

ECONOMIC COMPARISON OF SO₃ CONTROL OPTIONS FOR COAL-FIRED POWER PLANTS

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ABSTRACT

Sulfuric acid is present in most coal flue gases because a percentage of the SO₂ produced (typically 0.5 to 1.5%) is further oxidized in the boiler to SO₃, which combines with flue gas moisture to form vapor-phase or condensed sulfuric acid. Sulfuric acid in the flue gas can potentially lead to air heater corrosion, plugging and fouling; duct corrosion; and a visible plume. These effects are exacerbated if selective catalytic reduction (SCR) is retrofitted for NO_x control, as SCR catalysts further oxidize a portion of the flue gas SO₂ to SO₃.

This project tested the effectiveness of alkaline reagents injected into the furnace of coal-fired boilers for controlling sulfuric acid emissions. The project was co-funded by the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL), EPRI, FirstEnergy Corporation, TVA, and Carmeuse NA. Short-term, full-scale tests were conducted to evaluate the effectiveness of magnesium- and/or calcium-based sorbents injected into the furnace for SO₃ control. Two longer-term tests were conducted to confirm the effectiveness of the most promising sorbents over extended operation, and to determine balance-of-plant impacts. At the completion of the project, a comparative economic evaluation was made for a number of SO₃ control options for coal-fired power plants, including the furnace injection technologies tested. Results from this economic evaluation are presented and discussed in this paper.

INTRODUCTION

A wide range of SO₃ or sulfuric acid controls have been tested and/or applied for coal-fired power plants, such as low-sulfur-coal switches, injecting alkaline sorbents at various locations in the furnace or ductwork, and installing wet ESPs. The costs of applying these technologies

can vary over a wide range, and each has positive and negative attributes that could make it more or less favorable for application at a given power plant. This paper describes a number of SO₃/sulfuric acid control technologies and presents estimated costs for applying these technologies at an example plant.

Figure 1 shows the flue gas path of a typical coal-fired power plant, and illustrates where a number of candidate SO₃/sulfuric acid control technologies might typically be applied. The following paragraphs briefly discuss each of the potential control technologies illustrated.

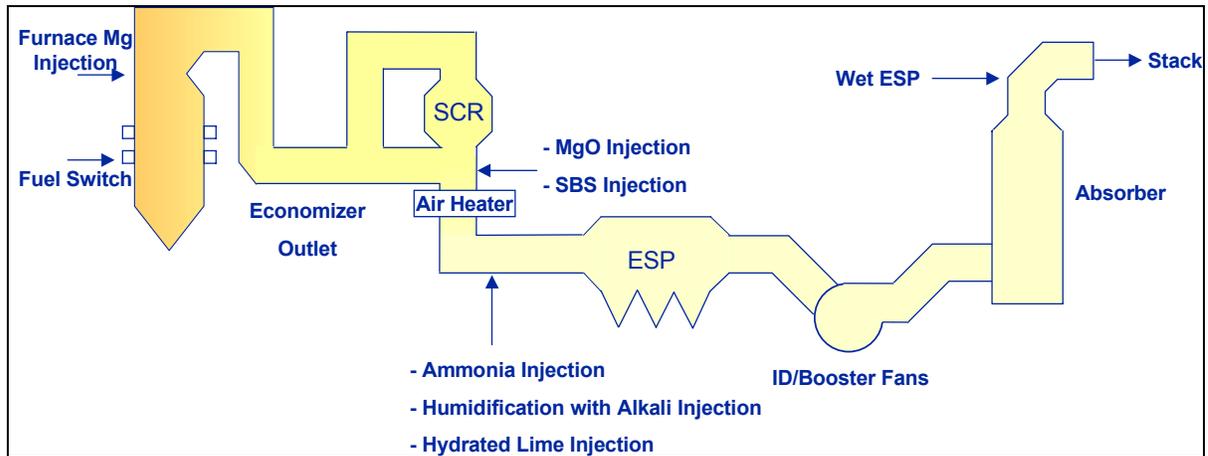


Figure 1. Illustration of potential SO₃/sulfuric acid control options.

Fuel Switch/Blending

Low-sulfur coal blending or switching lowers the SO₂ content of the flue gas to reduce the concentration of SO₃ produced in the furnace and across an SCR catalyst. The ability to implement this technology and its cost effectiveness can be very site specific. For example, the ability to blend or switch to low-sulfur coal can be limited by issues such as long-term coal contracts, coal mill capacity, furnace slagging and fouling tendencies, ESP performance, etc. Blending can also require room for multiple coal piles and the ability to prepare coal blends in the coal yard, on conveyors, and/or in bunkers. If low-sulfur-coal firing is feasible, though, it can result in other benefits such as making more SO₂ allowance tons available and allowing lower air heater outlet temperatures, which can result in heat rate improvements.

Notwithstanding any capital expenses that may be required, the economics of coal switching are driven almost entirely by the delivered cost differential between the current coal and the low-sulfur coal. Changes in the delivered fuel price of a few cents per million Btu can change the annual costs for this control option by hundreds of thousand dollars or more.

Furnace Injection of Magnesium-based Alkalis

This technology, which has been the subject of this project, involves injecting magnesium hydroxide (Mg(OH)₂) aqueous slurry into the upper furnace, where it reacts with SO₃ to produce magnesium sulfate solids. These solids are removed in the downstream particulate control device. For this evaluation, both an FGD byproduct Mg(OH)₂ slurry (byproduct Mg) and commercial Mg(OH)₂ slurry (commercial Mg) have been considered. Based on

unfavorable test results from this project, calcium-based and dolomitic reagents were not considered.

