FGD systems placed in service after 2011 had lower 2019 SO_2 emissions than the 2019 SO_2 emissions for systems that had been installed in 2011, but not to the same degree of improvement over existing systems as observed with wet FGD. Estimates of the cost of control improvements were made based upon the reported scope of some improvement projects, which largely used improvements in atomization or fabric filters. Costs were estimated to be in the range of $17/kW for atomization improvements and about $5/kW for fabric media improvements on a 500 MW unit. This cost estimate is significantly below what had been assumed by EPA in development of the MATS rule.

DSI – In 2019 about 30 GW of capacity (11% of coal capacity) and 66 units (12% of coal units) was equipped with dry sorbent injection (DSI). DSI usage for SO_2 control in 2011 was very limited. DSI is a lower cost option than a wet or dry FGD system for improvement of acid gas emissions for units with no other form of acid gas controls.[4] The degree of HCl control will be dependent upon treatment rate and the type of particulate matter (PM) controls. HCl capture will depend in part on the sorbent used and the PM capture device that is used. HCl is captured more effectively with DSI than SO_2. However, about 70% or more HCl capture is expected with an

[3] Six projects and seven FGD systems, based upon published technical papers. Notably, companies do not routinely report these upgrade projects in the same manner that they report new FGD installations. Therefore, it is necessary to rely upon those projects where technical papers were published.

[4] DSI can also be used in combination with activated carbon injection (ACI) for Hg control, although one may impact the other to a degree.

electrostatic precipitator (ESP) and over 90% capture is expected with a fabric filter (also known as a baghouse, or "BH"). DSI equipped units with fabric filters averaged an HCl emission rate of 0.00012 lb/MMBtu and units with DSI and ESPs averaged 0.00077 lb/MMBtu. Capital cost will be impacted by treatment rate, as storage and transport equipment are a significant portion of the cost, but may be in the range of $40/kW. Since 2011, there have been improvements in both reagents and improvements in the injection systems. The impacts have been to improve capture with lower cost reagents. Upgrades of reagent injection systems to existing DSI systems should enhance capture by about 25% (or, alternatively, reduce injection rates to achieve the preexisting capture percentage) at a capital cost of under $10/kW.

PM controls only – PM controls include electrostatic precipitators, baghouses, and combinations of the two.[5] Units with only PM controls may improve their acid gas emissions through addition of an acid gas control technology, such as FGD or DSI. They may also improve performance by adding a baghouse downstream of the ESP, which appears to provide some benefit to HCl control, but will provide even more benefit if combined with a DSI system. A fabric filter installation downstream of the existing ESP costs in the range of $150-$200/kW.

Trends in HCl emissions

Examination of HCl emission trends showed that the best controlled units were likely to be scrubbed (i.e., have an FGD system) or have combination ESP and fabric filter control systems with DSI. There was only one dry FGD equipped unit among the 89 units where HCl emission rate data was available, but it was among the best controlled units. Analysis of wet FGD equipped units showed a significant relationship between SO_2 emission rate and HCl emission rate, confirming that units with lower SO_2 emission rates are generally expected to have lower HCl emission rates.

The data suggests that wet FGD equipped units achieving an SO_2 emissions rate of 0.20 lb/MMBtu have lower HClemissions rates than is required, meaning lower HCl rates are possible. In other words, the surrogate SO_2 limit corresponds to a lower HCl emission rate than 0.002 lb/MMBtu. For the 14 wet FGD equipped units that provided HCl data and had SO_2 emissions at or below 0.20 lb/MMBtu, the highest HCl emission rate was 0.000737 lb/MMBtu.

DSI equipped units with a fabric filter demonstrated very low HCl emissions, at approximately the same level as the unit with dry FGD and a fabric filter. DSI equipped units with ESPs, not unexpectedly, had significantly higher HCl emissions than those with fabric filters. Lower SO_2 emission rates tended to correspond with lower HCl emissions. This was an impact of the PM control device and likely the coal type used.

[5] Consistent with industry practice, in this report the terms "baghouse" and "fabric filter" are used interchangeably. Combinations of an ESP and fabric filter (or baghouse) are often called a "compact hybrid particle collector," or "COHPAC." The use of a wet scrubber without either an ESP or baghouse is extremely rare – only one unit in the fleet.

For units reporting no acid gas controls, there was significant scatter when HCl emissions were compared to SO_2 emissions, except for units with both an ESP and a baghouse. For units with both an ESP and a baghouse, HCl emissions were consistently fairly low, resulting in a lower average HCl emission rate than for units with only an ESP or a baghouse.

Opportunities to improve acid gas control performance and associated costs

There are opportunities to reduce acid gas emissions further based on developments in the industry. These have been estimated to be:

Estimated impact of reduction in acid gas emission rate standard[6]

HCl Limit (lb/MMBTU) *(Current HCl standard is 0.002 lb/MMBTU or 0.20 lb/MMBtu SO_2 (as a surrogate for regulated acid gases) for units with FGD)*	**Control improvements likely to result**	**Costs for fleet as a whole** *(Preliminary estimates)*
0.001 lb/MMBtu HCl	• Some units with no acid gases controls install DSI	• ~$60 million annualized capital cost for units with no acid gas controls
	• Some ESP units upgrade DSI	• Roughly $21 million annualized capital cost for units with DSI
	• Few wet FGD units are impacted	• About $19 million in annualized capital cost for units with wet FGD
0.0006 lb/MMBtu HCl	• Most units with no acid gas controls install DSI	• About $120 million in annualized capital cost for units with no acid gas controls
	• Units with DSI and ESPs upgrade DSI system or add BH • Little or no impact for units with DSI and baghouses	• Assuming 30% of ESP equipped units install baghouse and 30% of ESP equipped units install DSI improvements, total cost is $118 million annualized capital
	• About 15% of wet FGD units and 30% of dry FGD units impacted, although dry FGD units likely comply on basis of HCl emission	• ~$42 million annualized capital cost for scrubber improvements
0.0001lb/MMBtu HCl	• Units with no acid gas controls install baghouses and DSI	• ~$494 million annualized capital cost for DSI and baghouses
	• Units with DSI and ESP install baghouse • Units with DSI and baghouse may need to upgrade DSI	• ~$382 million annualized capital cost for DSI improvements for baghouse equipped units and baghouses for ESP equipped units
	• Most scrubbed units impacted. Improvements or DSI on 75% of wet FGD capacity and improvements on 25% of dry FGD capacity	• ~$475 million annualized capital cost for scrubber improvements

[6] These cost estimates do not take into account all retirements that have occured since 2021, and therefore likely overstate costs.

Analysis Results

This study examined the results of implementing the 2012 MATS rule, and improvements in techniques for acid gas control since 2012, to determine what additional acid gas reductions are achievable. The study elements included assessments of:

Methods to reduce acid gas emissions, especially HCl, from the exhaust gases of coal-fired power plants. This includes methods that capture acid gases, such as wet and dry FGD and DSI. The installed base of acid gas controls for coal fired power plants was examined. For scrubbed units (i.e., units that had either wet or dry FGD), trends in emissions of SO_2 between 2011 and 2019 were examined to see to what degree emission rates improved on existing facilities during this period and compared to emissions of facilities with FGD systems that were placed in service over this period. It also examined what improvements were developed and potentially deployed during that period to permit greater control of acid gas emissions through improvements to the existing systems.

Trends in HCl emissions were examined to see what levels of control are possible for HCl using different emission control technologies. Because the majority of facilities with scrubbed units demonstrate compliance through maintaining SO_2 emissions below 0.20 lb/MMBtu, there is a limited amount of data on measured HCl emissions, but this includes a significant number of units with wet FGD, DSI and those without any SO_2 controls. This data on 89 units was examined to see what trends existed with regard to HCl emissions and control technologies, coal types, PM control and SO_2 emission rates.

Opportunities to improve acid gas control performance and associated costs were examined to estimate the approximate costs to the coal fleet of reductions in the acid gas emission rate requirement.

I. Methods for reduction of acid gas emissions

Methods for reducing acid gas emissions from coal-fired power plants include changing fuels or blending fuels, as well as adding control technology to remove acid gases from power plant exhaust gases and monitoring acid gas emissions to ensure that controls are functioning properly. This study will focus on the control technologies that are available for capturing acid gas emissions.

Acid gases include emissions of sulfur dioxide and of HCl, HF and other strong acids that may result from halogens in the coal when it is combusted. MATS set an emission limit of 0.0020 lb of HCl per million Btu of heat input. With the exception of low mass emitters, this emission standard could be met in a number of ways:

- Quarterly stack testing of HCl may be used to demonstrate compliance
- Use of an HCl continuous emission monitoring system[7]
- For units with wet or dry FGD systems, maintaining an SO_2 emission rate below 0.20 lb/million Btu. This is because HCl is removed more efficiently by FGD systems than SO_2, and at these emission levels it is presumed that HCl emissions are below the standard.

This report utilized an emissions database available from the NRDC website[8] that compiled the HCl emissions data reported for each unit in 2019. In addition to this database, ATP used 2019 Air Markets Program Data (AMPD) directly downloaded from US EPA's website for some of the analysis as well as US EPA's National Electric Energy Data System (NEEDS v6). NEEDS v6 from 2019 was used to assure temporal consistency with other data that was used in this study.

A. METHODS FOR CAPTURING ACID GASES

There are three principal means for capturing acid gases from the exhaust gases of coal-fired power plants: wet FGD systems, dry FGD systems, and dry sorbent injection (DSI) systems. Average SO_2 emission rates for 2019 are shown in Figure 1. As shown, the average emission rate for wet FGD is somewhat lower than for dry FGD. Notably, most units that burn high sulfur coal utilize wet FGD because a lower cost reagent – limestone – can be used. Although both wet and dry FGD have potentially high capture rates, wet FGD is capable of slightly higher SO_2 capture

[7] Increased HCl data availability through more widespread use of HCl CEMS would enable operators to monitor and improve operation and acid gas capture, and likely further reduce acid gas emissions from what is already achieved.

[8] https://www.nrdc.org/resources/coal-fired-power-plant-hazardous-air-pollution-emissions-and-pollution-control-data, Importantly, this database was additionally checked for consistency with some of the other reported data, such as that from the AMPD. Because this database was compiled from many other sources of data, there were a small number of duplicates that were found that were resolved. Also, in a small number of cases where the database indicated no SO_2 controls on the units, the reported 2019 SO_2 emission rate appeared too low. Comparison against 2019 AMPD data showed that these units actually did have emissions controls. Therefore, all of the analysis in this report that used this database incorporates these corrections.

efficiency, but this does not necessarily mean higher HCl capture efficiencies. DSI, on average, controls to about 0.25 lb/MMBtu, but as will be seen later, there is a range of control levels.

Wet FGD is by far the most commonly used SO_2 control technology, whether measured by number of units or by capacity installed (Figure 2). There are still a significant number (and capacity) of coal units that do not have any controls for acid gases. Figure 3 shows the PM control methods that are deployed. COHPAC are those cases where an ESP and baghouse are used in combination with the baghouse following the ESP. The ESP and baghouse totals shown include COHPAC installations. In this case, the baghouse follows an ESP, with the ESP capturing most of the PM and the baghouse capturing the remaining PM plus any flue gas treatment sorbents (such as activated carbon, trona or lime) that may be introduced downstream of the ESP. The latter configuration, in which treatment sorbents are added between the ESP and the baghouse, is also known as a "toxic emissions control device," or "TOXECON."

Figure 1. Average 2019 SO_2 Emission Rate for MATS affected coal-fired utility boilers

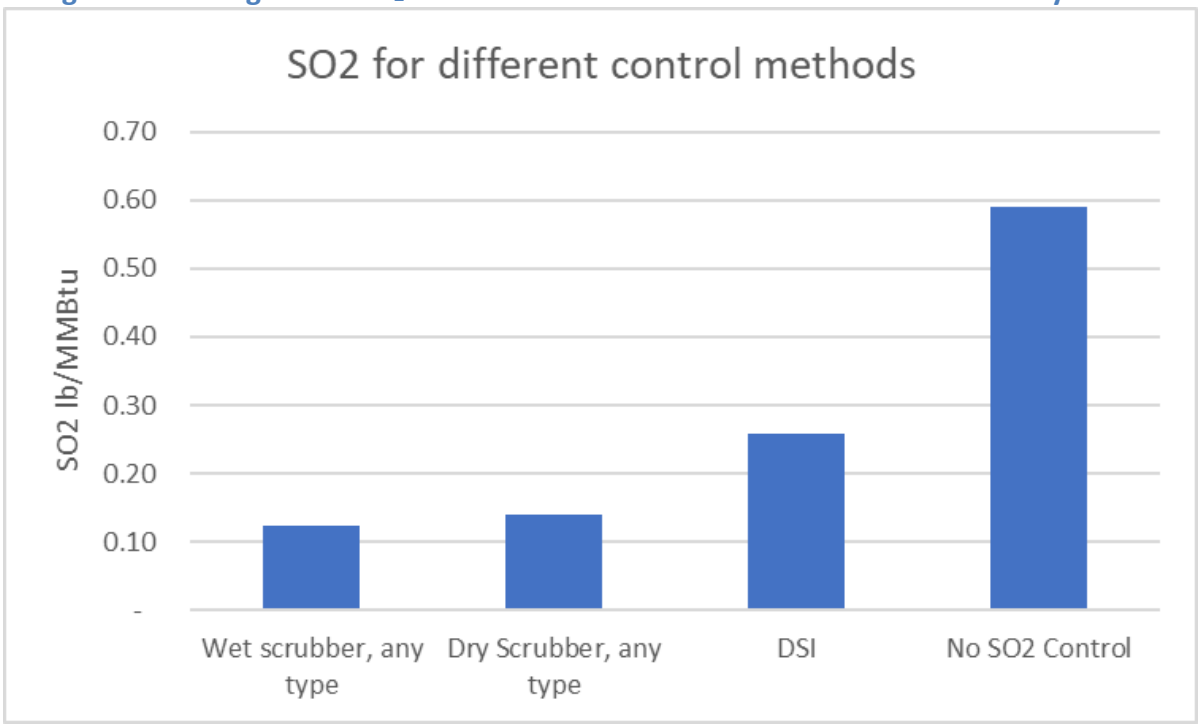


Figure 2. SO2 control technology in 2019

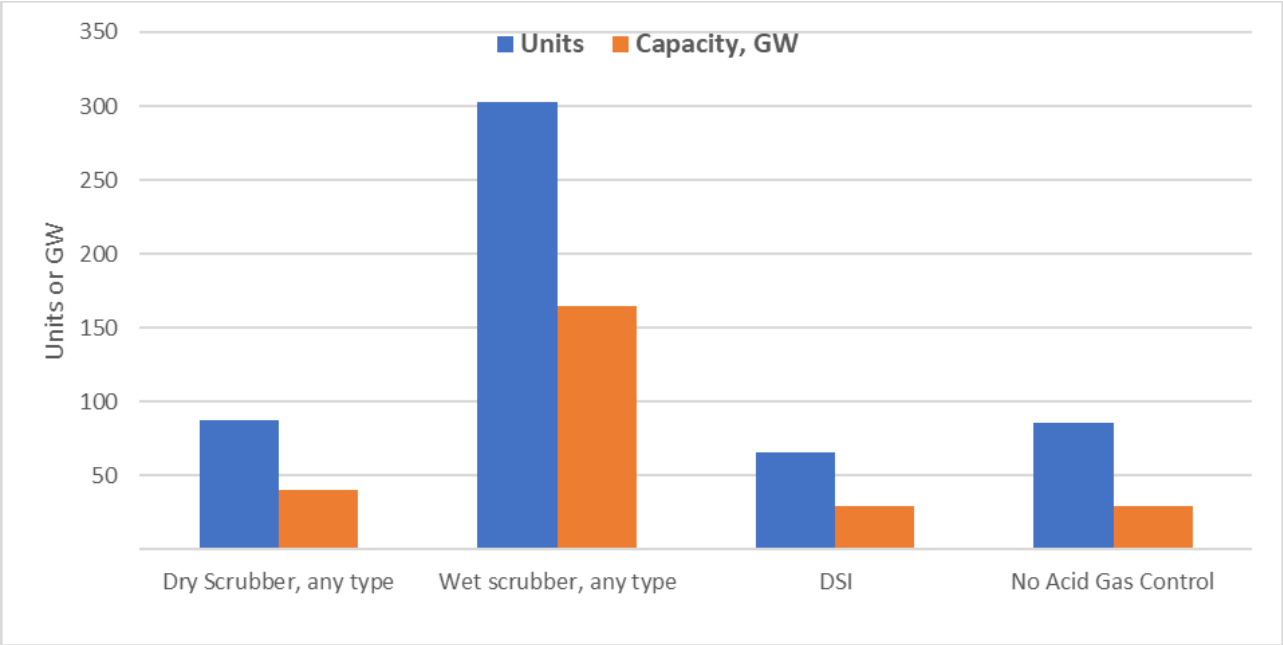
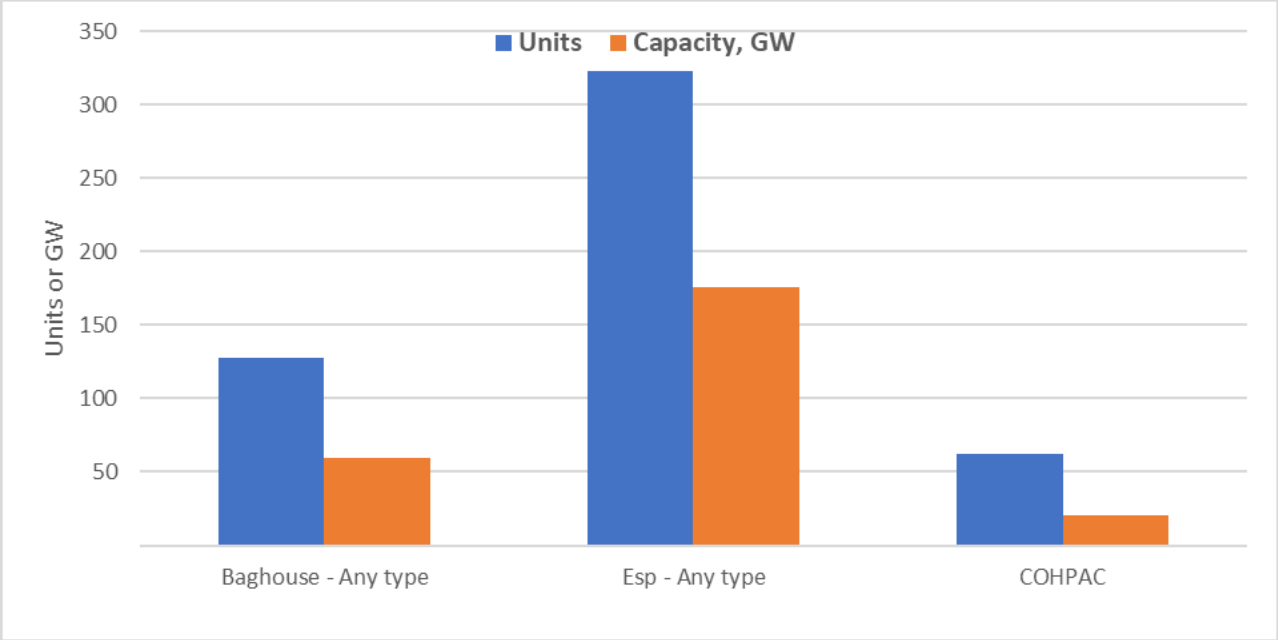


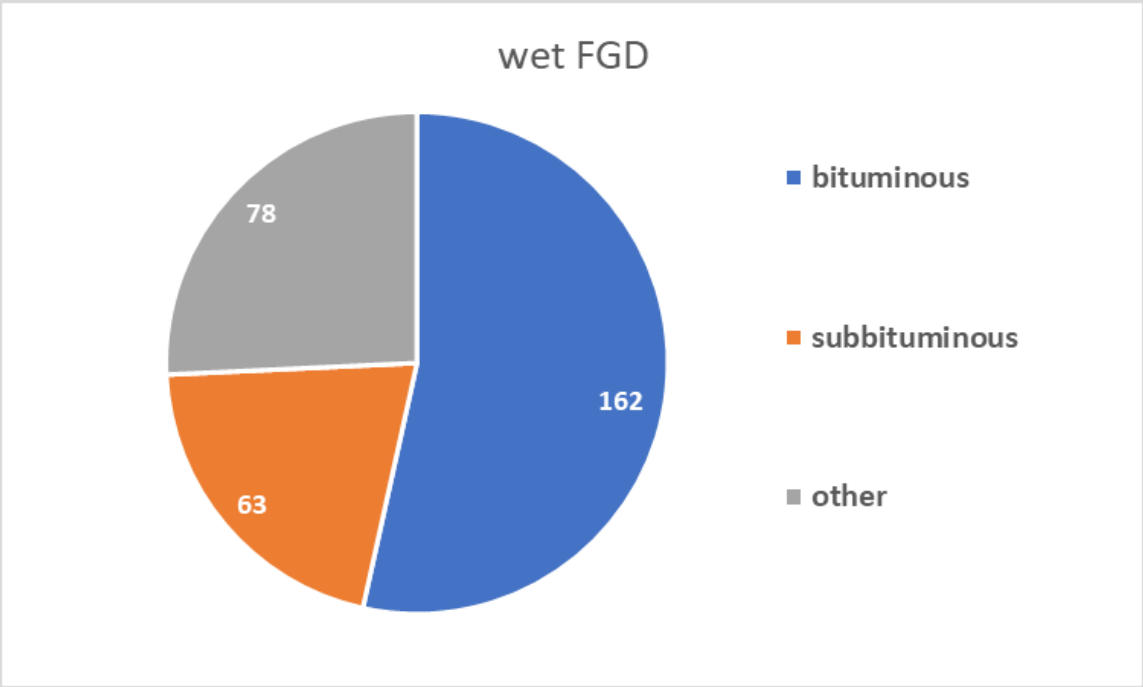
Figure 3. PM control technology in 2019[9]



[9] In this figure, "any type" is intended to mean that the total includes situations where the ESP or baghouse are installed individually or in combination as a COHPAC.

