

and surface area (for sulfur dioxide and oxidized mercury capture) have been shown to be most effective (Ref 2, 23).

Multi-pollutant calcium-based sorbents have been developed that can remove both elemental and oxidized mercury as effectively as the commercially available activated carbon in fixed-bed tests (at 80°C) (Ref. 26). In these tests, oxidant-enriched, calcium based sorbents⁴⁹ have proved far superior to activated carbon in SO₂ uptake. The performance of these materials was also better than the baseline lime hydrates for NO_x and SO₂ adsorption in fixed- and fluidized-bed tests.

The superiority of these sorbents has been confirmed at coal-fired boiler gas conditions typical of gas-cooled, semi-dry adsorption (SDA) processes. These sorbents need to be evaluated for higher-temperature conditions of duct sorbent injection, i.e., for application in boiler systems that are equipped only with ESP and/or FF.

Full-scale tests of calcium-based sorbents (in September 2000) on two boilers burning eastern bituminous coals and equipped with a SDA-FF (180 MWe) and a CFBA-FF (55 MWe) control system have indicated over 97 percent Hg removal in these control systems on the average (based on the inlet/outlet gas measurements). Further pilot- and field-scale testing has been planned for evaluation of mercury control (using calcium-based multi-pollutant sorbents) in systems equipped with SDA and CFBA controls (DOE-EPRI-EPA programs) (Ref. 2, 27).

Recently, a technology for the efficient capture of mercury through in-furnace injection of a calcium-based sorbent has been developed, and tested at full-scale. As part of a study conducted by McDermott Technologies, Inc. titled “Combustion 2000 Project/Low emission Boiler system Program,” limestone was injected into the upper furnace of a boiler firing bituminous coal and an 80% efficient cyclone was used to collect the fly ash and calcined lime. The mercury concentration in the gas was significantly lower when the limestone was injected compared to the baseline case (without sorbent injection), with an overall average mercury reduction of 82%. As the researchers noted, using the more efficient ESP or FF particulate control devices (with collection efficiencies of greater than 99%) in place of a cyclone would result in an additional increase in the Hg removal. Additional investigations with different lime injection levels have demonstrated that limestone injection substantially reduces gaseous oxidized mercury. However, limestone injection had no apparent effect on Hg⁰ emissions. The data indicated that injection of limestone sorbent at a rate of about 15 times that of the activated carbon (200 lbs/hr vs. 14 lbs/hr) achieved the same level of total Hg removal (53% reduction).⁵⁰ It was concluded that activated carbon injection is more efficient on a mass basis. However, the cost of limestone is typically an order of magnitude lower than the cost for activated carbon, therefore use of lime would be more cost-effective (Ref. 2, 12).

⁴⁹ Lime- and silicate- based sorbents, enriched with proprietary oxidants.

⁵⁰ Test data indicated a total mercury reduction of 41% using a lime sorbent with a Ca:S mass ratio of 0.04 and an injection rate of 25 lbs/hr. The lime sorbent with a Ca:S mass ratio of 0.35 and an injection rate of 200 lbs/hr achieved a total mercury reduction of 53%. This indicates that, with a change in the Ca:S mass ratio, an eight-fold decrease in the injection rate of the sorbent resulted in about 23 percent decrease in the total mercury reduction. Consequently, it may be possible to reduce significantly the lime sorbent injection rate under certain circumstances (i.e., depending on the desired level of mercury control and Ca:S requirements).

Co-injection of Activated Carbon with Alkaline Materials

There have been two studies, in two different coal-fired utility plants using two different types of coal, in which alkaline materials have been co-injected with activated carbon⁵¹ to investigate combined effects of sorbent injection for control of mercury and SO₂. The results of these two studies were not in agreement regarding the effect of the co-injection of alkaline materials (for SO₂ control) on mercury adsorption of activated carbon.

In one study (Ref. 28), activated carbon was co-injected with either sodium carbonate or lime for SO₂ control. With either of these sorbents, an improvement in the adsorption of gaseous Hg by the activated carbon was reported.

In a second study, co-injection of a sodium-based sorbent (sodium sesquicarbonate) with activated carbon impeded the removal of gaseous Hg by the native fly ash and the activated carbon. Negative mercury capture efficiencies were reported for co-injection of the sorbents. It is speculated that the impediment of the Hg capture was either due to inhibition of the sorbent mechanism by or increased levels of NO₂ in the gas due to the sodium sorbent impacts. NO₂ is a strong oxidizer and, if its level is increased, it can strip Hg from the internal surfaces of the system, thereby, increasing the Hg emissions.

A low-sulfur eastern bituminous coal and a PRB coal were used in the two studies respectively. Sufficient data is not available to reach definite conclusions regarding co-injection of alkaline materials with activated carbon.

3.2.2.a.ii. Nobel-Metal-Based Sorbents

Mercury can form amalgamates (alloys) with noble metals such as gold and silver. Mercury can be collected using noble metal sorbents and removed from the sorbent by a simple thermal desorption process. Under the trade name of Mercur-RE, ADA technologies Inc (ADA) has patented a process in which adsorption of mercury occurs in a fixed-bed of noble-metal sorbents (Ref. 29, 30). The sorbent is thermally regenerated, and the desorbed Hg is recovered for commercial recycle or disposal. Laboratory tests indicated that virtually all Hg (elemental and oxidized) was adsorbed by the sorbents. However, the slipstream tests performed at a coal-fired plant station during a six-month period indicated that acid gases in flue gas can negatively impact the adsorption capacity of the noble-metal sorbents. Laboratory testing indicated that prior scrubbing of the acid gases can eliminate this problem. Additional field tests are under evaluation.

3.2.2.b. Capture of Mercury in WFGD Scrubbers

Wet SO₂ scrubber performance in capturing mercury can be improved primarily by increasing the oxidation of elemental mercury in the flue gas, and reducing/preventing conversion of adsorbed Hg²⁺ to Hg⁰ in the scrubber. Several scrubbing and flue gas additives are currently under development for: a) oxidization of the Hg⁰, and b) preventing the conversion of adsorbed Hg²⁺ to gaseous Hg⁰ in WFGD systems. Promoting oxidization of elemental mercury to oxidized mercury may be accomplished by the injection of appropriate oxidizing agents or installation of fixed oxidizing catalysts (i.e., in fixed-bed configuration).

Mercury capture in WFGD systems can also be enhanced by injection of sorbents (such as activated carbon) upstream of the PM control device because this increases the oxidized mercury fraction of the

⁵¹ Both studies used the same commercially available activated carbon (Darco FGD activated carbon).

flue gas. A greater level of mercury reduction can be achieved when the PM control device is a fabric filter because, as discussed previously, the filter cake of the baghouse causes oxidization of mercury when the flue gas passes through the cake. When ESP is the PM control device preceding the WFGD system, the reduction improvements are limited by sorbent injection and mercury adsorption rates.

3.2.2.b.i. Oxidation Additives

The use of oxidizing agents that could potentially convert gaseous Hg^0 into more soluble species has been under investigation by Argonne National Laboratory (Ref. 2, 31). The oxidizing agent currently employed is NOXSORBJ (a commercial product containing hydrochloric acid and sodium chlorate). Introduction of a dilute solution of this agent into simulated flue gas upstream of a WFGD scrubber resulted in a 100 percent removal of the gaseous Hg^0 from the flue gas and its recovery in the WFGD process liquids. Approximately 80 percent of the NO was removed at the same time, indicating that the potential exists for a process that combines removal of SO_2 , NO, Hg^0 , and perhaps, PM. Research into the effects of process parameters such as reagent concentration, SO_2 concentration, NO concentration, and reaction time is in progress. Preliminary cost estimates have projected the chemical cost for NO oxidation to be less than \$5,000 per ton of NO removed, and about \$20,000 per lb of Hg^0 removed.

McDermott Technologies has investigated the use of additives to prevent conversion of adsorbed Hg^{2+} to gaseous Hg^0 (Ref. 2, 32). Two potential chemical additives, Hydrogen Sulfide (H_2S) and ethylenediamine-tetra-acetic-acid (EDTA), for controlling the conversion of Hg^{2+} to Hg^0 and enhancing the control of Hg in a WFGD system were investigated in pilot-scale tests⁵² (Ref. 12). Injection of H_2S ⁵³ gas into the flue gas entering the scrubber resulted in an increase (from 46% to 71%) in gaseous mercury removal by the WFGD. A decrease in the conversion of Hg^{2+} to Hg^0 is believed to be the main reason for this increase in the mercury removal. Addition of EDTA⁵⁴ to the scrubbing slurry also resulted in an increase in total mercury removal by the WFGD (from 46 to 73 percent). These tests were performed firing Ohio bituminous coals.

A full-scale test program of using scrubber additives to achieve increased mercury removal is being conducted by McDermott Technologies, Inc., under a new agreement with DOE/NERL⁵⁵ (Ref. 33). These full-scale tests involve units that burn high sulfur bituminous coals.

3.2.2.b.ii. Oxidation Catalysts

Laboratory and field test studies have been conducted to investigate catalytic oxidation of gaseous Hg^0 in coal-fired boiler flue gas (Under a DOE/NETL cooperative agreement) (Ref. 2, 34). Various fly ash and catalyst materials (carbon, palladium, and iron) were tested.⁵⁶ The actual rates to convert gaseous Hg^0 to a soluble Hg^{2+} were measured in both simulated and actual coal combustion flue gas, and the most-active catalysts were further investigated in field tests. The field tests indicated that there is agreement between

⁵² As part of a program titled the Advanced Emissions Control Development Program (AECDP), and jointly funded by the DOE Federal Energy Technology Center, the Ohio Coal Development Office (OCDO), and McDermott Technology Inc.

⁵³ Selection of H_2S was based on the possibility that a sulfide donating species has the potential to promote capture of oxidized mercury.

⁵⁴ EDTA was selected because it is a strong chelating agent. A chelating agent can bond with metallic ions and thus can potentially prevent the action of the transition metals in converting Hg^{2+} to Hg^0 .

⁵⁵ These two facilities are: Michigan South Central Power Agency's (MSCPA) 55-MWe Endicott Station located in Litchfield, MI; and Cinergy's 1300-MWe Zimmer Station located near Cincinnati, OH.

⁵⁶ The subbituminous and bituminous coal fly ashes generally showed higher oxidation rates than the lignite coal.

the lab and the field tests in oxidation percentages achieved. However, the metal-based and some carbon-based catalysts were deactivated in the field tests after relatively short time exposures to the combustion gases. Sulfur trioxide (SO₃) and selenium compounds have been identified as possible flue gas constituents for this deactivation. Additional bench-scale laboratory tests indicate that it should be possible to regenerate the spent catalysts (Ref. 2, 34, 35, 36).

