

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 SO₂ 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 announced³³ 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 SO₂ 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 SO₂ 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 SO₂ emissions between 2011 and 2019 was 0.111 lb/MMBtu and the average

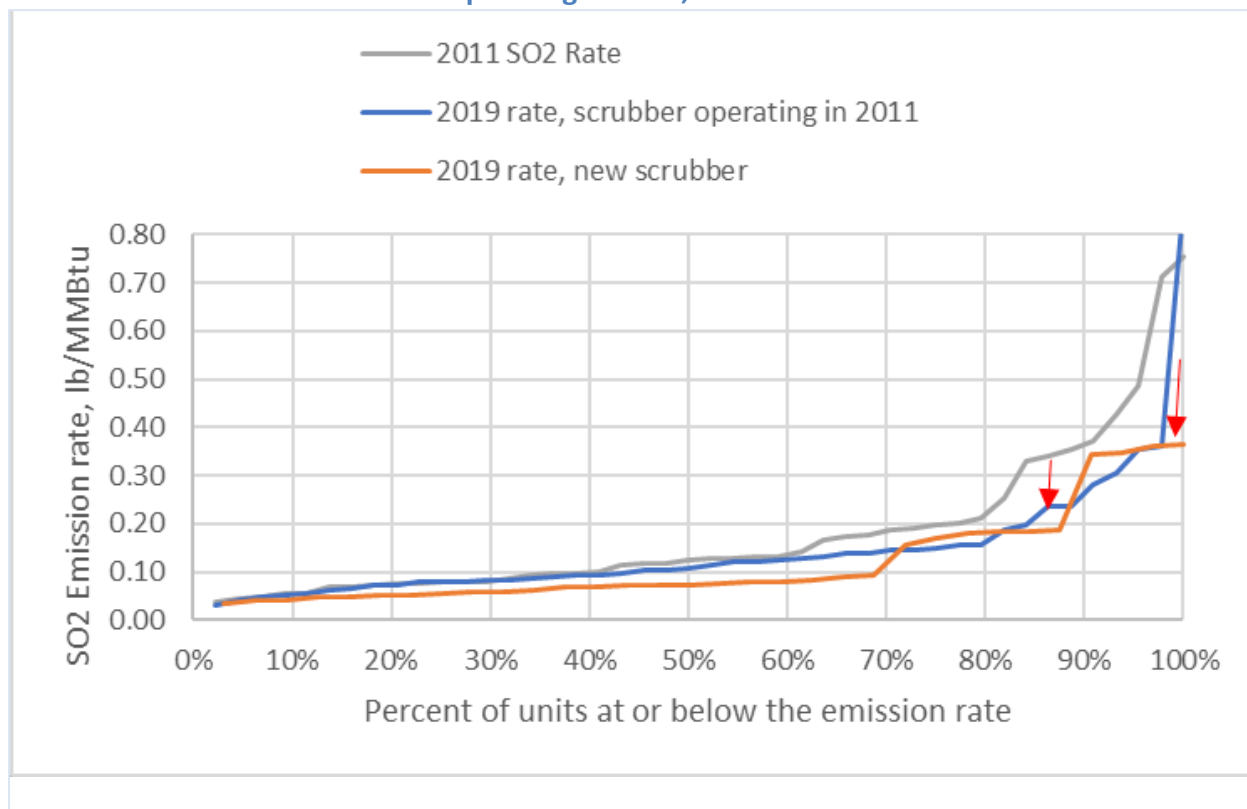
³³ The MATS rule was first announced in December 2011 and published in the Federal Register in April 2012

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 SO₂ 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 FGD 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 SO₂ 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 SO₂ emission rate.