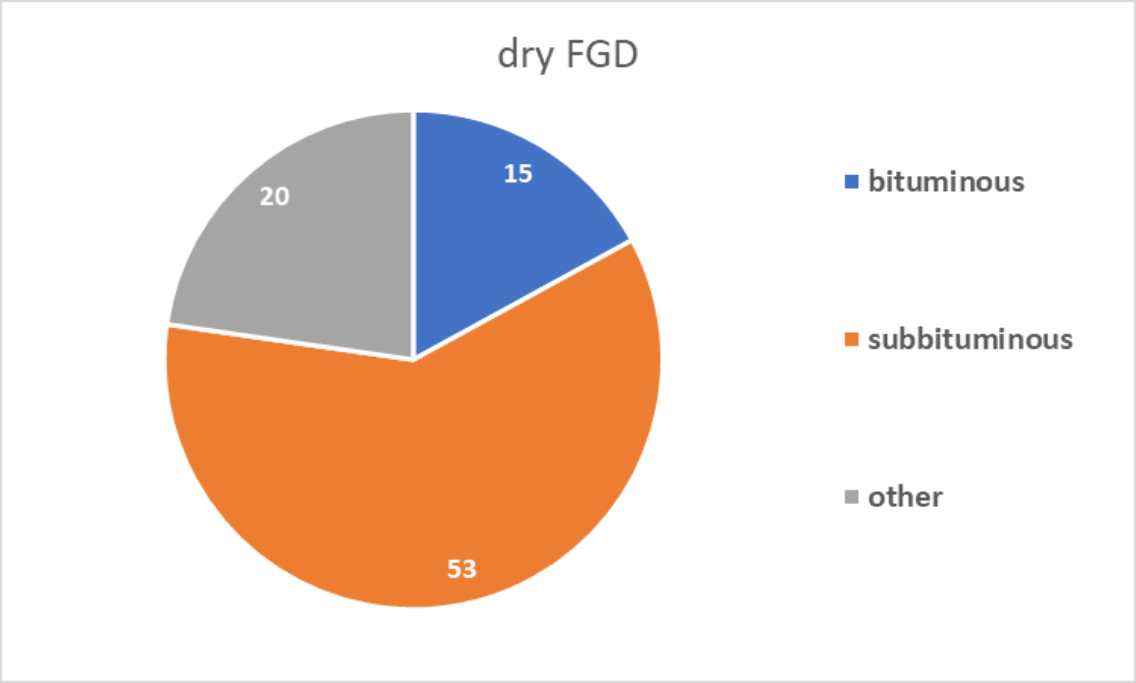
Because wet FGD systems primarily use a lower cost reagent (limestone) and achieve high levels of SO_2 capture, they are well suited for higher sulfur coals, which are bituminous. Figure 4 shows the distribution of coals used in wet FGD systems by the number of systems, and clearly most of the wet scrubbers are on bituminous coal fired units. "Other" coals include refined coals, lignite (a very small number) and coals in situations where the coal type was not indicated.

Figure 4. The coals that are used in wet FGD systems (# of coal units)



Because dry FGD systems all use lime, which is significantly more expensive than limestone, they are well suited for lower to medium sulfur coals, which are mostly subbituminous, but can be used on higher sulfur coals. Figure 5 shows the distribution of coals used in dry FGD systems by the number of systems, and clearly most of the dry scrubbers are on subbituminous coal fired units. "Other" coals would include refined coals, lignite (a very small number), or coals in situations where the coal type was not indicated.

Figure 5. The coals that are used in dry FGD systems (# of coal units)



Wet FGD systems

State-of-the-art wet FGD systems such as those used on electric utility boilers are capable of 99% or better SO_2 capture efficiencies, which would result in emissions rates below 0.05 lb SO_2/MMBtu assuming up to 5.0 lb SO_2/MMBtu uncontrolled levels. However, many facilities were constructed decades ago. Wet FGD systems typically offer slightly higher SO_2 removal efficiencies than dry FGD systems and are typically designed for one of two reagents – limestone or lime. State-of-the-art limestone and lime wet FGD systems are commonly used in large power plants, and the Electric Power Research Institute (EPRI) examined the potential for SO_2 removals over 99% on a consistent basis and found that such removal efficiencies are possible.[10]

[10] Electric Power Research Institute, Flue Gas Desulfurization (FGD) Performance Capability – High Efficiency Design and Operating Options, 1014171, March 2008

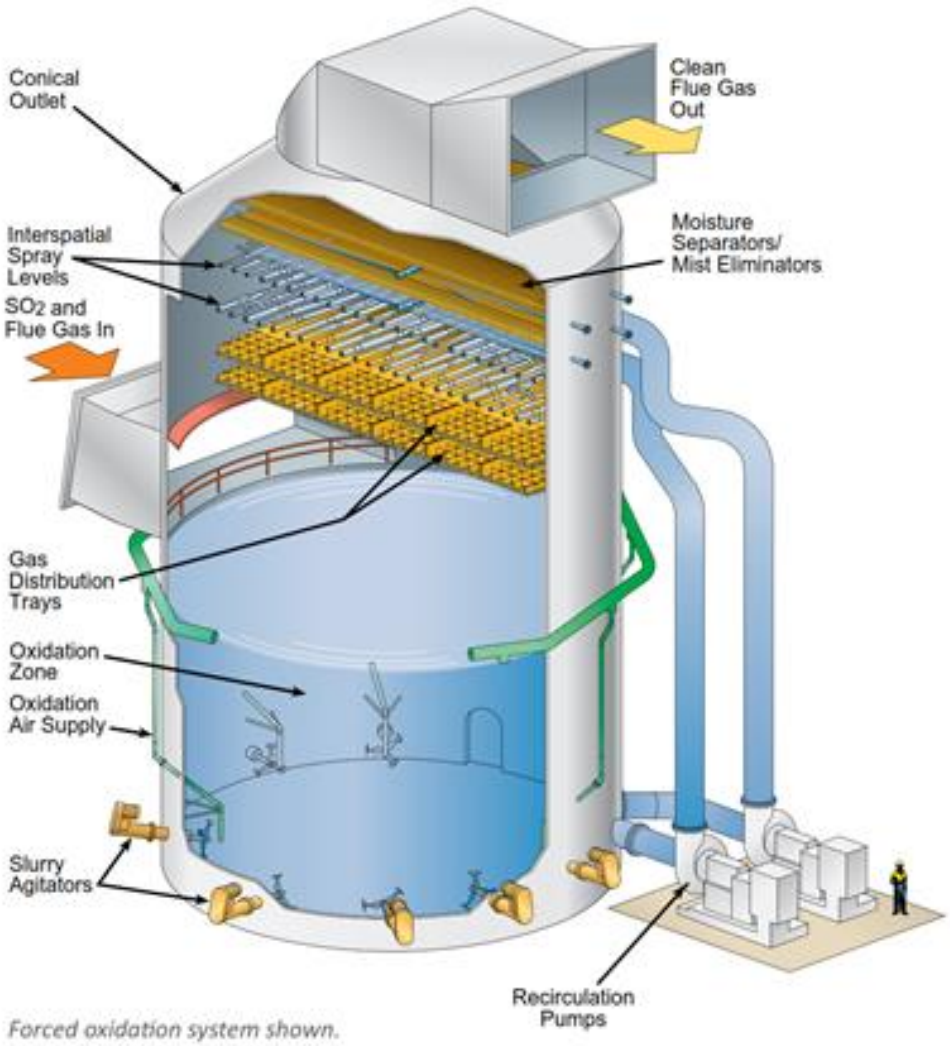
The most common form of wet FGD on coal power plants is limestone forced oxidation (LSFO) scrubbers. LSFO systems use limestone reagent, which is less expensive than other available reagents, and LSFO scrubbers also produce a gypsum by-product. Sparge air is introduced into the absorber slurry to oxidize calcium sulfite to calcium sulfate and produce gypsum. The gypsum by-product has commercial uses in production of wall board and Portland cement.

A significant number of wet FGD systems use lime rather than limestone. Lime is more reactive, and significantly more expensive, but the scrubber can be built to be somewhat smaller (and less costly) for the same emission reduction. There are very few wet FGD systems that use sodium-based reagents. Sodium-based reagents have the advantage of high water solubility, which makes the system simpler and less expensive, but can result in waste disposal issues due to the water-soluble product.

Figure 6 shows an example of an absorber vessel in an LSFO scrubber, again, the most commonly used wet FGD system. This is the heart of a wet FGD system, and although there is a lot of other equipment necessary to support wet FGD operation, the absorber vessel is where the pollutant capture occurs. This form of wet FGD is called a spray tower. There are other configurations as well, but the principles are generally the same. In the system depicted in this figure, flue gas enters the absorber vessel, it then passes upwards through gas distribution trays and injection nozzles that treat the gas with a limestone slurry, the gas then passes through mist eliminators to remove the moisture droplets, and then the cleaned gas passes out through the top.

Among the numerous factors that impact performance is liquid/gas interaction and mixing, and liquid-to-gas ratio. Liquid/gas interaction and mixing are impacted by the spray nozzle configuration, the use of baffles and other devices to improve liquid/gas interaction, and the number of spray levels. State-of-the-art wet FGD systems use engineering methods and equipment designs to improve FGD performance, and these will be explored more later in this report. Liquid-to-gas ratio is related to the treatment rate of the gas. It is important to ensure that the liquid-to-gas ratio is maintained evenly throughout the absorber vessel.

Figure 6. Spray Tower Wet FGD Absorber[11]



Other environmental impacts

Wet FGD will have the following impacts on other air pollutants.

Acid Gases – In addition to SO_2, HCl and other strong acids are removed. As a strong acid, HCl is removed at greater rates than SO_2, which is why the MATS rule permits a scrubbed unit with a controlled SO_2 emission rate continuously measured below 0.20 lb/MMBtu to comply with the HCl emission limit of 0.002 lb/MMBtu without HCl monitoring.

Filterable PM – some additional PM reduction is possible.

[11] Babcock and Wilcox, WET FLUE GAS DESULFURIZATION (FGD) SYSTEMS ADVANCED MULTI-POLLUTANT CONTROL TECHNOLOGY; available at www.babcock.com

Condensable PM – A wet FGD will reduce SO_3 somewhat, perhaps around 50%. SO_3 is the principal contributor to condensable PM in the form of H_2SO_4 fume.[12]

Mercury – A wet scrubber will generally have a high capture rate for oxidized mercury, but will not capture elemental mercury.[13]

Emissions performance, and improving emissions

Figure 7 shows annual SO_2 emissions for the population of wet FGD systems in the United States for systems operated by coal-fired electric utility or small power producers for the full years of 2011 and 2019. These years were selected because the MATS rule was announced at the end of 2011, and 2019 is the year where we also have HCl emissions data (which will be examined later). The curves show the annual emission rate versus the percent of the total number of units that had annual SO_2 emissions at or below the rate. There are three sets of data shown:

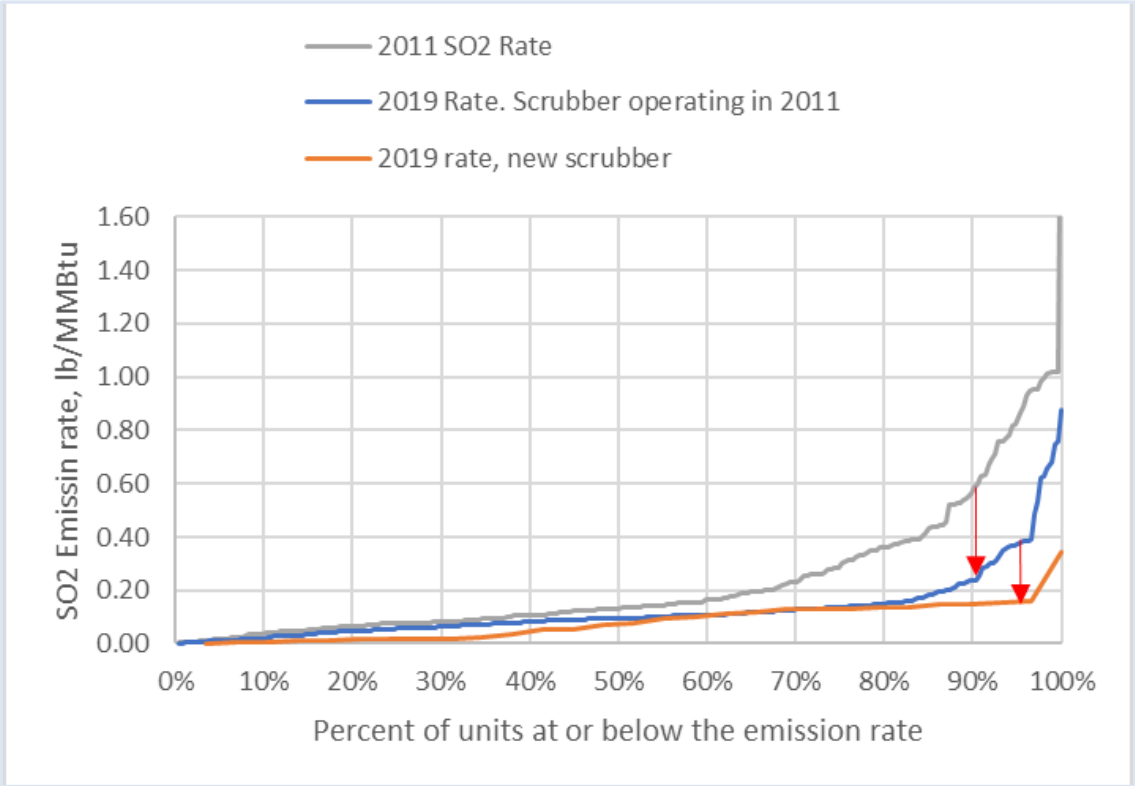
- 2011 emission rate performance of wet FGD systems in the Air Markets Program Data (AMPD) database that operated for a full year in 2011.
- 2019 emission rate performance of wet FGD systems in the AMPD database that operated for a full year in 2011 that were also operating in 2019.
- 2019 emission rate performance of wet FGD systems in the AMPD database that were not operating in 2011 and were operating for a full year in 2019 – that is, they were new FGD systems.

The data shows that in 2011 about 90% of all wet FGD systems had annual SO_2 emissions at or below 0.60 lb/MMBtu, while in 2019 90% of all wet FGD systems that had been in operation in 2011 had emissions below about 0.23 lb/MMBtu. As the red arrows show, there were significant reductions in emission rates between 2011 and 2019. Clearly, many of these facilities took measures between 2011 and 2019 to improve their emissions rates without installing any additional acid gas controls (aside from possible scrubber improvements). In some cases the measures may have simply been increased treatment rates with the existing systems, to include increasing liquid-to-gas ratios. In other cases, there were physical improvements to the FGD system.

[12] Electric Power Research Institute (EPRI), Estimating Total Sulfuric Acid Emissions from Stationary Power Plants 1016384, Technical Update, March 2008, p. 3-10

[13] Illinois Environmental Protection Agency, Bureau of Air, "Technical Support Document for Reducing Mercury Emissions from Coal Fired Electric Generating Units", AQPSTR 06-02, March 16, 2006, p. 118 http://www.epa.state.il.us/air/cair/documents/031406/final-tsd-hg.pdf

Figure 7. Annual SO_2 emission rate for wet FGD systems operating the full year in 2011, 2019 emissions of wet FGD systems that were operating in 2011, and new scrubbers built since 2011.[14]

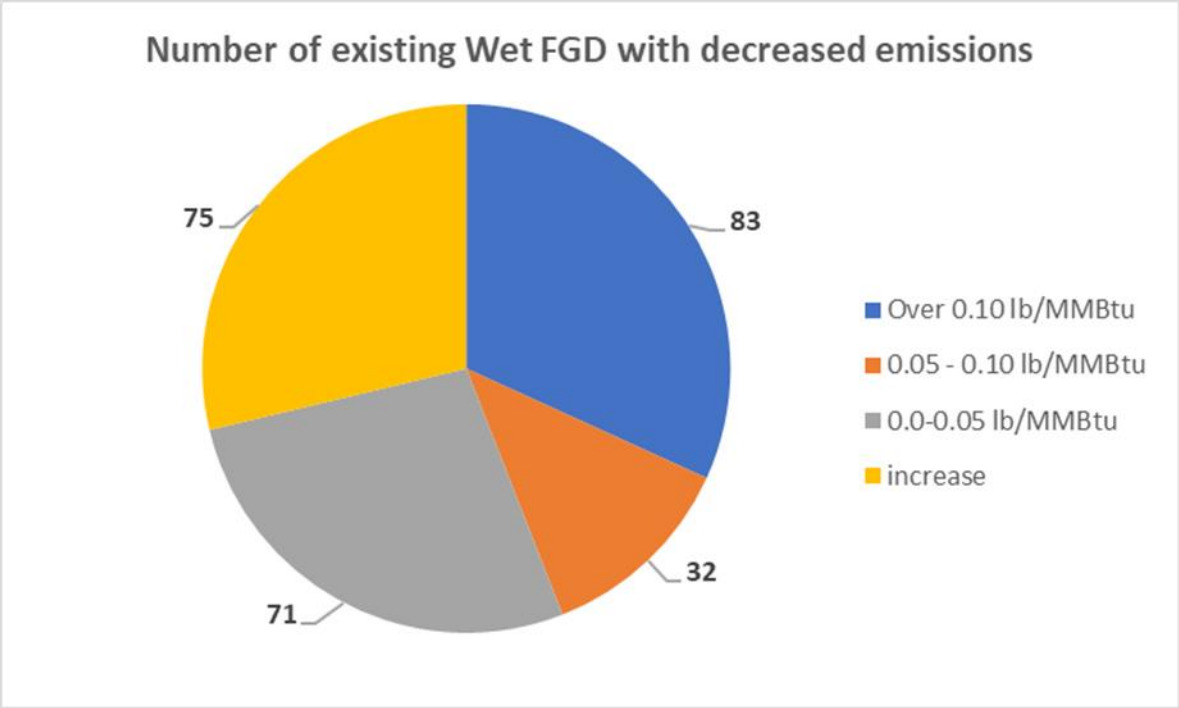


For the new wet FGD systems put in service after 2011, 90% of the units had SO_2 emissions below 0.15 lb/MMBtu.

Figure 8 shows how many wet FGDs that were in operation improved (reduced) their emission rate between 2011 and 2019. As shown, 71% of existing wet FGDs had an improvement in emissions rates. About 44% of the wet FGD systems improved SO_2 emission rates by 0.05 lb/MMBtu or more. The same data shows that over 50% improved emission rates by over 0.03 lb/MMBtu. As shown in Figure 7, about 40% of wet FGD facilities already had emission rates of 0.10 lb/MMBtu or less in 2011, and therefore may not have had any motivation for reducing emissions further. The average 2011 SO_2 emission rate for those facilities that increased their SO_2 emissions rate between 2011 and 2019 was 0.109 lb/MMBtu and the average increase was 0.0393 lb/MMBtu. So, these facilities could increase their emissions somewhat while remaining below the MATS level of 0.20 lb/MMBtu.

[14] Developed from US EPA Air Markets Program Data for 2011 and 2019. Annual emission rates were determined by multiplying reported emissions in tons by 2000 and dividing the result by reported heat input. The units were then sorted from lowest to highest emitting units according to calculated annual SO_2 emission rate.

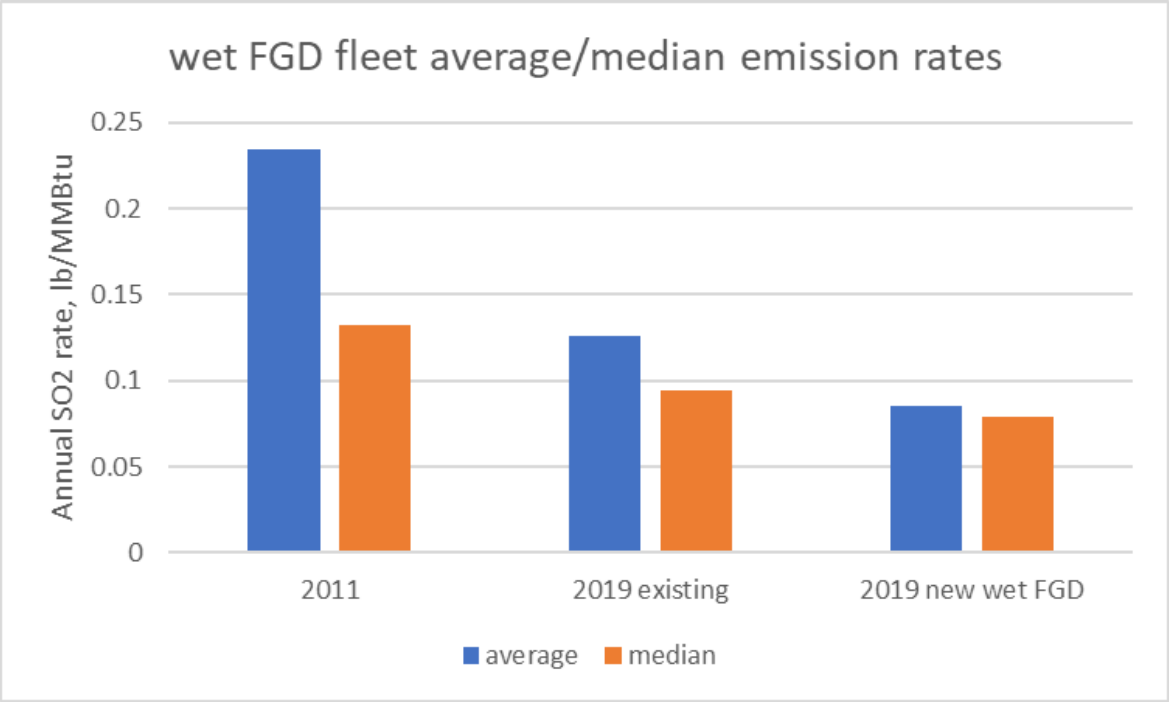
Figure 8. Wet FGD systems operating in 2011 that reduced their SO_2 emission rate in 2019 and how much (units)



This data demonstrates that state-of-the-art wet FGD systems built since 2011 have achieved performance that exceeds that of legacy wet FGD systems. It is also apparent that existing wet FGD systems can be improved.