Furnace injection can have an advantage over downstream injection technologies for plants that have SCR systems by lowering flue gas SO₃ concentrations at the SCR inlet. This can allow the SCR to operate at low unit loads and reduced SCR inlet flue gas temperatures without condensing ammonium bisulfate in catalyst pores. However, furnace injection appears to be relatively ineffective at removing SCR-formed SO₃ from the flue gas.

For plants without SCR, furnace Mg injection is capable of high SO₃ removal performance, but the performance of cold-side ESPs may be adversely affected by the loss of sulfuric acid conditioning of fly ash particles. With or without SCR, furnace injection should lower the flue gas acid dew point, which may allow the plant to operate at lower air heater outlet flue gas temperatures and realize heat rate improvements. The plant may also experience reduced corrosion in downstream equipment, and correspondingly reduced maintenance costs.

Alkali Injection into the Economizer Outlet or SCR Outlet Duct

Two technologies were evaluated: injection of MgO powder and injection of sodium bisulfite (SBS) solution into the ~700°F flue gas downstream of the economizer or SCR, upstream of the air heater. These processes react with SO₃ to form salts that are removed in the particulate control device. Since these technologies can remove SO₃ upstream of the air heater, they offer a potential for operating with lower air heater gas exit temperatures, with corresponding heat rate improvements. They may also reduce corrosion in the air heater and downstream.

The reactive MgO powder is available from Martin Marietta, but other vendors may provide similar products. Relatively few performance data are available in the literature for the MgO duct injection process. Martin Marietta literature cites examples of high SO₃ removal efficiency (>80%) with near stoichiometric amounts of MgO being injected.¹ However, one utility who asked to not be identified tested this sorbent downstream of an SCR reactor with little success. Balance-of-plant impacts have not been reported for the MgO duct injection process. High ash resistivity could be an issue for cold-side ESPs if MgO powder is injected to achieve high SO₃/sulfuric acid removal efficiency. A similar effect was seen in furnace Mg injection results from this project.²

The SBS process is patented by Codan Development LLC and available by license. SBS solution can be procured as a byproduct from sodium-based FGD systems, or commercially available sodium sulfite can be used as a feed material. SBS process performance data are available from full-scale testing at Vectren Corporation's A.B. Brown Station.³ Also, two commercial installations have come on line this year, at FirstEnergy's Bruce Mansfield Plant and TVA's Widows Creek Fossil Plant. Performance data and balance-of-plant impacts for the A.B. Brown tests were documented in the report cited above. High sulfuric acid removal levels are possible (down to less than 2 ppmv at the ESP outlet) when injecting at Na:SO₃ mole ratios in the range of 1.5:1 to 2:1. No adverse effects on ESP performance were noted even when removing sulfuric acid down to very low concentrations. This is apparently because the sodium salts formed condition fly ash resistivity in a manner similar to conditioning by sulfuric acid. The biggest balance-of-plant impact observed in the A.B.

Brown testing was a tendency for deposition of damp fly ash and sodium salts in the air heater inlet duct as a result of injection nozzle/lance upsets. The process developers have reportedly made modifications to reduce or eliminate solids deposition.

Alkali Injection into the Air Heater Outlet Duct

EPRI evaluated duct injection of alkali powders at pilot scale at their Environmental Control Technology Center (ECTC) in the early 1990s.⁴ The alkaline powders react with flue gas sulfuric acid to form sulfate salts that are collected with the fly ash in the particulate control device. EPRI found it was possible to achieve high sulfuric acid removal percentages when injecting hydrated lime, sodium bicarbonate, or other dry alkaline powders into the ductwork between the air heater and particulate control device, primarily a cold-side ESP. There were two disadvantages to this technology: high sorbent injection rates were required to achieve high SO₃ removal efficiencies (many times the stoichiometric amount), and high ash resistivity resulted when calcium-based alkalis such as hydrated lime were used. High resistivity was not an issue with sodium bicarbonate injection, but the reagent cost and impacts on fly ash waste disposal or sales when injecting a large excess of sodium salts were seen as an issue. A blend of 80% lime/20% sodium bicarbonate was also tested, and appeared to minimize ESP performance impacts at a lower sorbent cost than sodium bicarbonate alone.

Ammonia injection has been tested by many and has been used at a few plants as a sulfuric acid control technology. Ammonia can be injected between the air heater and cold-side ESP at NH₃:SO₃ mole ratios in the range of 1.5:1 to 2:1 to achieve high sulfuric acid removal levels (upwards of 95%). Ammonia injection does not adversely affect ESP performance. In fact, ammonia injection is often employed to enhance cold-side ESP performance, due to the cohesive properties of the ammonium sulfate/bisulfate salts that form. Furthermore, plants that have retrofitted SCR systems already have a supply of ammonia on site.

The biggest issue for ammonia injection is its effect on fly ash disposal/reuse. Ammonia slip from SCR systems can result in small quantities of ammonia in the fly ash, but using ammonia for sulfuric acid control can increase the amount in the fly ash more than tenfold. Ammonia is known to desorb from alkaline solutions containing the ammonium ion. If the fly ash is mixed with FGD byproduct to stabilize the sludge for disposal, ammonia in the ash can strip out and cause significant worker exposure and odor issues. If the fly ash is sold for cement admixture or road base use, worker exposure and nuisance odors can similarly result.