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

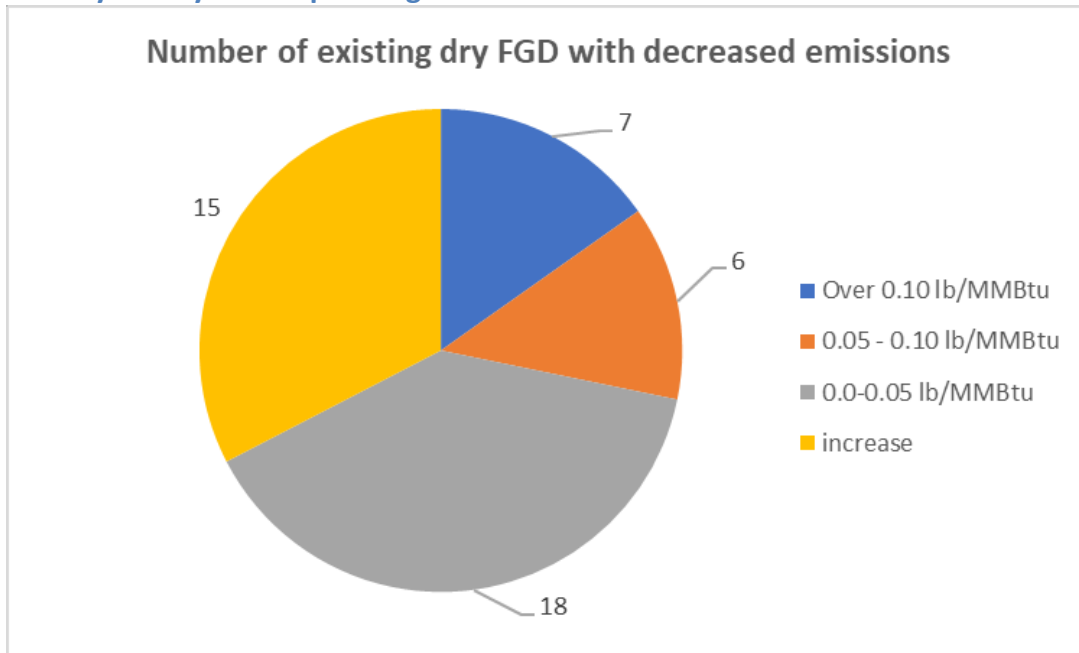


Figure 18. Average and median SO₂ emission rate for dry FGD systems operating the full year in 2011, 2019 emissions of units that were operating in 2011, and new scrubbers built since 2011