The potential commercial application of mercury oxidation catalysts to enhance mercury capture in a WFGD system downstream of a high-efficiency ESP is being investigated in a pilot-scale field test under a DOE/NETL cooperative agreement (Ref. 2, 37). These catalysts have been identified through previous DOE-sponsored research as being effective and are being evaluated in a commercial form in larger pilot-scale units for longer periods (over one year at each testing site). The DOE/NETL is working with URS Group, Inc. (formerly Radian International), EPRI, and two electric utility companies.⁵⁷

3.2.2.b.iii. Wet FGD Scrubber Design and Operating Modifications

Pilot-scale WFGD test studies suggest that modifying the operation and design of the scrubber and the upstream ESP system may improve the capture of gaseous Hg²⁺ and reduce the conversion of the adsorbed Hg²⁺ to Hg⁰. These studies indicate that the operating voltage of the ESP and the oxidation air of the WFGD influence the Hg²⁺ to Hg⁰ conversion in the WFGD.⁵⁸ Liquid-to-gas ratios and the tower design of the WFGD unit affect adsorption of Hg²⁺ (Ref. 2).

3.2.3. Multi-Pollutant Control Technologies⁵⁹

The control systems being commercially offered or developed for multi-pollutant emissions control are summarized in this section. Many of these technologies were initially developed for control of one or two pollutants and the explanation of their current status is based on reports with such a focus. An integrated approach in evaluating any control system should be adopted for a successful multi-pollutant control, i.e., in implementing a control device, the impact of that device on all pollutants as well as its interactions with and effects on all other pollution control devices and the system as a whole should be considered. Some control strategies can be effective in reducing multiple pollutants, and as a result can offer some cost savings and operational benefits. However, there is not as much research on multiple pollutant effects and performance as there is for single pollutant performance.⁶⁰

Corona Discharge

An intense corona discharge⁶¹ in the flue gas upstream of an ESP-WFGD system is under investigation for improving PM control. In this process, SO₂ and NO are converted to SO₃ and NO₂ (and subsequently to H₂SO₄ and HNO₃). Elemental mercury is oxidized by oxygen-carrying reactive species that are

⁵⁷ The first test site is the Great River Energy Coal Creek Station, which fires North Dakota lignite. The second site is the City Public Service of San Antonio's J.K. Spruce Plant, which fires a Powder River Basin (PRB) subbituminous coal.

⁵⁸ Lowering the ESP operating voltage and lowering the oxidation air of the WFGD reduces the conversion of Hg²⁺ to Hg⁰.

⁵⁹ This section is based on materials in the EPA Report (Ref. 2).

⁶⁰ Some of the available multipollutant preliminary data have been quoted in this report under the relevant sections that discuss these technologies in detail (such as the subsection 2.2.b.i.on Oxidation Additives”).

⁶¹ Corona discharge is generated by application of high voltage to a pair of electrodes in a gas and ionization of the gas.

generated by the corona discharge. The increased SO₃ helps oxidization of Hg⁰ and improves the PM collection in the ESP.

Two companies have been developing corona discharge pollution control systems. In the system developed by Environmental Elements Corporation, the oxidized sulfur and nitrogen compounds are recovered as marketable sulfuric and nitric acids in wet ESP sections and/or adsorbers. The initial slipstream pilot plant tests⁶² have indicated results of 80 percent mercury removal and a complete oxidation of elemental mercury (under two different control settings).

Power Span Corporation is developing a single, integrated pollution control device that uses a proprietary technology called Electro-Catalytic Oxidation™ or ECO™ to control SO₂, NO_x, Hg, and fine PM. A dielectric barrier discharge is used to convert NO_x and SO₂ to acids and oxidize Hg⁰. Acid mists, fine PM, and Hg are collected in a condensing wet ESP and are processed to generate saleable products (e.g., commercial grade acids, gypsum, and ammonia). A conventional ESP is placed upstream of the ECO™ unit to capture the majority of the fly ash particles. Slipstream pilot tests⁶³ of flue gas from a 150-MW boiler unit burning high-sulfur eastern bituminous coal have shown mercury emission reduction of 68 percent (Ref. 38).

Under a new DOE cooperative agreement, a research project is being conducted using the ECO™ pilot test facility to optimize the technology's Hg removal capability while maintaining the performance of the ECO™ unit for removal of nitrogen oxides, sulfur dioxide, and fine PM (Ref. 39). In addition, an \$11.9 million ECO commercial demonstration unit is currently under construction⁶⁴ (with a \$3.5 million co-funding from the Ohio Coal Development Office).

Electron Beam Irradiation

The chemical reactions in electron beam (E-beam) radiation are identical to corona discharge, however, the oxidation occurs by the electron bombardment. The oxidation products (H₂SO₄, and HNO₃) then enter a semi-dry absorption system and react with ammonia reagent to produce ammonium sulfate and nitrate salts suitable for use as a fertilizer. Elemental mercury is oxidized and would be present in the fertilizer as a contaminant. The E-Beam Process has been offered commercially since the 1980s and is now used in Japan and China (Ref. 40).

Oxidant Injection in Flue Gas

Injection of an oxidant such as chlorine, peroxide, or ozone into the flue gas upstream of an absorber has been proposed for multi-pollutant control (Ref. 2). The reaction products would be similar to corona or electron beam. The process wastes are saleable products such as weak acids, sulfate/nitrate fertilizers, or lower-value soil amendments. These products would contain trace mercury salts.

Lo-Tox is an example of this technology (Ref. 41). The ISCA is a chlorine-based system producing byproduct acids. Hydrogen peroxide and other chlorine-based oxidation schemes have been investigated but have not been proposed for commercial use (Ref. 42).

⁶² At Alabama Power Miller (Unit 3)

⁶³ At FirstEnergy's R.E. Burger Plant near Shadyside, OH

⁶⁴ At FirstEnergy's Eastlake Plant near Cleveland, OH

Catalytic Oxidation

Lower temperature catalysts (those applied in temperatures less than 500°F) would likely directly oxidize Hg^0 to Hg^{2+} . High temperature catalysts that oxidize SO_2 and NO_x ⁶⁵ can increase oxidation of Hg^0 indirectly by increasing SO_3 and $\text{NO}_2/\text{N}_2\text{O}_4/\text{N}_2\text{O}_5$ concentrations. Hg^0 oxidation occurs in the downstream acid gas and PM control devices due to the increased acid gas concentrations. Any catalytic oxidation scheme that produces byproduct acids would likely remove a substantial portion of the total Hg with the acids as mercury salts (chloride, sulfate, or nitrate). A number of catalytic technologies are currently under commercial development. SNO_x technology has been evaluated under DOE's Clean Coal Technology Program. The effectiveness of an oxidation catalyst upstream of WFGD scrubber to decrease total Hg emissions is under investigation (under DOE sponsorship) (Ref. 43)

Oxidant Addition to Scrubber⁶⁶

Several DOE and EPA projects focus on addition of an oxidant to a FGD scrubber. The effectiveness of adding a mercury oxidant to the liquor of commercial wet scrubbers is being investigated in a current DOE test program. Another research, sponsored by the EPA, will culminate in a pilot-scale slipstream evaluation of oxidant addition to the FGD scrubber (Ref. 44).

One DOE-sponsored project is investigating the use of lime and lime-silica sorbents in a semi-dry circulating bed absorber for combined SO_2 , NO_x , and Hg control (Ref. 45). An efficient PM collector such as the EPRI ToxeconTM process may be used in conjunction with combinations of sorbents injected upstream of the PM device for a multiple pollutant control strategy.

Catalytic Fabric Filters

Based on field pilot-scale observations that substantial mercury oxidation has occurred within a fabric filter (Ref. 46), presumably by catalytic action of certain fibers or residual fly ash imbedded within the fabric, development of woven carbon fibers or other catalytic materials that can be integrated into the bag filters for a combined Hg/PM control device have received attention. Currently, such options are being investigated.

Carbon-fiber FFs and ESPs

Combined Hg/PM control would be improved by using carbon-fiber fabric filters and ESP plates. Carbon-fiber fabric filters are commercially available. Carbon-fiber ESP plates are being investigated under a study sponsored by the Ohio Coal Development Office. The limited capacity of carbon to adsorb mercury does not allow continued operation of the FF or ESP after a short time. Therefore, a process for regeneration of the carbon active sites without replacing the fabric filter bags or ESP plates should be developed.

4. Summary of Post-Combustion Mercury Controls

The following summarizes the post-combustion mercury control approaches discussed above in detail.

4.1. Post-combustion Mercury Control Retrofit

Retrofitting existing air pollution control systems to add control of Hg has the potential advantage of reducing the costs of implementing Hg controls by enhancing the capability of Hg capture of the air

⁶⁵ Oxidation of Hg^0 does not occur by the high temperature catalysts.

⁶⁶ These technologies were briefly mentioned in the previous sections.

pollution control system(s) already in place. Retrofit control options have been a focus of the current research and development in coal-fired boiler flue gas mercury control. For the existing electric utility boilers that are only equipped with ESPs or FFs, retrofit technologies that are currently under development are based on injecting sorbents into the flue gas upstream of the FF or ESP. Retrofit technologies for improving Hg capture in the WFGD scrubbers are based on promoting oxidization of Hg⁰ to soluble species by addition of oxidizing agents or installation of fixed oxidizing catalysts upstream of the scrubber. Co-injection of a second sorbent can enhance mercury adsorption in boilers using SDA for SO₂ control. Specific retrofit mercury removal options that can be used with specific air control pollution control equipment are discussed below.

4.1.a. Cold-side ESP Retrofit Options

Flue Gas Cooling

Lowering the temperature of the gas entering the ESP assists natural fly ash sorption of Hg and improves the performance of any sorbents injected upstream for Hg control. A limitation is the potential for HCl or SO₃ mist formation in certain cases when the gas temperature approaches the acid dew point temperature.

Sorbent Injection

Injection of sorbents into the flue gas upstream of the ESP increases the Hg_p fraction of the total Hg in the flue gas (by adsorption of the gaseous Hg onto the sorbent particles) and enhances mercury removal in the PM control device. For marginally performing ESPs that have difficulty meeting opacity requirements, addition of a FF downstream of the ESP, or possibly modifying the ESP, can address the needed additional particulate collection requirements.

Sorbent Injection in conjunction with Installing A Polishing FF

Installing a FF downstream of the existing ESP improves PM collection efficiency significantly, leading to a significant improvement in mercury removal. A polishing FF requires a smaller collecting surface due to lower particulate loading, and can operate with longer cleaning cycles (good for sorbent performance and bag life). Consequently a smaller FF (compared to the case when FF is the main PM collection system) is required.

