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

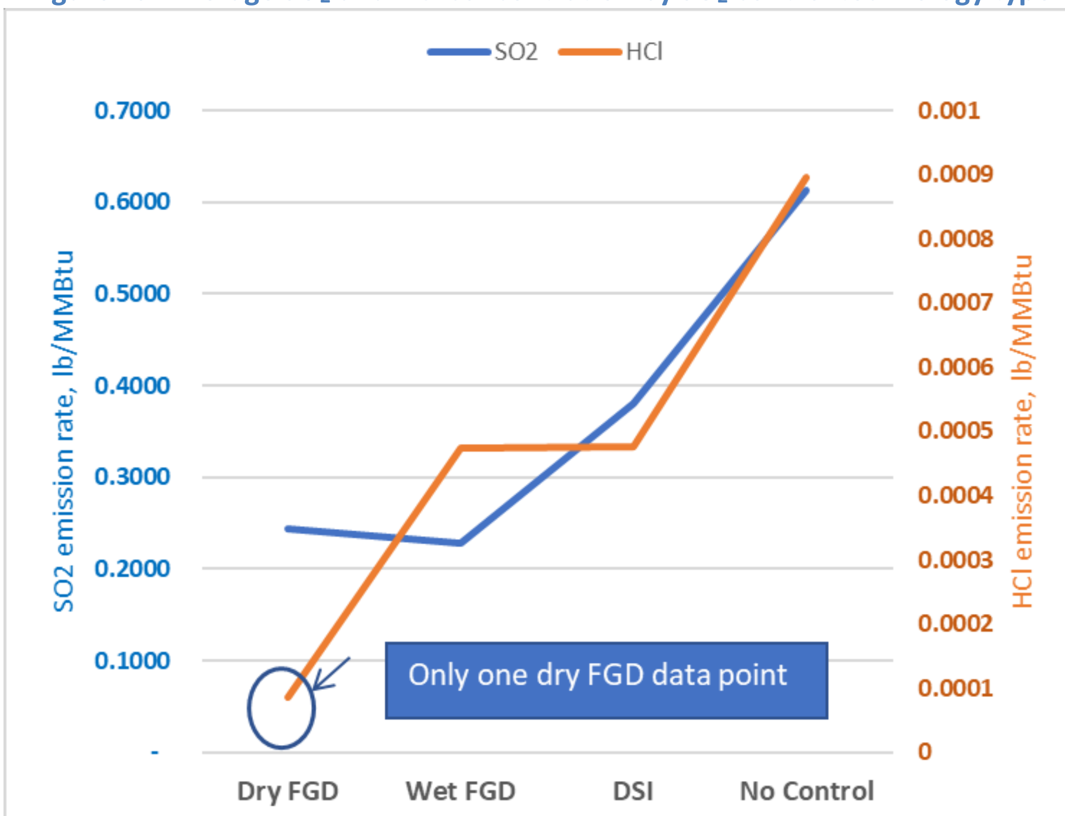


Figure 30. HCl v SO_2 emission rate (lb/MMBtu) for wet FGD equipped units

