Control *of* MERCURY EMISSIONS *from* Coal-Fired Electric Utility Boilers

An overview of the status of mercury control technologies.

PHOTODISC

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Mercury is a toxic, persistent pollutant that accumulates in the food chain (*1*). Atmospheric mercury is a global problem with many natural and anthropogenic emission sources. The U.S. fleet of coal-fired power plants, with generating capacity of >300 GW, is known to be the major anthropogenic source of domestic mercury emissions (*2*), although it contributes only ~1% of worldwide annual mercury emissions (*1*). The U.S. EPA recently promulgated the Clean Air Mercury Rule (CAMR) to permanently cap and reduce emissions of mercury from these plants (*3*). This rule makes the U.S. the first country in the world to regulate mercury emissions from coal-fired power plants.

CAMR will be implemented in two phases. Initially, a national annual cap of 38 tons (t) is to be reached by 2010, with emission reductions coming primarily as a cobenefit of technologies that control other air pollutants. The second phase sets a national annual cap of 15 t by 2018. The second-phase reductions will likely require use of dedicated mercury-control technologies. The time frame of CAMR implementation will allow added time for further development and testing of these technologies.

EPA has also recently promulgated the Clean Air Interstate Rule (CAIR), which requires further reductions of NO_x and SO_2 from U.S. coal-fired power plants. As a result, additional NO_x control and flue-gas desulfurization (FGD) systems are expected to be installed. By 2020, more than half of the U.S. coal-fired generating capacity is projected to be equipped with selective catalytic reduction (SCR) and FGD

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technology. Retrofitting the NO_x and SO_2 controls will also tend to reduce mercury emissions, because most oxidized mercury (Hg^{2+}) is collected in the FGD system, and SCR units can enhance the fraction of this form of mercury. This capture of Hg^{2+} is significant because it is this form that tends to deposit locally, whereas elemental mercury (Hg^0) tends to join the global pool of mercury and be transported much farther.

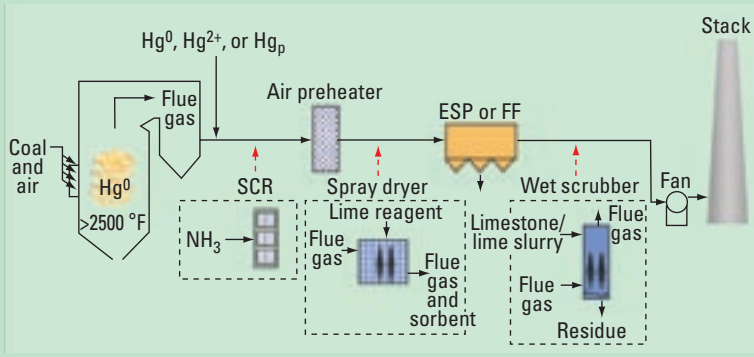
EPA's modeling shows that CAIR will significantly reduce coal-fired power-plant mercury emissions that deposit in the U.S., and those reductions will occur in areas where mercury deposition is currently highest. CAMR is expected to make additional reductions in emissions that are transported regionally and deposited domestically, and it will reduce emissions that contribute to atmospheric mercury worldwide (*1*).

The U.S. Department of Energy's (DOE's) National Energy Technology Laboratory (NETL) has sponsored much of the mercury control technology development and demonstration (*4*). Although many mercury-specific control technologies are currently under development, most initial mercury emission reductions will come as a cobenefit of existing controls used to remove particulate matter (PM), SO_2, and NO_x (*5*). The effectiveness of the various mercury control options depends significantly on site-specific characteristics, such as the configuration of existing air pollution controls and the type of coal burned.

In this feature, we explore what is known about existing technologies that remove mercury as a cobenefit of removing other pollutants and describe future approaches under development for achieving deeper cuts in mercury emissions.

FIGURE 1

Major air pollution control options for a coal-fired power plant



Mercury behavior in utility boilers

Mercury is present in coal in trace amounts (~0.1 ppm on average). Combustion releases the mercury into the exhaust gas as Hg^0. This vapor may then be oxidized to Hg^{2+} via homogeneous (gas–gas) or heterogeneous (gas–solid) reactions. The primary homogeneous oxidation mechanism is the reaction with gas-phase chlorine to form $HgCl_2$. Although this reaction is thermodynamically favorable, it is kinetically limited. The heterogeneous oxidation reactions are believed to occur on the surface of fly ash and unburned carbon (UBC).