Figure 9 shows the average and median SO_2 emission rates for the three data sets, demonstrating the significant improvements in performance that have been achieved since 2011. This data demonstrates that state-of-the-art wet FGD systems built since 2011 have achieved performance that exceeds that of legacy wet FGD systems. It is also apparent that existing wet FGD systems can be improved.

Figure 9. Average and median SO_2 emission rate for wet FGD systems operating the full year in 2011, 2019 emissions of units that were operating in 2011, and new scrubbers built since 2011



Performance, or emissions reduction, can be improved to a degree by increases in reagent usage without any physical changes in the FGD system. It is unclear how much of the aforementioned improvements were the result of increases in reagent use versus physical changes in the equipment. The level of improvement suggests that a significant portion of these units may have made physical changes. The following discusses methods to improve performance using physical changes to the FGD equipment.

Methods to improve wet FGD performance

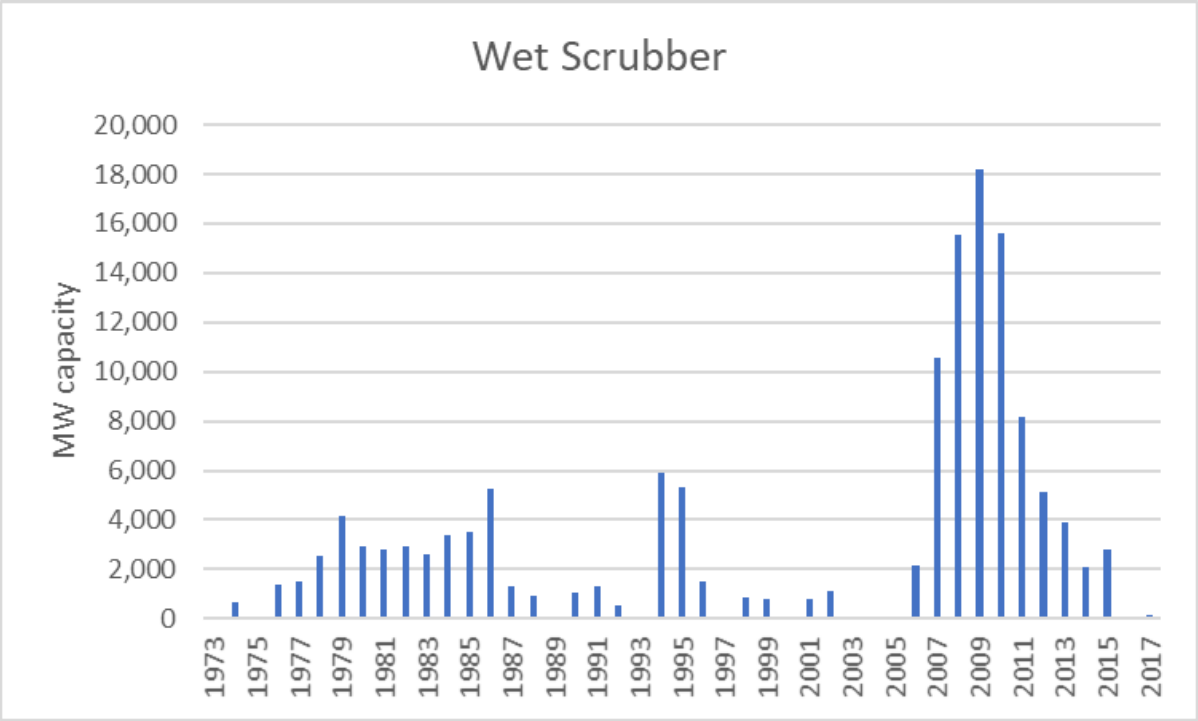
Many wet FGDs were built decades ago, using the engineering techniques and the equipment that was available at the time. Figure 10 shows historical installation of wet FGD systems. As shown, a fairly large amount of wet FGD capacity was installed in the 1970s through the 1990s. These were installed with older technology, often without the benefit of modern engineering tools, such as computational fluid dynamics (CFD), that permit design of systems that have higher liquid-to-gas interaction. The aforementioned data demonstrates clearly that wet FGD technology that thas become available since 2011 has substantial improvements in performance

over even the improved legacy wet FGD systems, and certainly over the wet FGD systems as installed in 2011. Also, a significant portion of the wet FGD systems that existed in 2011 did implement improvements, but not all did.

For an existing FGD system, an improvement to the FGD system is normally performed without modifying the existing absorber vessel or other, major scrubber island equipment (such as recirculation pumps) because changes to this equipment would be expensive. Improvements include:

- Methods to balance and improve flow through the absorption vessel, or
- Methods to improve liquid/gas contact

Figure 10. Historical installation of wet FGD systems, MW by year (NEEDS v6)[15]



These principles were previously understood, but these improvement methods were not widely deployed until after 2011. This is because the MATS rule motivated utilities to examine how to reduce SO_2 emissions from their wet FGD systems at the lowest cost. Figure 7 and Figure 8 demonstrate that these improvements were deployed on a large number of facilities after 2011. During this deployment, the industry developed innovations that, as will be shown, resulted in wet FGD improvements being far less costly than anticipated by EPA in 2011.

Methods to balance and improve flow through the absorption vessel – This includes using CFD and other modern engineering methods to design improved absorber vessel internals, which

[15] From US EPA National Electric Energy Database System (NEEDS, v6)

may include baffles, trays, or other devices to even flow. This assures that the liquid-to-gas ratio is maintained evenly throughout the flow field. For example,

Figure 11 shows how installation of a tray – essentially, a circular sheet with perforations– balances the flow in the absorber vessel. In the left image, which reflects conditions prior to the upgrade, the red regions in the Spray Header 1 level shows significant unevenness in the flow, meaning that some regions of the gas are being undertreated. The image on the right shows that the red regions are mostly gone with the installation of an internal tray to balance flow. This is a capability that has evolved over the years. The data clearly demonstrates that there is a great deal more experience with these improvement methods since 2011 than before. As a result, there is better understanding of how to execute these methods today than existed in 2011, and, as will be shown later in this report, significant improvements are possible at a much more modest scope and cost than expected in 2011.

Methods to improve liquid/gas contact - Figure 12 shows how improved absorber spray patterns can be used to ensure that there are no untreated portions of the gas. By increasing the number and proximity of nozzles, it is possible to improve the liquid-to-gas interaction.

Figure 13 shows still another example of improvements to a wet FGD system that includes a CFD model, wall rings (rings placed along the wall to prevent gas "sneakage" around the edge of the spray pattern), and bidirectional nozzles. According to the supplier of this approach, this approach provides the following advantages:[16]

<u>CFD Modeling</u>

- ■ Results in better gas distribution
- ■ Simulates droplets and full spray coverage over absorber(s)
- ■ Ensures proper flow along walls
- ■ Identifies areas requiring additional nozzles for proper liquid and gas distribution

<u>Bidirectional Nozzles Installed</u>

- ■ Wider-angle spray cone ensures efficient spray pattern through the spray zone
- ■ Increase gas - liquid collisions
- ■ Dual direction allows for complete coverage throughout the total spray zone

<u>Wall Baffles</u>

- ■ Improve distribution of flue gas over entire cross section
- ■ Reduce "gas sneakage" along absorber walls and corners
- ■ Minimize pressure drop

[16] Babcock Power, "Wet Flue Gas Desulfurization Scrubber Upgrades", available at: https://www.babcockpower.com/literature-library/

Figure 11 . Example of the use of trays to balance flow through an absorber vessel[17]

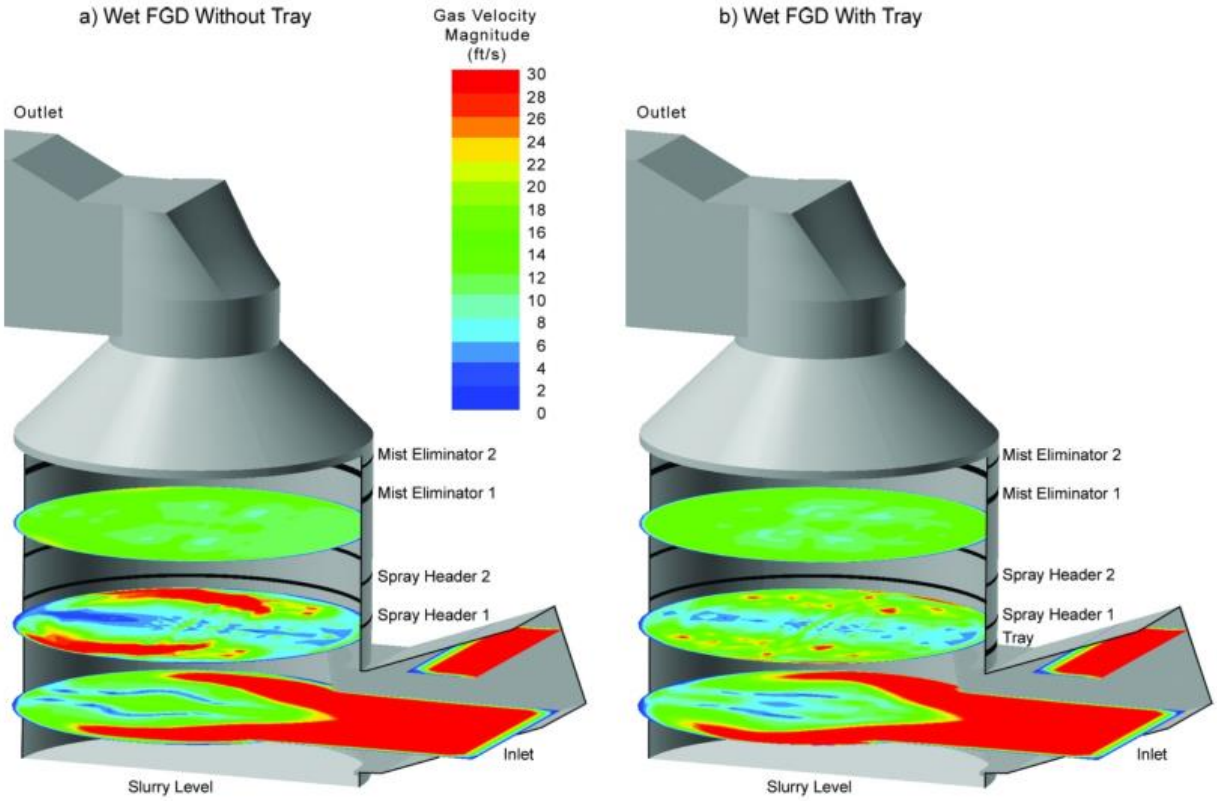
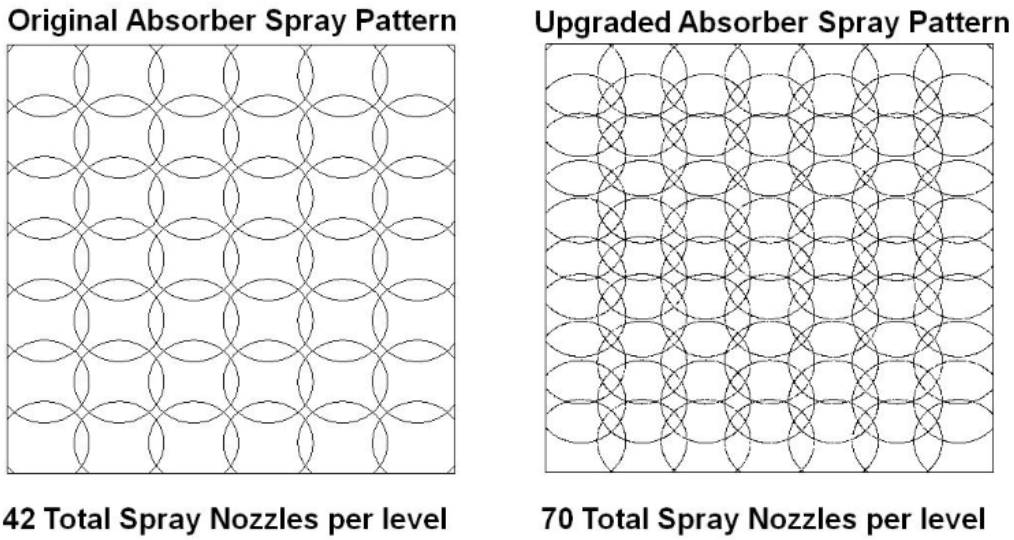


Figure 12. Improved Absorber Spray Pattern[18]



[17] Moretti, A.L., "State-of-the-Art Upgrades to Existing Wet FGD Systems to Improve SO_2 Removal, Reduce Operating Costs and Improve Reliability", Presented at Power-Gen Europe, June 3-5, 2014, Cologne, Germany

[18] Ibid.

Upgrades to scrubber systems are not commonly reported in the information submitted to EPA. Therefore, comprehensive data on FGD upgrade projects is not available, but the approximate number of improvements are reflected in the emissions data. Six examples of upgrade projects are shown in Table 1, with more information on these specific cases in the source documents. Table 1 shows the improvement in SO_2 removal efficiency for six wet FGD systems that have undergone upgrades of performance.

Figure 13. Use of wall rings and bi-directional flow nozzles to improve FGD performance[19]

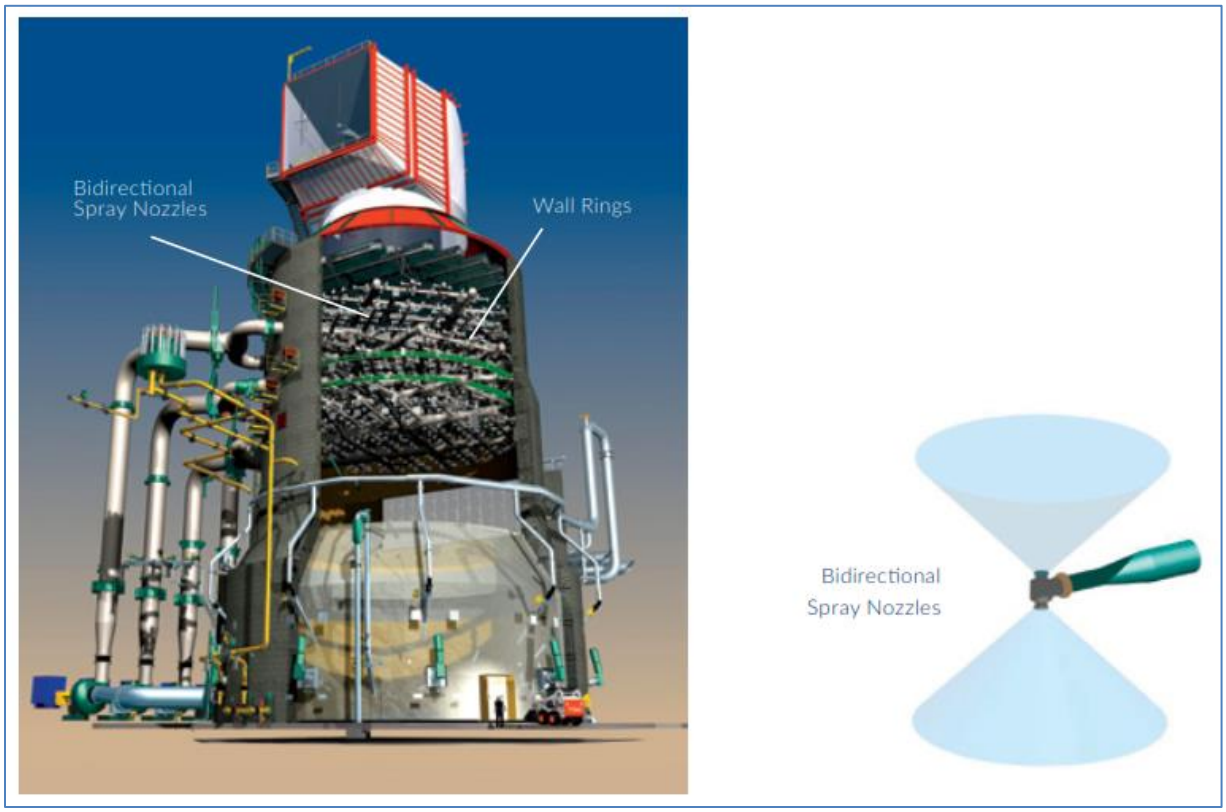


Table 1. Examples of performance improvement for wet FGD upgrades

Case	Starting percent removal	Final percent removal	Source
1	91%	>99%	20
2	93.5%	~98%	20
3	<94%	~98%	20
4	97%	99%	21
5	97%	99%	21
6	80%	97%	21

[19] Ibid.

[20] BabcockPower Environmental, *Wet Flue Gas Desulfurization Scrubber Upgrades*, available at: https://www.babcockpower.com/literature-library/

[21] Parsons, T.R., et al., "Adding a Tray to a Wet FGD Absorption Tower: A Simple but High-Impact Upgrade for an Existing Absorber", Power-Gen Asia, September, 20-22, 2016, Seoul, Korea

Addition of DSI to improve capture of HCl on wet FGD equipped units

Addition of DSI upstream of the PM control device is another option to improve HCl control if upgrades to the FGD are not an option or are not sufficient to reduce HCl to the required level. DSI systems can reduce inlet HCl to the wet FGD by at least 50% and at costs in the range of $40/kW. DSI is explained in more detail later.

Costs of Wet FGD Upgrades

EPA's documentation for the Integrated Planning Model (IPM) indicated that:

"In EPA Base Case v.5.13, coal steam units with existing FGD that do not achieve an SO2 removal rate of at least 90% are assumed to upgrade their FGDs in order to obtain at least 90% SO2 removal and 99% HCl removal. The cost of this "FGD Upgrade Adjustment" is assumed to be $100/kW and is considered a sunk cost for modeling purposes."[22]

This represents EPA's estimate of the cost based upon their envisioned scope of such a retrofit. But, at this point there is more information to estimate the scope of these retrofits.

The cost for performing a wet scrubber upgrade will vary depending upon the particular situation. However, it is possible to make a reasonable estimate of what an upgrade might cost using cost estimates of full scrubber installation and identifying the portions of the full scrubber that are affected.

Although an entire wet FGD system includes an extensive array of support equipment, upgrades to wet FGD systems to improve performance are generally focused on the absorber internals (spray nozzles, flow enhancing devices, etc.). The absorber vessel itself is not changed, nor are the recycle pumps, which are the largest cost items in the absorber island. None of the foundations or structural equipment is changed. It would be a reasonable assumption that the cost of a scrubber upgrade would be some fraction of the cost of the total absorber island. Because the most costly items in the absorber island would be unchanged (absorber vessel, recycle pumps, associated electrical and vessel external piping, support structure), and only internal items to the absorber vessel (spray nozzles, addition of flow control devices such as trays) are changed, an estimate of upgrades on the order of 25% of the cost of an absorber island cost would be very conservative, and likely on the high side.

For US EPA, Sargent & Lundy developed a cost for constructing a wet FGD system with costs allocated to each major system area.[23] The cost estimate is shown in Appendix A. This cost estimate includes an algorithm for the cost of the base absorber island cost equal to:

[22] IPM v5.13 documentation, Chapter 5, Section 5.5.2

[23] Sargent & Lundy, IPM Model - Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology", January 2017

584000*B*((F*G)^0.6)*(D/2)^0.02)*(A^0.716), where

- A = unit size in MW
- B = Retrofit factor (1.0 for typical retrofit)
- D = SO_2 inlet rate, lb/MMBtu
- F = coal factor, 1.0 for bituminous, 1.05 for subbituminous, 1.07 for lignite
- G = heat rate factor of C/1000, where C = Gross Heat Rate in Btu/kWh

25% of this would be

146000* B*((F*G)^0.6)*(D/2)^0.02)*(A^0.716)

Additional costs include costs for engineering, contractor profit, owner's costs, etc., adding another 35%.[24] Other costs would be Allowance for Funds Used During Construction (AFUDC) and Engineering Procure Construction (EPC) fees. AFUDC for an upgrade would be very modest, because an upgrade requires much less time than a full scrubber project, but EPC fees of perhaps 15% may be included. Therefore, if all of the costs but AFUDC are included, this would result in

226000* B*((F*G)^0.6)*(D/2)^0.02)*(A^0.716)

For the 500 MW example plant shown in the document, this would result in a cost of a wet FGD upgrade of roughly $19 million, or about $38/kW.

EPA estimated the cost of an FGD upgrade to be $100/kW in anticipation of the MATS rule.[25] This is well above what has been estimated here in light of the scope of most of these scrubber upgrades. Although the IPM documentation did not explain the expected cost for an FGD upgrade, it clearly was anticipated in 2011 to be greater than actual costs were after the MATS rule was promulgated. This was likely due to improvements in technology and other techniques for executing these projects that have been gained with experience.

EPA projected that roughly 63 GW of FGD capacity would be upgraded in response to MATS.[26] Given that about 44% of the wet FGD systems in operation in 2011 experienced emission rate reductions of 0.05 lb/MMBtu or more and 51% experienced emission rate reductions of 0.03 lb/MMBtu or more, this is likely greater than the 63 GW that EPA predicted and does not include dry FGD systems. However, because the costs of these improvements are about 38% of what EPA originally estimated, the cost of compliance with MATS was well below the anticipated cost in this regard.

[24] Ibid.
[25] IPM Documentation, v5.13, section 5.5.2
[26] Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards, EPA-452/R-11-011, December 2011

Dry FGD

State-of-the-Art dry FGD systems are capable of greater than 95% SO_2 removal. Most power plant dry FGD systems utilize hydrated lime; however, other reagents, such as sodium-based reagents, can be used. Examples of dry FGD systems are spray dryer absorber (SDA) with baghouse and circulating dry scrubber (CDS). Figure 14 depicts an SDA and Figure 15 depicts a CDS. In both the case of SDA and CDS, downstream PM removal devices are necessary and baghouses are most commonly used. CDS systems can generally achieve higher removal rates in high SO_2 environments than SDA systems because moisture and reagent are added independently of each other in a CDS system.