Releases of ammonia odors can also result if the ash is sluiced to an open pond, or if dry-handled fly ash is not quickly covered. Even if airborne releases of ammonia are not a concern, ammonia in fly ash can cause water quality issues. If the fly ash is handled dry and disposed of in a landfill, there is typically a leachate and runoff collection system to handle rainfall on the disposal area. With significant quantities of water-soluble ammonia salts in the fly ash, dissolved ammonia can limit the ability to discharge this leachate without treatment. For plants that sluice their fly ash to a pond and reuse or discharge pond water, the ammonium ion present in the water would also likely require some form of water treatment.

These, and all technologies applied downstream of the air heater, would offer no potential for benefits to SCR turn down or plant heat rate.

Flue Gas Humidification, With or Without Alkali Injection

This technology was also tested by EPRI at the ECTC. The flue gas is humidified and cooled, lowering the flue gas temperature below its acid dew point. The primary sulfuric acid removal mechanism appears to be condensation of large acid droplets that can be collected in a cold-side ESP or wet scrubber. The EPRI tests were conducted with humidification upstream of the ESP, and the fly ash in the flue gas may have provided surface area for sulfuric acid droplet condensation and growth. In contrast, the very rapid quenching of flue gas at the entrance to a wet scrubber in a low-dust environment is known to form sub-micron-diameter sulfuric acid droplets that are not effectively scrubbed.

The alkali injection serves several apparent purposes. One is to neutralize the sulfuric acid droplets formed, so they are less corrosive to ductwork, ESP collecting plates, etc. Another is to control the fly ash resistivity in the ideal range when injecting upstream of a cold-side ESP. In the EPRI tests, humidification without alkali injection was found to result in low fly ash resistivity and a tendency for increased ash re-entrainment emissions. Finally, the alkali particles may provide surface area for sulfuric acid condensation and droplet growth. Humidification is used for fly ash conditioning upstream of ESPs, but typically under low-sulfur-coal conditions. For high-sulfur-coal conditions, corrosion and the buildup of damp solids in ducts would be a concern.

A number of options are possible for sorbent injection and flue gas humidification downstream of the air heater. For example, the flue gas can be humidified and dry hydrated lime powder injected separately, or lime slurry could be injected in one step. Alternately, the flue gas could be humidified with water alone or with lime slurry between the ESP and wet FGD absorber, relying on the absorber to remove the sulfuric acid and/or calcium sulfate droplets that would form. EPRI's tests concentrated on humidification upstream of an ESP, where fly ash was available to serve as sulfuric acid droplet nucleation sites. Others have tested humidification downstream of the ESP but upstream of a wet scrubber. The Chemical Lime Company reportedly conducted full-scale tests of humidification with lime slurry injected upstream of a wet FGD absorber for sulfuric acid control, but results from those tests are not publicly available. A potential concern with lime slurry injection at that location is whether the lime particles are scrubbed at high enough efficiency to avoid particulate emission increases. PreussenElektra (now E.ON) reported the use of humidification immediately upstream of a wet scrubber as a means of reducing FGD outlet SO₃ concentrations.⁵

Humidification with separate hydrated lime powder injection downstream of the air heater was selected for evaluation in this paper, largely because performance data were available in the literature. Although several other duct injection/humidification configurations as described above have reportedly been tested, fewer performance data were available.

Wet ESP

Wet ESP technology has been in existence for nearly a century, but sulfuric acid control on coal-fired power plants represents a relatively new application. In this control technique, sub-micron diameter sulfuric acid mist is collected by electrostatic forces downstream of the wet FGD system in a wetted-plate ESP. The collected mist is washed from the plates periodically,

and the blow down would most likely go to the FGD system for treatment. The wet ESP could be installed downstream of the wet FGD absorber, or could even be installed inside the absorber vessel as a replacement for the chevron-style mist eliminator. Wet ESPs can be installed in two configurations: a conventional plate and wire configuration for horizontal gas flow situations, or as a bundle of tubes with wires running down the center of each tube for vertical gas flow situations.

Wet ESP technology solves the limitation on SO₃ control by conventional dry ESPs, where most of the sulfuric acid remains in the gas phase and thus is not collected by electrostatic forces. In a wet ESP downstream of an FGD absorber, the sulfuric acid is all present as a sub-micron mist that is collectable by this mechanism. The wet environment lowers particle resistivity and allows high power input levels to enhance the removal of sub-micron-diameter mist. Also, wet ESPs can remove other flue gas components that contribute to plume visibility, including fine fly ash particles, unreacted carbon or soot, and scrubber carryover. Removal of the latter can be a significant benefit in controlling “spitting” from wet stacks.

Based on discussions with some vendors, wet ESP retrofits can have capital costs in the range of \$40 to over \$90 per kW. The high capital cost is in part due to the lack of available real estate in retrofit applications, making for a difficult retrofit in an existing vessel or at an elevated location. Also, very corrosion resistant materials are typically required for the discharge electrodes and collecting plates or tubes, ranging from duplex stainless steels to “C” class alloys. Some wet ESP vendors are testing plastic collecting plates as a way of lowering implementation costs.