One proposed heterogeneous oxidation mechanism involves the chlorination of carbon as a first step toward the surface-mediated conversion of Hg^0 to $HgCl_2$ (*6*). This oxidized mercury may then be bound to the surface of fly ash or UBC, or released as $HgCl_2(g)$. The mercury that is adsorbed onto solid surfaces is known as particulate-bound mercury (Hg_p), which can be captured by downstream PM control devices. The specific form of mercury in flue gas (Hg^0, Hg^{2+}, or Hg_p) has a strong impact on the capture of mercury by air pollution control (APC) equipment.

Cobenefit mercury removal

Although mercury may be captured as a cobenefit of existing PM, NO_x, and SO_2 controls, the degree of this cobenefit will vary significantly depending on the type of coal burned and the specific control-technology configuration. Figure 1 shows the major APC options used at coal-fired power plants, and Table 1 gives current and projected uses of these controls. The percentage of native capture (i.e., mercury capture without additional mercury-specific control technology) is also given in Table 1 for those control configurations for which EPA Information Collection Request data are available. The tendency of boilers burning bituminous coals to achieve higher native mercury capture is likely a result of the higher chlorine content of the coals and of the tendency of the coals to produce higher levels of UBC in the flue gas. Both factors contribute to greater levels of mercury as Hg^{2+} and Hg_p, which are easier to capture in existing APC equipment than Hg^0.

Several approaches are being tested to enhance the cobenefit mercury capture in existing APC equipment. Blending of small amounts of bituminous coal with subbituminous coal or lignite may provide some benefit. However, the effectiveness of this approach is likely to be very site-specific and needs further evaluation. Adding chlorine to the fuel or injecting it into the flue gas is another approach being tested to enhance the native capture of mercury (*7*). However, concerns such as corrosion, plugging, and impacts on combustion equipment need to be addressed in long-term testing.

Table 1 reveals that a fabric filter (FF) can be more effective for mercury capture than an electrostatic precipitator (ESP), especially with bituminous coals, because of the increased contact of the gas with fly ash and UBC as those accumulate as a filter cake on the

TABLE 1

Pollution controls and their connection to mercury capture

System	Total capacity (%)[a] Current	2010	2020	Coal type (B, bituminous; S, subbitum.; L, lignite)	Native capture (%)	Range of capture (%)	Number of units tested[b]	Effect on mercury capture
PM controls								
CS-ESP	36.6	25.4	15.6	B	29	0–63	4	Good capture of particulate- or sorbent-bound mercury; better native capture for bituminous coals than low-rank coals.
				S	3	0–18	3	
				L	0	0–2	1	
HS-ESP	6.2	3.9	3.2	B	11	0–48	3	Low native capture; probably requires specially formulated sorbents for high-temperature mercury capture.
				S	0	0–27	4	
				L	[c]			
FF	3.9	3.6	2.4	B	89	84–93	2	Good cobenefit capture; Hg^0 may be oxidized across the FF.
				S	73	53–87	2	
				L	[c]			
PM and SO_2 controls								
CS-ESP + wet FGD	13.7	11.6	10.5	B	69	64–74	2	Good native capture for bituminous coals because of presence of soluble Hg^{2+} in the flue gas; relatively poor capture for low-rank coals.
				S	16	0–58	3	
				L	42	21–56	2	
HS-ESP + wet FGD	2.9	3.9	3.3	B	39	6–54	3	Moderate native capture for bituminous coals; poor native capture for low-rank coals.
				S	8	0–42	3	
				L	[c]			
FF + dry scrubber	2.9	2.7	2.9	[d]				Very high native capture expected for bituminous coals, less for low-rank coals.
FF + wet FGD	1.6	1.7	1.6	B	75	62–89	2	Good cobenefit capture for bituminous coals; Hg^0 may be oxidized across the FF and captured in the wet scrubber.
				S	[c]			
				L	[c]			
NO_x and PM controls								
SCR + CS-ESP	15.1	11.8	7.2	[d]				Good capture of particulate- or sorbent-bound mercury and better native capture for bituminous coals than low-rank coals are expected.
SCR + HS-ESP	2.0	1.1	0.6	[d]				Low native capture is expected.
NO_x, PM, and SO_2 controls								
SCR + CS-ESP + wet FGD	9.1	21.0	31.2	Native capture >90% (based on 2 tests at the Dominion Resources Mount Storm power plant, Unit 2) [d]				Good capture of particulate- or sorbent-bound mercury; better native capture for bituminous coals than low-rank coals; SCR will tend to enhance capture for bituminous coals by oxidizing Hg^0 to the Hg^{2+} form.
SCR + spray dryer + FF	0.7	0.9	1.4	B	97	94–99	2	Very high native capture for bituminous coals, less for low-rank coals; SCR may enhance capture by oxidizing Hg^0 to Hg^{2+} form.
				S	23	0–47	3	
				L	17	0–96	2	
SCR + HS-ESP + wet FGD	0.2	2.3	3.2	[d]				Poor capture of particulate-bound mercury in general and total mercury for low-rank coals; SCR may enhance capture for bituminous coals by oxidizing Hg^0 to the Hg^{2+} form.
SCR + FF + wet FGD	0.3	0.3	6.3	[d]				High level of mercury capture would be expected for all coals. SCR may enhance capture for bituminous coals by oxidizing Hg^0 to the more soluble Hg^{2+} form.