SDAs using lime reagent can become less efficient with high sulfur coals and high removal rates, so they are most often applied in low sulfur coal applications. CDS systems can achieve higher removal rates than SDA systems on high sulfur coals because moisture and lime reagent are added independently of one another.

SDA and CDS systems reduce particulate matter emissions because a fabric filter is commonly used downstream of the absorber vessel to capture the solids.

Dry lime FGD (such as SDA and CDS technology) is widely used today and has become more cost effective partly due to cost improvements in the baghouse – a large part of the total cost of a dry scrubber. Modern baghouses typically use pulse-jet technology while older baghouses used reverse-air technology. Pulse-jet fabric filters have higher air-to-cloth ratios, meaning that less cloth is needed to treat the same gas flowrate, and the baghouse can be smaller. This means that a pulse-jet fabric filter can be smaller and less expensive than a reverse air fabric filter treating the same gas flowrate.

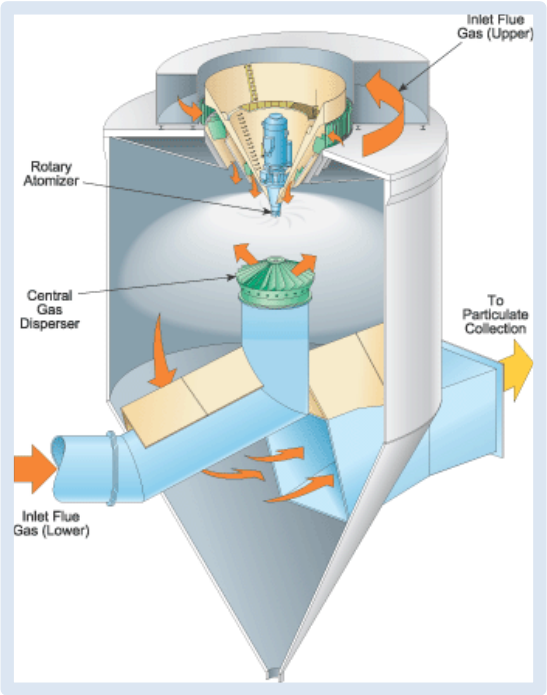


Figure 14. A Spray Dryer Absorber

Lime reagent and water mixture are atomized and coinjected into a reaction vessel with flue gas. As the injected droplets dry, they react with SO_2 in the gas and the dry product is sent to a fabric filter for capture.[27]

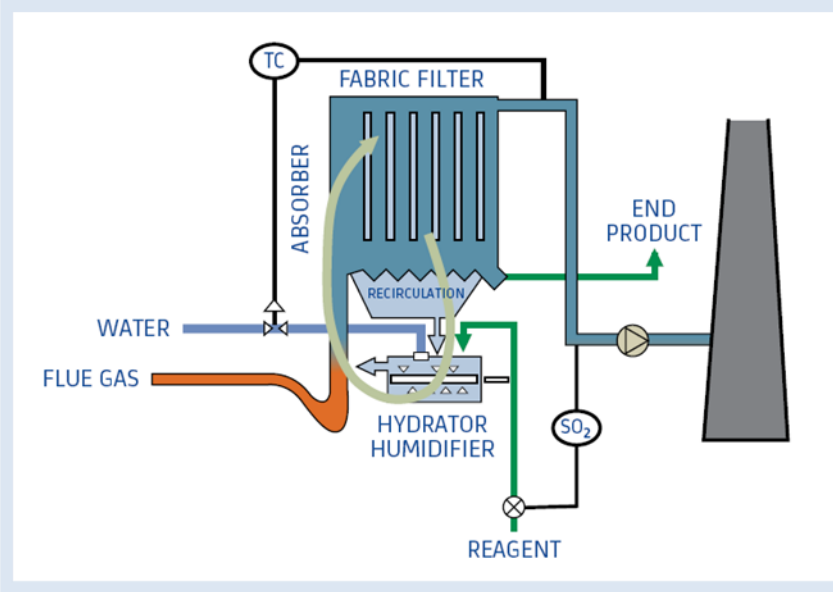


Figure 15. A Circulating Dry Scrubber – Lime reagent and water are introduced separately to cool gas and make a humidified reagent. The lime reacts with SO_2 in the cooled gas. The dry product is captured in a fabric filter and recirculated to increase reagent utilization.[28]

[27] Staudt, J. E., "Candidate Control Measures for Industrial Sources in the LADCO Region", for Lake Michigan Air Directors Consortium, January 24, 2012, page 67 http://www.ladco.org/reports/so_2_reports/C_11_011_LADCO_SO2_Final.pdf

[28] Ibid.

CDS technology can provide 96% removal and 0.15 lb SO_2/MMBtu emissions with coal that would produce 3.6 lb SO_2/MMBtu uncontrolled, as demonstrated at the AES Greenidge plant. Table 2 shows coal fired utility boilers where the Babcock Power Turbosorp (a CDS technology) is applied and Table 2 shows where Turbosorp and other CDS systems have been applied.

Energy Impacts

Dry FGD will increase the parasitic loads on the plant due to the pressure drop across the fabric filter, the increased induced draft fan demands and other power demands such as compressed air.

Other Environmental Impacts

Dry FGD will have the following impacts on other air pollutants:

Filterable PM – All dry FGD systems have fabric filters. As a result of the addition of a fabric filter, filterable PM emissions will likely be reduced if dry FGD is deployed.

Mercury – For bituminous fuel boilers dry FGD systems will result in high mercury capture because SO_3 (which inhibits mercury capture) is removed efficiently and the mercury is readily captured on the fabric filter. At the AES Greenidge dry scrubber, over 95% total mercury capture was achieved without use of activated carbon.[29] For Powder River Basin (PRB) fueled boilers it may be necessary to add halogen in the form of a coal additive or halogenated activated carbon. In this case high mercury capture is possible.

Condensable PM – Very high reductions of SO_3 and H_2SO_4 are expected from dry FGD systems with a baghouse, and higher than 95% SO_3 reduction was measured at the AES Greenidge dry scrubber.[30, 31]

[29] Connell, D., "GREENIDGE MULTI-POLLUTANT CONTROL PROJECT - Final Report of Work Performed", Report to US DOE, May 19, 2006 – October 18, 2008, pages 153, 154

[30] Electric Power Research Institute (EPRI), Estimating Total Sulfuric Acid Emissions from Stationary Power Plants 1016384, Technical Update, March 2008, p. 3-11

[31] Connell, D., "GREENIDGE MULTI-POLLUTANT CONTROL PROJECT - Final Report of Work Performed", Report to US DOE, May 19, 2006 – October 18, 2008, pages 153, 154

Table 2. Turbosorb and other Dry Scrubber Systems (note, CFB Scrubber in this table denotes Circulating Fluidized Bed scrubber and is the same as a CDS system as described in this report) from Wisconsin Department of Natural Resources, "BART Determination – Amended July 2011 Georgia Pacific Broadway Mill, Green Bay Wisconsin", Facility ID 405032870, July 1, 2011, page 9[32]

		From Babcock Power			From NEEDs Database				From NPS BART Compilation (updated 08/2010)					
	GP	Greenidge - NC *	Deerhaven - FL (Case 1) *	Deerhaven - FL (Case 2)*	Altavista - VA	Southampton - VA	Roanoke - NC	Edgecombe - NC	Eastman - TN (non-EGU)	Stanton - ND	Stanton - ND	Pacificorps - WY	CSU - CO	CSU - CO
Control Technology	CFB (Turbosorp)	CFB (Turbosorp)	CFB (Turbosorp)	CFB (Turbosorp)	SDA	SDA	CFB	SDA	SDA	CFB	SDA	SDA	SDA	SDA
Installation Date	---	2006	2010	2010	1992	1995	1995	1990	---	---	---	---	---	---
Heat input (mmbtu/hr) and/or MW output	965 (75 MW)	107 MWe	238 MWg	238 MWg	31.5 MW x2	63 MW	44 MW	28.9 MW	655 x 5	1,800	1,800	2,500	1,336	850
Pre-control (tpy)	10,889	14,877	N/A	N/A	N/A	N/A	N/A	N/A	14,309	9,376	9,376	13,316	4349	2853
Pre-control (#/mmBtu)	3.48	3.62	3.8	2.2	Fuel limited to 1.5 % S	Bituminous	Fuel limited to 1.6 % S	Bitum.	2.4	2.4	2.4	1.21	0.99	1
Post-control (tpy)	762	---	N/A	N/A	N/A	N/A	N/A	N/A	379	656	938	1,656	739	485
Post-control (#/mmBtu)	0.25	0.13	0.11 (WDNR estim.)	0.10 (WDNR estim.)	0.19	0.162 (limit)	N/A	0.31 (limit)	0.20	0.17	0.24	0.15	0.13	0.13
% reduction	93	96.3	97.2 *	95.4 *	95% required (95-96 % actual)	92% required (96 % actual)	93% required	90% required (95 % design)	92	93	90	87.6	83	83

[32] http://dnr.wi.gov/topic/AirQuality/documents/HazeSIPBARTAttachment3.pdf

Like wet FGD, dry FGD has also undergone a substantial improvement in performance, although not to the degree that wet FGD has. CDS technology is newer and is capable of higher capture efficiencies for higher sulfur coal than SDA, but conversion from SDA to CDS technology is not possible, except at a very high cost. Figure 16 shows annual SO_2 emissions for the population of dry FGD systems in the United States that were operated by coal-fired electric utility or small power producers for the full years of 2011 and 2019. These years were selected because 2011 was the year that the MATS rule was announced[33] and 2019 is the year of the HCl emissions data used in this report (which will be examined later). The curves show the annual emission rate versus the percent of the total units that had annual SO_2 emissions at or below the rate. There are three sets of data shown:

- Performance of dry FGD systems in the Air Markets Program Data (AMPD) database that operated for a full year in 2011.
- Performance of dry FGD systems in the AMPD database that operated for a full year in 2011 that were also operating in 2019.
- Performance of dry FGD systems in the AMPD database that were not operating in 2011 and were operating for a full year in 2019 – that is, they were new FGD systems.

The data shows that in 2011 about 90% of all dry FGD systems had annual SO_2 emissions at or below 0.36 lb/MMBtu, while in 2019 90% of the same systems had emissions below about 0.28 lb/MMBtu. As the red arrows show, there were significant reductions in emission rates between 2011 and 2019. Clearly, many of these facilities took measures between 2011 and 2019 to improve their emissions rates without installing any additional acid gas controls (although the scrubber improvements may have been deployed). In some cases the measures may have simply been increased treatment rates with the existing systems, to include increasing liquid-to-gas ratios. In other cases, there were physical improvements to the FGD system. Some of these physical improvements may have been upgrades in fabric filter material that would permit improved cleaning and, therefore, higher treatment rates. In other cases, improvements in SDA atomizer could be used to improve efficiency because the older dry FGD systems are all SDA systems that were designed with 1980s or 1990s atomization technology.

For the new dry FGD systems put in service after 2011, 90% of the units had emissions at or below about 0.30 lb/MMBtu, very similar to the emissions of the existing units for that year. Figure 17 shows how many dry FGDs that were in operation improved (reduced) the emission rate. As shown, 67% had some decrease in emission rate. About 28% of the dry FGD systems improved emission rates by 0.05 lb/MMBtu or more and the same data show that over 34% reduced emission rates by over 0.03 lb/MMBtu. The average 2011 emission rate for those facilities that increased their SO_2 emissions between 2011 and 2019 was 0.111 lb/MMBtu and the average

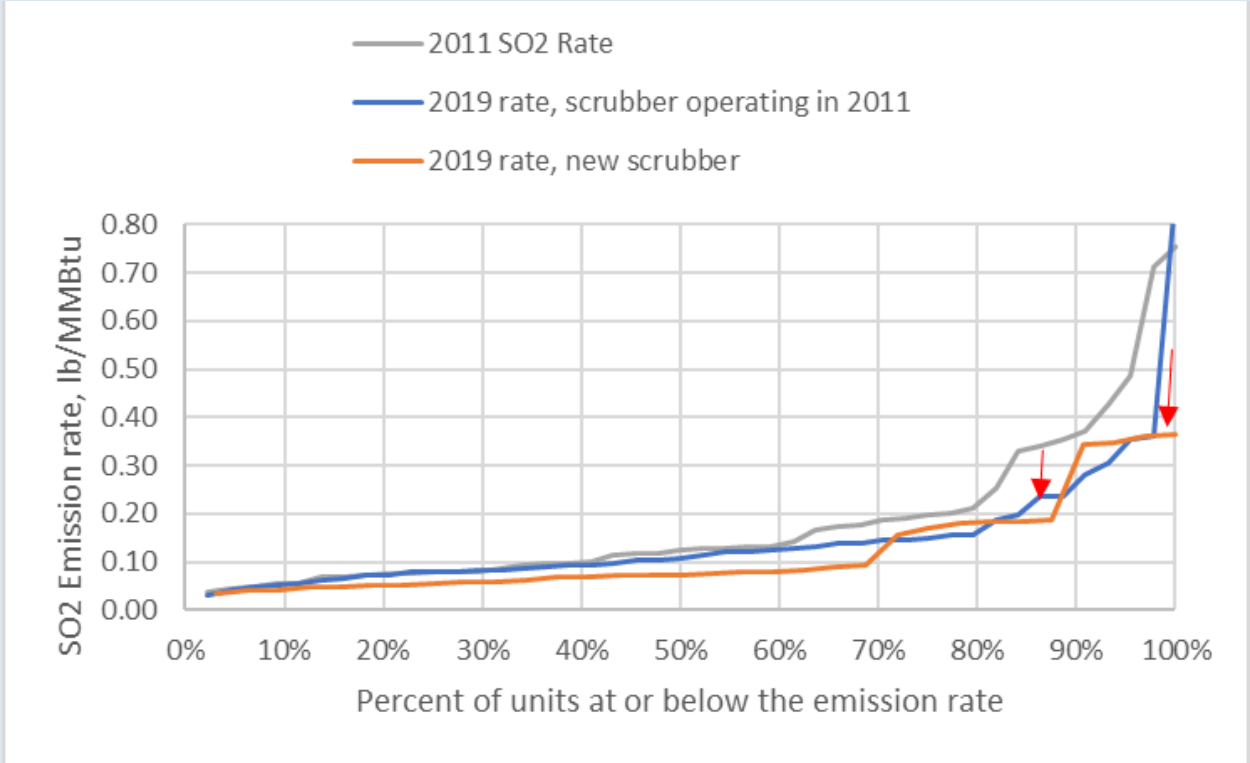
[33] The MATS rule was first announced in December 2011 and published in the Federal Register in April 2012

increase was 0.015 lb/MMBtu. So, these facilities could increase their emissions somewhat while remaining below the MATS level of 0.20 lb/MMBtu.

Figure 18 shows the average and median SO_2 emission rates for the three data sets, demonstrating the significant improvements in performance that have been achieved since 2011. This demonstrates that existing dry FGD systems improved emissions significantly, and new systems since 2011 have improved emissions to an even greater degree. This data demonstrates that state-of-the-art FGD systems built since 2011 have performance that exceeds that of even the improved legacy dry FGD systems, and certainly over the dry FDG systems as installed in 2011. It is also apparent that existing dry FGD systems can be improved.

Performance, or emissions reduction, can be improved to a degree by increases in reagent usage without any physical changes in the FGD system. It is unclear how much of the aforementioned improvements were the result of increases in reagent use versus physical changes in the equipment. The following discusses methods to improve performance using physical changes to the FGD equipment.

Figure 16. Annual SO_2 emission rate for dry FGD systems operating the full year in 2011, 2019 emissions of units that were operating in 2011, and new scrubbers built since 2011.[34]



[34] Developed from US EPA Air Markets Program Data for 2011 and 2019. Annual emission rates were determined by multiplying reported emissions in tons by 2000 and dividing the result by reported heat input. The units were then sorted from lowest to highest emitting units according to calculated annual SO_2 emission rate.

Figure 17 Dry FGD systems operating in 2011 that reduced their emission rate and how much

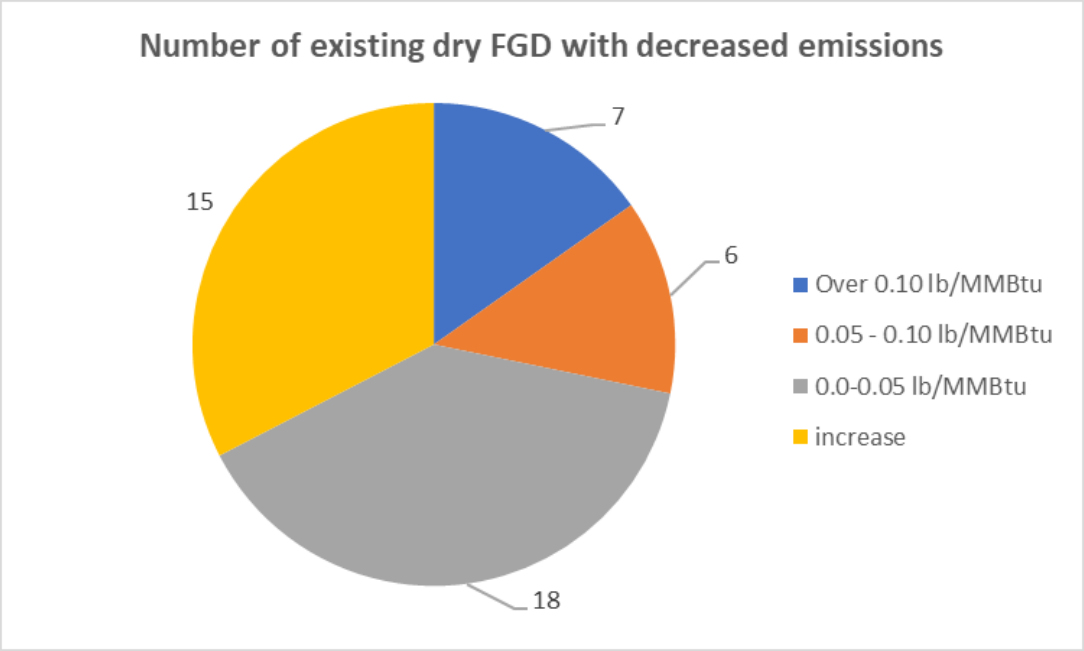


Figure 18. Average and median SO_2 emission rate for dry FGD systems operating the full year in 2011, 2019 emissions of units that were operating in 2011, and new scrubbers built since 2011

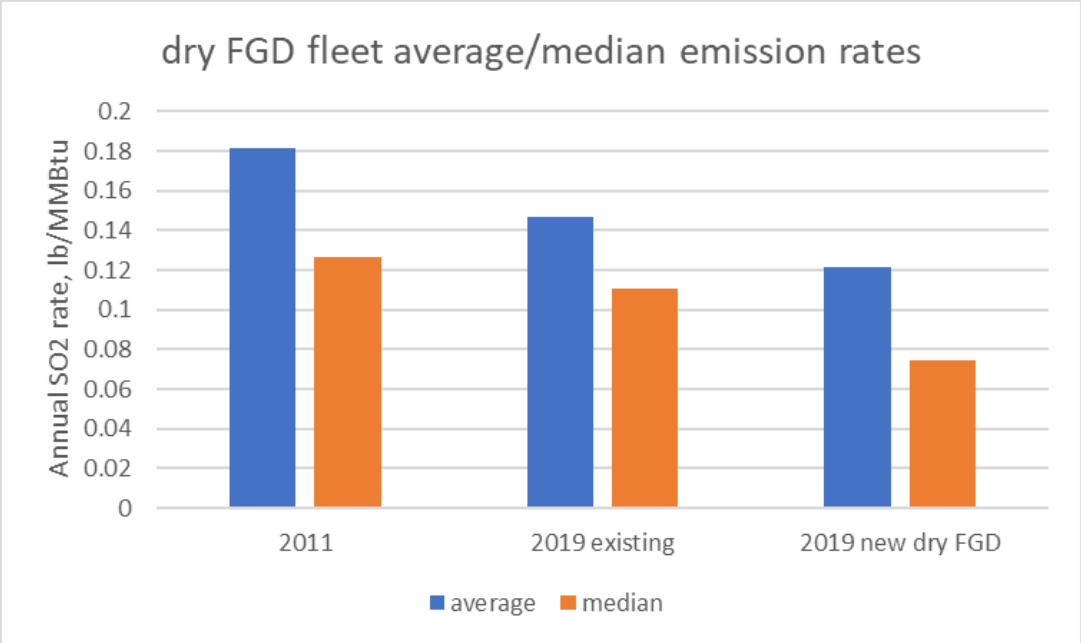
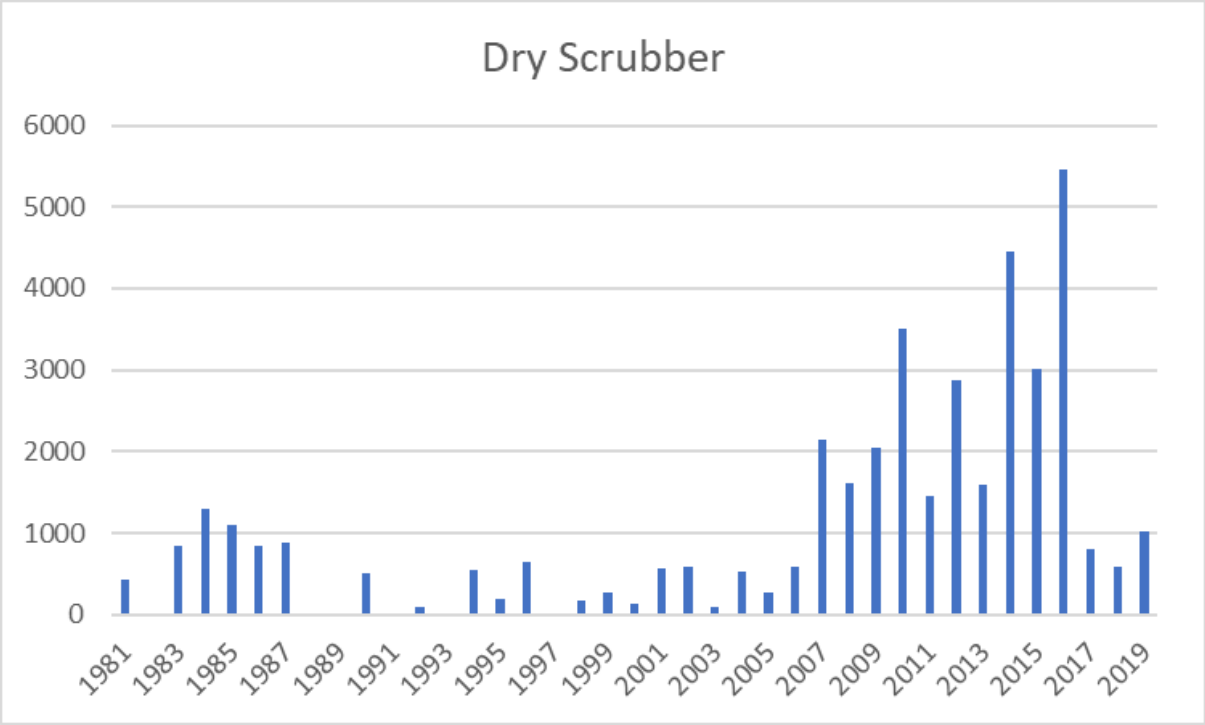


Figure 19 Historical installation of dry FGD systems, MW by year (NEEDS v6)[35]



Methods to improve dry FGD performance

A significant number of dry FGD systems were built decades ago, using the engineering techniques and the equipment that were available at the time. Figure 19 shows historical installation of dry FGD systems. As shown, a significant portion of dry FGD capacity was installed in the 1980s through the 1990s. These were all SDA technology, as CDS technology was not sold in the United States to a significant degree until after 2000. These were installed with older technology, often without the benefit of modern engineering tools, such as computational fluid dynamics (CFD), that permit design of systems that have higher liquid-to-gas interaction. SDA systems, in particular, are very reliant on having good atomization. Therefore, in some cases the existing atomizer could simply be replaced with a better atomizer or modifications that better balance the flow through the atomization region. For any dry FGD that has older bag materials, installation of improved bag materials may facilitate better cleaning and permit higher treatment rates. This is a capability that has evolved over the years. The data clearly demonstrates that there is a great deal more experience with these improvement methods since 2011 than before. As a result, there is better understanding of how to execute these methods today than existed in 2011, and, as will be shown later in this report, significant improvements are possible at a much more modest scope and cost than expected in 2011.