ESP Modifications

The last field of the ESP can be converted to a wet ESP⁶⁷ or a very compact pulsejet FF. Such modifications may arise from a need for increased PM collection efficiency due to reduced opacity requirements, and will reduce mercury emissions.

4.1.b. Fabric Filter Retrofit Options

Flue Gas Cooling

This option poses the same opportunities and potential limitations as the case for lowering the flue gas temperatures entering ESPs, which is discussed above.

Sorbent Injection

Some internal FF modifications may be required⁶⁸ when injecting sorbents upstream of a FF. There may be a need for more frequent cleaning with the additional sorbent loading.

⁶⁷ It is also possible to install a separate tubular wet ESP to improve the PM collection. Such systems do not have the same footprint requirements as the dry ESPs.

⁶⁸ Removing baffles, changing the point of gas entry, increasing gas velocity, or using smaller sorbent particles are possible options for optimizing the FF performance for sorbent injection.

FF Modifications

Fabric bags can be potentially replaced with catalytic bags that oxidize Hg^0 to Hg^{++} and Hg_p , or electrostatic augmentation can be added to the FF to increase the bag cleaning cycle interval time (this increases mercury capture by increasing sorbent/gas contact time). Electrostatic augmentation would be especially beneficial in conjunction with higher-cost, high-capacity sorbent injection.

4.1.c. HS-ESP and PS System Retrofit Options

These options have not been discussed in this document because currently no Massachusetts coal-fired electric utility boiler affected by mercury requirements of the 310 CMR 7.29 regulations has an existing HS-ESP or PS PM control system. Due to the fact that these PM control systems are less effective compared to other PM control systems, deployment of these systems in future is not expected.

4.1.d. Spray Dryer Absorber Retrofit Options

Oxidation Additives

Possible performance improvements include direct addition of activated carbon to the absorber with lime, use of calcium-based sorbents (for multi-pollutant control), and addition of oxidants to the absorber. Boiler modifications (such as use of low- NO_x burners) that result in production of a fly ash with higher unburned carbon content can also improve the performance of the SDA.⁶⁹

Improving PM Collection Downstream of the SDA System

In control systems that use an ESP downstream of the SDA, replacement of the ESP unit with a FF is likely to improve Hg removal as a result of enhanced PM control efficiency as well as greater conversion of Hg^{2+} to Hg_p (on the filter cake). Use of a polishing FF in addition to the ESP can improve the PM collection as well.

4.1.e. Wet FGD Scrubber Retrofit Options

Oxidation Additives

As discussed earlier, in general, improving mercury oxidation increases the total Hg removal by the wet scrubber. Several flue gas and scrubbing additives for enhancing mercury oxidation in the flue gas upstream of WFGD or in the WFGD scrubber itself, as well as flue gas and scrubber additives that prevent conversion of Hg^{2+} to Hg^0 in wet FGD systems, are being developed. Increasing oxidation potential of mercury upstream or within the scrubber may also increase the potential to oxidize other species such as SO_2 and NO/NO_2 to acid aerosols. This potential increase in formation of acid aerosols needs to be addressed in the operational requirements of the system when this retrofit is selected.

Fixed Oxidizing Catalysts Upstream of Scrubber

The performance of Wet FGD scrubber in mercury capture can be enhanced by installing fixed oxidizing catalysts upstream of the scrubber to promote oxidization of Hg^0 to soluble mercury salts. Several potentially suitable catalysts are currently being tested.

Wet FGD Scrubber Modifications

Pilot-scale studies of wet FGD systems suggest that the design and operation of a wet FGD and its upstream ESP affect the capture of Hg^{2+} and the conversion of absorbed Hg^{2+} to Hg^0 in the scrubber. Factors affecting mercury emissions are the liquid-to-gas ratio and tower design of the wet FGD, as well as the operating voltage of the ESP.

⁶⁹ As discussed earlier, use of low NO_x burners increases the unburned carbon content of the fly ash. This can improve adsorption of mercury onto the native fly ash and improve mercury adsorption in the PM control device.

4.2. Integrating Mercury Control into a Multi-pollutant Control Strategy

Implementation of new SO₂, NO_x, and fine particulate control systems can reduce mercury emissions from coal-fired electric utility boilers, hence reducing or eliminating the need for mercury specific control devices. For example, installation of a wet or semi-dry FGD unit can significantly reduce oxidized Hg emissions (by 90 to 95 percent over previous levels); and adding a SCR NO_x control system upstream of the FGD would further reduce total Hg emissions (by increasing the oxidized Hg). Installation of new particulate control systems (such as EPRI COHPAC, advanced hybrid particulate collectors, electrostatic augmentation of pulsed fabric filters, and wet ESPs optimized for use in coal-fired plants), as well as taking advantage of new developments in improving the collection efficiency of the existing PM systems (such as new conditioning additives for improving ESP performance) can result in high-efficiency control of particulate matter⁷⁰ and lead to additional mercury reductions. The efficacy of these PM control systems in mercury capture further increases when they are used in combination with sorbent injection.

A number of new multi-pollutant control systems are under development and at least one technology (electron beam irradiation) is currently commercially available and in use in Japan and China. Some of these technologies were initially developed to address a single specific pollutant, and have been undergoing further development for multi-pollutant control (e.g., calcium-based sorbents).

In conclusion, although every control option cannot be implemented in every coal-fired electric utility plant, several mercury control options are available for each plant configuration to achieve further reductions in mercury emissions. Some of these mercury control options are based on commercially available technology/equipment. A number of these control technologies are in the field-demonstration stage and are approaching commercialization. Others are in earlier stages of development and have proved promising. Due to the highly interactive nature of SO₂, NO_x, Hg, and PM control, the interaction of control equipment used for control of single pollutants should be considered in a multi-pollutant context. A multi-pollutant emission control strategy may be the most cost-effective Hg control approach in the long-term perspective.

⁷⁰ In many cases collection efficiency of fine particulate mater is improved in addition to the total PM collection efficiency.

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APPENDIX B: MERCURY CONTROL COSTS

In general, the air pollution control methods appropriate for a given coal-fired electric utility boiler depend on many factors including the age and size of the unit, unit location and plant space limitations, and the type of coal burned. The costs of controls, for mercury and other pollutants, are highly variable based on these and other factors. This section does not attempt to assess the costs of any specific control measure for any given coal-fired facility. Rather, it presents some preliminary cost evaluations of mercury controls that have been performed as part of the development of mercury control technologies.

Various mercury control methods and their general availability and feasibility have been discussed above. Technologies based on injection of powdered activated carbon (PAC) have been investigated most and are likely to reach commercialization for mercury removal from coal-fired utility boiler flue gas before other technologies. Non-PAC-based mercury control technologies, such as enhanced mercury oxidation using oxidants or catalysts followed by wet scrubbing, are expected to become available in the future. The commercially available SCR-FGD control combinations already achieve significant mercury reductions and may become more cost effective (Ref. 1).

Some preliminary cost evaluations of the PAC injection-based and other technologies are available. A brief discussion of these cost estimates and a few related issues are presented below.

EPA-Estimated Costs for PAC Injection-Based Mercury Control Technologies

As part of the EPA's coal-fired utility boiler MACT development process, EPA has developed a preliminary estimate of costs⁷¹ for a retrofit of PAC injection-based technology to a series of model plant scenarios representative of coal-fired electric utility power plants operating in the United States. The PAC injection-based technologies were selected by EPA because sufficient pilot-scale data were available to make reasonable cost estimates. EPA deemed mercury-capture performance data for other potential control technologies insufficient to develop equivalent cost estimates for those technologies.

EPA cost estimates for PAC injection-based control technology were calculated using the PAC injection technology pilot-scale test and ICR data, and a computer cost model⁷² developed by DOE/NETL for estimating the costs of Hg control options for coal-fired electric utility boilers.^{73,74} The information developed in this cost analysis has been used in EPA's coal-fired utility boiler MACT development process regarding mercury and other air toxics.

The total annual costs of controlling Hg emissions were examined. These costs include annualized capital costs, annual fixed operation and maintenance (O&M) costs, and annual variable O&M costs.⁷⁵ In general, the major fraction of the annual costs for mercury control associated with PAC injection-based

⁷¹ EPA notes that this calculation is based on pilot-scale data (and hence few data-points) and is considered preliminary. Some performance aspects of the technology in a full-scale application (e.g., the degree of mixing between the flue gas and activated carbon in large ducts, and potential system impacts such as formation of deposits arising from continuous long term operation) are not identical to pilot-scale operation and their effects may not be completely accounted for in preliminary cost projections (Ref. 1).

⁷² This model is called Integrated Environmental Control Model (IECM) and has been expanded to include performance and cost models for a variety of mercury control options. This model is used to obtain quantitative estimates of the cost and emissions impacts of interactions among technologies for multi-pollutant controls. This model currently incorporates a powdered activated carbon injection module (Ref. 2).

⁷³ For more information, please refer to the Appendix D of the document in Reference (1) of this section.

⁷⁴ The DOE/NETL cost model has also been used in other pollution control cost study evaluations. Please refer to the document in Reference (1) of the Reference list for this section, and references therein for more information.

⁷⁵ An examination of these costs including the cost of PAC is provided in the document in Reference (3).

control technologies is the cost related to the use of PAC; the capital costs comprise a relatively minor portion of the total annual costs.

The Model Plant Scenarios and Assumptions

The model scenarios that EPA developed for this cost evaluation incorporate retrofit PAC injection-based technologies on various existing coal-fired utility boiler plant pollution control systems. These retrofit PAC configurations include plants with an existing HS-ESP, CS-ESP, FF, SDA + FF, and SDA + CS-ESP for control of PM. Several variations on the retrofit options were considered including retrofit systems with and without spray cooling and retrofit systems with and without added polishing fabric filter (PFF). The retrofit options also included a case in which lime was co-injected with PAC because pilot-scale tests have indicated that lime co-injection can significantly reduce the rate of PAC injection. The model plant scenarios included plants that burn bituminous coals (both low- and high-sulfur cases were modeled) as well as plants that fire subbituminous coal. For both coal types, both larger (975 MWe) and smaller (100 MWe) plants were modeled with appropriate⁷⁶ applicable existing pollution control devices.

In these cost estimates, a plant capacity factor of 65 percent, a PAC cost of \$1.00/per kilogram, and a flue gas mercury concentration of 10 microgram/Nm³ were assumed.⁷⁷ An approach to acid dew point (ADP) of 10°C (18°F) was used for the retrofit system with spray cooling (SC) to operate above the ADP and avoid problems associated with acid mist (SO₃) formation. No PAC recycling was considered in this analysis. Because PAC injection rate requirements increase nonlinearly with increases in Hg removal efficiency, model plant costs were estimated for Hg removal efficiencies of 60, 70, 80, and 90 percent.