[a] CAIR projections; totals do not sum to 100%; less-common control configurations not included here.
[b] From EPA's 1999 ICR on mercury emissions for coal-fired power plants.
[c] None tested.
[d] No ICR data available.

Acronyms

APC	air pollution control
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CCRs	coal combustion residues
CS-ESP	cold-side electrostatic precipitator
ESP	electrostatic precipitator
FF	fabric filter
FGD	flue-gas desulfurization
HS-ESP	hot-side electrostatic precipitator
ICR	Information Collection Request
LSFO	limestone-forced oxidation
MEL	magnesium-enhanced lime
NETL	National Energy Technology Laboratory
PAC	powdered activated carbon
PM	particulate matter
SCR	selective catalytic reduction
SDA	spray dryer absorber
UBC	unburned carbon

FF. The filter cake acts as a fixed-bed reactor and contributes to greater heterogeneous oxidation and adsorption of mercury. However, as seen in Table 1, the use of FF at U.S. coal-fired power plants is limited.

The native mercury capture in plants with only cold-side (CS-) or hot-side (HS-) ESPs was shown to be less effective than that in plants with the FF-only configuration. This is because much less contact between gaseous mercury and fly ash occurs in ESPs. Also, HS-ESPs operate at higher temperatures, at which capture of mercury on fly ash is not effective. The ESP-only configuration is expected to become less common during the next 15 years with the expected installation of NO_x and SO_2 controls, although plants with this configuration will still provide ~20% of the total capacity.

FGD systems typically fall into two broad categories. Wet FGD systems, which are currently installed on about one-third of the total coal-fired generating capacity, include the commonly used limestone-forced oxidation (LSFO) and the magnesium-enhanced lime (MEL, or "mag-lime") scrubbers. Dry FGD systems, which are found on <5% of the capacity (MW), are typically spray dryer absorbers (SDAs) that are usually installed in combination with an FF (SDA/FF). The use of both wet and dry systems is expected to increase with implementation of CAIR.

Highly water soluble Hg^{2+} species may be captured efficiently in wet FGD systems. Under certain conditions, SCRs can promote the oxidation of Hg^0 to Hg^{2+}. A comparison of the effects of SCR shows that the oxidation of Hg^0 to Hg^{2+} is significant for bituminous coals but not for subbituminous coals; no data are available for lignite. In fact, in most cases, the use of SCR resulted in ~85–90+% Hg^{2+} when bituminous coals were fired. Additional research efforts are under way to evaluate mercury-specific oxidation catalysts and/or oxidizing agents that are used upstream of the wet FGD system. These approaches for generating soluble Hg^{2+} species are undergoing full-scale evaluation.

Table 1 also shows that ~95% of mercury is removed by SDA/FF combinations when they are used on bituminous-coal-fired boilers. Mercury, mostly in the form of Hg^{2+} at the inlet of the SDA with bituminous coals, is captured on the FF. However, mercury capture in SDA/FF systems tends to be much less with low-rank coals. In this case, the SDA scrubs halogen species such as HCl from the flue gases, which results in reduced oxidation and mercury capture in the downstream FF. In fact, the data in Table 1 show higher mercury capture by FF than by SDA/FF systems when subbituminous coal is fired. This is believed to be a result of the SDA scrubbing effect, which removes halogen species that could otherwise react on the FF.

A series of field tests have been completed at three commercial coal-fired utilities with wet FGD systems. One of the objectives was to evaluate the effectiveness of wet FGD systems at capturing Hg^{2+} species under various conditions. It is known that a portion of the Hg^{2+} absorbed in the wet scrubber can be converted back to Hg^0 and reemitted. Therefore, sodium hydrosulfide (NaHS) was injected into the scrubber solution during the tests to prevent the conversion of captured Hg^{2+} to Hg^0 and subsequent reemission.

At Michigan South Central Power Agency's Endicott Station in Litchfield, Mich. (55 MW, high-sulfur bituminous coal, LSFO scrubber), ~96% of the oxidized mercury (76–79% of total mercury) was removed in the scrubber system, and the NaHS additive was successful in preventing reemission of captured mercury. A subsequent 15-day test at Cinergy's Zimmer Station in Moscow, Ohio (1300 MW, high-sulfur bituminous coal, Thiosorbic MEL scrubber with ex situ oxidation), recorded a lower removal of total mercury (51%) and of Hg^{2+} (87%) than Endicott Station. In addition, the Hg^0 concentration increased across the wet FGD system by ~40%; this indicates that in this case, the additive was not successful in suppressing the reemission of captured mercury from the scrubber.