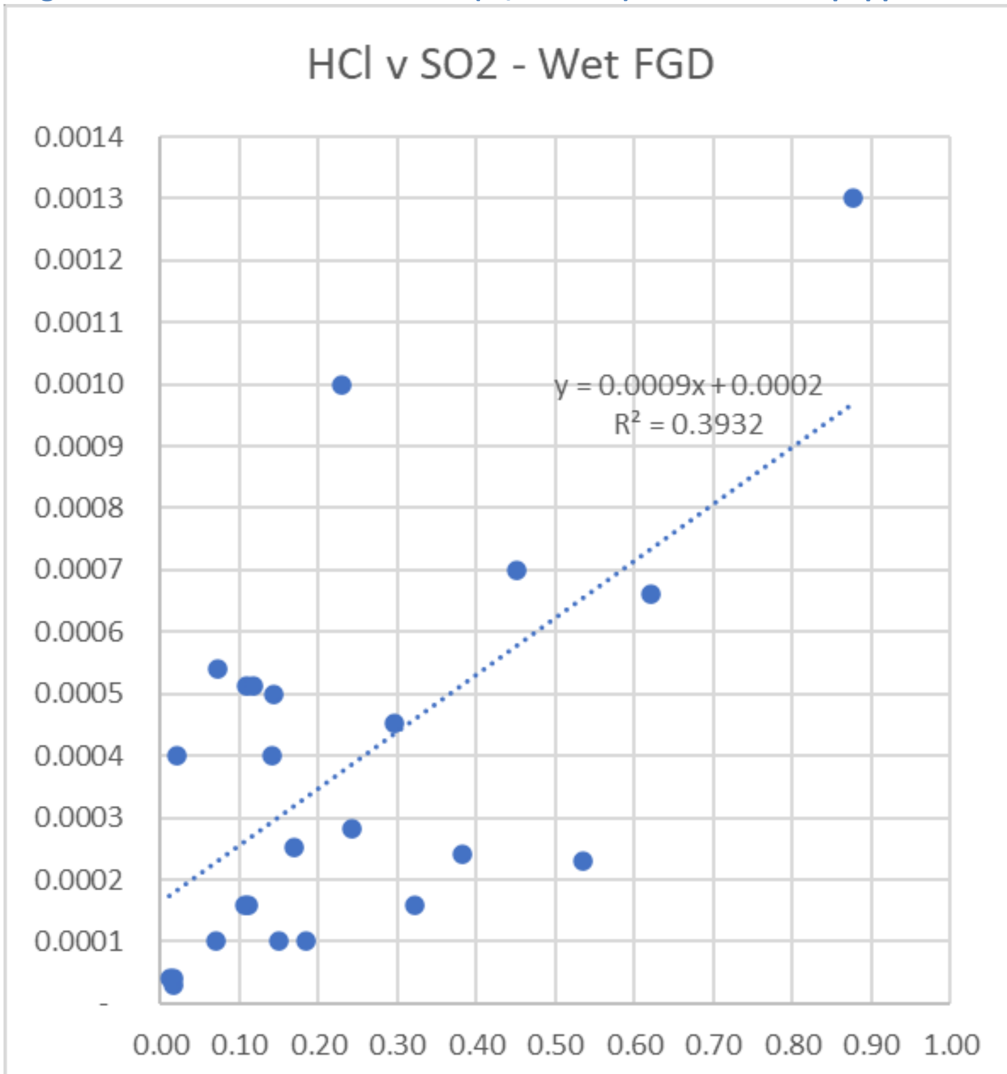


Figure 31. HCl and SO_2 emission rates for DSI-equipped units with baghouses and with ESPs