A disadvantage of using wet ESPs is that, by being installed at the end of the flue gas path, they address only plume opacity and particulate emissions, and provide no benefits such as reduced air heater exit temperatures. Also, a wet ESP generates an aqueous waste that must either be treated separately or added to an FGD system. Adding this stream to the FGD system would consume a small amount of FGD reagent to neutralize the acid, and would add sulfates and trace metals that could adversely affect FGD chemistry. On scrubbed units, because the wet ESP would remove both sulfuric acid and calcium-based scrubber carryover, there is a possibility for gypsum scale formation on wet ESP collector plates and/or blow down piping. Finally, wet ESPs can use a significant amount of electric power. Based on discussions with wet ESP vendors, a wet ESP sized to achieve 90% control of sulfuric acid mist at the scrubber outlet could consume approximately 0.5% of the station’s gross output. This represents about one-fourth of the power typically used by a wet FGD system.

EXPERIMENTAL

Cost estimates were prepared for applying a number of sulfuric acid control technologies to a hypothetical power plant. The plant has a single 500-MW unit, is located in the Midwest on the Ohio River, and fires a 3.5% sulfur bituminous coal. The plant is retrofitting an SCR system for NO_x control, and has a cold-side ESP for particulate control and a wet FGD system for SO₂ control. The FGD system uses limestone reagent and produces wallboard grade gypsum as a saleable byproduct. The fly ash is handled dry, and during the warm weather “ozone season”, all of the fly ash is typically sold.

The plant has a pulverized coal boiler that typically converts 1% of the coal sulfur to SO_3 . The SCR catalyst guarantee is for no more than 0.75% conversion of SO_2 to SO_3 across the catalyst. Figure 2 summarizes the baseline SO_3 /sulfuric acid concentrations at various locations in the flue gas path, with and without the SCR in line. The concentrations in the figure assume approximately 6 ppmv of SO_3 /sulfuric acid removal each across the air heater and ESP and 50% removal of sulfuric acid mist across the FGD absorber for both cases. For the air heater and ESP, it was assumed that the removal is primarily by adsorption on fly ash and that a similar quantity would be adsorbed whether the SCR is in service or not. The removal across the FGD absorber was assumed to be by physical collection, so the percentage removal was assumed independent of sulfuric acid mist concentration.

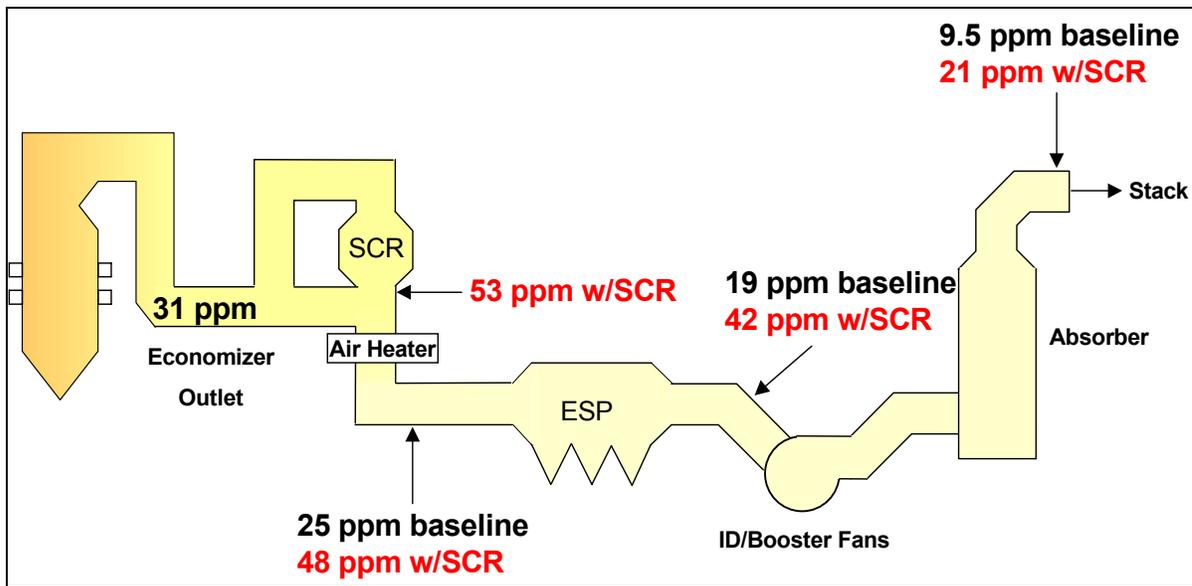


Figure 2. Baseline and post-SCR SO_3 /sulfuric acid concentrations for hypothetical plant.

Two levels of sulfuric acid control were considered. One was to restore the stack sulfuric acid concentration to the pre-SCR value of 9.5 ppmv (dry basis) from the projected value of 21 ppmv with the SCR in service. An alternate case looks at costs for achieving a higher level of SO_3 control, down to 3 ppmv at the stack. The lower concentration should be adequate to result in a clear stack, or low stack plume opacity (at least due to the sulfuric acid mist contribution to opacity) under most conditions. The SCR operates only during the “ozone season” from May 1 through September 30, and for both removal levels it was assumed the sulfuric acid controls will only operate during that time period.

The nine potential sulfuric acid controls described above were considered for this hypothetical plant. Figure 1 previously illustrated the gas path for the plant and indicated where in the gas path these candidate SO_3 /sulfuric acid control technologies were assumed to be installed. The first step in developing cost estimates for these potential sulfuric acid controls was to conduct heat (enthalpy) and material balance calculations. These calculations were used to estimate the expected SO_3 /sulfuric acid control performance of each technology and corresponding reagent and utility consumption rates, for both of the target removal levels. A number of assumptions had to be made about plant conditions such as capacity factor and coal composition, as summarized in Table 1. Table 2 summarizes the bases used for estimating

reagent and other consumables quantities for achieving the two projected SO₃ removal levels for each technology, with the SCR operating. Table 3 summarizes plant operating cost considerations for each technology.