Additional tests were undertaken at the Dominion Resources power plant in Mount Storm, W.Va. (Unit 2, 563 MW, medium-sulfur bituminous coal, LSFO scrubber, SCR). With the SCR unit bypassed and no NaHS injected, the scrubber captured >90% of the Hg^{2+} (71% of total mercury); captured Hg^{2+} was reemitted as Hg^0 vapor, giving a net increase of Hg^0 across the scrubber. Under the same conditions but with NaHS injection, the scrubber again captured >90% of the Hg^{2+} (78% of total mercury). However, this time NaHS effectively suppressed reemission from the scrubber. In tests in which the flue gas was directed through the SCR unit, both with and without NaHS in the scrubber solution, the removal of Hg^{2+} increased to >95% and total mercury removal was >90%. These results appear to indicate that, in certain cases, the use of SCR may suppress reemission.

To meet regulatory time lines, R&D efforts should be focused on those areas that are likely to affect

the largest number of boilers or are likely to significantly affect the ability of a class of boilers to reduce mercury. Knowledge of mercury oxidation mechanisms across SCR catalysts is needed and may best be obtained through coordinated laboratory, pilot, and field testing. Field testing alone may not provide adequate control of conditions to understand this phenomenon. Reduction of oxidized mercury in wet FGD and subsequent reemission also requires better insight into the processes. Finally, an improved understanding of the behavior of mercury in the boiler and APC system may offer insights into addressing operational variability. Modeling and testing are needed to develop this understanding.

Sorbent injection

Mercury control via the injection of sorbent materials into the gas stream of coal-fired boilers is under development. Currently, it is being demonstrated on selected full-scale systems. A typical implementation of this control technology would entail the injection of powdered sorbent upstream of the existing PM control device (ESP or FF). An alternative is the TOXECON configuration, in which a relatively small FF is installed downstream of an existing ESP. Sorbent is injected downstream of the ESP after most of the flue-gas PM has been removed. The sorbent is then collected in the downstream FF, which effectively segregates the fly ash and injected sorbent.

Some of the factors that appear to affect the performance of any particular sorbent include the method and rate of sorbent injection; flue gas conditions, including temperature and concentrations of halogen species (e.g., HCl) and sulfur trioxide (SO_3); the existing APC configuration; and the physicochemical characteristics of the sorbent. The sorbent injection rate is usually expressed as pounds of sorbent per million actual cubic feet of flue gas (lb/MMacf). For a 500-MW boiler, a sorbent rate of 1.0 lb/MMacf corresponds to ~120 lb/h of sorbent.

During 2001–2003, DOE/NETL, the Electric Power Research Institute, and a group of utility companies funded relatively short term field-test projects to evaluate the use of powdered activated carbon (PAC) injection. The initial four DOE-sponsored projects were referred to as DOE/NETL Phase I tests (*4*). These projects provided additional insights into the factors that appear to affect the mercury capture performance that is achieved with PAC injection.

Generally, the injection of PAC in greater amounts tends to increase mercury removal efficiency. However, at the We Energies Pleasant Prairie, Wis., power plant, which burns subbituminous coal, a mercury removal efficiency of ~60% was reached with modest sorbent addition, but additional carbon injection resulted in only minimal improvement. This is thought to be a result of lower levels of chlorine in the subbituminous coal used and the neutralization of flue-gas halogen species by high levels of sodium and calcium in the fly ash—conditions that result in little free chlorine in the flue gas. Because an adequate amount of halogen in the gas stream is believed to be necessary for the capture of Hg^0 by standard PAC, mercury capture via standard PAC injection may be limited in boilers firing low-rank coal.

Temperature is known to affect the adsorption capacity of PAC. In most cases, the gas temperature at the available injection location upstream of the PM control device is ~300 °F; PACs have been shown to work effectively at this temperature. However, at temperatures approaching 350 °F or more, the effectiveness of standard PAC drops rapidly (*8*). Temperatures >350 °F may be relevant for lignite-fired boilers and boilers equipped with HS-ESPs. Enhanced PACs or other sorbents may offer the capability to implement sorbent injection at those higher temperatures.

Acidic gas components such as SO_3 are thought to compete with mercury for the active sites on PAC and thereby can affect mercury capture performance. This may be relevant to PAC injection applications at plants firing high-sulfur coal.