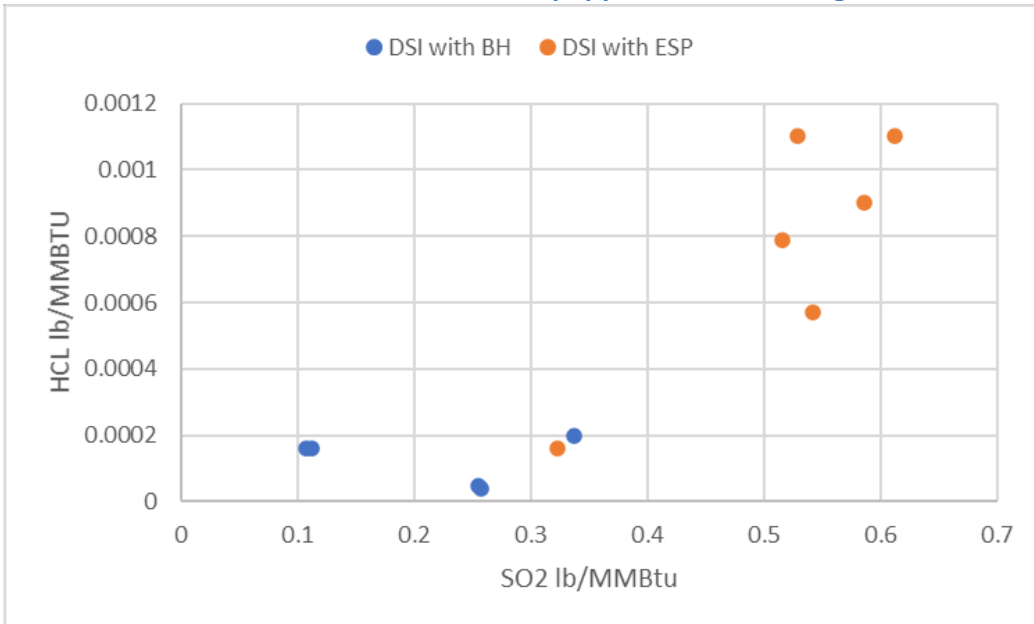


Figure 32 shows the relationship between HCl emissions and SO_2 emissions for units without DSI or either form of FGD, that is, only PM controls (ACI for Hg may be present). There is a fair amount of