Two of the technologies were not estimated for the lower SO₃ removal percentage. Ammonia injection can cause operating problems at lower removal percentages. If ammonia is added at low rates, so as to achieve only the 55% sulfuric acid removal percentage required to meet the 9.5 ppmv stack target, the byproduct would be ammonium bisulfate (NH₄HSO₄). Ammonium bisulfate is sticky and corrosive, and would likely cause ESP operating and maintenance problems. Ammonia is typically added at higher NH₃:H₂SO₄ mole ratios, in the range of 1.5 to 2.0, to predominantly form ammonium sulfate [(NH₄)₂SO₄] which is less sticky and less corrosive. When injected at these mole ratios, 90 to 95% sulfuric acid removal would be expected. Wet ESP technology was also not evaluated for the lower sulfuric acid removal target. It is unlikely that a power generator would retrofit a capital-intensive control technology and not design for “clear stack” capability.

The heat and material balances formed the basis for capital cost estimates for seven of the nine technologies. The exceptions were the wet ESP and fuel switch technologies. Capital cost estimates were developed for the wet ESP case, but based solely on a general budgetary cost factor of \$70/KW provided by a wet ESP vendor. The capital costs for a wet ESP retrofit can be very site specific, depending on the difficulty of the retrofit and the materials of construction, and could readily vary by ±50% for a specific circumstance. The capital cost factor of \$70/KW is based on the use of C-276 alloy. This was assumed to be required because the wet ESP would be downstream of the wet scrubber, with the potential for the carry-up of chloride-containing FGD liquor into the extremely acidic environment. No capital costs were estimated for fuel switching, as the capital requirements for this technology can be very site specific. Some plants may require little or no capital changes, while other plants may require extensive revisions such as coal blending conveyors, increased mill capacity, soot blower upgrades, etc.

For the seven technologies, major equipment items such as silos, tanks, pumps, and air compressor sizes were estimated from the material balance results. Storage silos or tanks were sized for 15-day storage at full load and the corresponding SO₃/sulfuric acid removal target. For technologies using a day tank or silo near the unit, this was sized for 24 hours of capacity at full load. Pumps, blowers, and air compressors were also sized based on the material balance results for full load operation. Once sized, the major equipment costs were interpolated from recent URS cost data for similar equipment. Spreadsheets were used to develop overall cost estimates. Piping costs were based on estimated pipe run lengths and standard per-foot costs for each pipe size and material. Instrument requirements were based on typical process flow diagrams for each technology. Items such as motor controls and valves were estimated from the number of motors and pipe run estimates, respectively. Factors were used for estimating costs for process design, detailed design and procurement, installation, construction management, etc. Labor rates were based on Midwest union labor.

An estimate of this type is typically regarded as having an accuracy of ±25%. However, for these estimates the accuracy is more likely in the range of ±30 to 50%, for a variety of

Table 1. Assumptions made for heat and material balances for model plant.

Parameter	Value
Unit Load (gross MW)	500
Gross Plant Heat Rate (Btu/hr/KW)	9200
Capacity Factor (%)	85
Flue Gas Flow Rate (acfm at economizer outlet)	2.07×10^6
Coal Sulfur Content (%)	3.5
Flue Gas SO ₂ Content (ppmv at economizer outlet)	2790
NO _x Season Duration (months/yr)	5
Target Stack Sulfuric Acid Concentration (ppmv, dry basis):	
For lower SO ₃ removal percentage target	9.5 (return to pre-SCR conditions)
For higher SO ₃ removal percentage target	3.0 (assumed value for “clear” stack)

Table 2. Bases for quantity estimates for candidate control technologies.

Technology	For 9.5 ppmv at Stack	For 3.0 ppmv at Stack
Fuel Blending	32% low-sulfur (0.5 wt%) coal	87% low-sulfur (0.5 wt%) coal
Byproduct Mg Injection in Furnace	3.9:1 Mg:SO ₃ mole ratio (based on SCR outlet)	Not estimated to achieve target
Commercial Mg Injection in Furnace	3.9:1 Mg:SO ₃ mole ratio (based on SCR outlet)	Not estimated to achieve target
MgO Injection Upstream of Air Heater	1.25 moles Mg injected per mole SO ₃ removed	1.25 moles Mg injected per mole SO ₃ removed
SBS Injection Upstream of Air Heater	1.6 moles Na injected per mole SO ₃ removed	2.0 moles Na injected per mole SO ₃ removed
NH ₃ Injection Upstream of ESP	Not estimated at lower removal percentage	1.8 moles NH ₃ injected per mole SO ₃ removed
Humidification/Lime Injection Upstream of ESP	Humidification to 293°F, hydrated lime injection at 1 lb/hr per kacfm	Humidification to 275°F, hydrated lime injection at 1 lb/hr per kacfm
Hydrated Lime Injection Upstream of ESP	Hydrated lime injection at 2 lb/hr per kacfm	Hydrated lime injection at 5.6 lb/hr per kacfm
Wet ESP between Wet FGD and Stack	Not estimated at lower removal percentage	Electric power at 320 W/kacfm, water at 0.05 gal/kacf

Table 3. Summary of SO₃ control technology operating cost impacts.