The configuration of existing APC equipment can have a significant impact on PAC performance. For example, the use of a retrofitted, smaller FF after an existing ESP with PAC injection between these control devices (the TOXECON configuration) can provide high levels of mercury removal with modest PAC injection rates. The PAC properties, such as particle size, probably have an impact on mercury capture performance when most of the mercury capture is in-flight, as in PAC injection with an ESP, but little, if any, impact when PAC injection is used with an FF.

Speciated mercury capture data collected in short-term projects indicated that PAC injection appears to be effective at controlling emissions of Hg^{2+}.

Speciated mercury capture data collected in the previously mentioned short-term projects indicated that PAC injection appears to be effective at controlling emissions of Hg^{2+}. However, this finding needs to be substantiated by additional tests.

Longer-term tests of the TOXECON configuration were conducted at Southern Company's Gaston plant in Wilsonville, Ala. The main objectives were to further evaluate the potential for the mercury capture performance seen in earlier short-term tests and to test higher-permeability FF bags with lower pressure drop. In full-load (270-MW) tests, PAC was injected nearly continuously for 5 months. The PAC was injected at rates of <0.7 lb/MMacf to maintain acceptable FF cleaning frequency for operation at an air-to-cloth ratio of 8.0 ft/min. This approach re-

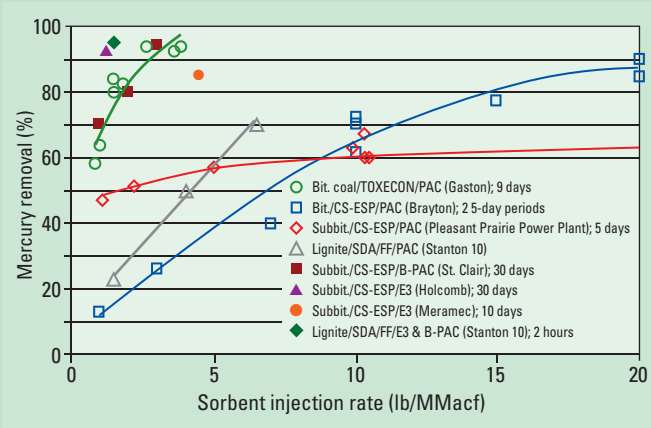
sulted in weekly mercury removal of 80–90%, with an average of 86%, for about 4 months.

So that 90% removal could be achieved, additional lower-load (195-MW), or lower-throughput, tests were conducted with the FF operating at an air-to-cloth ratio of 6.0 ft/min. In these tests, PAC was injected for 2 weeks in November 2003, which led to >90% mercury removal at injection rates of ≥2 lb/MMacf. In December 2003, full-load (270-MW) tests were conducted with higher-permeability bags operated at an air-to-cloth ratio of 8.0 ft/min. Mercury removal of >90% was achieved at injection rates of ≥0.8 lb/MMacf, with acceptable FF cleaning frequency. The results of these tests indicate that the TOXECON configuration, with proper design of the FF to accommodate the carbon loading, may be capable of ≥90% mercury removal with relatively modest PAC injection rates.

FIGURE 2

Performance of halogenated PACs compared with that of standard PACs

PAC = powdered activated carbon; B-PAC and E3 = commercial halogenated PAC sorbents.



In general, the efficacy of mercury capture with standard PAC injection improves with increasing amounts of Hg^{2+} in the flue gas, more active adsorption sites in the PAC, and lower temperatures. In addition, the amount of Hg^{2+} in the flue gas is directly influenced by the amount of halogen in the flue gas. Given these factors, standard PAC injection appears to be generally effective for mercury capture in low-sulfur bituminous coal applications but less effective for four other types of application cases.

The first case is plants that are fitted with ESPs and use low-rank coals. In these plants, lower chlorine and higher calcium and sodium contents in the coal lead to lower chlorine levels in the flue gas, which result in reduced levels of Hg^{2+} in the flue gas. The second case is plants that are equipped with SDA/FF and use low-rank coals. These plants experience an effect similar to that described in the first case, except that lime reagent from the SDA scavenges even more chlorine from the flue gas. The third case is plants that use high-sulfur coal. In these plants, relatively high levels of SO_3 compete for active sites on PAC, thereby reducing the number of sites available for mercury. In general, these plants will use wet FGD—and in many cases, SCR—and can be expected to remove high levels of mercury as a cobenefit. However, small amounts of PAC injection may be needed to achieve deeper mercury reductions. The final case is plants with HS-ESPs. At these plants, weak (physical) bonds of mercury adsorbed to carbon are ruptured at higher temperatures, which results in lower sorption capacity.