scatter without any clear correlation between the two variables. Figure 33 shows the average HCl emissions 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

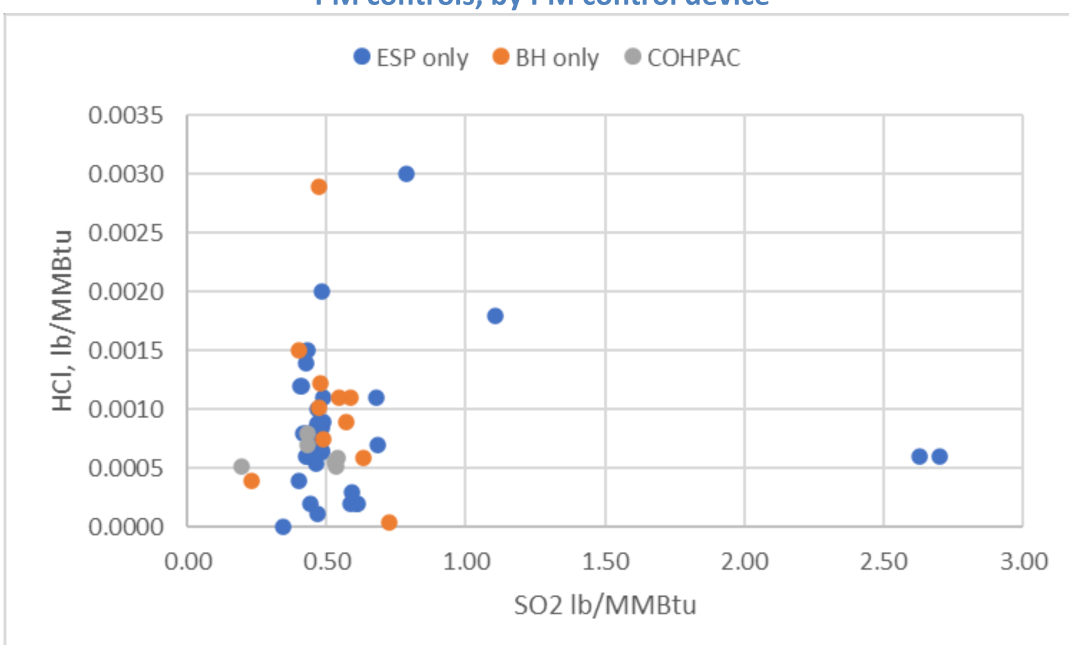
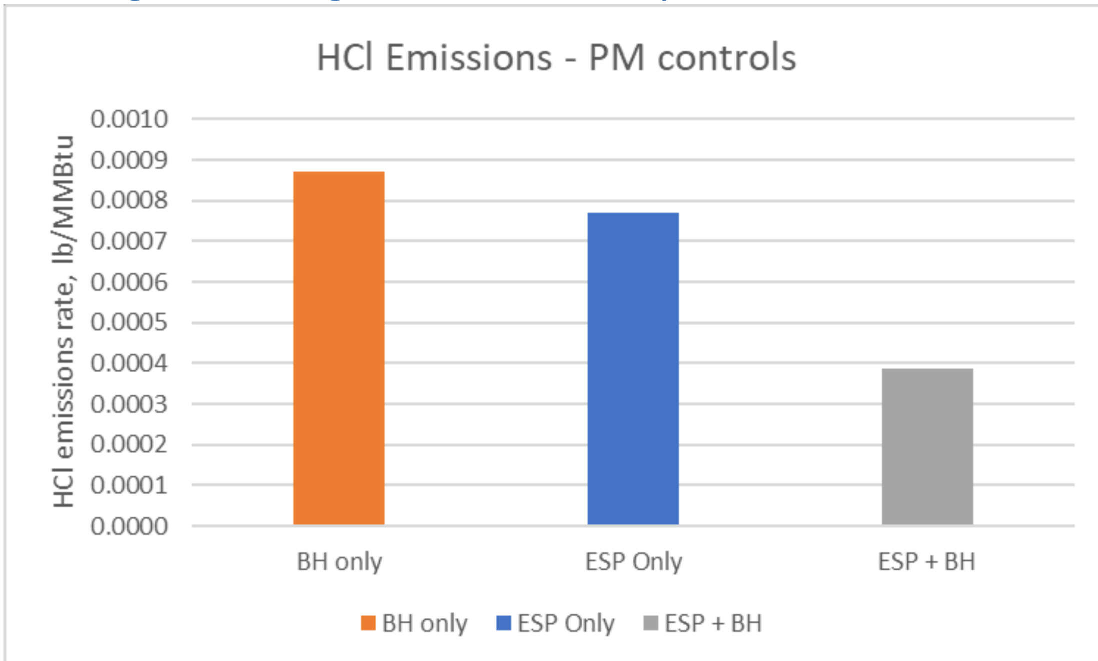