Costs of improving dry FGD performance

EPA's IPM documentation indicated that:

[35] From US EPA National Electric Energy Database System (NEEDS, v6)

"In EPA Base Case v.5.13, coal steam units with existing FGD that do not achieve an SO2 removal rate of at least 90% are assumed to upgrade their FGDs in order to obtain at least 90% SO2 removal and 99% HCl removal. The cost of this "FGD Upgrade Adjustment" is assumed to be $100/kW and is considered a sunk cost for modeling purposes."[36]

This represents EPA's estimate of the cost based upon their envisioned scope of such a retrofit. But, at this point there is more information to estimate the scope of these retrofits.

Past work found the cost of more frequent bag replacement for a fabric filter to be in the range of $2/kW to $5/kW every 3-5 years,[37] and this could be part of an SDA retrofit. However, for SDA systems, improvements in atomizer technology can also contribute to improved performance.

To estimate the cost of an upgrade of the atomizer of an SDA system, it is possible to examine the cost estimate from Sargent & Lundy in IPM.[38]

The base SDA module absorber island cost algorithm, which would include the absorber vessel, any internal piping, the fabric filter, support structure, foundations, etc. is:

637000*(A^0.716)*B*(F*G)^0.6*(D/4)^0.1, where:

- A = capacity in MW
- B = retrofit factor, nominally 1.0 for a typical retrofit
- C = gross heat rate, Btu/kWh
- D = SO_2 rate, in lb/MMBtu
- F = Coal factor, 1.0 bituminous, 1.05 for PRB, 1.07 for lignite
- G = C/1000, where C = Gross Heat Rate in Btu/kWh

Considering that this includes both the absorber and fabric filter and associated support structure, the atomization equipment would not be more than about 10% of the cost, or

63700*(A^0.716)*B*(F*G)^0.6*(D/4)^0.1

Adding 35% for engineering and construction, labor adjustments, and contractor profits, and home office fees, and then an additional 15% for engineering procure construction cost, results in

99900*(A^0.716)*B*(F*G)^0.6*(D/4)^0.1

For example, a 500 MW bituminous unit, results in $8,552,000, or $17/kW for modification of the atomizer in an SDA system. This is well below the cost anticipated by EPA in 2011.

EPA estimated the cost of an FGD upgrade to be $100/kW in anticipation of the MATS rule.[39] This is well above what has been estimated here in light of the scope of most of these

[36] IPM v5.13 documentation, Chapter 5, Section 5.5.2

[37] Andover Technology Partners, *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants*, August 19, 2021, pg . 32

[38] Sargent & Lundy, IPM Model - Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology", January 2017

[39] IPM Documentation, v5.13, section 5.5.2

scrubber upgrades. Although the IPM documentation did not explain the expected cost for an FGD upgrade, it clearly was anticipated in 2011 to be greater than actually occured when the MATS rule was promulgated. This was likely due to improvements in technology and other techniques for executing these projects that have been gained with experience.

Dry Sorbent Injection (DSI)

DSI systems are comprised of storage systems, pneumatic conveying systems and injection piping, as shown in Figure 20. Figure 21 shows the injection system that introduces the material into the ductwork. As shown, it entails piping of modest diameter that is easily installed. An advantage of DSI technology is that the space requirements are very low, making it an ideal retrofit technology. For PRB fuel, DSI may not be necessary for the control of HCl to MATS emission levels, although a system might be installed as a precaution in the event of some coal chlorine variability. Evaluation of information collection request data suggests that the HCl emissions of most PRB-fueled boilers (about 90%) are below the MATS limit, as shown in Figure 22. This is because of the low intrinsic chlorine levels of PRB fuel and also the high free lime content in the fly ash that neutralizes most of what little HCl is produced. Figure 23 illustrates the difference between HCl concentration for PRB fuel and blends with bituminous fuels. It also demonstrates the impact of using trona DSI for reducing HCl emissions as experienced at DTE Energy's St. Clair plant. As shown, HCl emissions with the PRB fuel were below the MATS limit without the need for any trona injection while, on the other hand, when blended with bituminous fuel, trona injection was necessary to reduce HCl emissions to below the MATS limit, but was fairly limited to low treatment rates (NSR, or normalized stoichometric ratio, which is a measure of treatment rate, at a level under 0.50). Highly activated lime hydrate has also been demonstrated to be effective in capture of HCl. [40]

When used in combination with a baghouse, treatment rates can be reduced by about half from what they would be for the same removal rate when using a downstream ESP. Figure 24 shows treatment rates for lime hydrate when used for HCl capture when using a baghouse versus an ESP. Other studies have shown similar levels of reduction.[41] Today, since 2011, there are activated lime hydrate products available that would even further reduce treatment rate.[42]

DSI can have a beneficial or detrimental impact on Hg capture with ACI, depending upon the situation. When SO_3 adversely impacts ACI performance (such as with bituminous coals), DSI can have a beneficial impact on mercury capture with ACI by mitigating SO_3. This is shown in Figure 25, which shows data taken from DSI testing at the Constellation Wagner Station. Sodium-

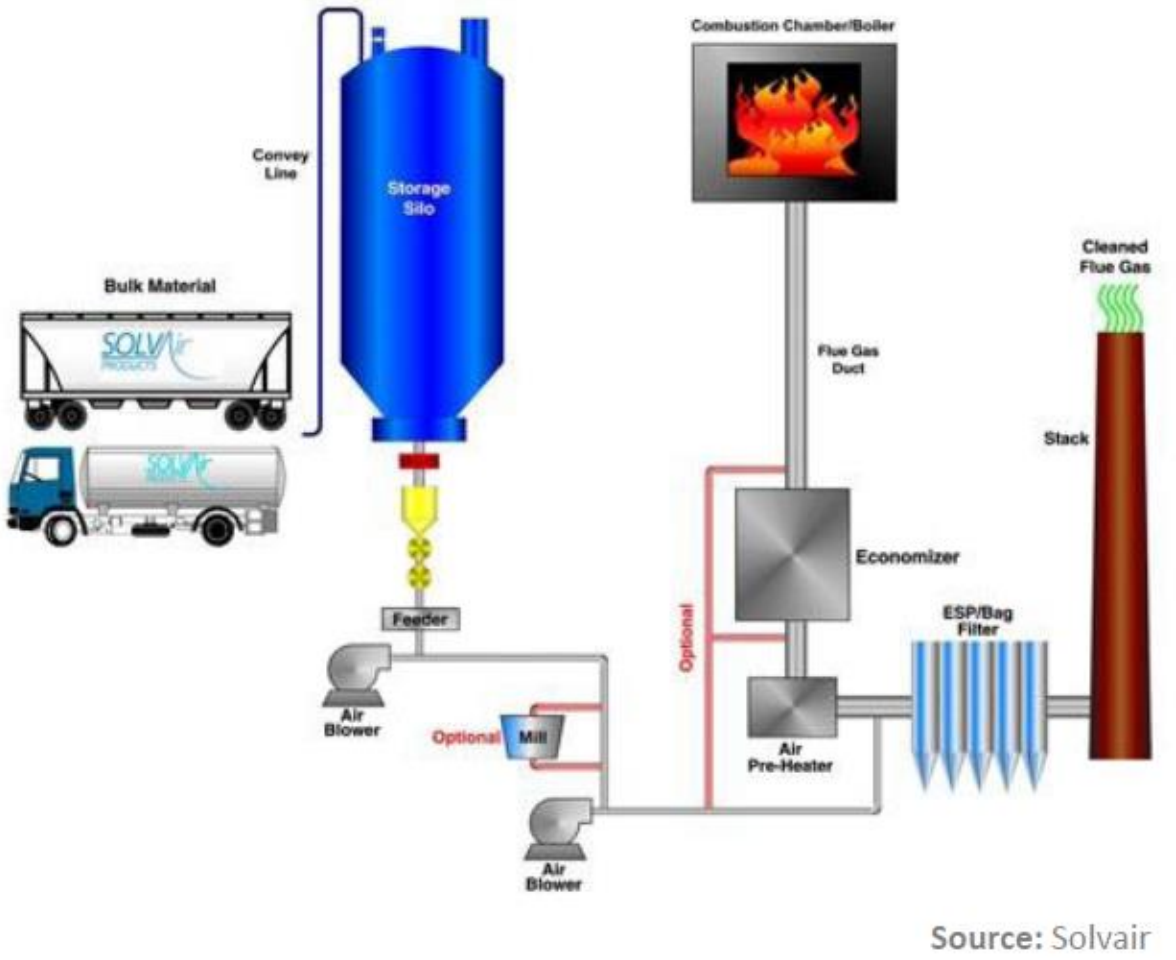
[40] Fitzgerald, H., "Hydrated Lime DSI - Solution for Acid Gas Control (SO3, HCl, and HF)", MARAMA /ICAC SO2/HCl CONTROL TECHNOLOGIES WEBINAR, July 19, 2012

[41] Laird, C.; Smith, J. *Results of Dry Sorbent Injection Testing to Reduce HCl*. Paper #107 to the 2012 Mega-Symposium, August 2012, Baltimore, MD, see Tables 4 and 5.

[42] Dickerman, J., Schantz, M., "Improved DSI Performance with Optimized Hydrated Lime"; *see also* Filippelli, G.," Sorbacal® SPS - Changing Perceptions on Hydrated Lime for SO_2 Removal and ESP Impacts", APC-Wastewater Round Table/PCUG, July 2016; Sewell, M., and Millwee, T., "L'hoist North America Introduction", December 10, 2015.

based DSI agents like trona or sodium bicarbonate, on the other hand, can have a detrimental impact on ACI by increasing NO_2 concentration. This is more prone to occur when trona is injected at high rates, such as for SO_2 control and when NO_x emissions are higher and upstream of a fabric filter.[43] New activated carbons available since 2011 are able to address the adverse impacts of sodium DSI reagents on ACI and other situations that were previously challenging for activated carbon.[44]

Figure 20. Dry Sorbent Injection (DSI) system[45]



[43] Filippelli, G., et al, "The Inherent Benefits of a Coordinated MATS Solution: Lessons-Learned from Providing ACI and DSI Together", Power Plant Control "MEGA Symposium, paper # 118, August 19-22, 2014, Baltimore, MD

[44] Fessenden, J., Satterfield, J., "Cost Effective Reduction of Mercury Using Powder Activated Carbon Injection", March 2, 2017

[45] Kong, Y., et al, "Dry Sorbent Injection of Trona and Sodium Bicarbonate for SO2, SO3, NOx and Mercury Mitigation", Power Gen 2009

Figure 21. A DSI injection system[46]

[46] http://www.nol-tec.com/dry-sorbent-injection.html

Figure 22. HCl emissions for PRB fired utility boilers from EPA's ICR database[47] (CS-ESP is cold-side ESP)

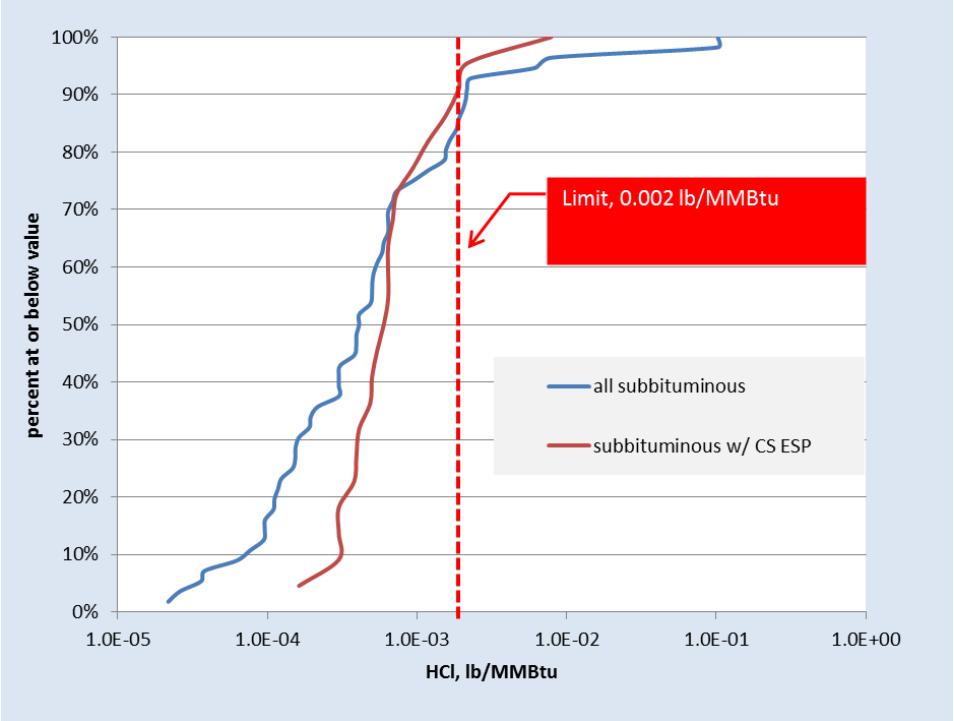
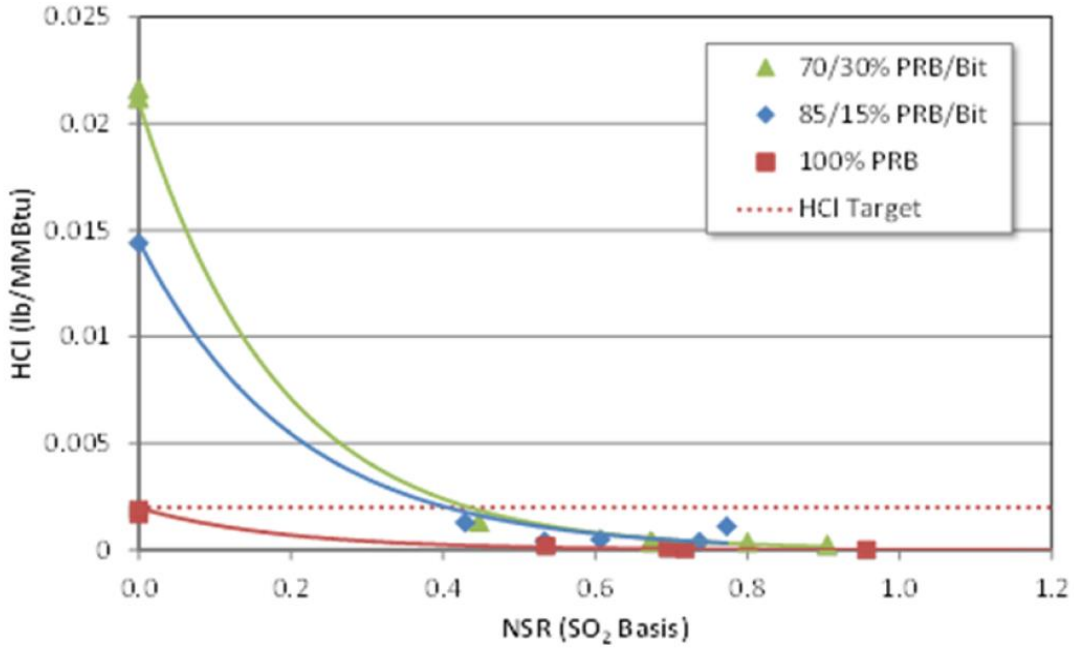


Figure 23. HCl emissions as a function of trona NSR and coal blend at DTE Energy St. Clair[48] (NSR, or normalized stoichometric ratio, is a measure of treatment rate)



[47] Staudt, J., "Air Pollution Compliance Strategies for Coal Generation", EUCI, December 5-6, 2011

[48] Filippelli, G., et al, "The Inherent Benefits of a Coordinated MATS Solution: Lessons-Learned from Providing ACI and DSI Together", Power Plant Control MEGA Symposium, paper # 118, August 19-22, 2014, Baltimore, MD

Figure 24. HCl Removal versus treatment rate using hydrated lime - Baghouse vs. ESP[49] (SPS is the sodium-based DSI sorbent)

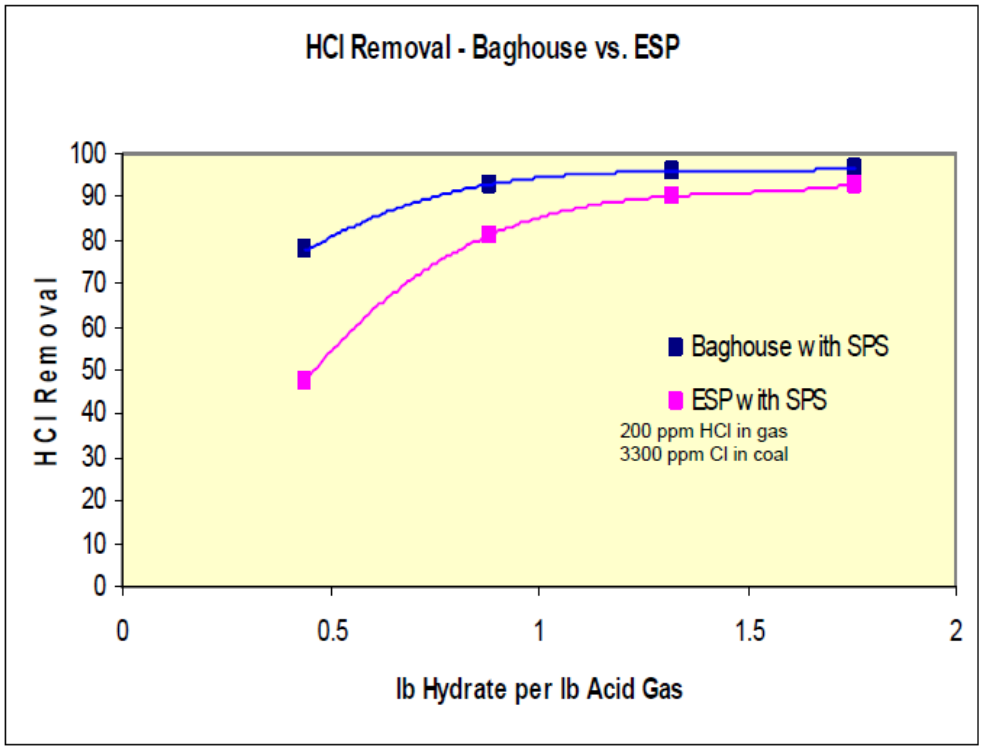
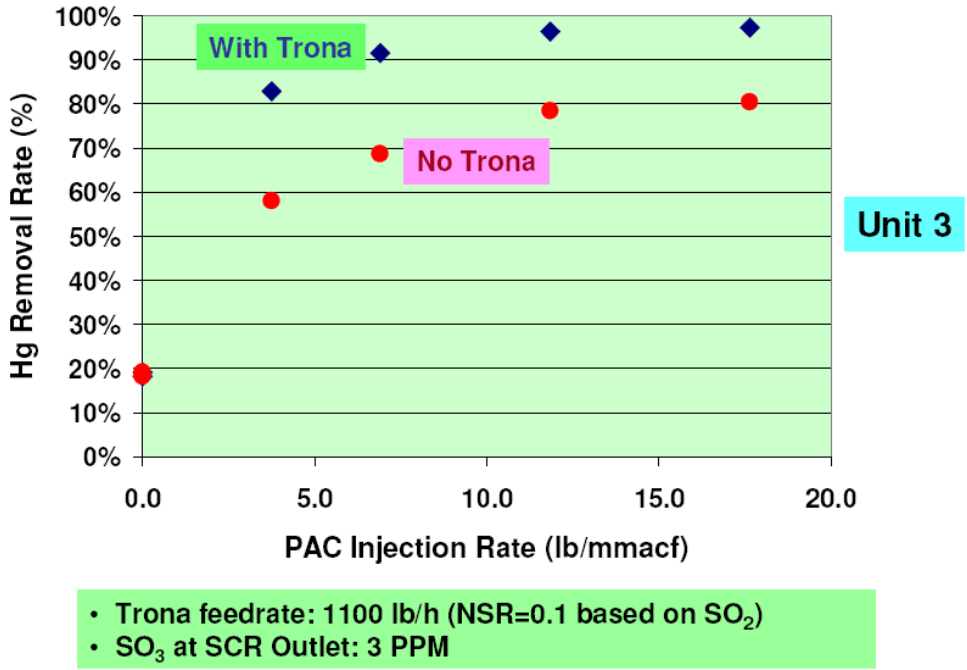


Figure 25. Effect of trona injection on mercury capture using powdered activated carbon at bituminous coal fired Constellation Wagner 3.[50]



[49]Fitzgerald, Howard, "Hydrated Lime DSI - Solution for Acid Gas Control (SO3, HCl, and HF)", MARAMA /ICAC SO_2/HCl Control Technologies Webinar, July 19, 2012.