Because halogenation of the carbon surface is thought to be the first step in the oxidation-and-capture process, the effectiveness of standard PAC injection is limited in many situations by inadequate free halogen in the flue gas. Accordingly, halogenated PAC sorbents have been developed (*9*, *10*). Iodated carbon has been investigated for mercury capture in fixed beds. Chlorinated carbons have been tested in bench-scale experiments at EPA laboratories (*11*). To date, only brominated PAC sorbents have been evaluated in full-scale field tests.

Halogenated PACs offer several potential benefits. They may expand the usefulness of sorbent injection to many situations in which standard PAC may not be as effective. Their use may not require the installation of a downstream FF, thereby improving the cost-effectiveness of mercury capture. Halogenated PACs would, in general, be used at lower injection rates, which potentially would lead to fewer plant impacts and a lower carbon content in the captured fly ash. They appear to provide high levels of mercury capture with low-rank coals. Finally, they may be a relatively inexpensive and attractive control technology option for developing countries because capital-intensive FF installation could be avoided.

Halogenated PACs have been tested at full scale for many different combinations of coal types and PM controls. In each test, relatively high levels of mercury removal were achieved with modest injection rates compared with nonhalogenated PAC injection rates in similar plant configurations. The exception was a mercury removal efficiency of only 70% with a halogenated PAC injection rate of 4 lb/MMacf at Ohio University's Lausche heating plant, which fires high-sulfur bituminous coal and has a mid-sized ESP with specific collection area of 370 ft^2/1000 actual ft^3 per minute (kacfm) (*9*). It is believed that mercury capture at Lausche was affected by the high sulfur content in the coal, which resulted in competition between SO_3 and mercury for active sites on the halogenated sorbent in the flue gas.

At the Duke Power Cliffside plant in Rutherford County, N.C., which fires low-sulfur bituminous coal with an HS-ESP, mercury reductions of 80% were measured at reduced load and 40% at full load during short-term (2-week parametric) tests with halogenated PAC (*12*). As mentioned before, the mercury removal performance of PAC sorbents at plants with HS-ESPs is constrained by higher operating temperatures.

Available data indicate that the mercury removal performance of halogenated PACs injected into

boilers firing high-sulfur coals and/or using HS-ESPs appears to be constrained. The performance of halogenated PACs appears to be relatively consistent for subbituminous coals and lignite. Figure 2 shows that the performance of halogenated PAC sorbents for subbituminous coal and lignite is similar to that of TOXECON (with standard PAC) for eastern bituminous coal. This is a significant development, because the performance of standard PAC is affected by coal type as well as equipment. In general, halogenated PAC injection appears to be quite effective at controlling the emissions of Hg^0 and Hg^{2+}. This contrasts with data from the Pleasant Prairie plant, which indicated that the injection of standard PAC may be limited in controlling Hg^0 in the absence of adequate amounts of halogen in the flue gas.

A significant number of field tests are planned or ongoing over the next few years to further evaluate halogenated PACs for power-plant applications. These tests, referred to as the DOE Phase II tests, are described elsewhere (*4*). Other advanced sorbents and additives that are designed to overcome shortcomings of PAC in certain power-plant applications also are being developed and tested (*4*).

Although sorbent injection appears to be a very promising technology for mercury control, it is important to consider any potential adverse side effects that may significantly affect plant reliability. To date, none of the PAC injection test programs has shown significant adverse impact. However, some effects may be cumulative and may only be revealed through long-term field testing of several months or more.

Calculations and full-scale tests reveal that the increase in PM loading due to PAC injection is relatively modest, <4%, and is even lower when halogenated sorbents are injected. This change in PM loading is likely to be less than the loading change seen with routine fuel or fuel batch changes at a power plant. Calculations suggest that the increase in $PM_{2.5}$ (fine PM <2.5 µm in diameter) loading (i.e., $PM_{2.5}$ added with sorbent injection relative to total PM mass in the flue gas) with a sorbent injection rate of 10 lb/MMacf would be <0.2%. Furthermore, the $PM_{2.5}$ removal efficiency of ESPs is typically ~96% (*13*). Accordingly, sorbent injection would be expected to increase direct $PM_{2.5}$ emissions by <0.01%. These indications, however, need to be substantiated with measurements.

During parametric PAC injection tests at two units with small CS-ESPs, greater sorbent injection rates were accompanied by increasing arcing rates: from <1 to >10 arcs/min within all fields of the ESPs (*14*). Because arcing can degrade an ESP's performance, a subsequent 1-month test was undertaken at one of the units; it revealed that the higher injection rates did not provide increased mercury removal. As such, it is unclear whether increased ESP arcing will occur at practical injection rates (*15*). Final results from longer-term testing are pending.