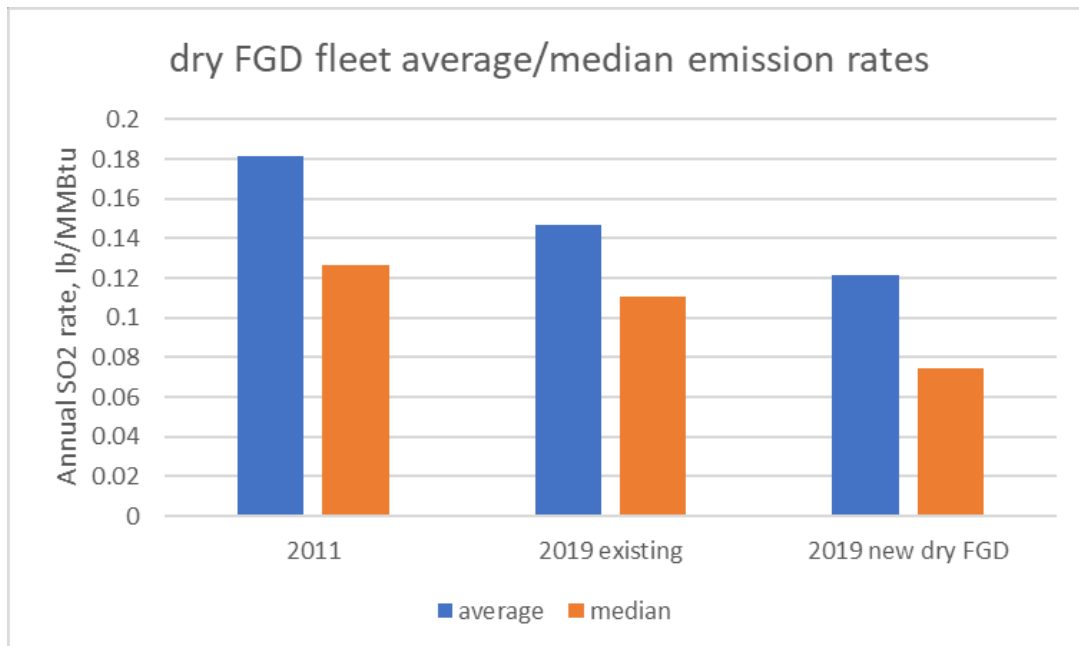
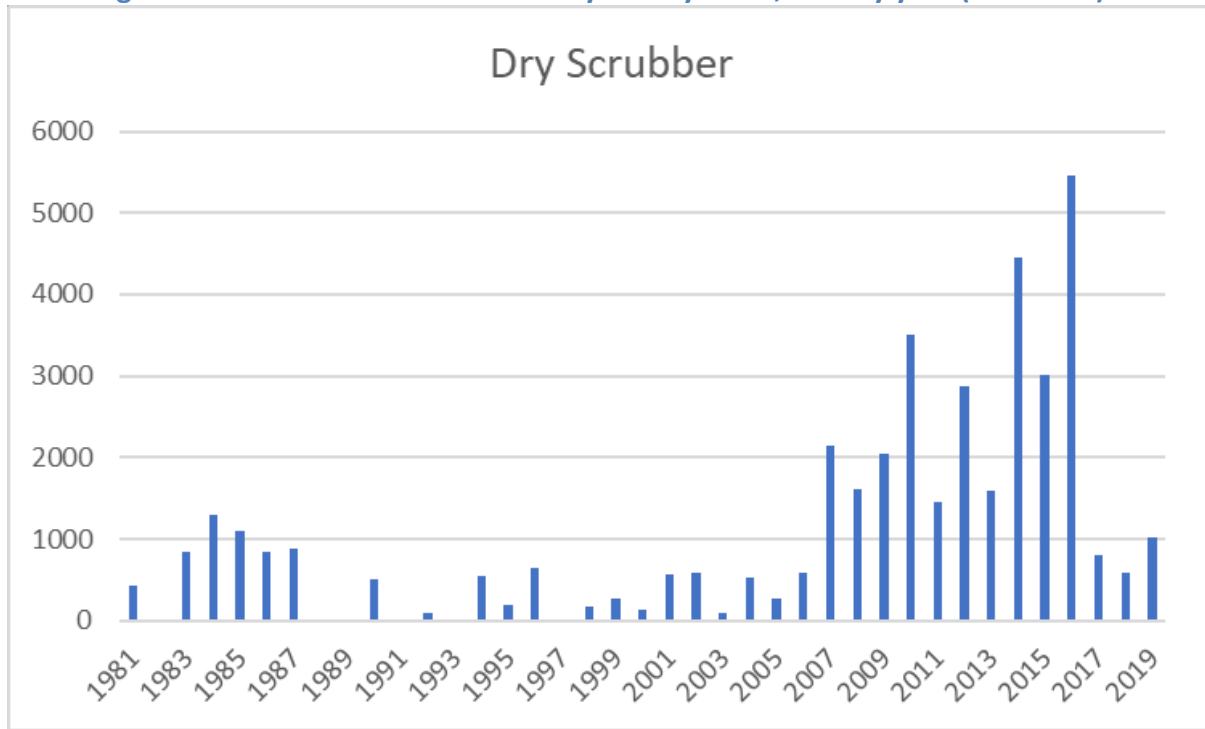


Figure 19 Historical installation of dry FGD systems, MW by year (NEEDS v6)³⁵



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:

$$637000*(A^{0.716})*B*(F*G)^{0.6}*(D/4)^{0.1}, \text{ where:}$$

- A = capacity in MW
- B = retrofit factor, nominally 1.0 for a typical retrofit
- C = gross heat rate, Btu/kWh
- D = SO₂ 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 occurred 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 stoichiometric 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 SO₃ adversely impacts ACI performance (such as with bituminous coals), DSI can have a beneficial impact on mercury capture with ACI by mitigating SO₃. This is shown in Figure 25, which shows data taken from DSI testing at the Constellation Wagner Station. Sodium-