[50] Kong, Y., et al, "Dry Sorbent Injection of Trona and Sodium Bicarbonate for SO2, SO3, NOx and Mercury Mitigation", Power Gen 2009

Trona and other sodium-based DSI agents generally have a positive impact on ESP PM capture performance. This is because sodium-based DSI agents have a positive impact on fly ash resistivity – an important parameter that impacts ESP performance. An exception to this might be a unit with a very marginal ESP firing high sulfur coal.[51] Table 3 shows results from Constellation Wagner Unit 2 where filterable PM emissions were reduced by 95% from 0.088 lb/MMBtu to 0.0045 lb/MMBtu using DSI.[52] There was no powdered activated carbon injection at the time and the trona was being injected to reduce SO_2 by 29%. Therefore, despite a higher PM loading to the ESP, the PM emissions went down. To what degree a benefit may result from the use of DSI will vary based upon the specifics of the situation.

DSI may be sufficiently effective in removing acid gases with the existing PM control device; however, in some cases it may be necessary or desirable to modify the existing PM control device or to install a new PM control device. For example, DSI using sodium sorbents will generally improve ESP performance so that PM emissions will drop as well as acid gases, despite higher inlet PM loading to the ESP. On the other hand, hydrated lime will not have the beneficial impact on ESP performance that sodium reagents provide. Therefore, depending upon the circumstances and the DSI reagent used, acid gas capture with DSI may be limited for ESP-equipped units. Further reduction can be achieved with a fabric filter. If a fabric filter is installed for PM control, this will facilitate capture of acid gases with DSI and mercury with ACI in addition to improved PM capture. Such an approach will be far less expensive than installing a scrubber. As a result of the progress of installing DSI systems and developing improvements to these systems since 2011, there is far more data today on the capabilities of DSI than there was in 2011.

Table 3. Effect of trona injection on PM emissions Constellation Wagner Unit 2[53]

	Baseline (No Trona)	With Trona (NSR=1.1 based on SO_2)	PM Reduction Rate
Filterable PM (g/dscf)	0.088	0.0045	95%
Condensable PM (g/dscf)	0.0288	0.01424	51%
Total PM (g/dscf)	0.1209	0.0276	77%

The cost of a DSI system will depend a great deal upon the treatment rate, which determines the size of the storage and conveying system.

[51] Mastropietro, R., "Fly Ash Resistivity with Injected Reagents and Predicted Impacts on Electrostatic Precipitators", http://www.carmeusena.com/sites/default/files/brochures/flue-gas-treatment/tp-LCI-NOL-TEC-Systems-inj-reagents-fly-ash-resistivity-ESP-perf.pdf, page 4

[52] Kong, Y., et al, "Dry Sorbent Injection of Trona and Sodium Bicarbonate for SO2, SO3, NOx and Mercury Mitigation", Power Gen 2009

[53] Ibid

In general, if a fabric filter were to be installed, hydrated lime would be selected as the reagent since it is less costly and produces a stable product in the ash. Sodium reagent may be preferred for a smaller ESP since it usually provides benefits to ESP performance. The timeline for installation of a DSI system would be a year or so from when an order is placed with an outage of a few days to a week.

Energy Impacts

DSI will increase energy demand modestly due to the energy used to transport and inject the DSI reagent.

Other Environmental Impacts

DSI will have the following impacts on other air pollutants.

Filterable PM – DSI increases dust loading to the ESP, but it can also improve the electrical performance of the ESP. When using sodium-based sorbents (trona or sodium bicarbonate), PM emissions downstream of the ESP will frequently drop even though particle loading into the ESP is higher.

Condensable PM – DSI should reduce condensable PM by capturing some SO_3, which is a main contributor to condensable PM.

Mercury – DSI will enhance the capture of mercury when bituminous fuels are used because they produce SO_3 that competes with mercury to bind with carbon, and DSI removes SO_3. Sodium-based DSI reagents can adversely impact mercury capture from activated carbon, especially for PRB fuels that do not have significant SO_3 (no beneficial impact of removing SO_3). This is because NO can be oxidized to NO_2, which reduces mercury capture. In this case a facility may choose to utilize DSI-tolerant carbons that are more costly. The availability of these new carbons since 2011 have made use of sodium-based DSI more attractive in situations where ACI and DSI might both be used.[54]

Improvements in DSI technology since 2011

Based upon a review of 2011 AMPD data and closer examination of facilities, only eleven units were equipped with DSI in 2011 for the purpose of SO_2 control. Therefore, there was very limited experience with this technology. In preparation of the MATS rule, EPA's IPM v5.13 documentation assumed that if DSI was used for HCl control, then a fabric filter would be required downstream of sorbent injection. That proved to not be the case. With the fabric filter, IPM v5.13 assumed 90% HCl reduction with a floor emission rate of 0.0001 lb/MMBtu. These assumptions were shown to impact EPA's forecast for fabric filters in response to the MATS rule that far exceeded the actual installations. EPA also underestimated the improvements that would occur in DSI technology (equipment and sorbents) that would improve performance and reduce reagent

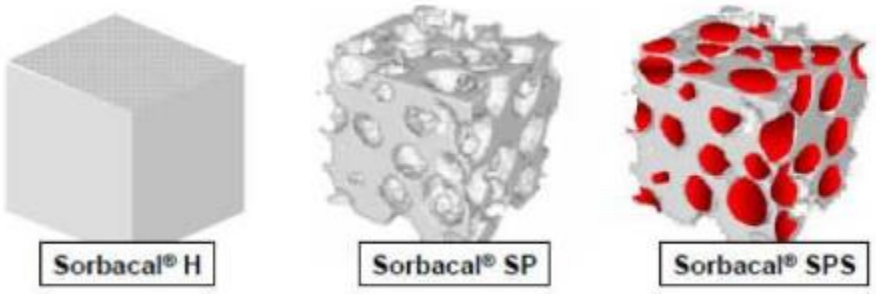
[54] Andover Technology Partners, *Analysis of PM and Hg Emissions and Controls from Caol-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), August 19, 2021, pp 48-51

requirements.[55] In their IPM v5.13 assumption, EPA did not anticipate the improvements that would occur in DSI technology.

According to the NRDC database, DSI installations increased to 66 units by 2019. In addition to the increased use of DSI since 2011, there have been advances in DSI technology. These advances have included advances in reagent/sorbent,[56] advances in equipment,[57] and advances in engineering tools to design DSI injection systems.[58]

Advances in reagent since 2011 have primarily been with hydrated lime that has been activated by improving physical and chemical properties so that it can be used in a wider range of applications. In the past, sodium-based reagents were assumed to be best for ESP-equipped units; however, advances in lime reagents have permitted use of calcium reagents in some ESP-equipped units. Lime-based sorbents can be less expensive, but they do not interfere with ACI in the manner that sodium reagents can, and the lime sorbents do not create a water-soluble product. Figure 26 shows different hydrated lime particles. They differ by the degree of porosity and surface area and activation with other chemicals to make them more reactive.

Figure 26. Illustration of various hydrated lime particles[59]



Advances in equipment since 2011 have included better methods for dispersing the reagent, such as shown in the dispersion model for standard DSI injectors and the newer, Sorb-Tec injector, shown in Figure 27. Figure 28 shows how the improved injection method reduces the treatment rate for any given level of SO_2 capture. For example, at 60% SO_2 removal the improved injection

[55] Staudt, J., Declaration before United States Court of Appeals for the District of Columbia Circuit, September 23, 2015

[56] Foo, R., et al, "ESP Compatible Calcium Sorbent for SO2 Capture at Great River Energy's Stanton Station," Power plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-19, 2016, Baltimore
Zhang, R., et al, "A high Reactivity Hydrated Lime for Improved SO2 Capture", Power plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-19, 2016, Baltimore

[57] Liu, G., "An Innovative Mixing Method to Lower the Cost of Operating DSI and ACI Systems", Power Engineering Magazine, December 2, 2015, available at: https://www.power-eng.com/emissions/air-pollution-control-equipment-services/an-innovative-mixing-method-to-lower-the-cost-of-operating-dsi-and-aci-systems/#gref

[58] Liu, G., et al, "Optimizing Dry Sorbent Injection Performance Using Chemistry-Based CFD Modeling", Power plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-19, 2016, Baltimore

[59] Hunt, G., and Sewell, M., "Utilizing Dry Sorbent Injection Technology to improve Acid Gas Control", Presented at the 34th International Conference on Thermal Treatment Technologies & Hazardous Waste Combustors October 20-22, 2015, Houston, TX

system offers roughly a 30% reduction in reagent. Or, alternatively, if treatment rate remains the same, capture can increase from about 60% to about 70%. Although this figure shows results for lime reagent, one would expect similar improvements for sodium-based reagents because the impact shown here is a result of improved reagent distribution rather than changes in the reagent.

Figure 27. Dispersion model for standard DSI injection lance (left) and Sorb-Tec DSI injection lance (right)[60]

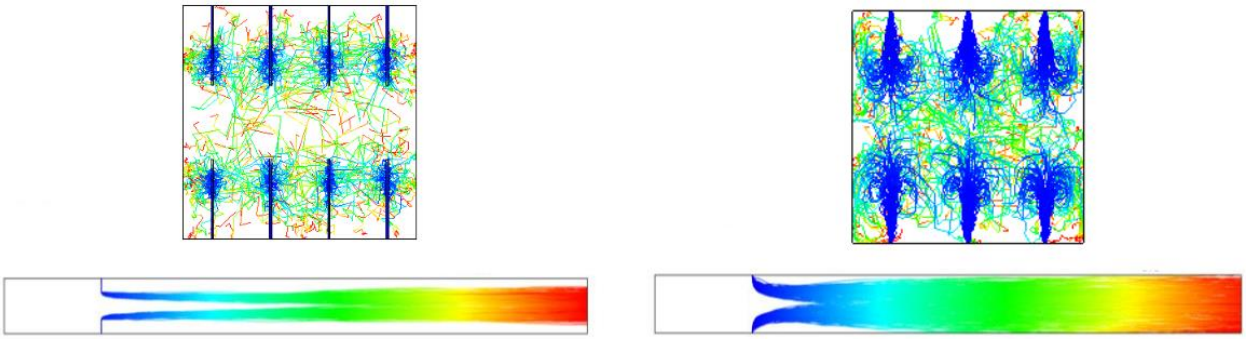
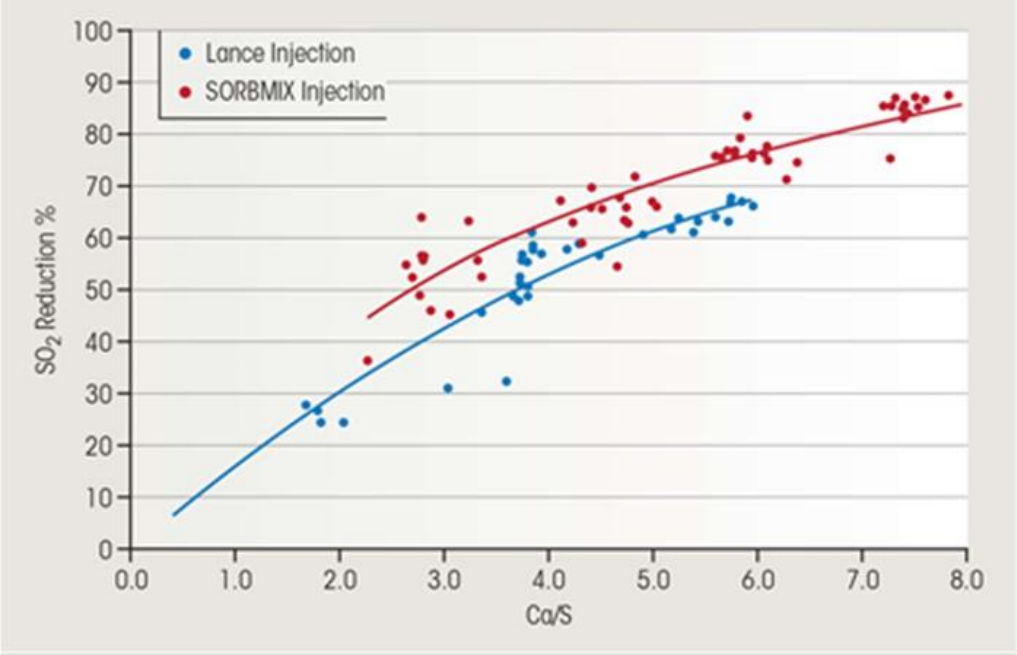


Figure 28. Performance improvement using Sorbmix DSI injector on power plant[61]



[60] Evans, N. et al, "Sob-Tec Lance-Less Technology Reduced Costs and Improved Performance for your DSI and ACI Systems", Power plant Pollutant Control and Carbon Management "MEGA" Symposium, August 16-19, 2016, Baltimore

[61] Liu, G., "An Innovative Mixing Method to Lower the Cost of Operating DSI and ACI Systems", Power Engineering Magazine, December 2, 2015, available at: https://www.power-eng.com/emissions/air-pollution-control-equipment-services/an-innovative-mixing-method-to-lower-the-cost-of-operating-dsi-and-aci-systems/#gref

Cost of improvements in DSI technology

Estimates of cost of DSI installations are provided in a document by Sargent & Lundy,[62] and these are shown in the appendices. Generally, these systems are in the range of $40/kW. Improved injectors would comprise some portion of the total cost, but new injectors would not require replacement of the storage or metering system, or most of the distribution piping. Some modifications to distribution piping near the injectors would be needed. The cost would likely be on the order of $10/kW or less.

II. Trends in HCl emissions

The majority of coal plants in the United States are scrubbed and rely upon maintaining SO_2 below 0.20 lb/MMBtu to demonstrate compliance with the acid gas requirements of the MATS rule, and they do not report HCl emissions. Therefore, HCl emissions rate data is limited to those facilities that measure HCl for compliance demonstration. The HCl emissions rate data available in the NRDC database totals 89 units, and includes a range of facility types. Most scrubbed units demonstrate compliance by maintaining SO_2 emissions under 0.20 lb/MMBtu and therefore do not report HCl emissions. The majority (63) of the 89 units with reported HCl emissions in the NRDC database are not scrubbed, while 26 have a scrubber. Table 4 shows the breakdown of units with HCl data, by control type for acid gases and for PM. Only one was equipped with dry FGD, but 25 included units with wet scrubbers. 55 units had no acid gas controls at all. Table 5 shows the breakdown of fuels used for the scrubbed units. Subbituminous coals are typically lower in HCl emissions than bituminous coals due to lower Cl content and higher free lime content in the fly ash. "OTH" or other coals includes refined coals or lignite. Figure 29 shows the average HCl and SO_2 emissions rates for facilities for each type of SO_2 control. As shown, the units with DSI had substantially lower HCl and SO_2 emissions than uncontrolled units, and scrubbed units had even lower emissions. More detailed examination of this data will show that some of the facilities for each technology type achieve emission rates well below the average, and some of the factors that contribute to better performance will be examined.

Table 4. Breakdown of 89 units with HCl data by type of control

	Dry Scrubber, any type	Wet scrubber, any type	DSI	No Acid Gas Control	Baghouse - Any type	ESP - Any type	COHPAC
Total	1	25	11	55	31	75	17

Table 5. Breakdown of scrubbed units with HCl data by coal type

	Dry FGD	Wet FGD		
Coal type	SUB	BIT	SUB	OTH
Total	1	16	6	3

[62] Sargent & Lundy, IPM Model - Updates to Cost and Performance for APC Technologies, Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology", January 2017

Figure 30 and Figure 31 show the relationship between HCl emissions and SO_2 emissions for units with wet FGD (Figure 30) and DSI (Figure 31). It is clear that lower SO_2 emission rates are associated with lower HCl emission rates. As expected, Figure 31 demonstrates that DSI-equipped facilities with baghouses tend to be better controlled for acid gases than DSI-equipped facilities with ESPs.

Figure 29. Average SO_2 and HCl concentration by SO_2 control technology type

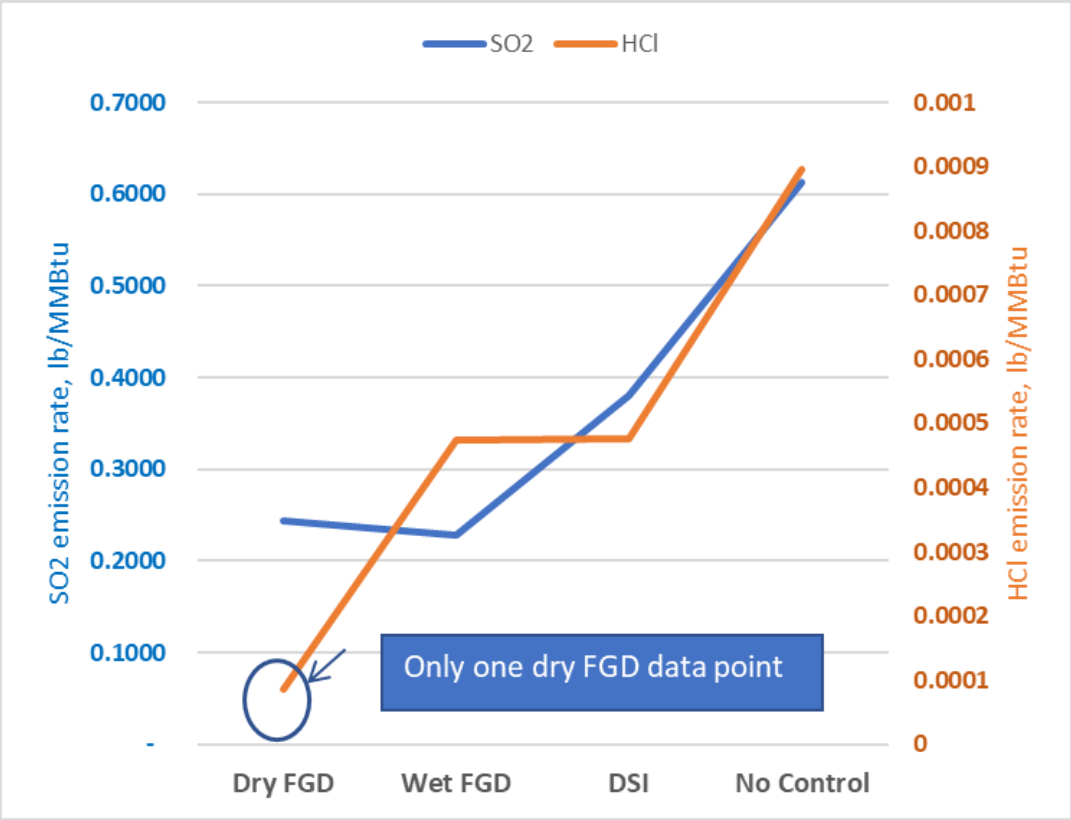


Figure 30. HCl v SO_2 emission rate (lb/MMBtu) for wet FGD equipped units

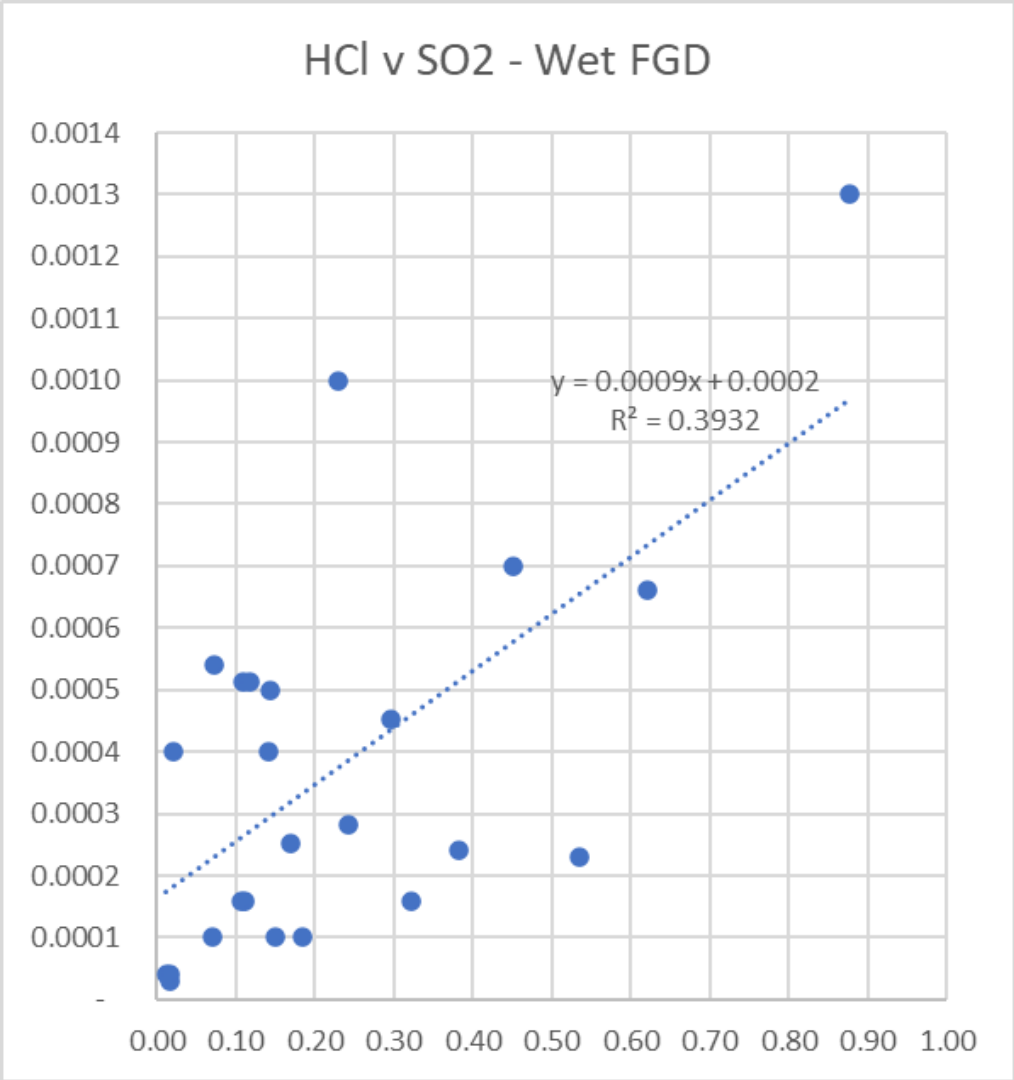


Figure 31. HCl and SO_2 emission rates for DSI-equipped units with baghouses and with ESPs