Figure 33. Average HCl emissions based upon PM control device



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

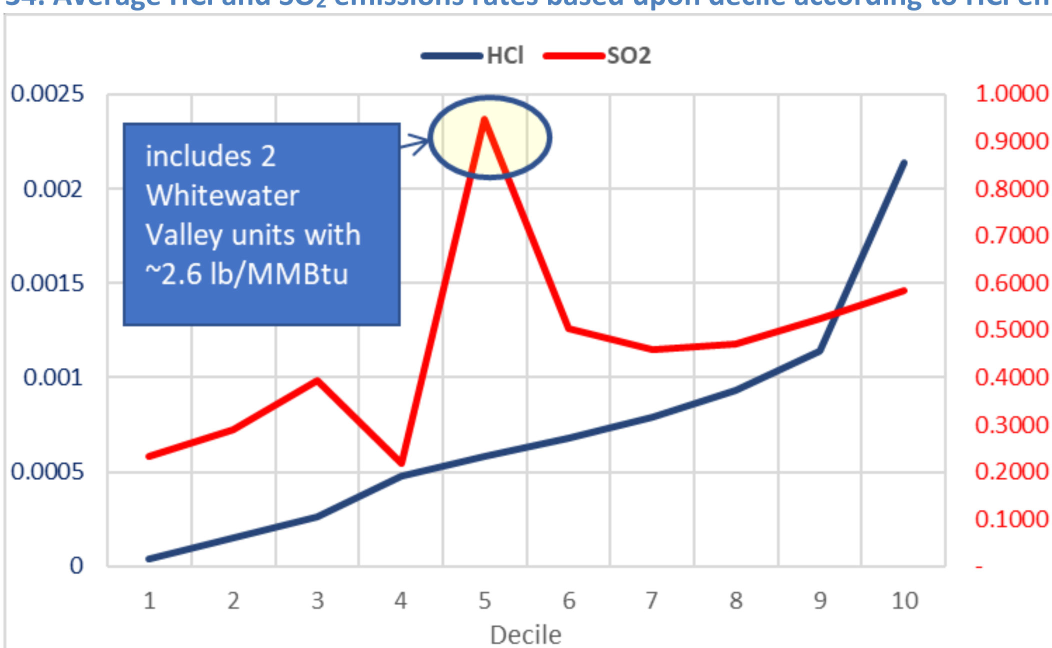


Figure 35. Median HCl and SO_2 emissions rates based upon decile according to HCl emissions

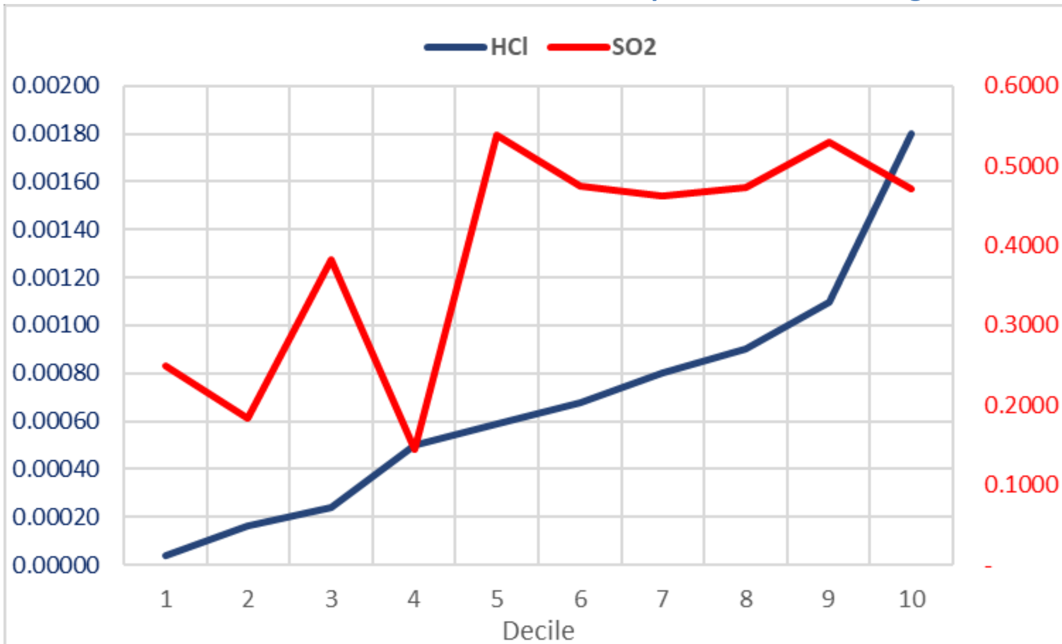


Figure 36 shows the fuel type by decile. Except for the top decile, bituminous coals seem to be used in the best deciles and subbituminous shows a higher probability for higher emissions deciles. Because subbituminous coals tend to have lower HCl emissions, this must be explained by equipment, which 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