Sensitivity Analysis

EPA also performed sensitivity analysis on a selected group of variables in this cost evaluation to assess the impact of factors such as the acid dew point approach, PAC recycling, increased flue gas residence time (by adding ductwork to the plant), and use of composite PAC-lime sorbents.⁷⁸ The sensitivity analysis indicates that neither PAC recycling at a rate of 20 percent, nor increased flue gas residence time has any significant impact on the control costs.⁷⁹ However, use of composite PAC-lime sorbent (with a PAC-to-lime injection ratio of 2:19) lowers the total annual costs by 34.7 to 38 percent (based on a 90% Hg removal in a 500 MWe plant). The sensitivity analysis shows that an increase in the ADP (from ADP+18°F to ADP+ 40°F) would increase the Hg control costs for a plant firing bituminous coal, while it would decrease the costs for a plant firing subbituminous coal (because the water injection requirements significantly decreases, while the PAC injection rate for mercury removal does not increase much).⁸⁰

Projection of Mercury Control Costs

EPA estimated the mercury control costs for various boiler and control device combinations with the following assumptions:⁸¹

⁷⁶ For example, larger plants that use high sulfur bituminous coal tend to use a WFGD for SO₂ control; while in smaller plants that use high sulfur bituminous coal, use of both SDA + ESP/FF or WFGD for SO₂ control is common.

⁷⁷ This Hg concentration is in the range of mean concentrations (1.7-50.1 microgram/Nm³) determined from ICR for pulverized-coal-fired electric utility boilers equipped with different air pollution controls.

⁷⁸ The sensitivity analysis was performed on a model scenario with a 500 MWe plant.

⁷⁹ For the recycling to impact the control costs, a much higher rate of recycling is necessary.

⁸⁰ Generally an approach of ADP+18°F is considered. When a higher temperature is required, use of SC + PAC injection + PFF may be less expensive.

⁸¹ Please refer to the document in Reference (1) for a full discussion.

- A mercury capture efficiency of 80% is obtained using ESPs and 90% using FFs (due to the fact that FFs are more efficient than ESPs in control of PM).
- The projected costs for PAC injection technology were arrived at by applying a 40 percent reduction to the total annual costs of the current cost estimates. A 40 percent reduction reflects the potential cost savings that may be possible with the use of more effective sorbents. It was based on the results of the sensitivity analysis, which indicated that using composite PAC-lime sorbent injection would reduce the costs by nearly 40 percent, and the expectation that injection of composite sorbents would not pose any significant technical constraints.⁸²

The results of this study show that, because FFs provide better sorbent utilization than ESPs, reducing Hg emissions between 60 and 90 percent using FFs instead of ESPs would significantly reduce the total annual costs on the average (about 70% for the 975 MWe plants, and 45 % for the 100 MWe plants, i.e., an average of 58% across all plants). Hg control costs may be negligible (essentially equal to the cost of monitoring) for plants with SCR and WFGD firing bituminous coal where the percentage of Hg²⁺ content in the flue gas is at least 95 % of the total Hg, as a result of fuel, combustion conditions, and Hg oxidation due to SCR.

The cost estimates obtained in this EPA study are comparable to the mercury control cost estimates obtained in an earlier EPA study⁸³ of lime and PAC injection in which EPA used the Integrated Planning Model (IPM) for boilers ranging in size from 100 to 1000 MWe (Ref. 3, 4). The current EPA cost estimates range from 0.305 to 3.783 mills/kWh. The costs in the earlier EPA study ranged from 0.7 to 1.76 mills/kWh.

Comparison with NO_x Control Costs

In order to provide a context for the impact of the Hg control costs to the utility plants that burn coal in their electric power generation, these costs have been compared to the costs of another currently controlled air pollutant, namely NO_x. Table B-1 presents the ranges of total annual costs in year 2000 constant dollars for the mercury controls examined in the EPA cost-estimate study and the costs for two currently used NO_x technologies, i.e., low NO_x burners (LNB) and SCR.^{84,85} In this comparison, the costs associated with the LNB and SCR control technologies were selected for NO_x because, in general, the costs of currently used NO_x controls are expected to fall within the range of costs associated with LNB and SCR.

⁸² Some data are available for PAC-lime sorbent with PFF.

⁸³ Published March 1999.

⁸⁴ EPA has derived the NO_x cost information from the document in Reference (5).

⁸⁵ The NO_x costs are for boilers ranging in size from 100 to 1000 MWe and operated at a plant capacity factor of 65 percent. The Hg control costs were estimated for boilers ranging in size from 100 to 975 MWe and operated at a plant capacity factor of 65 percent.

Table B-1. Comparison of mercury control costs using powdered activated carbon injection technology to the costs of NO_x control.⁸⁶

Air Pollutant Controlled	Control Technology	Total Annual Control Cost Range (mills/kWh)	
		Current Costs	Projected Costs
Hg	PAC Injection	0.305 - 3.783 (a)	0.183 - 2.270 (a)
		0.035 - 1.915 (b)	0.183 - 1.149 (b)
NO _x	LNB	0.210 - 0.827 (c)	
	SCR	1.846 - 3.619 (c)	

Key: (a) All modeled plants; (b) All modeled plants except those with HS-ESP; (c) Actual costs

These estimates indicate that, based on the currently available information, the cost of mercury control, using PAC technology, ranges from 0.305 to 3.783 mills/kWh.⁸⁷ If the plants with an existing HS-ESP system for PM control are excluded,⁸⁸ these costs would range from 0.305 to 1.915 mills/kWh. Future cost projections based on a composite lime-PAC sorbent injection for Hg removal, range from 0.183 to 2.270 mills/kWh for all modeled plants and from 0.183 to 1.149 mills/kWh excluding plants with a HS-ESP.

The data show that the current cost of mercury control using PAC injection-based control technologies is comparable to the current cost of NO_x control. For facilities that do not have an existing HS-ESP, Hg control costs lie within the range of the NO_x control costs. A mercury control cost reduction of about 40% is expected by application of more efficient sorbents (such as PAC-lime composite sorbents).

An important point to note is that for technology applications on bituminous-coal-fired boilers using ESPs, the current estimates were based on the PAC injection rates derived from the mercury fly ash capture in the pilot-scale test data. The EPA ICR data reflects higher levels of Hg capture by the native fly ash than those seen in pilot-scale tests (leading to lower PAC injection rates for achieving the same level of Hg control). Therefore, these cost estimates for technology applications on bituminous-coal-fired boilers using ESPs may be conservatively high (i.e., if the PAC injection rates are estimated using the EPA ICR data instead of the pilot-scale data, the estimated control costs would be lower than the figures presented here⁸⁹).

It should be noted that these preliminary cost estimates were developed based on short-term pilot-scale tests and may not account for factors such as mass transfer effects in full-scale applications (i.e., the impact of flue gas and sorbent mixing in larger ducts). However, on-going research is expected to address these issues and to improve the cost-effectiveness of PAC injection technologies.

In addition to using sorbents with higher mercury adsorption capacity and/or lower costs (such as composite PAC-lime sorbents or impregnated activated carbons), improvements in the PM control device, such as use of an EPRI COHPAC (a pulsed high-ratio fabric filter known as Compact Hybrid Particulate Collector or COHPAC) could improve the cost-effectiveness of PAC injection-based technologies.

⁸⁶ Adapted from the document in Reference (1).

⁸⁷ 1.00 mill/kWh is equivalent to \$0.01/MWh.

⁸⁸ The coal-fired utility boilers in Massachusetts, subject to provisions of mercury standards in 310 CMR 7.29, do not have any hot-side ESP. All ESP units in these facilities are cold-side.

⁸⁹ EPA performed two sets of cost analysis. The required PAC injection rate for mercury control was derived in the first set from ICR data, and in the second set from the pilot-scale test data for PAC injection-based technology.

Availability of A Methodology for Assessing Sorbents for Mercury Control in Coal-Combustion Flue Gas

Current studies indicate that use of sorbents with ultra fine mean particle size can significantly affect the efficacy of sorbent use and the costs associated with sorbent injection-based mercury control technology. Additionally, because the sorbent injection rate (for achieving the same mercury control efficiency) is reduced when ultra fine sorbents are used, issues related to excess carbon content of fly ash (as a result of AC sorbent injection) can potentially be addressed. The following section provides some detail regarding use of ultra fine sorbents.

A sorbent evaluation methodology (model) has been developed by EPRI and its contractors (URS, Apogee and Meserole Consulting) that provides an effective and low-cost method to compare potential sorbents for mercury control prior to testing at full-scale (Ref. 6). The results obtained during sorbent evaluations at several sites have indicated that laboratory tests (in conjunction with the evaluation methodology developed by EPRI) can be used effectively to identify sorbents with the greatest potential for success in field test applications. Fixed-bed⁹⁰ test results in conjunction with model predictions can be used to project the estimated removal (in an ESP or in a baghouse). Consequently, availability of this tool can facilitate evaluation and comparison of sorbents and help expedite development of cost-effective sorbent injection technologies.

Impacts of Particle Size on Predicted Costs of Mercury Control Using Sorbent Injection

Under an EPRI contract,⁹¹ a theoretical model has been developed that combines sorbent adsorption characteristics with mass transfer considerations to predict mercury removal by duct-injection in full-scale applications (Ref. 7). The model predicts the effects of various sorbent properties on mercury removal and associated costs when the sorbent is injected upstream of an ESP or FF.

The estimated costs are affected by the sorbent characteristics, price, and the nature of the downstream pollution devices. The calculations suggest that the economics of the injection of a dry sorbent upstream of an ESP may depend largely on the average particle size of the sorbent if the price and sorption capacity are reasonable (Ref. 8).

It has been shown that the particle size of the sorbent is a major determining factor in the required sorbent injection rate for achieving a certain degree of mercury removal. This especially affects the injection upstream of an ESP. Reducing the particle size of the sorbent has a positive impact on mercury removal. Finer particles of a given sorbent can be produced by grinding the commercially available material prior to injection.

The effects of mercury adsorption capacity for ultra fine sorbents is predicted to be more pronounced at higher removal efficiencies (i.e., the smaller the particle size, the greater the impact of sorbent capacity on the higher removal efficiencies). Another advantage of having smaller particle sizes at a given sorbent capacity is that high removal efficiencies can be achieved at low sorbent residence times.

These investigations have indicated that the use of high capacity fine-sized sorbents injected upstream of an ESP have the potential to achieve mercury removals that is competitive with a fabric filter if the

⁹⁰ In this configuration the sorbent materials is not injected into the flue gas, rather the flue gas passes through a fixed bed of sorbent material in a container (such as a tube). Such tests are generally performed prior to injection tests.