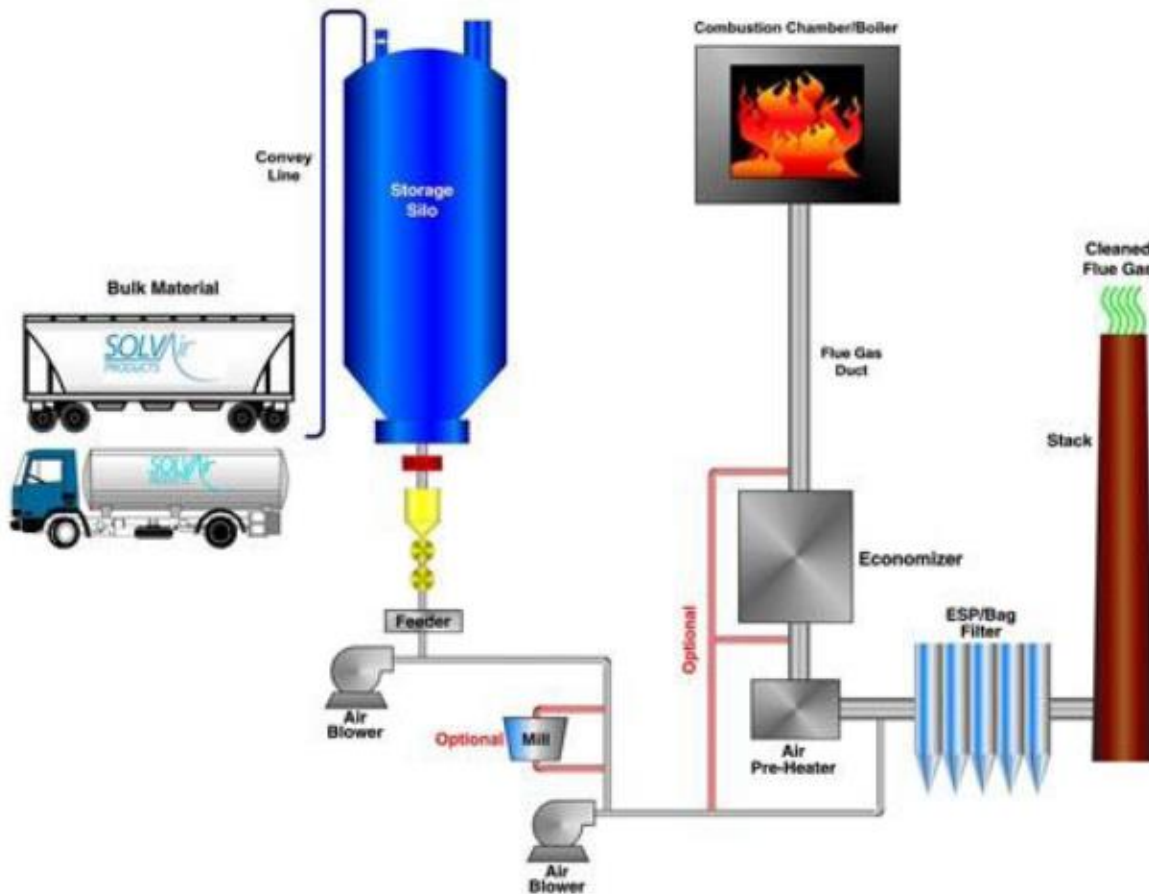
⁴⁰ Fitzgerald, H., "Hydrated Lime DSI - Solution for Acid Gas Control (SO₃, HCl, and HF)", MARAMA /ICAC SO₂/HCl CONTROL TECHNOLOGIES WEBINAR, July 19, 2012

⁴¹Laird, 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.