Some evidence exists that the cleaning frequency of an FF in the TOXECON configuration or in combination with an SDA may increase with sorbent injection (*16*). Some evidence has also been found of a short (<5-min) increase in stack opacity immediately after each FF cleaning step. These concerns must be addressed with additional tests.

Some concern exists about the impacts of PAC injection on the marketing of fly ash for beneficial reuse, for example, as a cement additive. The concern is greater for units with ESPs, where a standard PAC treatment rate could be high enough to increase the carbon content in the fly ash beyond acceptable levels. Certain technical approaches may mitigate such concerns. One is segregating the fly ash with a TOXECON system. This, however, would entail higher capital costs. The approach with the lowest capital cost (still under development) is specially formulated sorbents that would not affect the marketability of fly ash for cement manufacturing.

Studies of mercury and metal leaching from byproducts of PAC injection have generally shown that the leaching of mercury does not appear to be a concern (*17*, *18*). EPA's Office of Research and Development (ORD) has a program to evaluate whether metals leach during the management of mercury-enriched coal combustion residues (CCRs). To date, findings indicate that for most management practices, the leaching of mercury from fly ash does not appear to be of concern for the land disposal of CCRs from facilities with PAC (standard or brominated) injection. The limited results from scrubber sludge samples suggest that further evaluation is warranted. Efforts are under way to obtain additional CCRs from a wider range of coal types and APC configurations. In addition, better information about CCR management practices is being obtained to help clarify and document the fate and transport of mercury and other metals.

The capital costs of a sorbent injection system are usually small compared with those of other APC equipment, if no FF or other major PM-control-device retrofit is added. Capital costs for such systems may be ~$5/kW (*19*). Because sorbent injection systems are simple pieces of equipment, their fixed operating costs are also relatively low. So, the major costs associated with these systems are the costs of sorbent use and of the disposal of additional material.

The capital costs of a sorbent injection system are usually small compared with those of other APC equipment.

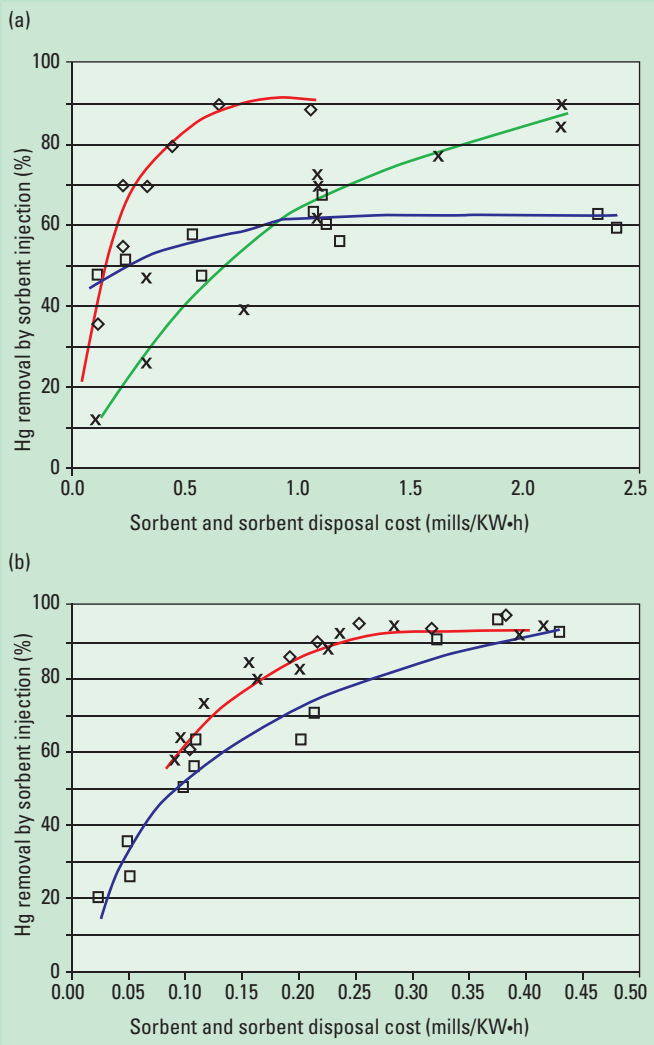
Figure 3a shows estimates of the cost of sorbent injection application upstream of a CS-ESP, the most likely injection configuration. Estimates are made with costs of halogenated PAC sorbent set at $1.00/lb and standard PAC sorbent at $0.50/lb; disposal is estimated at $25/t. (Note vendors claim that halogenated PACs cost about $0.75/lb today, but giv-

en that these sorbents are under development for potentially a narrow market, a more conservative $1.00/lb was assumed in this analysis.) Figure 3a shows that halogenated PAC is estimated to provide up to ~90% removal at a cost of <$1.00/MW·h (1 mill/kW·h, where 1 mill = $0.001). Costs for standard PAC injection are estimated to be greater than those for halogenated PAC injection, because the former requires significantly higher injection rates.