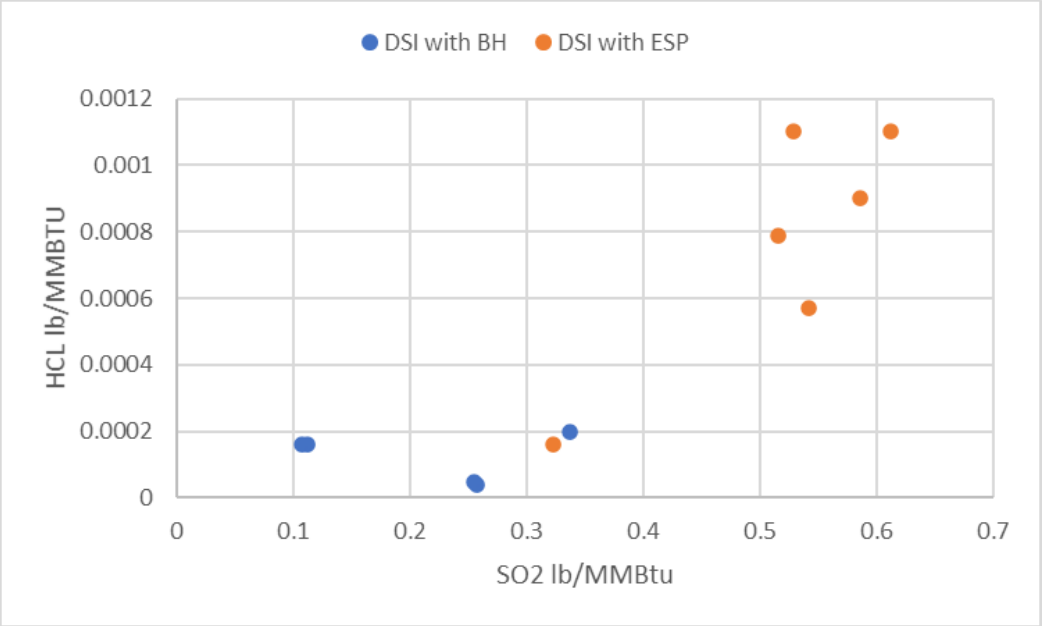


Figure 32 shows the relationship between HCl emissions and SO_2 emissions for units without DSI or either form of FGD, that is, only PM controls (ACI for Hg may be present). There is a fair amount of scatter without any clear correlation between the two variables. Figure 33 shows the average HCl emissions of Figure 32 for each PM control technology. As shown, the combination of a baghouse and ESP was associated with a lower HCl emissions rate.

Figure 32. HCl and SO_2 emissions for units without any form of acid gas/SO_2 control and only PM controls, by PM control device

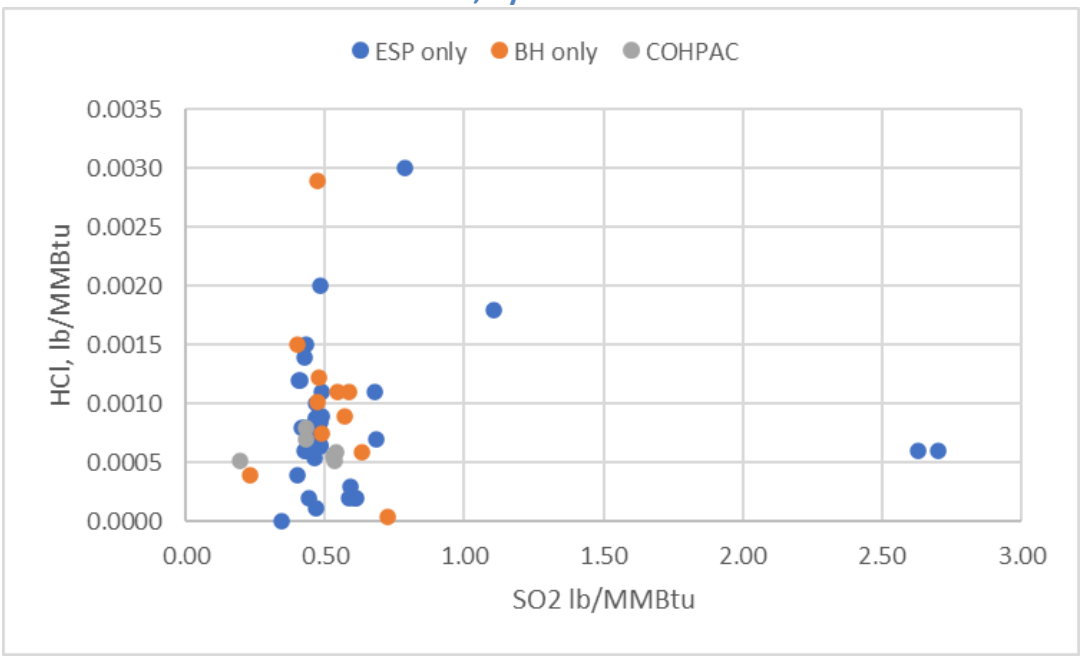
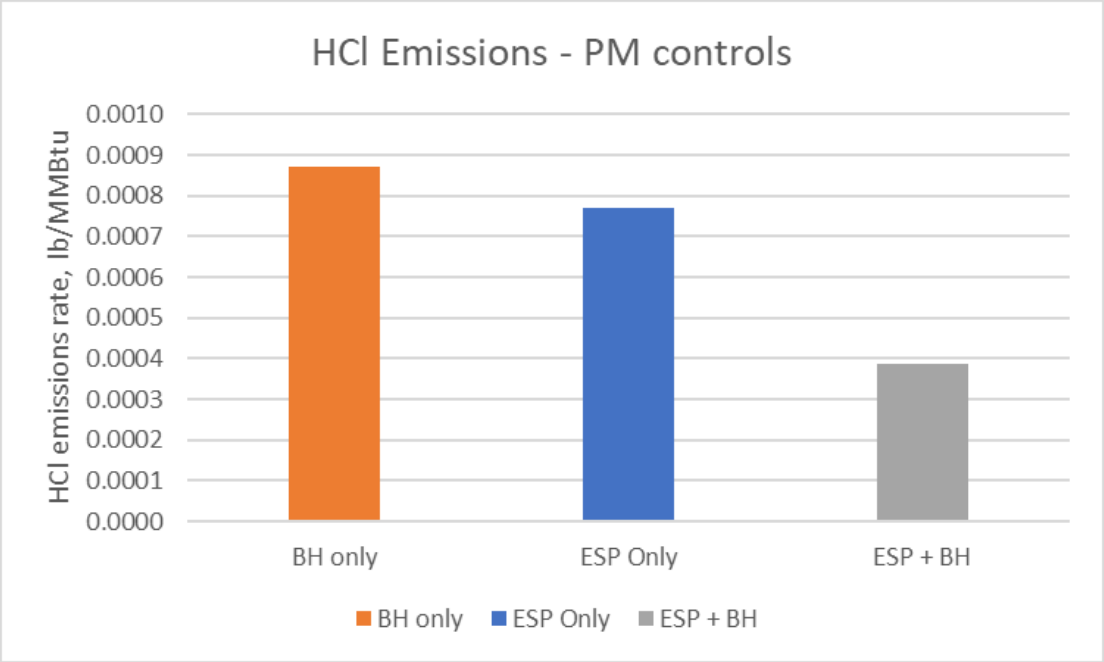


Figure 33. Average HCl emissions based upon PM control device



The HCl data for units was divided into deciles, from the 10% lowest HCl emission rate units to the 10% highest HCl emission rate units. Figure 34 shows average SO2 and HCl emission rates and Figure 35 shows median SO_2 and HCl emission rates by decile from lowest HCl rate to highest. There is a general trend between SO_2 and HCl rates, with higher SO_2 more often than not associated with higher HCl. Median and Average are shown in order to address the impact of two high SO_2 emitting units on the average.

Figure 34. Average HCl and SO_2 emissions rates based upon decile according to HCl emissions

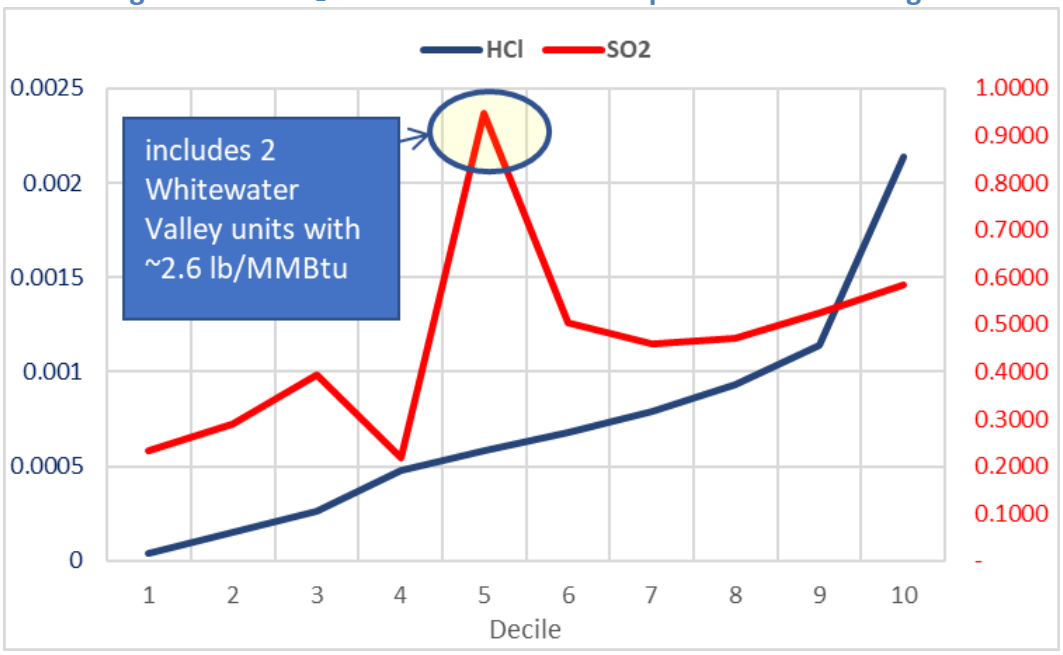


Figure 35. Median HCl and SO_2 emissions rates based upon decile according to HCl emissions

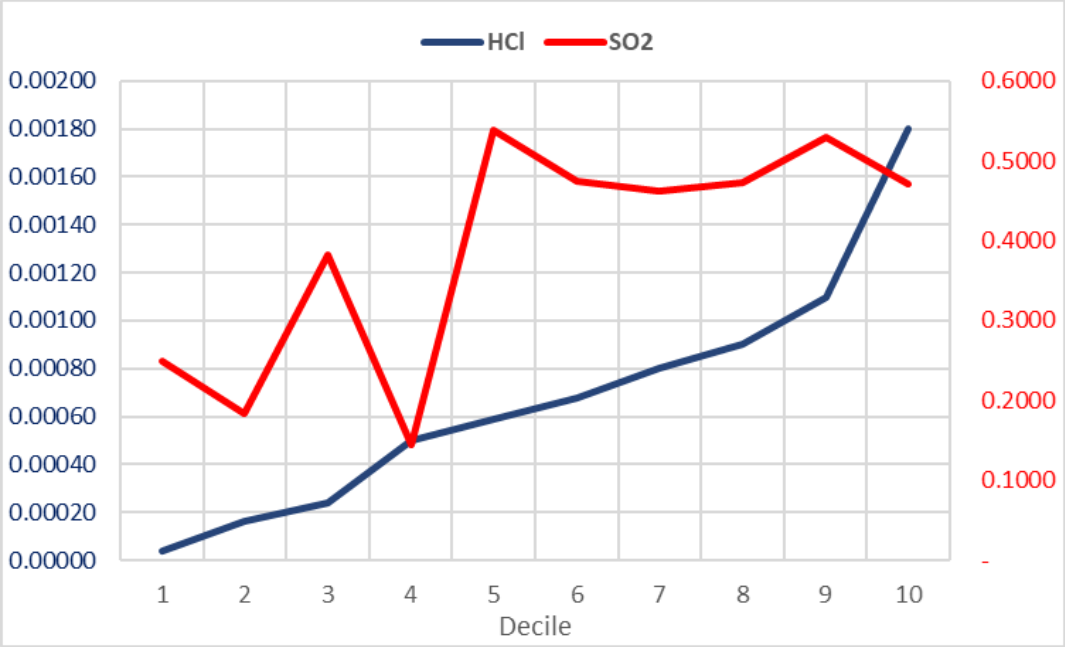


Figure 36 shows the fuel type by decile. Except for the top decile, bituminous coals seem to be used in the best deciles and subbituminous shows a higher probability for higher emissions deciles. Because subbituminous coals tend to have lower HCl emissions, this must be explained by equipment, which will be shown to be the case. Figure 37 shows PM emissions control by decile. The top decile is most likely to have both ESPs and baghouses. The bottom deciles are most likely to have just an ESP. Figure 38 shows the average age of PM emissions controls by decile. There is no apparent trend.

Figure 36. Percent of decile using coal type

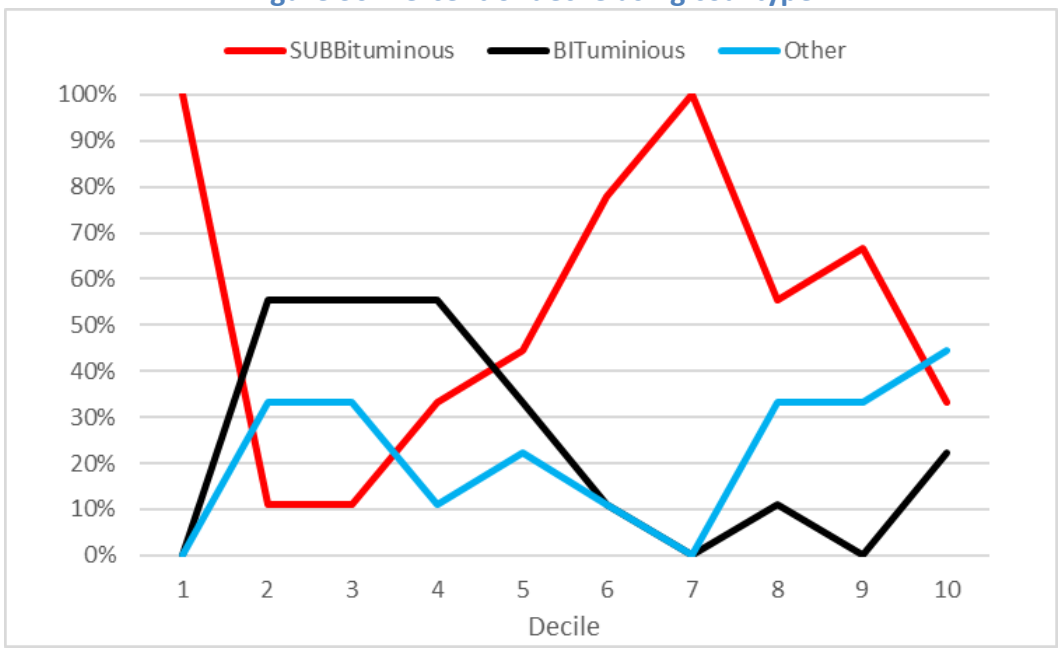


Figure 37. Percent of decile using PM emission control

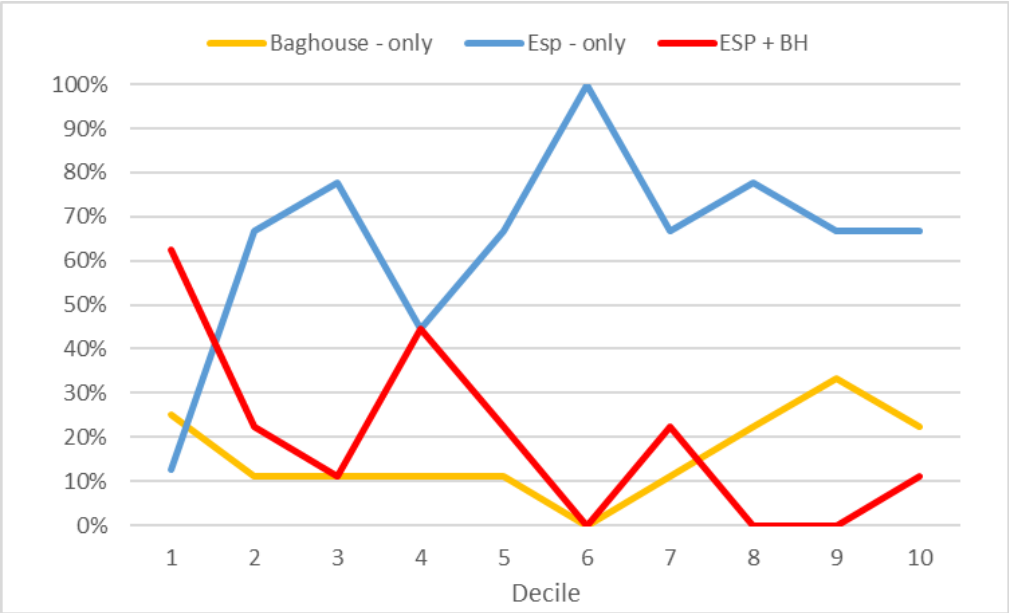


Figure 39 shows acid gas/SO_2 control methods by decile. There is a clear trend that the top deciles are most likely to have acid gas/SO_2 controls, especially FGD and wet FGD in particular. Since there is only one dry FGD system in the 89 unit data set being used and because dry FGD systems typically use lower sulfur (and lower HCl) coal, it is expected that dry FGD systems would be likely to be low HCl emitters.Data on DSI units with a fabric filter suggests that they might be very low emitters – lower than wet FGD. Figure 40 shows the average age of acid gas/SO_2 controls in each decile. There are no strong trends; however, the best performing two deciles each have relatively new wet FGD systems.