⁴²Dickerman, J., Schantz, M., "Improved DSI Performance with Optimized Hydrated Lime"; *see also* Filippelli, G., "Sorbacal® SPS - Changing Perceptions on Hydrated Lime for SO₂ 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) system⁴⁵



Source: Solvair

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 SO_2 , SO_3 , NO_x and Mercury Mitigation", Power Gen 2009

Figure 21. A DSI injection system⁴⁶



⁴⁶ <http://www.nol-tec.com/dry-sorbent-injection.html>

Figure 22. HCl emissions for PRB fired utility boilers from EPA's ICR database⁴⁷
(CS-ESP is cold-side ESP)

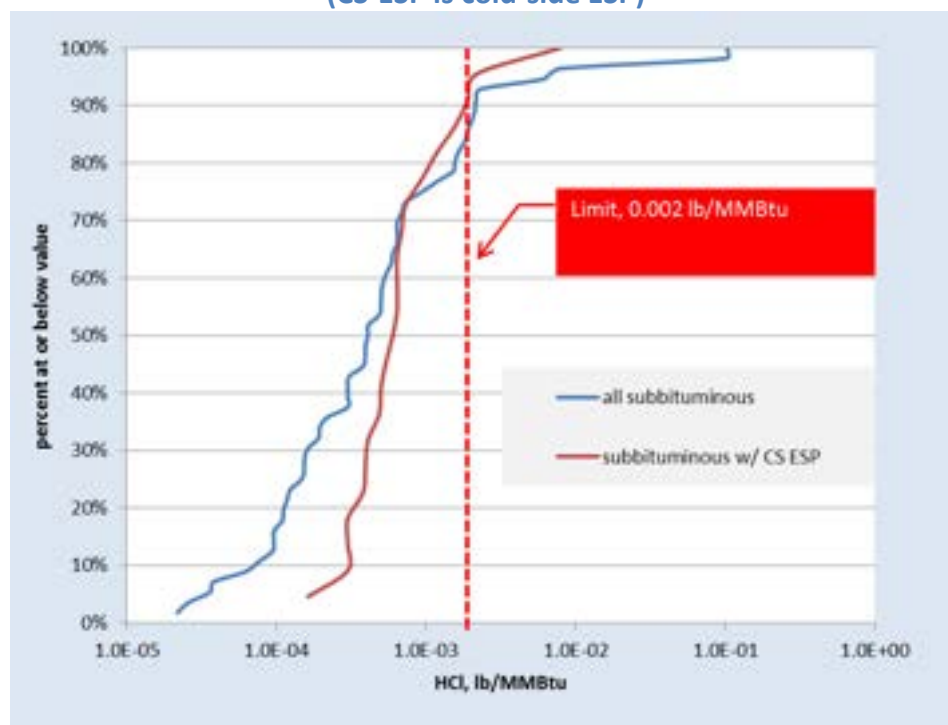
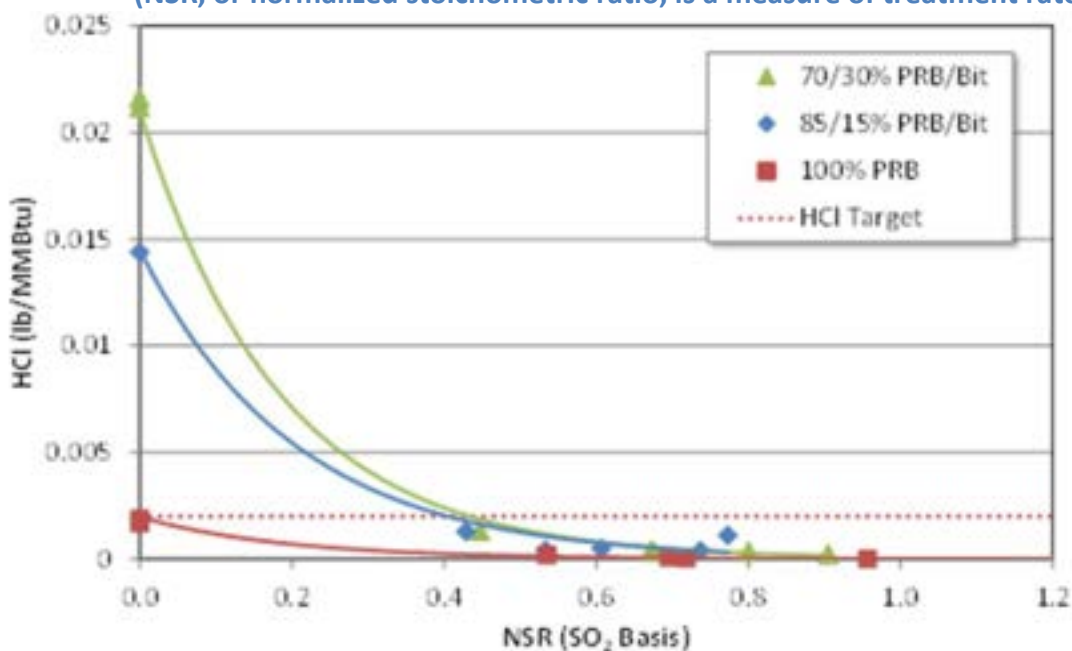