FIGURE 3

Estimated cost of sorbent injection application upstream of (a) a CS-ESP and (b) an FF

Diamonds represent halogenated PAC, squares are for standard PAC with subbituminous or lignite coals, and Xs are for standard PAC with bituminous coal.



A potential cost not included in the previous estimates is the cost of the disposal of fly ash with unacceptable levels of carbon at plants that currently sell their byproducts for beneficial reuse. Because most plants do not currently sell their fly ash, this is not an incremental cost for them. However, for those plants that do sell their fly ash, the incremental costs are estimated to be 0.38–1 mill/kW·h, depending on the heating value and ash content of the coal and the heat rate of the unit (we assume a differential between fly ash revenues and disposal cost of $30/t; *19*).

Figure 3b shows the results of similar cost calculations for PAC injection upstream of an FF. The cost advantage of halogenated PAC over standard PAC injection is not expected to be as great as when it is injected upstream of a CS-ESP. Regardless of the sorbent, 90% removal appears to be possible at sorbent and disposal costs well below 0.50 mill/KW·h when this technology is available. For facilities that sell their fly ash for concrete, the cost of disposing of the fly ash instead is similar to that for CS-ESP.

Outlook for technology availability

Research activities into mercury control are proceeding at a rapid pace. Much has been learned in the past year, and more progress is anticipated over the next few years. Planned test programs will explore mercury capture by FGD and the impact of SCR on FGD capture; the use of advanced sorbents in difficult configurations, such as HS-ESP; sorbents formulated to work with concrete additives; the first commercial, full-scale TOXECON system designed expressly to accommodate sorbent addition; methods to enhance the capture of mercury by existing equipment, standard PAC, and low-cost sorbents by using fuel additives, oxidizing chemicals, or oxidation catalysts upstream of FGD; and the fate of mercury in wallboard produced from FGD byproducts to prevent mercury volatilization and reemission. Data from these programs should help advance the development of a broad suite of viable mercury control approaches.

In general, the technology availability for mercury control will vary by boiler configuration and coal type and will depend on what direct and relevant data are available and on the nature of the regulatory framework (i.e., a spectrum from minimum risk to technology forcing). The principal concerns for the broad-scale use of mercury controls are the reliability of the reductions and the risks of adverse side effects. To the extent that required mercury reductions are within the capabilities of the technology and pose minimal side effects, mercury controls may be considered "available". However, as discussed in this article, some questions remain regarding their performance for broad-scale use, and they are being investigated.

Although some data, mostly from short-term tests, have become available on mercury control approaches for power plants, a broad and aggressive R&D program now under way will yield more experience and information in the next few years. Accordingly, EPA believes that PAC injection and enhanced cobenefit controls to provide mercury removal levels of 60–90% will become available after 2010 for commercial application on most, if not all, key combinations of coal type and control technologies. Moreover, considering the progress made with halogenated PAC sorbents and other chemical injection approaches, EPA believes that optimized multipollutant controls to reduce mercury levels

by 90–95% will be available between 2010 and 2015 for commercial application on most, if not all, key combinations of coal type and control technologies. Such optimized controls could include the less-expensive use of sorbent (standard or halogenated PAC) injection with enhanced SCR and/or enhanced FGD systems.

Halogenated PAC is estimated to provide up to ~90% removal at a cost of <$1.00/MW·h.

A national retrofit program can be initiated after the technology is available. However, full implementation of such a program would take several years to achieve emissions reductions, because large numbers of utilities would need time to order, design, fabricate, and test such units. On the basis of EPA's experience with retrofit technologies for coal-fired utility boilers, we estimate that after a utility has signed a contract with a vendor, installation of each boiler could take between 6 months and 3 years. For example, sorbent injection upstream of an existing ESP or FF system could be installed and commissioned in 6 months to 1 year. Sorbent injection upstream of a retrofitted FF could be retrofitted to an existing ESP in <2 years. A new SCR/FGD/PM/mercury control system could be retrofitted in 2–3 years, depending on the retrofit complexity. However, because of the high capital cost of SCR and FGD, these technologies are expected to be installed not solely to remove mercury but primarily to control other pollutants. An upgrade of existing SCR or FGD systems to enhance mercury control could be retrofitted in 1–2 years.

These installation time frames include the time associated with control technology fabrication, delivery, construction, and testing; approval of the construction permit; and modification of the operating permit. Time frames are for typical situations; extenuating circumstances (e.g., delays due to legal and permitting activities) could lengthen some of the installation activities.

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