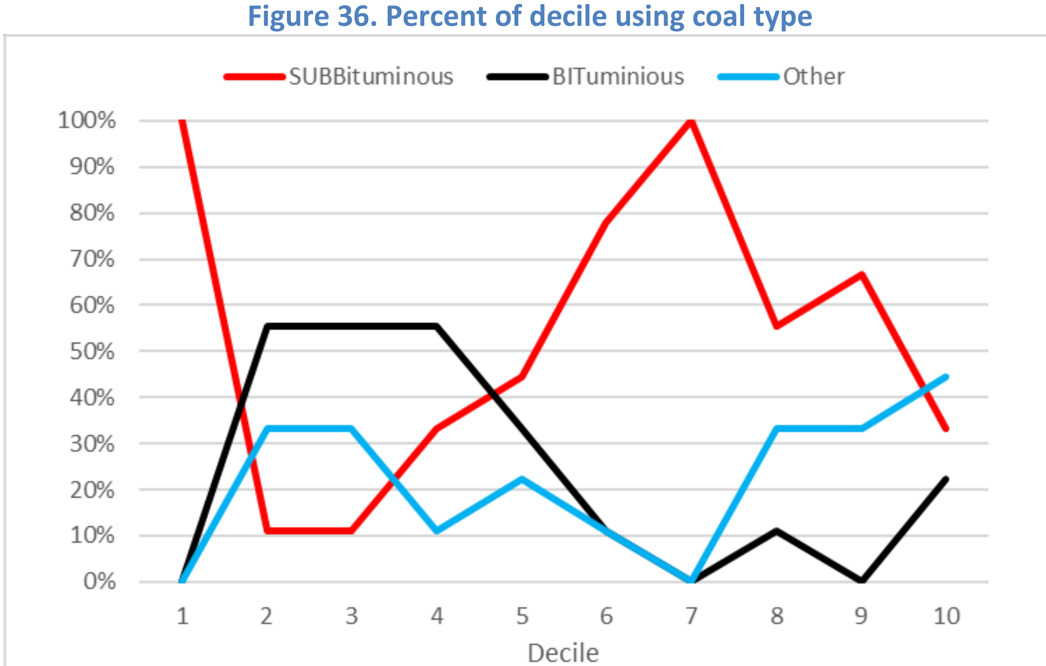


Figure 37. Percent of decile using PM emission control

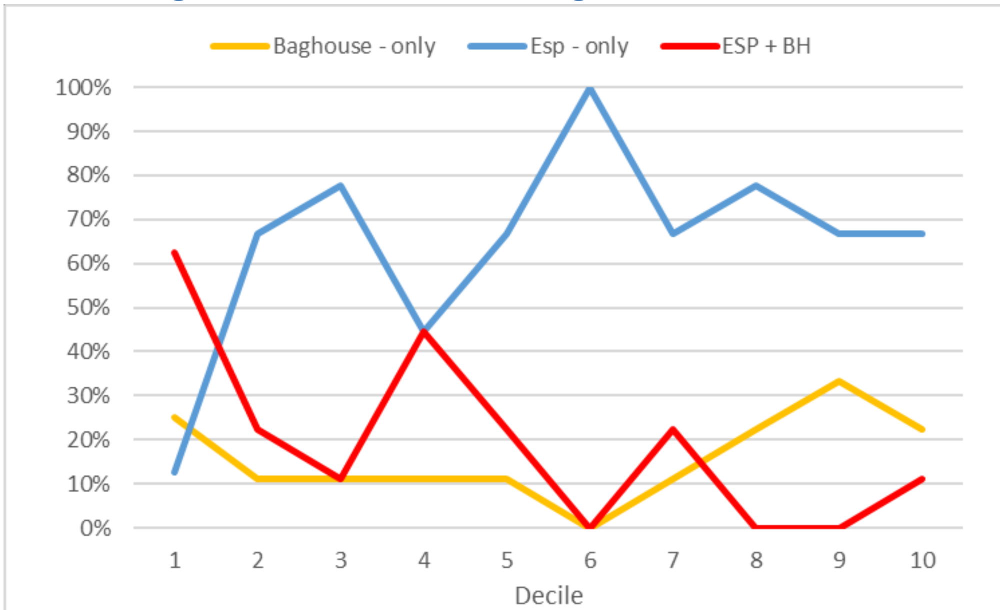


Figure 39 shows acid gas/SO_2 control methods by decile. There is a clear trend that the top deciles are most likely to have acid gas/SO_2 controls, especially FGD and wet FGD in particular. Since there is only one dry FGD system in the 89 unit data set being used and because dry FGD systems typically 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