Figure 23. HCl emissions as a function of trona NSR and coal blend at DTE Energy St. Clair⁴⁸
(NSR, or normalized stoichiometric ratio, is a measure of treatment rate)



⁴⁷ Staudt, J., "Air Pollution Compliance Strategies for Coal Generation", EUCL, 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. ESP⁴⁹
(SPS is the sodium-based DSI sorbent)

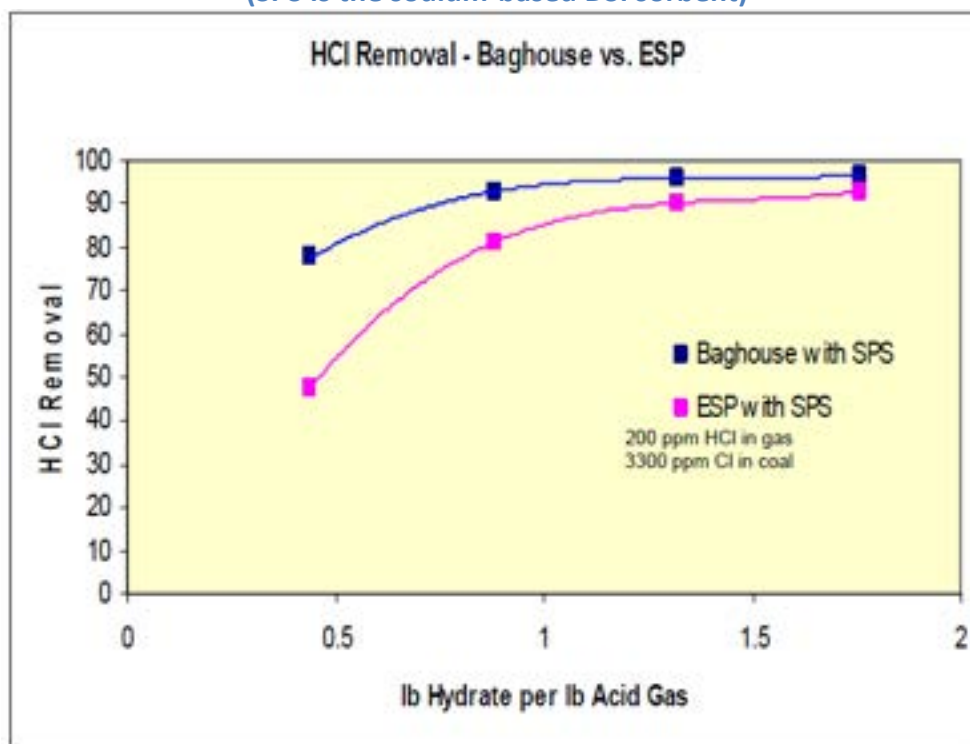
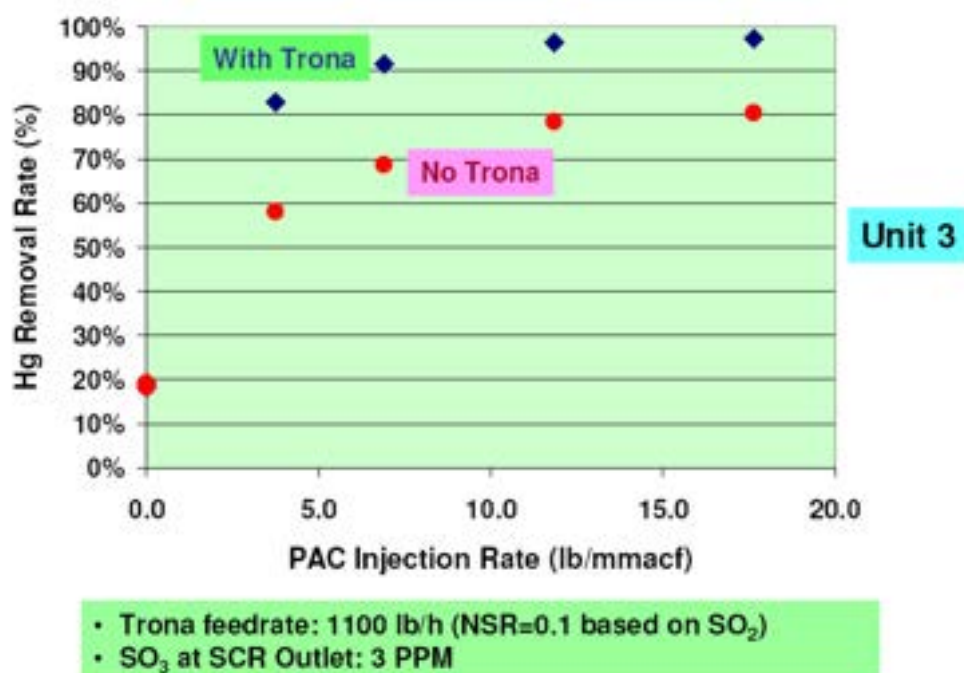