Figure 38. Average age of PM controls in each decile

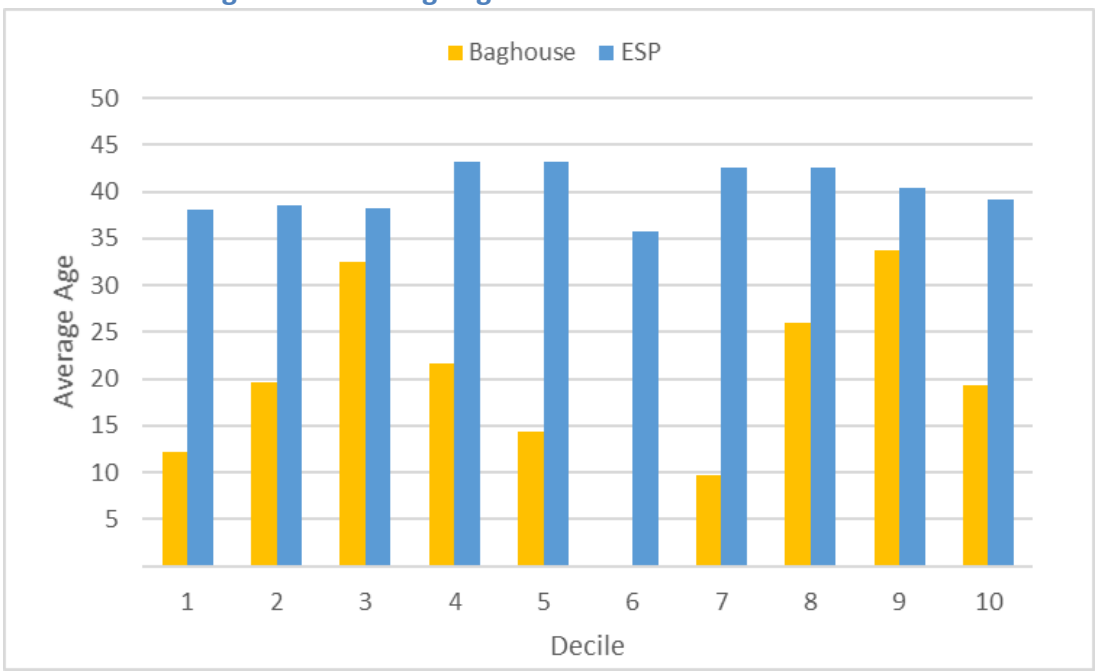


Figure 39. Percent of decile using acid gas/SO_2 control technology

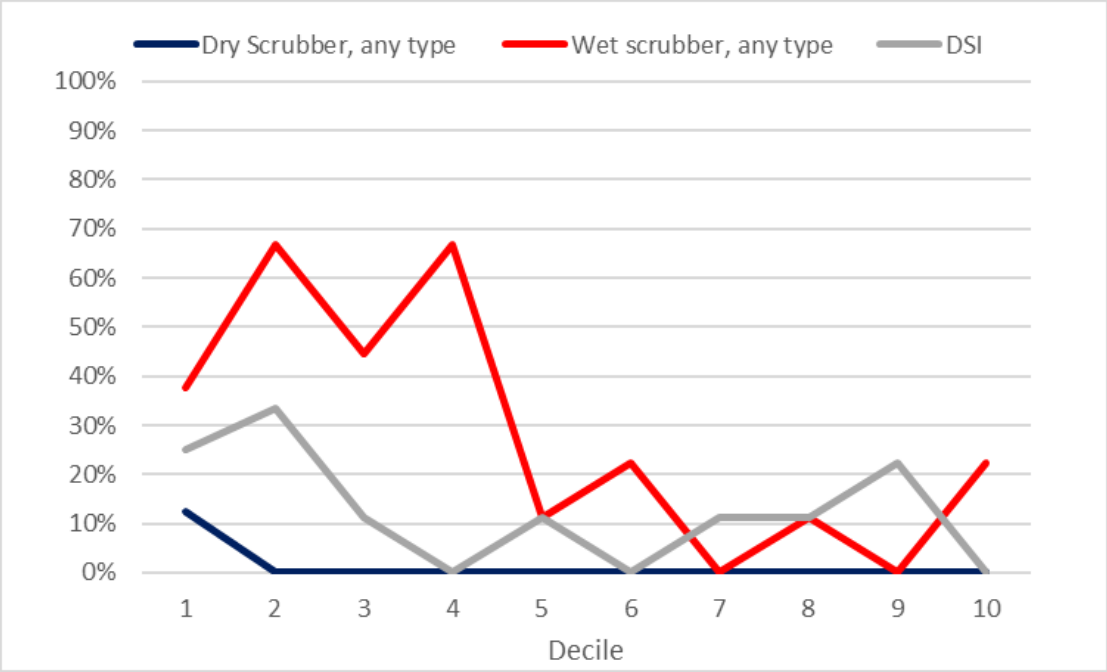
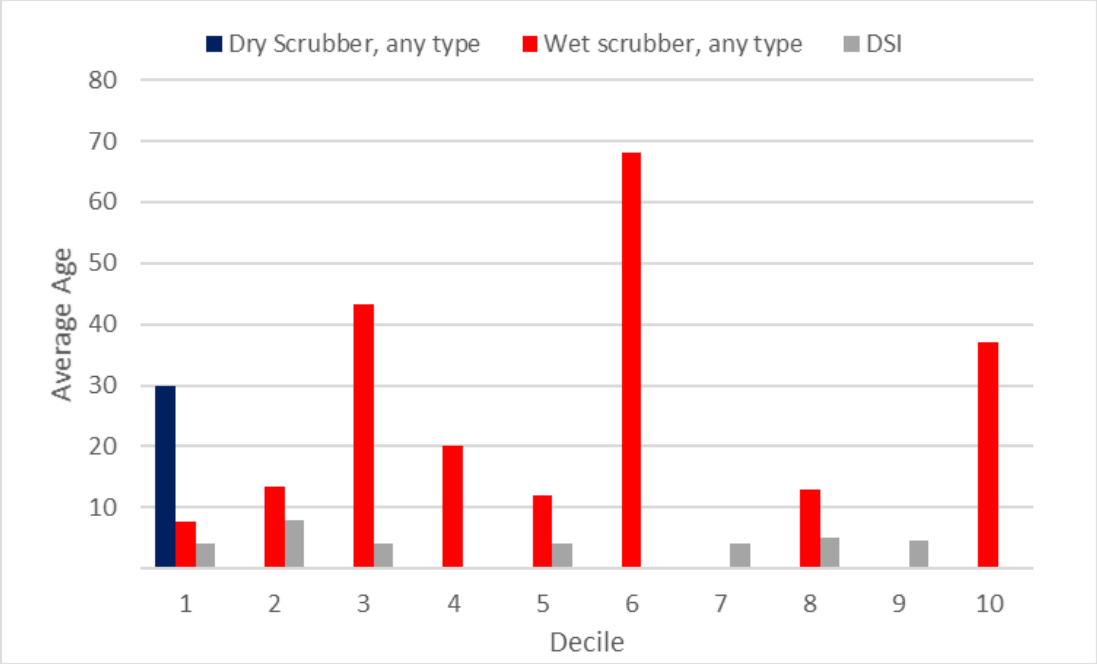


Figure 40. Average age of acid gas/SO_2 control technology in each decile



III. Emissions Monitoring

HCl CEMS are generally not used because the MATS rule allows other options for demonstrating compliance. HCl CEMS; however, would provide operators the data that they could use to improve operations and optimize their systems to minimize HCl emissions.

Available technologies for the measurement of HCl include two infrared methods, fourier transfer infrared (FTIR) spectroscopy, and near-infrared tunable diode laser spectroscopy (TDL). Both methods analyze the transmittance of light through the gas to measure gas species. FTIR instruments can potentially measure multiple species because it uses a broad-band light source and transmittance over the range of wavelengths is evaluated. FTIR systems require the sample to be transported to the analyzer where the optical path is. The sample system which entails a probe and heated umbilical. Preserving sample integrity is therefore a concern with FTIR.

TDL methods use a narrow band light source (a laser) that is scanned over a narrow wavelength band to look for a specific gas species. The TDL instruments typically measure a single species, and take the measurement in-situ in a cross-duct or cross-stack measurement because the optical path is in the duct or chimney, and the optical path is linked to the analyzer (where the lazer and electronics are located) by fiber optic. This offers the advantage of avoiding the need to transport a sample while preserving sample integrity.

For the TDL systems the level of detection is related to the distance of the path, so that for longer paths (wider chimneys or ducts) the level of detection (in terms of ppm or an equivalent for lb/MMBtu) is lower.

US EPA had developed Performance Specification 18 (PS-18) for quality assurance of HCl CEMS.[63] At this point only one supplier has passed PS-18, and that is Unisearch, which provides a TDL analyzer which is available from two US CEMS system integration companies. The technology has proven to work for both wet and dry stacks. PS-18, however, may benefit from some revision. Some suggestions to consider for PS-18 include:

- Allow dual ranging similar to what is possible for criteria pollutant analyzers
- Update the PS-18 calibration procedure to accommodate the features of the analysers that are available
- Consider revisions to the certification procedure to meet the goals of certification while accommodating the technology that is used for HCl.

The cost of these analyzers will range from around $80,000 to around $250,000, but additional costs are associated with start up and costs may be greater depending upon distance from the sample or measurement point to the analyzer. Full installation of the analyzers, to include commissioning and start up testing might be up to double that amount. The TDL instruments would be expected to be less costly and at the lower end of the scale due to the avoidance of heated sampling line, sample probe, etc. and FTIR at the higher end.

[63] https://www.epa.gov/emc/performance-specification-18-gaseous-hydrogen-chloride

IV. Opportunities to improve acid gas control performance and associated costs

There are a number of means to improve the acid gas emissions of coal-fired facilities based on developments in the industry, and the best selection will depend upon the configuration of the facility. Since 2011, when MATS was developed, technologies have become available that were not available then. Some technologies may have dropped in cost and/or become more effective since then. Finally, there are technologies where there was little or no data prior to promulgation of the MATS rule where we have much more data today than before MATS to help assess the cost or performance that is possible.

Units without any acid gas controls

A total of 29,780 MW of coal capacity (9,247 MW with baghouses and 22,702 MW with ESPs, 2,169 MW with both ESPs and baghouses) and 86 units do not have any acid gas controls, with an average capacity of about 300 MW. The average HCl emission rate for these units where HCl data was available is about 0.0007-0.0009 lb/MMBtu. These facilities can install DSI, and likely reduce their HCl emissions at least 50% and likely 70% or more, depending upon whether or not they are equipped with a fabric filter. This would result in a controlled HCl emission rate of about 0.0003 lb/MMBtu.

Assuming a capital cost of roughly $40/kW, it would cost the industry roughly $1.2 billion in capital (or about $130 million per year in annualized capital charges)[64] to add DSI to all of these units.

For ESP-equipped units, the addition of a baghouse will also result in greater HCl emissions reduction than with DSI alone. This is expected to cost somewhere in the range of $150-$200/kW in capital cost. [65] In combination with DSI, this would likely result in over 90% reduction in HCl emissions. Units with DSI and a fabric filter averaged HCl emissions of about 0.0001 lb/MMBtu. To retrofit all of these facilities with both fabric filters and DSI would entail in the range of $450-$500 million in annualized capital costs.

Units with DSI for acid gas control

There are 29,218 MW of capacity with DSI. Of this, 21,169 MW has ESPs, 5,257 MW has baghouses, and 2,795 MW has both ESPs and baghouses, or COHPAC. For those units where HCl data was available the average HCl emission rate was 0.00077 lb/MMBtu for units with DSI and ESPs and 0.000087 for units with DSI and baghouses.

Improvements to DSI systems are now available at a relatively low cost. These have proven (given experience since 2012) to improve SO_2 capture significantly on ESP-equipped units, and similar improvements are expected for HCl. It would be reasonable to achieve roughly 25% improvement in HCl capture, getting HCl emission rates under 0.0006 lb/MMBtu at approximate

[64] Assuming 7% interest and 15 year period.

[65] Staudt, J., Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants, for Center for Applied Environmental Law and Policy (CAELP), August 19, 2021, https://www.andovertechnology.com/articles-archive/

costs under $10/kW. Addition of a baghouse to units with only ESPs would reduce HCl further, to potentially under 0.0001 lb/MMBtu, but this would be at a higher cost of roughly $150-$200/kW. This would entail an annualized capital cost of about $400 million if all DSI equipped units with ESPs were retrofit in this fashion.

Modest upgrades to ESP-equipped units using DSI to reduce emissions somewhat would cost approximately $100 million in capital (about $11 million on an annualized basis). Adding a fabric filter would be substantially more, close to $3.7 billion, or about $400 million on an annualized basis, which would be necessary if HCl emission rates were limited to about 0.0001 lb/MMBtu or less.

Units with wet or dry FGD

It is clear from Figure 7, Figure 8, Figure 16 and Figure 17, that many existing FGD units made improvements, and Figure 30 demonstrates that these improvements likely reduced HCl emission rates. It is unclear how many facilities can be improved further. Based upon the trends in Figure 30 it appears that those units that control SO_2 emissions to under 0.20 lb/MMBtu have HCl emissions below 0.0006 lb/MMBtu. In fact, there are only four wet FGD equipped units with HCl emissions greater than 0.0006 lb/MMBtu in the 89-unit dataset. As a result, modification of these facilities to improve emissions rates could be possible. Another option might be addition of DSI, which for some units would likely be necessary upstream of the PM control device to assure HCl emissions under 0.0001 lb/MMBtu. Because most of the lowest emitting wet FGD units are not part of the 89-unit set of data where there is HCl emissions data, it is difficult to reach a firm conclusion about what additional emission reductions would be necessary for the full fleet of wet FGD units. It is reasonable to expect that most of those units would be better performing on average than the units in the 89-unit dataset. But, given the scatter in Figure 30, determining an estimate of what would be necessary across the wet-FGD fleet to achieve emissions in the range of 0.0001 lb/MMBtu of HCl or less is very uncertain at this time. Those wet-FGD equipped units with upstream fabric filters should be able to achieve very low HCl emissions on the order of 0.0001 lb/MMBtu or less with the addition of DSI, if needed, but it is less certain for those facilities with ESPs.

Because DSI with a fabric filter achieved very low HCl emissions rates, averaging under 0.0001 lb/MMBtu, it is likely that dry FGD systems equipped with fabric filters also have very high HCl capture and would require little or no further improvement to achieve this emission level.

V. Conclusions

This study examined acid gas emissions controls and acid gas emission rates for the fleet of coal fired power plants, with the objective of trying to identify what opportunities may exist for reduction of acid gas emissions in the coal fleet based on developments in the industry. The following are some of the conclusions of the study.

Methods to reduce acid gas emissions

Wet FGD – About 160 GW of capacity and 300 units are equipped with wet FGD. Most of these use bituminous coal. There have been significant improvements in emissions from wet FGD controlled units, with roughly 50% having a SO_2 emission rate improvement of 0.03 lb/MMBtu or more from 2011 to 2019. About 32% did not have an improvement in emission rate. Therefore, it appears that a significant portion of the coal fleet deployed improvements in wet FGD technology. Estimates of the cost of control improvements were made based upon the reported scope of some improvement projects, which largely used improvements in absorber flow balancing and atomization methods. Costs were estimated to be in the range of $38/kW for a 500 MW unit.

Dry FGD - About 40 GW of capacity and 88 units are equipped with dry FGD. Most of these use subbituminous coal. There have been significant improvements in emissions from dry FGD controlled units, with roughly 35% having a SO_2 emission rate improvement of 0.03 lb/MMBtu or more from 2011 to 2019. About 33% did not have an improvement in emission rate. Therefore, it appears that a significant portion of the coal fleet deployed improvements in dry FGD technology. Estimates of the cost of control improvements were made based upon the reported scope of some improvement projects, which largely used improvements in atomization or fabric filters. Costs were estimated to be in the range of $17/kW for atomization improvements and about $5/kW for fabric media improvements on a 500 MW unit.

DSI - About 30 GW of capacity and 66 units are equipped with DSI. DSI is a lower cost option for improvement of acid gas emissions for units with only PM controls. The degree of HCl control will be dependent upon treatment rate and the type of PM controls. At least 70% HCl capture is typically expected to be possible, and over 90% HCl capture is possible with a fabric filter. Capital cost will be impacted by treatment rate, as storage and transport equipment are a significant portion of the cost, but may be in the range of $40/kW. Since 2011, there have been improvements in both reagents and improvements in the injection systems. The impacts have been to improve capture with lower cost reagents. Improvements with reagent injection systems to existing DSI systems should improve capture by about 25% (or, alternatively, reduce injection rates to achieve the same emissions rate) at a capital cost of under $10/kW.

PM controls only – Units with only PM controls may improve their emissions through addition of an acid gas control technology. They may also improve performance by adding a baghouse downstream of the ESP, which appears to provide some benefit to HCl control, but will provide even more benefit if combined with a DSI system. A fabric filter upgrade costs in the range of $150-$200/kW, or perhaps more.

Trends in HCl emissions

Examination of HCl emission trends showed that the best-controlled units were likely to be scrubbed or have combination ESP and fabric filter control systems. This was not unexpected. Analysis of wet FGD equipped units showed a significant relationship between SO_2 emission rate and HCl emission rate, confirming that units with lower SO_2 emission rates are generally expected to have lower HCl emission rates.

DSI equipped units with a fabric filter demonstrated very low HCl emissions, at approximately the same level as the one data point available for dry FGD equipped units. DSI equipped units with ESPs, not unexpectedly, had significantly higher HCl emissions than those with fabric filters. Lower SO_2 emission rates tended to correspond with lower HCl emissions. This was an impact of the PM control device and likely the coal type used.

For units reporting no acid gas controls, there was significant scatter when HCl emissions were compared to SO_2 emissions, except for units with both an ESP and a baghouse. For units with both an ESP and a baghouse, HCl emissions were consistently fairly low, resulting in lower average HCl emission rate than for units with only an ESP or a baghouse.

Opportunities to improve acid gas control performance and associated costs

There are opportunities to reduce acid gas emissions further. Preliminary estimates of the annualized capital costs have been developed, and they are shown in Table 6.

Table 6. Estimated impact of reduction in acid gas emission rate standard[66]

HCl Limit (lb/MMBTU) *(Current HCl standard is 0.002 lb/MMBTU or 0.20 lb/MMBtu SO_2 (as a surrogate for regulated acid gases) for units with FGD)*	**Control improvements likely to result**	**Costs for fleet as a whole** *(Preliminary estimates)*
0.001 lb/MMBtu HCl	• Some units with no acid gases controls install DSI	• ~$60 million annualized capital cost for units with no acid gas controls
	• Some ESP units upgrade DSI	• Roughly $21 million annualized capital cost for units with DSI
	• Few wet FGD units are impacted	• About $19 million in annualized capital cost for units with wet FGD
0.0006 lb/MMBtu HCl	• Most units with no acid gas controls install DSI	• About $120 million in annualized capital cost for units with no acid gas controls
	• Units with DSI and ESPs upgrade DSI system or add BH • Little or no impact for units with DSI and baghouses	• Assuming 30% of ESP equipped units install baghouse and 30% of ESP equipped units install DSI improvements, total cost is $118 million annualized capital
	• About 15% of wet FGD units and 30% of dry FGD units impacted, although dry FGD units likely comply on basis of HCl emission	• ~$42 million annualized capital cost for scrubber improvements
0.0001lb/MMBtu HCl	• Units with no acid gas controls install baghouses and DSI	• ~$494 million annualized capital cost for DSI and baghouses
	• Units with DSI and ESP install baghouse • Units with DSI and baghouse may need to upgrade DSI	• ~$382 million annualized capital cost for DSI improvements for baghouse equipped units and baghouses for ESP equipped units
	• Most scrubbed units impacted. Improvements or DSI on 75% of wet FGD capacity and improvements on 25% of dry FGD capacity	• ~$475 million annualized capital cost for scrubber improvements

[66] These cost estimates do not take into account all retirements that have occured since 2021, and therefore likely overstate costs.

Wet FGD Cost Estimate for a 500 MW Coal Fired Boiler[67]

Costs are all based on 2016 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty				
BMR ($) =	554000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$	46,669,000	Base absorber island cost
BMF ($) =	202000*(B)*((D*G)^0.3)*(A^0.716)	$	23,674,000	Base reagent preparation cost
BMW ($) =	106000*(B)*((D*G)^0.45)*(A^0.716)	$	14,536,000	Base waste handling cost
BMB ($) =	1070000*(B)*((F*G)^0.4)*(A^0.716)	$	89,730,000	Base balance of plant costs including: ID or booster fans, new wet chimney, piping, ductwork modifications and strengthening, etc…
BMWW ($) =	10600000*(B)*(A/500)^0.6	$	10,600,000	Base wastewater treatment facility to comply with ELG. Based on ~ 0.4 gpm/MW waste water treatment facility
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$	187,409,000	Total base cost including retrofit factor
BM ($/KW) =			375	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	18,741,000	Engineering and Construction Management costs
A2 = 10% of BM		$	18,741,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	18,741,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**243,632,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**487**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	12,182,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**255,814,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**512**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	25,581,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of (CECC + B1)		$	-	EPC fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**281,395,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**563**	Total project cost per kW

[67] Sargent & Lundy, IPM Model - Updates to Cost and Performance for APC Technologies, Wet FGD Cost Development Methodology", January 2017

Dry FGD Cost Estimate for a 500 MW Coal Fired Boiler[68]

Costs are all based on 2016 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMR ($) =	if (A>600 then (A*98000) else 637000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$	55,086,000	Base module absorber island cost
BMF ($) =	if (A>600 then (A*52000) else 338000*(A^0.716))*B*(D*G)^0.2	$	33,100,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if (A>600 then (A*138000) else 899000*(A^0.716))*B*(F*G)^0.4	$	77,837,000	Base module balance of plant costs including: ID or booster fans, piping, ductwork modifications and strengthening, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$	166,023,000	Total Base module cost including retrofit factor
BM ($/KW) =			332	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	16,602,000	Engineering and Construction Management costs
A2 = 10% of BM		$	16,602,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	16,602,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**215,829,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**432**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	10,791,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**226,620,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**453**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	22,662,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of (CECC + B1)		$	-	EPC fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**249,282,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**499**	Total project cost per kW

[68] Sargent & Lundy, IPM Model - Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology", January 2017

Costs are all based on 2016 dollars

Capital Cost Calculation Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty		Example		Comments
BM ($) =	Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	18,348,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =			37	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	1,835,000	Engineering and Construction Management costs
A2 = 5% of BM		$	917,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 5% of BM		$	917,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**22,017,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**44**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	1,101,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**23,118,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**46**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$**	**23,118,000**	Total project cost
TPC ($/kW) =			**46**	Total project cost per kW
Fixed O&M Cost				
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)		$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)		$	0.37	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)		$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA		**$**	**0.89**	Total Fixed O&M costs
Variable O&M Cost				
VOMR ($/MWh) = M*R/A		$	5.55	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A		$	3.39	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10		$	0.39	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP		**$**	**9.33**	

Costs are all based on 2016 dollars

Capital Cost Calculation Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty		Example		Comments
BM ($) =	Unmilled Trona or Hydrated Lime if (M>25 then (745,000*B*M) else 7,500,000*B*(M^0.284) Milled Trona if (M>25 then (820,000*B*M) else 8,300,000*B*(M^0.284)	$	15,812,000	Base module for unmilled sorbent includes all equipment from unloading to injection, including dehumification system
BM ($/KW) =			32	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	1,581,000	Engineering and Construction Management costs
A2 = 5% of BM		$	791,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 5% of BM		$	791,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**18,975,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**38**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	949,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**19,924,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**40**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2		**$**	**19,924,000**	Total project cost
TPC ($/kW) =			**40**	Total project cost per kW
Fixed O&M Cost				
FOMO ($/kW yr) = (2 additional operator)*2080*U/(A*1000)		$	0.50	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)		$	0.32	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)		$	0.02	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA		**$**	**0.83**	Total Fixed O&M costs
Variable O&M Cost				
VOMR ($/MWh) = M*R/A		$	3.29	Variable O&M costs for sorbent
VOMW ($/MWh) = (N+P)*S/A		$	2.89	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste not removed prior to the sorbent injection
VOMP ($/MWh) =Q*T*10		$	0.23	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP		**$**	**6.41**	