	Fuel Switch/Blend	Furnace Injection of Byproduct Mg	Furnace Injection of Commercial Mg	MgO Injection Downstream of SCR	SBS Injection Downstream of SCR	Ammonia Injection Between Air Heater and ESP	Humidification and Lime Injection Between Air Heater and ESP	Hydrated Lime Injection Between Air Heater and ESP	Wet ESP Between FGD Absorber and Stack
Major Power Consumers	None	Air compressors, pumps	Air compressors, pumps	Air blower	Air compressors, pumps	Air blower, heater	Air compressors, pumps, air blower	Air blower	T/R set input power
Waste Disposal/ Byproduct Stream	Potentially reduced fly ash production; reduced FGD gypsum production	MgSO ₄ , mixed with fly ash	MgSO ₄ , mixed with fly ash	MgSO ₄ , mixed with fly ash	Na ₂ SO ₄ , mixed with fly ash, CaSO ₄ ; increased FGD gypsum production ¹	(NH ₄) ₂ SO ₄ , NH ₄ HSO ₄ , mixed with fly ash	CaSO ₄ , excess lime mixed with fly ash	CaSO ₄ , excess lime mixed with fly ash	CaSO ₄ , increased FGD gypsum production ²
Boiler Efficiency Impacts	Potential increase due to lowered SO ₃ concentration upstream of air heater	Decrease due to water evaporated in furnace, potential increase due to SO ₃ removal upstream of air heater	Decrease due to water evaporated in furnace, potential increase due to SO ₃ removal upstream of air heater	Potential increase due to SO ₃ removal upstream of air heater	Decrease due to water evaporated upstream of air heater, potential increase due to SO ₃ removal upstream of air heater	None	None	None	None
SO ₂ Allowance Impacts	Reduced SO ₂ emissions due to lower coal sulfur	None	None	None	None	None	None	None	None
NO _x Removal Impacts	May allow SCR operation at low load	May allow SCR operation at low load	May allow SCR operation at low load	None	None	None	None	None	None

¹The reaction of SBS or sodium sulfite to remove SO₃ and form sodium sulfate releases an equal molar amount of SO₂ into the flue gas, that must be scrubbed in the FGD absorber.

²Sulfuric acid collected will end up in the FGD liquor, requiring additional FGD limestone for neutralization.

reasons. For example, assumptions were made regarding redundancy that might change during a detailed design effort, and the placement and retrofit difficulty for each equipment item could not be determined for the hypothetical plant.

RESULTS AND DISCUSSION

Reagent and utility consumption and amortized capital cost estimates were combined to generate annual cost estimates for each of the technologies. The estimates were not leveled to reflect escalation and discount rates, but instead represent first-year costs. Nor do they include operating labor, maintenance labor or materials. For most of the technologies, there is not a good experience basis for estimating these values. The annual cost estimates are summarized in Figure 3 for both removal targets.

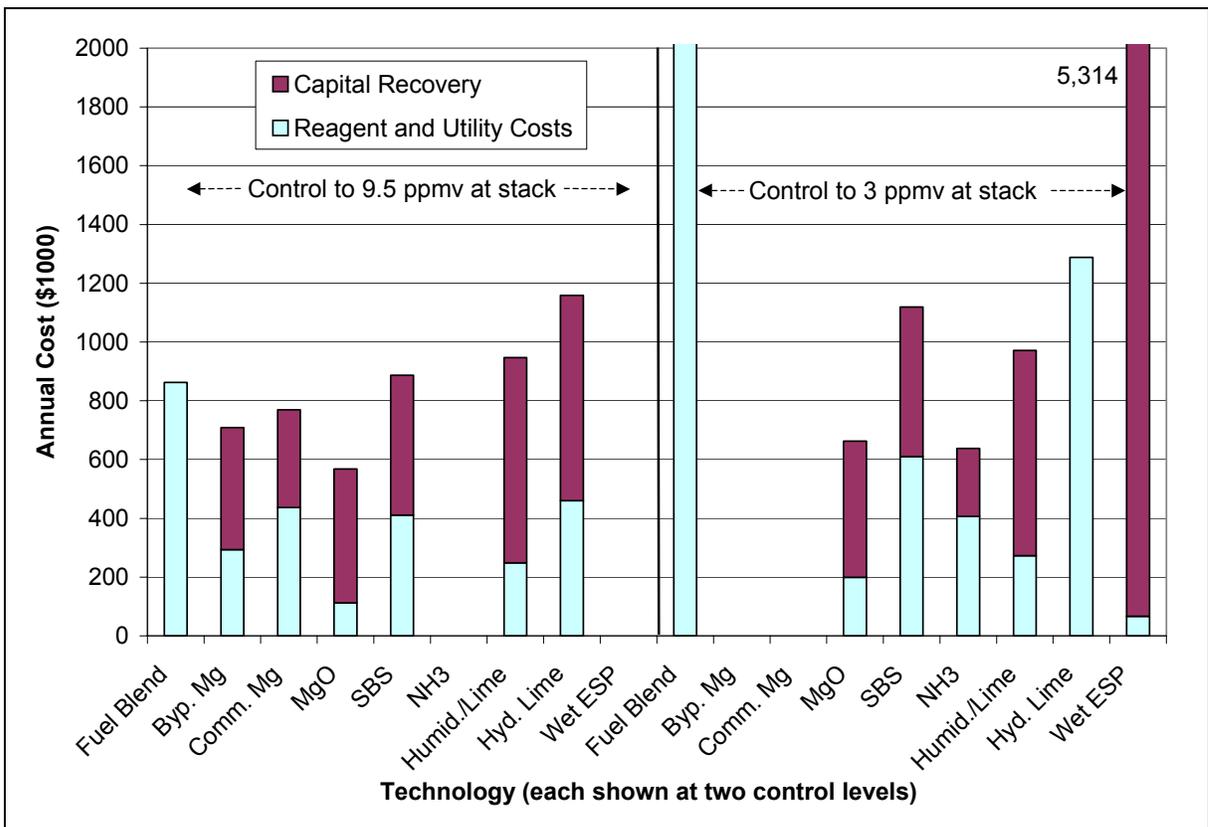


Figure 3. Summary of first-year capital recovery and non-labor operating cost estimates.