⁹¹ The contractors were Meserole Consulting and URS Corporation.

sorbent price is less than about \$1.00 per pound.⁹² Thus, the use of fine sorbents has the potential to lower the cost of mercury control for sorbent injection upstream of an ESP below that predicted for fabric filter.

Ultra fine sorbents with high capacity have the potential to substantially control the cost of achieving high mercury removal efficiencies compared to using commercially available activated carbons. The overall costs could be decreased by a factor of 2 or 3 depending on the price of these small diameter sorbents⁹³ (assumed to be \$1.00/lb and \$0.50/lb respectively for this study). Development of cost-effective sorbents with high mercury sorption capacities and small diameters, and injection technology for materials with average diameters less than 5 microns, would result in significant cost reductions.

Estimated Mercury Control Costs for Oxidation Catalyst-Based Technology

Preliminary cost estimates were developed for a catalytic oxidation-based mercury control technology following field tests that indicated high elemental mercury oxidation of flue gas (Ref. 9). This technology can be used for mercury control in coal-fired power plants that are equipped with WFGD. The catalyst materials⁹⁴ were applied to conventional (commercially available) honeycomb structures.⁹⁵ The costs for this control technology were compared to the PAC control technology cost estimates presented in an EPRI paper (Ref. 10).

The plant modeled for the cost evaluation of this catalyst-based control technology is a 400 MWe coal-fired utility plant that has a conventional ESP for particulate control followed by a wet FGD system. The flue gas was assumed to have a total mercury content of 10 microgram/Nm³, of which 75% is in elemental and 25% in oxidized form.⁹⁶ It was assumed that the WFGD system will remove 95% of the oxidized mercury in the flue gas but no elemental mercury. Mercury control costs were estimated for both the 80% and 90% mercury reduction levels. The same economic factors and plant descriptions were used in these calculations as those in the above-mentioned EPRI paper calculations for consistency. Costs estimated for PAC injection application were based on a system retrofitted with a COHPAC system as the PM control device because such a system is more cost effective than a CS-ESP.⁹⁷ PAC injection in plants with only a CS-ESP would require much higher rates of PAC injection.

The preliminary cost estimates for mercury control using oxidation catalyst technology indicate significant cost reductions compared to PAC injection-based control technology using an EPRI COHPAC retrofit. For plants firing subbituminous PRB coal, 44% and 17% cost reductions were achieved at the

⁹² For example, a high adsorption capacity (2000 microgram/g) fine particle (5 micron mean diameter) sorbent (which costs \$0.05/lb) injected upstream of ESP would be more cost effective compared to a sorbent with the same mercury adsorption capacity but with larger particle size (15 micron, and with a cost of \$0.25/lb) injected upstream of an FF. It should be noted that the mercury adsorption capacity assumed for these cost calculations is within the adsorption capacity range of commercially available activated carbon. For reference, the capacities of sorbents such as commercially available activated carbon typically range from 500 to 2000 microgram/g.

⁹³ The base-case cost for the commercially available activated carbon was set to be \$0.25/lb, based on an anticipated reduction of the cost currently used in pilot-scale applications (i.e., \$0.50/lb).

⁹⁴ Several materials warrant further development at larger scale, i.e., for periods of two to three years to better establish catalyst life.

⁹⁵ This technology has been tested at three facilities at the slipstream test level. For the full-scale tests, the catalysts would be placed downstream of the PM control device and upstream of WFGD.

⁹⁶ This mercury content is same as that in the PAC cost study.

⁹⁷ The EPA study of the cost estimates for PAC injection-based technology models the commonly used PM control configurations in US coal-fired plants and does not include the more efficient COHPAC particulate matter control system.

80% and 90% mercury removal levels respectively. The corresponding cost reductions for plants firing bituminous coal are 62% and 9%.

This technology appears to be cost-effective relative to competing processes for plants that have existing FGD systems. Lower-cost catalyst materials and extending catalyst life through regeneration could further improve the economics.

Estimated Control Costs for Oxidation-Enhanced Sorbent Technology

Multi-pollutant oxidant-rich calcium-based hydrated lime and silicate sorbents that can be used in flue gas desulfurization systems⁹⁸ have been under investigation. Preliminary economic analysis suggests that the oxidant-rich calcium-based silicate sorbents reduce the mercury control costs by 80% compared to PAC injection-based technology⁹⁹ (Ref. 11). Although the oxidant-rich calcium-based lime sorbents offer somewhat lower cost reductions, they still offer significant cost savings compared to PAC injection. The same methodology used by EPA¹⁰⁰ for PAC cost calculations was used in the cost calculations for these sorbents.

The investigations indicated that injection of the oxidant-rich calcium-based silicate sorbent for mercury control, in the presence of a relative abundance of SO₂, can result in significant SO₂ removal (above the baseline reductions achieved with the currently used FGD calcium-based sorbents without optimizing the sorbent for SO₂ or NO_x control. The reductions for both SO₂ and NO_x were above the baseline for both oxidant-enriched calcium-based lime and silicate sorbents.

Impact of Multi-Pollutant Controls on Costs

Coal-fired electric utility power plants are currently required to limit their emissions of NO_x, SO₂, and PM under federal requirements.¹⁰¹ Under 310 CMR 7.29, these facilities are required to address their emissions of mercury and CO₂, as well as reduce the emissions of NO_x and SO₂. Multi-pollutant interactions affect the emissions of each pollutant and the cost of environmental compliance. Therefore, an evaluation of the emissions and compliance costs would need to be performed in the context of a multi-pollutant approach.

To address this multi-pollutant evaluation need, the Integrated Environmental Control Model (IECM) was developed for DOE/NETL by Carnegie Mellon University (Ref. 12, 13, 14). IECM provides plant-level performance, emissions, and cost estimates for a variety of environmental control options for coal-fired power plants (Ref. 15). The IECM modeling framework accounts for emissions of criteria air pollutants (SO₂, NO_x, and particulates), major air toxics (especially mercury), CO₂ and other greenhouse gases, and all system solid wastes or byproducts. In particular, the interactions among technologies designed to control individual pollutants are addressed. The effects of such interactions are illustrated in a few examples below.

⁹⁸ These sorbents have been tested with superior results compared to PAC for flue gas conditions in semi-dry adsorber systems (80°C). Their application in high temperature duct injection conditions has not yet been tested.

⁹⁹ At mercury control costs of 1.79 mills/kWh for the oxidant-enriched silicate sorbent and 0.36 mills/kWh for the oxidant-enriched lime sorbent.

¹⁰⁰ A 100-MWe boiler firing low-sulfur bituminous coal that has a capacity factor of 65% was used in the modeling. The costs were calculated for a mercury removal of 80%. The sorbent costs for PAC, oxidant-enriched silicate sorbents, and oxidant-enriched lime sorbents were assumed to be \$1.00/kg, \$0.20/kg, and \$0.13/kg respectively.

¹⁰¹ These are the requirements under Acid Rain (CAA Title IV, for SO₂), Ozone (CAA Title I for ozone precursors including NO_x) and requirements for PM to meet federal opacity requirements. There are also state requirements for opacity.

SO₂ emissions can be controlled by switching to a low-sulfur coal or by post-combustion control technologies such as WFGD. Reducing emissions by switching to a low-sulfur coal, however, can adversely affect the performance of an electrostatic precipitator (ESP), the most common method of particulate control, because lowering the flue gas sulfur content increases the flyash resistivity, lowering the overall PM collection efficiency.¹⁰² A lowered PM collection efficiency would result in lower mercury removal.

On the other hand, a WFGD removes particulate matter and air toxics in addition to capturing SO₂. However, a WFGD control system also generates additional emissions of CO₂ (by chemical reactions that capture the SO₂) and a substantial amount of solid waste although some plants eliminate this problem by reclaiming the byproduct gypsum for use in wallboard manufacturing. Modeling evaluations indicate that power plants already equipped with a WFGD system can achieve mercury reductions at substantially lower costs.^{103,104}

For power plants burning eastern bituminous coals, the presence of an SCR system together with a WFGD system can achieve high levels of mercury reduction, and potentially eliminate the need for powdered activated carbon injection. The SCR systems also tend to oxidize some SO₂ into SO₃, which is a gas-conditioning agent that can improve the performance of an ESP. For plants without a WFGD, addition of a SCR appears to have little or no effect on mercury capture.

Due to the highly interactive nature of environmental control systems for SO₂, NO_x, Hg and CO₂, multipollutant control strategies will be more cost-effective. During the SO₂ and NO_x emissions control planning and implementation, the effects of the SO₂ and NO_x control systems/approaches on mercury control should be considered and the synergistic effects of these controls in mercury reduction should be exploited. Mercury control in a multi-pollutant control context can be more cost-effective than if it is considered alone.

Summary

The estimated costs for powdered activated carbon injection-based technology, which most likely will reach commercialization for mercury control before other technologies, is within the current control costs for NO_x. The results of the pilot tests of this technology indicate that implementation of more effective particulate control devices such as EPRI COHPAC, and use of more effective sorbents (such as composite PAC-lime) would further reduce these costs. Availability of less expensive sorbents (either through the impact of economies of scale on use of commercially available PAC or development of materials that are cheaper) would improve the economics of mercury control using this technology option. Another factor that can lower these control costs is the use of ultra fine sorbents.

As discussed above, the preliminary cost estimates on several other technologies, a number of which can be implemented on coal-fired plants with FGDs, indicate favorable economics compared to PAC injection-based control technologies. The superiority of oxidant-enriched calcium-based sorbents to powdered activated carbon has been confirmed at coal-fired boiler gas conditions typical of gas-cooled, semi-dry adsorption processes. Implementation of in-furnace injection of calcium-based sorbents (as discussed previously in this report) has been projected to be more cost-effective than PAC injection-based

¹⁰² We note that flue gas conditioning additives for addressing flue gas resistivity are under development and the results seem promising.

¹⁰³ For a comparison of mercury control costs using PAC injection for plants with and without FGD see Reference (2).

¹⁰⁴ The ICR data and other publicly available information also support this conclusion.

technologies because the cost of limestone is typically an order of magnitude lower than the cost of activated carbon.

Implementation of multi-pollutant control technologies enhances cost-effectiveness. Additionally, the impact of technologies traditionally used for control of single pollutants on emissions and control costs of other pollutants of concern should be considered. Many control devices that are used for SO₂, NO_x, and PM control can provide the co-benefit of mercury control. In a multi-pollutant control approach, such as that provided by 310 CMR 7.29, mercury control costs should be considered in the context of the overall emissions reduction and control costs of all pollutants. The synergistic effects of the interactions between various control technologies should be exploited in evaluation of emissions and costs. The economics of mercury control can be more favorable in this context.