Figure 25. Effect of trona injection on mercury capture using powdered activated carbon at bituminous coal fired Constellation Wagner 3.⁵⁰



⁴⁹Fitzgerald, Howard, "Hydrated Lime DSI - Solution for Acid Gas Control (SO₃, HCl, and HF)", MARAMA /ICAC SO₂/HCl Control Technologies Webinar, July 19, 2012.

⁵⁰ Kong, Y., et al, "Dry Sorbent Injection of Trona and Sodium Bicarbonate for SO₂, SO₃, NO_x 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 SO₂ 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 2⁵³

	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.carneusena.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, NO_x 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 SO₃, which is a main contributor to condensable PM.

Mercury – DSI will enhance the capture of mercury when bituminous fuels are used because they produce SO₃ that competes with mercury to bind with carbon, and DSI removes SO₃. Sodium-based DSI reagents can adversely impact mercury capture from activated carbon, especially for PRB fuels that do not have significant SO₃ (no beneficial impact of removing SO₃). This is because NO can be oxidized to NO₂, 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 SO₂ 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

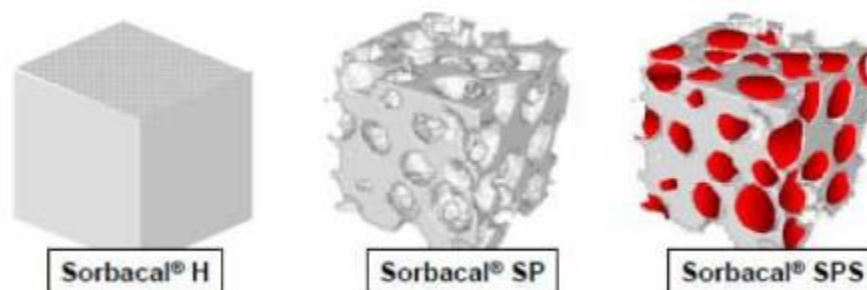
⁵⁴ Andover Technology Partners, *Analysis of PM and Hg Emissions and Controls from Coal-Fired Power Plants*, for Center for Applied Environmental Law and Policy (CAELP), August 19, 2021, pp 48-51