Reagent and utility costs are based on operating at the target SO₃ control level from May 1 to September 30 each year (the ozone season). The factors used to develop costs from reagent and utility consumption rates are shown in Table 4. Capital recovery is an annual cost irrespective of the months of operation, and is based on a capital recovery factor of 0.15.

For the lower sulfuric acid control percentage, the MgO powder injection technology was projected as having the lowest annual cost, at \$570,000. However, the performance of that technology is not well supported by third-party measurements, so one would expect this estimate to have a large range of uncertainty. Five other technologies have projected reagent,

Table 4. Factors used to generate annual reagent and utility costs.

Factor	Value Used
Byproduct Mg Reagent, f.o.b. Midwest supplier (\$/dry ton of pure Mg(OH) ₂), shipped at 18% solids, 65% purity in solids	100
Commercial Mg, f.o.b. Manistee, MI (\$/dry ton Mg(OH) ₂), shipped at 58 wt% solids, 100% purity in solids	210
Utilimag 40 MgO powder, f.o.b. Manistee, MI (\$/dry ton Mg(OH) ₂)	350
Sodium Bisulfite, delivered (\$/dry ton available Na as Na ₂ SO ₃)	300
Ammonia, delivered from existing plant system (\$/ton)	300
Hydrated Lime, delivered (\$/ton)	80
Truck Transit Costs (\$/ton-mile)	0.12
Plant Water Cost (\$/1000 gal)	0.40
Plant Softened Water Cost (\$/1000 gal)	2.30
Plant Auxiliary Power (\$/kwh)	0.032
Plant Fuel Costs (\$/MM Btu)	1.04
Plant Low-sulfur Fuel Cost (\$/MM Btu)	1.24
Gypsum Byproduct Value (\$/wet ton, f.o.b. plant)	5.00
Fly Ash Sales Value (\$/ton, f.o.b. plant)	3.00
Incremental Landfill Disposal Costs (\$/ton)	4.00
Capital Recovery Factor	0.15

utility, and capital recovery costs in the range of \$710,000 to \$950,000 annually per unit. The differences between the projected costs of these technologies are not great relative to the level of uncertainty for the projections. These five technologies include fuel blending, furnace injection of byproduct Mg, furnace injection of commercial Mg, SBS injection downstream of the SCR, and humidification with hydrated lime injection between the air heater and ESP. The costs for fuel blending with low-sulfur coal disregard any potential capital modifications that may be required by the plant. Significant capital modification requirements could make this option less attractive. The remaining technology for which costs were developed for the lower removal percentage case, dry hydrated lime powder injection between the air heater and ESP, appears to be less cost effective, with annual costs projected at nearly \$1.2 million.

The estimated costs for the higher sulfuric acid removal percentage show two technologies with projected first-year costs of around \$650,000 (ammonia injection and MgO powder injection). Two other technologies, SBS injection and humidification with hydrated lime

injection, have annual projected costs of \$1 million to \$1.1 million. The wet ESP case shows considerably higher first-year costs of over \$5 million. This comparison is skewed by the assumption that the control technologies will only operate five months out of the year and the relatively high capital recovery factor (10-year recovery), both of which favor low capital cost technologies. Two other technologies that were projected to be able to achieve the higher removal percentage, fuel switching and dry hydrated lime powder injection, show higher first-year operating costs of \$1.3 million or greater. Capital cost estimates were not prepared for those cases. Finally, the two furnace injection technologies were not projected to achieve the higher SO₃/sulfuric acid removal, so no results are shown in the right side of Figure 3.

The results of this economic comparison are highly dependent on assumptions made about performance, cost and technical issues regarding the potential control technologies. The following describes the factors that affect the cost effectiveness of each technology.

Fuel Blending/Fuel Switch. Costs for this technology are very dependent on the cost differential between the normal plant coal and low-sulfur coal. At the differential of \$0.20 per million Btu used for this evaluation, fuel blending/switching was not cost competitive with some of the injection technologies for the higher sulfuric acid control percentage target. But at a \$0.10 per million Btu differential it would be cost competitive. This assumes minimal capital cost requirements to be able to blend and fire the low-sulfur coal.

Furnace Injection of Byproduct or Commercial Mg. The costs for this technology are driven by the delivered cost of the Mg reagent, which is dependent on the shipping method and distance. Rail or barge delivery, shorter distances, or (in the case of byproduct Mg) production on site could make this technology more cost effective. Also, for the byproduct Mg, there is not a well-established sales price for this material.

For plants that have an SCR, there are potential benefits from furnace Mg injection that were not evaluated in this comparison. In plants that cycle load, SCR operation may be limited at low load by the formation of ammonium bisulfate on active catalyst sites. Economizer bypass ducts or economizer tube bundle removal may be required to maintain high SCR inlet flue gas temperatures at low load. Mg injection to remove furnace-formed SO₃ could allow SCR operation at low unit load without economizer bypasses or tube removal.