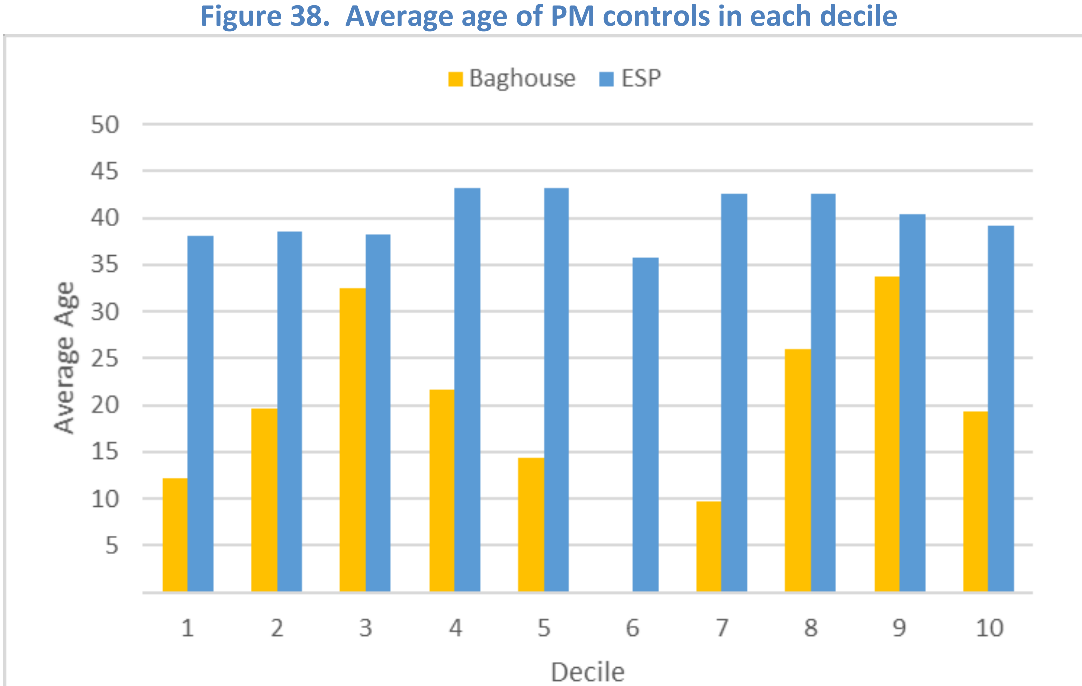


Figure 39. Percent of decile using acid gas/SO_2 control technology

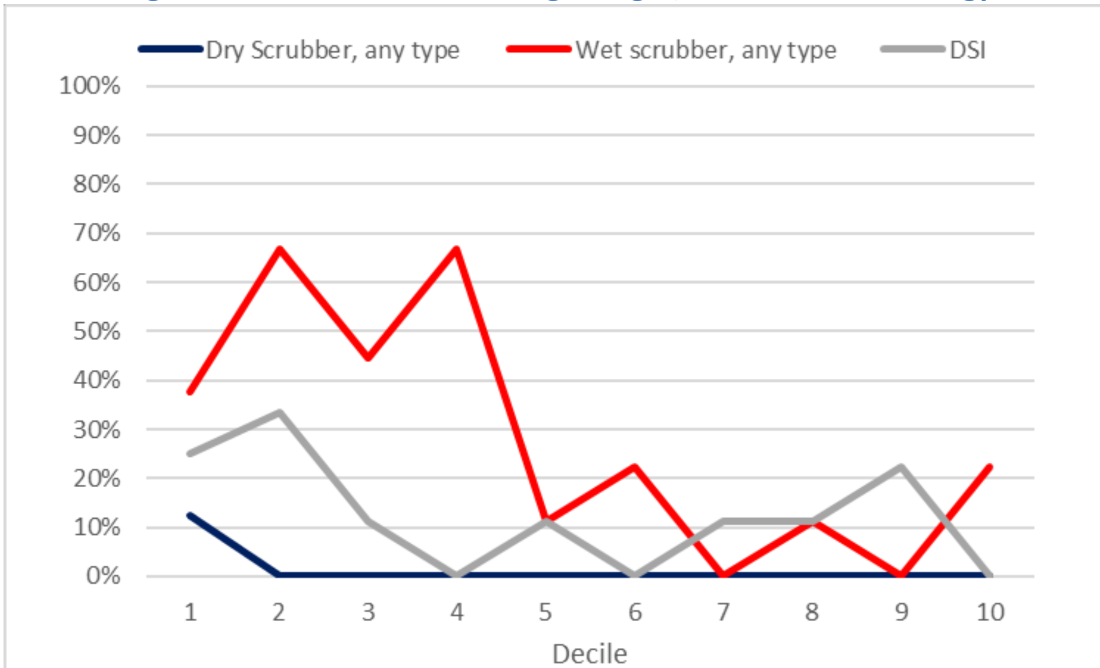
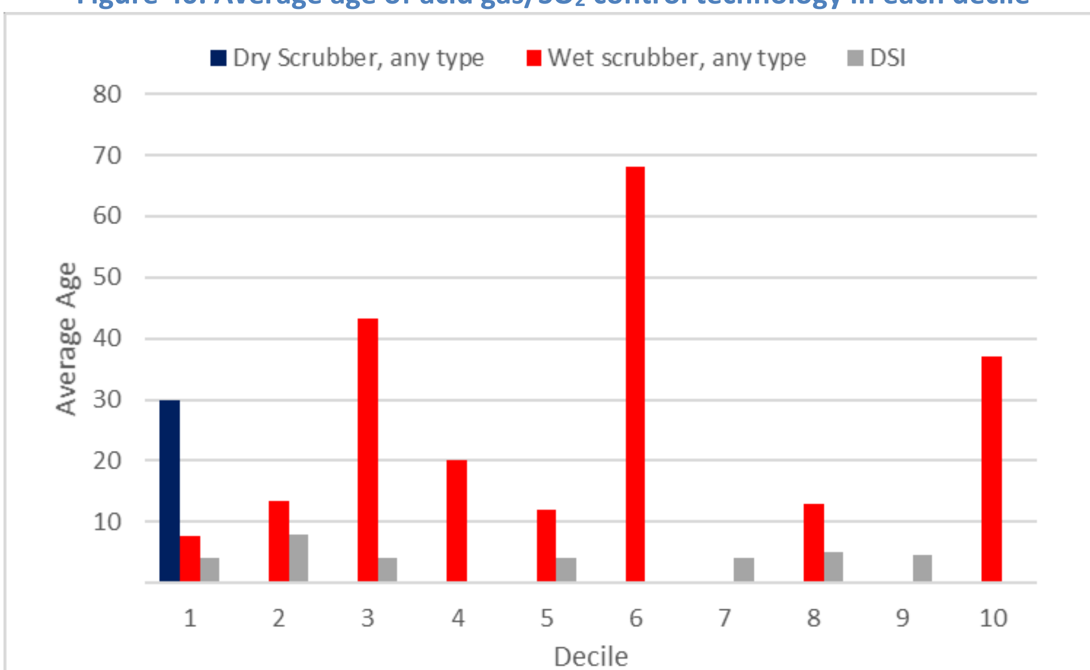


Figure 40. Average age of acid gas/SO_2 control technology in each decile



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

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[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 ($) =	584000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$	48,869,000	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)	$	69,730,000	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	$	167,409,000	Total base cost including retrofit factor
BM ($/KW) =			375	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	16,741,000	Engineering and Construction Management costs
A2 = 10% of BM		$	16,741,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc...
A3 = 10% of BM		$	16,741,000	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		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
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		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
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**	