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 particles⁵⁹



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 SO₂ capture. For example, at 60% SO₂ 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

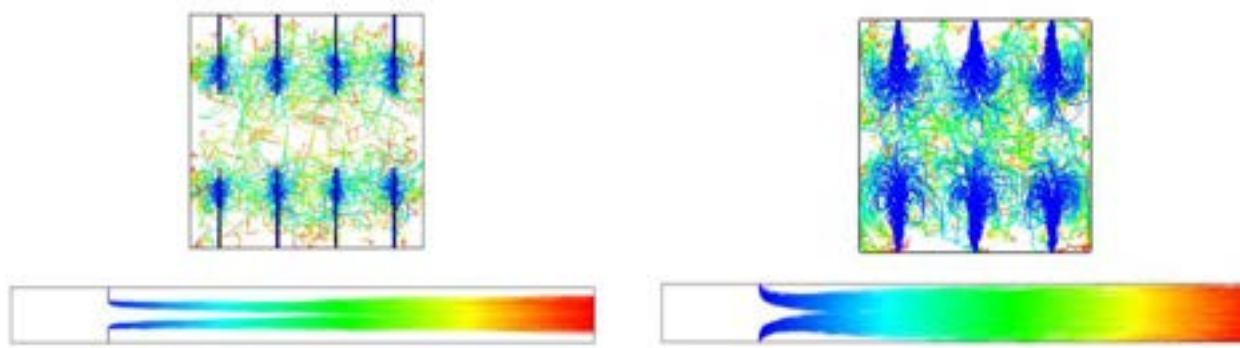
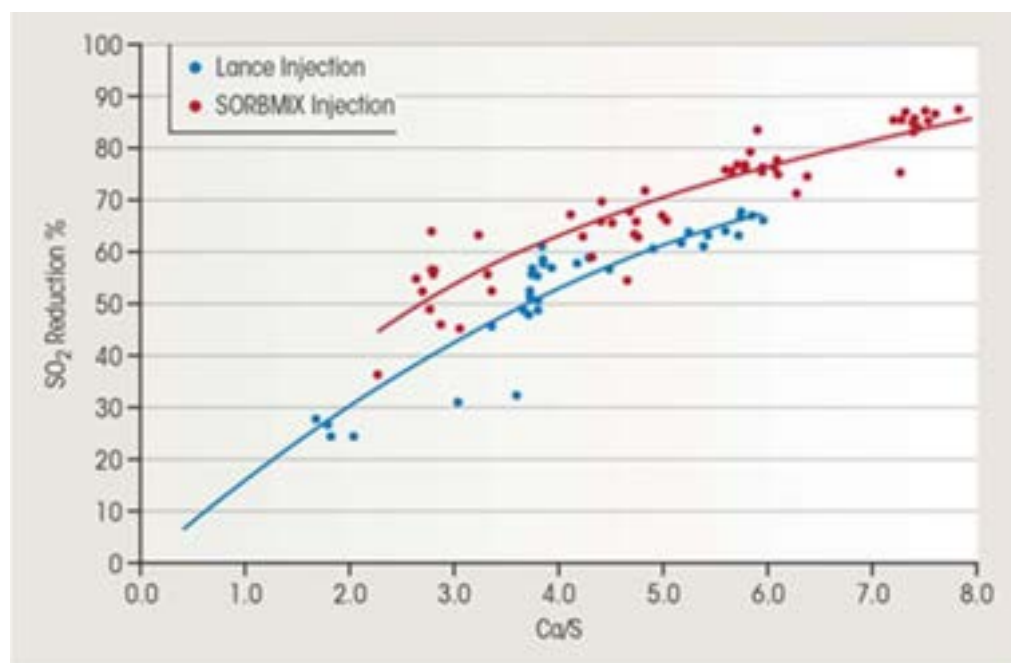


Figure 28. Performance improvement using Sorbmix DSI injector on power plant⁶¹



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 SO₂ 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 SO₂ 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 SO₂ emissions rates for facilities for each type of SO₂ control. As shown, the units with DSI had substantially lower HCl and SO₂ 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