Improved sorbents and other methods for controlling mercury and multi-pollutant emissions are under development by DOE, EPA, EPRI, the electric industry, and the utility vendors. These activities include large-scale programs focused on full-scale demonstrations of PAC injection technologies. As a result of these research and development activities, mercury and multi-pollutant control options are expected to become available with improved cost-effectiveness (the status of each technology regarding its development/commercialization stage has been discussed in the specific relevant technical subsections in Appendix A, under Mercury Control And Control Technology, of this report).

Although every pollution control technology/system cannot reasonably be implemented on every plant configuration, an examination of the available and emerging control technologies indicates that control of mercury can be achieved cost-effectively for various plant conditions and configurations in the near future. Clearly, a key factor in the availability of viable control technologies and the feasibility of the control costs is the level of mercury control that would be required.

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APPENDIX C: TECHNOLOGY OPTIONS FOR COMPLIANCE DEMONSTRATION

Facilities subject to 310 CMR 7.29 will need to demonstrate compliance with the Hg standards to be proposed by the Department in Spring 2003. The compliance demonstration that will be required will, of course, be closely tied to the form of the standard. Even though a standard has not yet been proposed, it is, nevertheless, possible to provide a general overview of the measurement technologies and methods that are available to measure Hg both in coal and in stack emissions. One or more of these methods are likely to be required in order to demonstrate compliance with whatever standard is adopted.

The following are some of the compliance demonstration methods that are representative of various technologies. Each of these methods may be used alone or in combination with other methods, depending on the parameters to be measured and the standard that is to be met:

- sampling of Hg in coal
- material balance [Hg in coal samples-Hg in samples of non-gaseous coal combustion residues (CCRs)]
- emissions tests at a frequency to be specified in the standard, possibly at the stack, possibly at both the stack and ESP inlet
- integrated sampling of emissions over an extended time period using absorption media
- continuous emissions monitoring systems (CEMS) to monitor stack-level Hg emissions, averaging the data over a time period to be specified in the standard.

The methods vary as to the parameters measured. For example, the sampling of Hg in coal, material balance and extended period integrated sampling measure total Hg only, not speciated Hg. The emissions tests or CEMS could be used to demonstrate compliance on a total Hg basis and/or for each chemical species of Hg, as necessitated by the standard to be proposed.

The level of experience with various compliance methods also varies. Facilities and stack testing companies have extensive experience with sampling of Hg in coal and with Hg stack testing, due to EPA's 1999 Mercury Information Collection Request (ICR) and due to the Hg testing requirements established by DEP's 310 CMR 7.29 regulation. However, U.S. facilities have little to no experience with sampling of Hg in certain CCRs, integrated Hg sampling or Hg CEMS; the state of the technology for these three methods is discussed in greater detail below.

Sampling of Hg in CCRs

There are some 15 categories of non-gaseous CCRs; the actual number of categories at any particular facility is dependant on its specific operating characteristics. Tests methods to determine the amount of Hg present in most CCR categories have been developed, but the overall approach is problematic because of the difficulty of attempting to take samples of each CCR over a comparable time frame in order to assure a correct mass balance. The mass balance approach generally has been presented as a research dilemma, not as a practical compliance demonstration approach.

Integrated Hg Sampling

This sampling method has been suggested by the Electric Power Research Institute (EPRI) in the hope that it would prove less expensive than Hg CEMS. The absorption method entails placing a charcoal absorbing medium in the path of the gaseous emissions, removing the sample after a given time period, and quantifying the Hg contained in the sample. The approach assumes that the Hg standard proposed will have a "long" averaging time (on the order of weeks rather than hours), thusly producing a "small" number of samples per year. The approach was tested concurrent with EPA testing of Hg CEMS at a coal-fired boiler unit, but the Department is not aware of any of the resulting data having been made

available to the public at this time. One drawback of the approach is that the sample is not proportional, i.e., there is no way to account for the actual flow rate seen by the sample due to varying unit loads over time; this is in contrast to stack testing methods which require isokinetic sampling to ensure a representative stack sample is analyzed.

EPA's Environmental Technology Verification Hg CEMS Tests

Hg CEMS has been the focus of great attention as a possible compliance demonstration approach and, therefore, the remainder of this section will discuss issues related to Hg CEMS. The US EPA, working with other agencies, has been investigating Hg CEMS, in the following series of projects:

ETV Phase I – Pilot-Scale Verification of Continuous Emission Monitors for Hg

EPA's Office of Research and Development, National Exposure Research Laboratory (NERL), in coordination with EPA's Environmental Technology Verification (ETV) program, and with funding from the Massachusetts Department of Environmental Protection, conducted Hg CEMS pilot scale tests in North Carolina in January 2001. The Advanced Monitoring Systems Center, one of six technology centers under ETV, is operated by Battelle in cooperation with EPA. Battelle tested 4 commercially available Hg CEMS at the Rotary Kiln Incinerator Simulator, a pilot scale combustion facility at the Environmental Research Center, a part of EPA's National Risk Management Research Laboratory at Research Triangle Park, North Carolina. The Hg CEMS were considered commercially available in that a buyer could contact a monitor vendor and arrange to purchase a monitor.

The CEMS were tested over a two-week period, with Week 1 simulating lower-level emissions typical of a coal-fired power plant and Week 2 simulating higher-level emissions typical of a municipal waste combustor. The statistical data tests performed included:

- relative accuracy as compared to the Ontario Hydro (OH) Method;
- correlation with the reference method;
- precision at stable flue gas conditions;
- calibration/zero drift; sampling system bias;
- interference effects of flue gas constituents;
- response time to changing Hg levels;
- response to low levels of Hg;
- data completeness; and
- setup and maintenance needs.

Features of each CEMS and the relative accuracy found at the levels typical of a coal-fired power plant follow; full statistical results of testing are available¹⁰⁵. For comparison, when CEMS were first used for pollutants such as NO_x and SO₂, a relative accuracy of up to 20% was considered acceptable; in addition, the current draft performance specification for mercury CEMS keeps 20% as the acceptability limit. Each monitor description states whether the monitor requires chemicals to operate (monitors requiring chemicals are considered "wet;" monitors not requiring chemicals are considered "dry"). "Dry" monitors offer lower ongoing operation costs and simpler operation, and are therefore preferable. The following CEMS were tested:

- *PS Analytical's Sir Galahad II* is a continuous monitor that measures elemental Hg and total vapor phase Hg using an aqueous reagent to convert oxidized Hg to elemental Hg. The monitor must be supplied with aqueous reagent and Argon gas. SG-II provided an accuracy relative to the OH method of 20.6% for total mercury, at total mercury levels of about 7 to 8 µg/m³. Testing

¹⁰⁵ See <http://www.epa.gov/etv/verifications/vcenter1-11.html>

showed relative accuracy of 22.8% for elemental mercury, and 27.2% for oxidized mercury at elemental mercury levels of approximately 6 to 7 $\mu\text{g}/\text{m}^3$ and oxidized mercury levels of approximately 1 to 1.5 $\mu\text{g}/\text{m}^3$.

- *Lumex Ltd. 's Lumex Mercury CEM* is a real-time continuous monitor that determines elemental and total Hg using catalytic pyrolysis to decompose oxidized Hg to elemental Hg, and cold vapor atomic absorption spectroscopy (CVAAS) to detect elemental Hg. The monitor uses no wet chemical reagents or external gas supplies. The Lumex CEM provided accuracy relative to the OH method of 58.2% for total mercury, at levels of about 7 to 8 $\mu\text{g}/\text{m}^3$. Testing showed relative accuracy of 50.2% for elemental mercury, and 99% for oxidized mercury, at elemental mercury levels of about 6 to 7 $\mu\text{g}/\text{m}^3$ and oxidized mercury levels of about 1 to 1.5 $\mu\text{g}/\text{m}^3$.
- *Nippon Instrument Corp. 's Model AM-2* measures elemental Hg by removing the oxidized Hg with distilled water and using a gold amalgam trap to capture the elemental Hg with subsequent CVAAS to detect elemental Hg. The monitor consumes no chemicals or gasses, except purified air. The Nippon AM-2 provided relative accuracy for elemental mercury of about 14% relative to OH results, at elemental mercury levels of approximately 6 to 7 $\mu\text{g}/\text{m}^3$.
- *Nippon Instrument Corp 's Model MS-1/DM-5* is a continuous monitor that measures elemental and oxidized Hg using de-ionized water to reduce oxidized Hg to elemental Hg and CVAAS to detect the elemental Hg. The monitor requires no external gas supplies. The MS-1/DM-5 provided accuracy relative to the OH method of 13.2% for total mercury, at total mercury levels of about 7 to 8 $\mu\text{g}/\text{m}^3$. Testing showed relative accuracy of 11.0% for elemental mercury and 54.9% for oxidized mercury, at elemental mercury levels of approximately 6 to 7 $\mu\text{g}/\text{m}^3$ and oxidized mercury levels of approximately 1 to 1.5 $\mu\text{g}/\text{m}^3$.

Some of these commercially available monitors achieved the desired 20% relative accuracy; modifications to the monitors are anticipated, with the goal of improving accuracy in the subsequent testing phases discussed below.

ETV Phase II – Field Demonstration of Hg Continuous Emission Monitors

EPA's ETV program in coordination with DOE's Mixed Waste Focus Area conducted Hg CEMS field tests at a hazardous waste combustor in Tennessee in August-September 2002. ETV/Battelle and DOE tested four commercial Hg CEMS at DOE's Toxic Substances Control Act Incinerator test facility in Oak Ridge, Tennessee. The facility burns hazardous and low-level radioactive waste. The Hg CEMS were considered commercially available in that a buyer could contact a monitor vendor and arrange to purchase a monitor. Mercury emissions levels were expected to be comparable with those from coal-fired power plants. The same type of statistical data tests were to be performed as in Phase I. Participating vendors include: Envimetrics, PS Analytical, Nippon Instruments Corp. (2 instruments) and OPSIS AB. The instruments from PS Analytical and Nippon were also tested in Phase I. The results of the Phase II tests are expected to be available in March 2003.

ETV Phase III – Testing to be conducted at a coal-fired power plant

ETV hopes to receive funding to conduct a third phase of testing at a coal-fired power plant.