MgO Injection Downstream of the SCR. This technology appeared to be cost effective in the economics presented above. However, the performance of this technology was based on a very limited amount of vendor-supplied data, all of which were on flue gases with relatively low uncontrolled SO₃ concentrations (less than 20 ppmv). More data are needed, particularly for higher SO₃ concentrations and preferably measured by a third party, to be able to use these estimates with confidence. As for the Mg slurry injection processes, the costs for this technology will be dependent on the distance from reagent source. Also, the ability to achieve high SO₃ control efficiencies could be limited by adverse effects on ESP operation.

SBS Injection. A major issue for estimating the cost of this technology is the delivered cost of the reagent, which will be a function of the reagent type, f.o.b. cost, distance and delivery method. Also, this is a proprietary technology, so the cost estimate includes an annual technology fee (\$0.20 per kW of generator capacity) not included for the other processes.

Ammonia Injection. This process may not be applicable to many plants because of impacts of the ammonium salts on byproduct reuse or disposal. The economics presented here consider the loss of fly ash sales revenue and costs for landfill disposing of the ammonia-containing fly ash. However, potential costs associated with treating ammonia-containing landfill leachate or costs associated with avoiding nuisance odors during fly ash handling were not considered. These potential costs could make ammonia injection for sulfuric acid control more expensive than was estimated here. Furthermore, some plant configurations may not be compatible with ammonia injection for sulfuric acid control. This could include plants that mix ash with FGD byproduct for stabilization, plants that use wet scrubbers for particulate control, and plants that sluice and/or pond dispose of fly ash.

Humidification and Lime Injection. The costs for this technology will vary significantly depending on the configuration implemented. If the humidification and lime injection can be implemented in one step by injecting lime slurry into the duct, reagent costs could be reduced by using slaked quicklime rather than hydrated lime powder. Capital costs would be reduced by eliminating the need for separate humidification and powder handling and injection systems. Also, if the injection is between an ESP and wet scrubber, the excess reagent would be carried into the FGD system, and should reduce FGD reagent consumption.

Hydrated Lime Powder Injection. The performance and cost estimates for this technology are based on ECTC pilot-scale results. There is anecdotal information that others have tested hydrated lime injection at full scale, and have seen lower lime injection rates to achieve a given level of sulfuric acid removal than the ECTC results predict. However, those results were not available to serve as the basis for performance estimates for this evaluation. Even if with significantly lower lime requirements, the ability to achieve the higher sulfuric acid control target with this technology remains in question for plants that would inject hydrated lime upstream of ESPs. Removal of sulfuric acid from the flue gas and the injection of high-resistivity, calcium-based solids could significantly degrade ESP performance. Dry injection of a blend of calcium and sodium-based sorbents, as was tested by EPRI, could be employed to overcome adverse effects on ash resistivity, although at a higher sorbent cost.

Wet ESP. Wet ESP retrofit costs will be very site specific, depending on the retrofit difficulty, the required level of sulfuric acid mist control, and the materials of construction. Wet ESP costs would also be lower for a new installation than for a retrofit. Regardless of this potential variation, the wet ESP option is the most capital intensive control technology considered in this evaluation. Wet ESP technology offers an advantage over the other technologies because it can also control fine fly ash or carbon particulate that may contribute to elevated plume opacity. However, since a wet ESP would be installed at the very end of the flue gas path, just before the stack, it would not address upstream impacts of elevated SO₃/sulfuric acid concentrations such as air heater plugging or corrosion.

Wet ESP technology is the most mature of these technologies, but is not well demonstrated for the situation at the example plant: SCR in service, downstream of a wet lime or limestone FGD system on high-sulfur coal, and high required sulfuric acid control percentages. Only one existing U.S. installation is even close to demonstrating these criteria, at AES' Deepwater plant. There is little doubt that a wet ESP can achieve high sulfuric acid control, with coincident removal of other fine particulates that contribute to plume opacity. However,

reliability in a situation such as at the model plant needs to be better demonstrated before many utilities would commit to such a capital-intensive retrofit.

CONCLUSIONS

These example economics show that byproduct Mg or commercial Mg injection in the furnace, which were tested as part of this project, can be cost effective for restoring stack sulfuric acid concentrations to pre-SCR levels. The furnace injection technology was not estimated to be able to achieve the higher sulfuric acid removal percentage target with an SCR in operation, though. Ammonia injection was projected to be a low cost technology, but balance-of-plant impacts may preclude its use. MgO injection and SBS injection appear to be cost competitive technologies at either control level. Humidification combined with lime injection may also be a cost-competitive control approach, particularly if the two steps can be combined by injecting lime slurry.

These example economics also demonstrate two important observations about SO₃/sulfuric acid controls. One is that there is no one “best” control option. The cost effectiveness of control options depends on many site specifics. These can include whether an SCR is in service, reagent shipping distances, ash and FGD byproduct reuse/disposal practices, the SO₃ control level required, and the extent to which other particulate matter contributes to plume opacity. Depending on these specifics, one technology may be favored over the others. The second observation is that there are several candidate SO₃/sulfuric acid control technologies for which there is not adequate full-scale demonstration or test data to serve as a basis for evaluating these technologies. In particular, MgO powder injection and humidification/lime injection technologies (combined or separately) show promise as being cost effective for some situations, but neither has been adequately demonstrated and characterized at full scale.

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