ETV's Multi-Metals CEMS Verification

EPA's ETV program verified the performance of a Multi-Metal CEMS at the U.S. Army's Construction Engineering Research Laboratory at its Tooele, UT Army Depot demilitarization incinerator in May 2001. *Cooper Environmental Services' XCEM* is an x-ray based CEM for multiple metals. The XCEM collects particulate matter and gaseous Hg on a filter tape, then subjects the collected material to X-ray

fluorescence analysis. The collection and analysis steps are automated to provide continuous measurement of emitted metals. The verification test was conducted in collaboration with the U.S. Army's Construction Engineering Research Laboratory at its demilitarization incinerator at the Tooele, UT Army Depot. Metal solutions containing Hg and other metals were spiked into the flue gas. The XCEM was evaluated for: accuracy relative to EPA Method 29; correlation with Method 29 results; precision; response time; zero, span, and internal standard drift; and other factors. Relative accuracy (RA) results for Hg are summarized here; full statistical testing results are available¹⁰⁶. XCEM Hg readings were very low at the start of each test day, rising gradually until they stabilized. The best agreement of XCEM and M29 Hg results (within about 20%) was found with M29 runs conducted late in the test day, when XCEM readings had stabilized.

EPA's Office of Air Quality Planning and Standards Field Hg CEMS Tests

EPA's Office of Air Quality Planning and Standards (OAQPS) has been conducting Hg CEMS field tests at a coal-fired utility unit since August 2001. OAQPS, like ETV, is performing three phases of work, of which the first phase is complete, and the second phase is in process. OAQPS may conduct a third Hg CEMS testing phase to obtain additional information. The current OAQPS tests represent the test of the majority of commercially available Hg CEMS. The Hg CEMS are considered commercially available in that a buyer could contact a monitor vendor and arrange to purchase a monitor. The test facility chosen by OAQPS (a 140 MW tangentially-fired pulverized coal boiler with cold-side ESP, burning eastern bituminous coal) is similar to the coal-fired units in Massachusetts subject to 310 CMR 7.29.

OAQPS Phase 1

After selecting a test facility, OAQPS' main activities and achievements from May 2001 to March 2002 were to:

- verify availability and stability of elemental and oxidized Hg standards for detector and sample handling system instrument field calibration,
- conduct Relative Accuracy Test Audits (RATAs) with the Ontario Hydro Method, and
- collect data for 3 months on performance criteria.

The best Phase 1 results were on a Hg CEMS utilizing a wet chemical converter, which had a relative accuracy (RA) of 9.5% on 10 of 15 runs. For comparison, when CEMS were first used for pollutants such as NO_x and SO₂, a RA of up to 20% was considered acceptable; in addition, the current draft performance specification for mercury CEMS keeps 20% as the acceptability limit. The best Phase 1 results on a Hg CEMS utilizing a dry converter showed a materially improved performance on its second RATA after modifications to its converter. In general, it would be preferable to utilize dry CEMS instead of wet, to avoid issues associated with the handling of wet chemicals.

OAQPS Phase 2

OAQPS' main activities from June 2002 to December 2002 were to:

- resurvey vendors to locate more participants
- acquire and install 2 additional dry converter Hg CEMS, as well as further modify a dry converter-based Hg CEMS tested in Phase 1
- relocate a wet converter Hg CEMS tested in Phase 1 to trailer
- add EPRI's integrated sample monitoring system for concurrent testing with the initial Phase 2 RATA (i.e., the third RATA overall)
- complete the third RATA series

¹⁰⁶ See <http://www.epa.gov/etv/verifications/vcenter1-20.html>

- add another two dry converter Hg CEMS, one using plasma emission spectroscopy, a different measurement technology than the other Hg monitors tested
- plan a fourth RATA series

Although EPA has indicated that preliminary Phase 2 data include results that positively track test method and monitor values, the full report detailing the results is not expected until May 2003.

OAQPS Phase 3

OAQPS may conduct a third phase of testing to obtain information on additional source configurations expected to have controls more comparable with what regulations such as the utility MACT or those developed from multi-pollutant legislation may contain (e.g., a bituminous fired unit with wet scrubber and ESP, or a subbituminous fired unit with secondary emission controls such as SCR or SNCR, or a unit with adsorbent injection with a hot side ESP), on additional sampling locations (i.e., at the inlet to the control device), on additional Hg CEMS models (such as the Cooper Environmental Services XCEM mentioned above), or to obtain additional Hg CEMS operating time data.

Costs

Costs for certain Hg compliance determination options are known, while others are not. Capital costs of Hg CEMS have been estimated by a number of vendors to be in the range of \$60,000. In addition, there would be on-going equipment and personnel costs to maintain a CEMS (though most large power plants already have staff dedicated to CEMS that would presumably take on Hg CEMS maintenance as part of general CEMS responsibilities). The costs for coal sampling or stack testing are known on a per-test basis (i.e., \$100-150 per coal sample and \$15,000-40,000 per inlet/outlet stack test), but the total cost would depend on the actual number and type of samples or tests ultimately required by the regulation. The Department is not aware of any cost information for extended period integrated samplers, nor do we have information on the costs to measure Hg in each type of CCR.

Summary

The Department evaluated options that might be used by facilities to demonstrate compliance with a mercury emission standard. The specific compliance demonstration technique used must be selected in concert with the form of the emissions limit in the standard and will be considered during development of the Department's proposed standard. There are approaches currently commercially available to allow facilities to demonstrate compliance with a mercury emission standard, including fuel and emissions sampling. In addition, mercury CEMS can be purchased from monitor vendors at the present time. The most accurate Hg CEMS currently available are of the "wet" type. Some of the commercially available monitors achieve the desired 20% relative accuracy, though modifications to the monitors are anticipated, with the goal of improving accuracy. Research into "dry" CEMS is ongoing, and will be followed by the Department as it develops a mercury standard. The results of a number of new mercury CEMS studies are expected between March and May 2003, and will provide more information about emerging mercury CEMS approaches.

APPENDIX D: WASTE ISSUES RELATED TO MERCURY CONTROL

It is possible that facilities subject to 7.29 will install controls for mercury that would change the ultimate fate of mercury originating in the coal burned at the facilities. It is expected that some controls installed to meet the NO_x and SO₂ requirements of 7.29 will change the ultimate fate of mercury originating in the coal burned at the facilities. This section discusses some issues related to the fate of mercury from coal.¹⁰⁷

Background

When coal is burned in a boiler, the mercury contained in the coal either is emitted from the stack as a gaseous air pollutant, or ends up in the major high-volume¹⁰⁸ coal combustion residues (CCRs): fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) wastes. Fly ash is the particulate matter that is light enough to be carried out of the boiler, and to subsequently be either captured by air pollution control equipment such as Electrostatic Precipitators (ESPs) and Fabric Filters (FFs) or emitted from the stack. Bottom ash is unburned material that is too heavy to be carried out of the boiler, and therefore falls to the bottom of the boiler. Boiler slag is unburned material that falls to the bottom of the boiler and then melts, forming slag upon cooling. FGD wastes are formed by SO₂ air pollution control equipment.

The specific emissions control technologies used by eight coal-fired units subject to 310 CMR 7.29 and the current quantity and fate of ash generated by those units is discussed below.

Current and expected emissions controls on MA coal-fired units

All eight coal fired units subject to 7.29 are currently equipped with coal-side ESPs. None of the units are currently equipped with FGD; however, 7.29 Emission Control Plan (ECP) approvals for two facilities include future installation of FGD. Wet FGD is to be installed on Brayton Point unit 3, and dry FGD is to be installed on Salem Harbor units 1 and 3. The three coal-fired units at Salem Harbor and the one at NRG Somerset currently use Selective Non-Catalytic Reduction (SNCR) for NO_x control. The 7.29 ECP approvals for Brayton Point units 1 and 3 and Salem Harbor units 1, 2, and 3 include future installation of Selective Catalytic Reduction (SCR).

Coal ash generated by MA coal-fired units in 2001

The current quantity and fate of coal ash generated by the eight coal-fired units subject to 310 CMR 7.29 are listed in the following table. Even in the absence of 310 CMR 7.29, changes in disposal practices at some facilities were expected, due to efforts by some communities to limit the disposal of fly ash in local landfills.

¹⁰⁷ Much of this information is taken from “Characterization and Management of Residues from Coal-Fired Power Plants, Interim Report” United States Environmental Protection Agency, Office of Research and Development, Washington, DC 20460, EPA/R-00/XXXX, February 13, 2002.

¹⁰⁸ There are numerous “low-volume” categories of CCRs, see op. cit. page 2-7.

Table D-1. Quantity and fate of coal ash generated by MA coal-fired units in 2001.

	Fly Ash	Bottom Ash	Total	landfilled	recycled
Wet basis tons					
Brayton Point ¹⁰⁹	369,139	44,364	413,503	54.8% ¹¹⁰	45.2% ¹¹¹
Salem Harbor	134,476.56	1818.28	136,294.84	100% ¹¹²	
Mt. Tom			59,165	95.6% ¹¹³	4.4% ¹¹⁴
NRG Somerset			27,000		100% ¹¹⁵

Potential Waste Stream Changes After Installation of Controls

The mercury control strategy implemented at a facility may have an effect on 1) the quantity of waste produced by a facility, 2) the mercury content of the waste produced, and 3) the chemical properties of the wastes produced, including the availability of mercury.

Waste Quantity

One mercury control device under investigation injects activated carbon (or other sorbents) into the flue gas, increasing the amount of material ultimately collected by the particulate control device. The amount of carbon used is a function of 1) the mercury content of the flue gas, including chemical speciation 2) the mercury reduction sought, 3) the type of carbon injected, and 4) the composition and temperature of the flue gas.

Another possible mercury control device is to add a polishing filter after an existing ESP. Such an approach would increase the amount of fly ash caught, thereby decreasing particulate emissions, including the portion of mercury associated with the particulate.

Alternatively, switching fuels from coal to a lower-ash content fuel is a mercury control strategy that would reduce the overall quantity of ash generated.

It is also possible to clean coal of mercury and other substances before combustion. Most coal cleaning processes are based on the principle that coal is less dense than the pyritic sulfur, rock, clay, or other ash-producing impurities imbedded in it, decreasing the production of CCRs from the boiler. Coal cleaning also affects mercury emissions, as discussed in the following section.

The control devices proposed for SO₂ control at Brayton Point and Salem Harbor will have an effect on the quantity of waste produced by the facilities (there are also mercury emission implications of FGD controls, as discussed in the following section). Dry FGD systems inject a substance that absorbs SO₂, with the resulting dry reaction product collected with the fly ash by a particulate air pollution control device. Wet FGD systems inject a slurry of water and a sorbent, which results in greater capture of SO₂ than in a dry FGD, but with a greater volume of waste produced.

¹⁰⁹ Assumes 30% water content.

¹¹⁰ In Pennsylvania, Maine, Massachusetts and New Hampshire.

¹¹¹ Brayton Point's recycled ash was used as flowable fill and as a cement substitute in concrete.

¹¹² In Maine, Massachusetts and New Hampshire.

¹¹³ In Massachusetts.

¹¹⁴ Mt. Tom's recycled ash was used to cap a landfill in Massachusetts.

¹¹⁵ Based on 1998 data, NRG's recycled ash was used as landfill daily cover, flowable fill, and as a cement substitute in concrete.

Mercury Content of Waste

Coal cleaning reduces the concentration of mercury in combusted coal because the pyrite that is removed contains higher levels of mercury than does the rest of the coal. When mercury is removed from coal before combustion, the amount of mercury in CCRs and stack emissions, in total, decreases. Coal cleaning entails a transfer of mercury from CCRs and emissions to coal cleaning wastes. One coal cleaning waste component of particular concern is pyrite, which has been associated with acid generation within waste management areas, often requiring isolation from water and oxygen.

The intent of many mercury control strategies is to capture mercury instead of allowing it to be emitted from coal-fired units. EPA has estimated that, nationwide, the mercury concentration in CCRs will change in the future due to installation of mercury, NO_x and SO₂ control devices. Because control devices were assumed to be installed after the boiler, mercury concentrations in bottom ash and boiler slag are not predicted to change. EPA's estimates of the change in mercury concentration in CCRs are in Table D-2, below.

Table D-2. Comparison of Current Versus Predicted Future Mercury Concentrations in CCRs Based on Mass Balance Calculations¹¹⁶

CCR	Average Mercury Concentration (ppm) ^a	
	1999 ^b	2010 (Projected)
Fly ash	0.33	0.81
Bottom ash	0.065	0.065
Boiler slag	0.041	0.041
FGD residue	0.22	0.49

a All values to 2 significant digits.

b 1999 values based on mercury input of 75 tons and stack emissions of 48 tons (i.e., capture efficiency of 36%). [2010] values are based mercury input of 82 tons and stack emissions of 12 tons (i.e., capture efficiency of approximately 85%).

Wet FGD scrubbers have been found to capture mercury, but with a wide range of capture efficiencies. It is believed that the concentration and species of mercury in the flue gas influences capture efficiencies; specifically, subbituminous coals seem to generate a higher proportion of difficult-to-capture elemental mercury than bituminous coals. All eight coal-fired units subject to 7.29 burn bituminous coal.

Chemical Properties of Wastes

Two questions of interest are: how will chemistry affect beneficial uses? and will the mercury captured by control devices ultimately be available for leaching after disposal?

The first question is largely one of the effect of carbon on re-use of CCRs. Generally, installation of low-NO_x burners can increase the amount of carbon in ash (also known as Loss on Ignition (LOI)), which directly affects the ability to re-use ash as a substitute for cement in concrete. While this effect is of concern nationally, Massachusetts facilities have already installed low-NO_x burners to comply with the NO_x RACT requirements of 310 CMR 7.19, so the effects of low-NO_x burners on ash chemistry have already been felt in Massachusetts. Similarly, mercury control achieved by injecting carbon into the flue gas increases the amount of carbon in the captured fly ash, with the same potential effect as low-NO_x burners of making the ash unsuitable for use as a cement substitute. Various ash reburn approaches have been proposed, in order to recover energy from ash when high carbon levels are left in the ash. If ash from mercury control devices (containing higher mercury levels) were subsequently reburned in an uncontrolled combustion device, the mercury previously captured would be released to the atmosphere, negating the benefit of the mercury control device.

¹¹⁶ Op. cit. page ES-4.

The second question is whether CCRs disposed of in a landfill or recycled in some form of beneficial use could release mercury to the environment. EPA has analyzed this question for a number of disposal and use approaches, and found that the major categories of disposal and use appear to release little mercury to the environment, but that specific uses are a cause for concern.

Disposal and uses that appear to release little mercury via leaching and volatilization include:

- cement substitute in concrete
- flowable fill
- structural fill
- road base/subbase
- landfill disposal

Uses that appear to have the potential for mercury release via leaching and volatilization include:

- cement kiln fuel
- mineral filler in asphalt
- snow and ice control
- blasting grit/roofing granules
- wallboard (leaching not significant, volatilization may be significant)
- waste stabilization/solidification (volatilization probably not significant, leaching may be significant)
- agriculture

Use of ash in mining remediation applications may result in mercury leaching; however, it may be that more mercury can be leached to the environment if no remediation is done than if CCRs are used.

Legal framework for proper disposal of coal ash: federal, state, local

Federal

Ash disposal is regulated under the federal Resource Conservation and Recovery Act (RCRA)'s Subtitle D solid waste provisions. EPA concluded in a May 22, 2000 Federal Register Regulatory Determination that regulation of ash as a hazardous waste under Subtitle C was not warranted, but that regulations should be established for certain disposal techniques, including use of CCRs to fill underground mines.

State

Massachusetts has jurisdiction over coal ash disposed of in Massachusetts landfills. Coal ash that is disposed of in a landfill in Massachusetts is defined as a solid waste. However, an exemption was added to the Solid Waste Statute (Massachusetts General Law Chapter 111, Section 150A) in the 1970s that specifically exempted various uses of coal ash, as follows:

“Ash...shall not be construed as refuse...under this section when used as a raw material for concrete block manufacture, aggregate, fill, base for road construction, or other commercial or industrial purpose, or stored for such use.” “...provided, further, that no final disposal of ash produced by the combustion of coal may be accomplished by burial of such ash in the ground, other than as base for road construction or fill, unless the place where such disposal takes place has been assigned for such disposal by the board of health and plans for such disposal have been approved by the department pursuant to this section. The department may waive the requirements of the preceding paragraphs as they may apply to the disposal of burial of ash...”

Therefore, coal ash that is used in products such as concrete, or as a fill material in certain circumstances, is exempt from management as a solid waste. This statutory exemption is still in effect in Massachusetts.

Local

Coal ash disposal landfills are required to obtain a site assignment and a permit. The local Board of Health issues the site assignment and DEP issues the permit. However, where coal ash is used as a “fill” material, there is no site assignment issued by the local Board of Health or permit issued by DEP.

Recently, several municipalities in Massachusetts have passed bylaws banning disposal of ash within their respective towns. However, depending on how the bylaws were written, some of these bylaws may not be valid. The Solid Waste Act of 1987 included a provision that disallows a town from passing a bylaw after July 1, 1987 that would have the effect of banning landfills from an area where the land was already zoned industrial, except specifically to protect a town’s public drinking water supply.

Summary

Certain mercury emission reduction approaches will affect the quantity of waste produced, its mercury concentration, and its chemical properties. The Department believes that there are currently, and will continue to be, safe options for the disposal or management of waste generated from coal-fired power plants. The Department will continue to consider issues such as landfill capacity and ultimate fate of mercury, including water quality and coal ash re-use options, as it develops a mercury standard.

APPENDIX E: 310 CMR 7.29 EMISSION CONTROL PLAN SUMMARIES FOR COAL-FIRED FACILITIES

For reference, the pollution control measures listed in the 310 CMR 7.29 Emission Control Plan (ECP) approvals issued June 7, 2002 for the coal-fired Massachusetts facilities subject to 310 CMR 7.29 are summarized below. The June 7, 2002 ECP approvals were for the initial 310 CMR 7.29 applications submitted by the facilities; some facilities have since revised their applications, but no modified ECP approvals have been issued as of the writing of this report.

Key Highlighted text in the second column indicates new equipment or a new pollution control technique expected to be installed or utilized. Plain text indicates existing equipment or an existing pollution control technique.

Facility Name	Emission Control Plan Summary
Holyoke Water Power Company Mt. Tom Station	Single Unit Facility Proposed Pollution Control Technique(s): Management of Lower Sulfur Fuels (Conversion to cleaner Coals) Upgraded combustion controls and burner system – NO _x control Selective Non-Catalytic Reduction – NO _x control Electrostatic Precipitators – PM control SO ₂ Early Reduction Credits SO ₂ Acid Rain Allowances Off-site CO ₂ Reductions
PG&E Salem Harbor Station	Multi Unit Facility Proposed Pollution Control Technique(s): Units 1 and 3 – Low NO _x Burners Selective Catalytic Reduction – NO _x control Combustion Tuning and Controls – NO _x control Electrostatic Precipitators – PM control Management of Lower Sulfur Fuels Dry Flue Gas Desulfurization with Fabric Filter – SO ₂ controls Unit 2 – Low NO _x Burners Selective Catalytic Reduction – NO _x control Combustion Tuning and Controls – NO _x control Electrostatic Precipitators– PM control Management of Lower Sulfur Fuels Unit 4 – Low NO _x Burners Combustion Tuning and Controls – NO _x control Electrostatic Precipitators – PM control Management of Lower Sulfur Fuels Off-site CO ₂ Reductions

<p>PG&E Brayton Point Station</p>	<p>Multi Unit Facility Proposed Pollution Control Technique(s): Unit 1 – Selective Catalytic Reduction – NO_x control Ash Reduction Process Electrostatic Precipitators – PM control Low NO_x Burners with Overfire Air Management of Lower Sulfur Fuels Unit 2 – Ash Reduction Process Electrostatic Precipitators – PM control Low NO_x Burners with Overfire Air Management of Lower Sulfur Fuels EPRICON Flue Gas Conditioning – SO₂ control Unit 3 – Selective Catalytic Reduction – NO_x control Ash Reduction Process Electrostatic Precipitators – PM control Low NO_x Burners with Over fire Air Management of Lower Sulfur Fuels Wet Flue Gas Desulfurization – SO₂ control A new taller stack Unit 4 – Electrostatic Precipitators – PM control Low NO_x Burners Management of Lower Sulfur Fuels Flue Gas Recirculation – NO_x control Off-site CO₂ Reductions</p>
<p>NRG Somerset Station</p>	<p>Single Unit Facility Proposed Pollution Control Technique(s): Natural Gas Reburn Management of Lower Sulfur Fuels (Reduced sulfur coal) Selective Non-Catalytic Reduction – NO_x control Overfire Air Ports – NO_x control Electrostatic Precipitators – PM control SO₂ Early Reduction Credits SO₂ Acid Rain Allowances Off-site CO₂ Reductions On-site CO₂ Reductions</p>

APPENDIX F: FIELD DEMONSTRATION OF MERCURY CONTROL USING ACTIVATED CARBON INJECTION CONTROL TECHNOLOGIES

Under the auspices of the Department of Energy (DOE) National Energy Technology Laboratory, studies of mercury control devices are occurring across the US. One study of particular relevance to Massachusetts includes testing at four facilities: Alabama Power's Gaston unit 3, Wisconsin Power's Pleasant Prairie unit 2, and two Massachusetts units subject to 310 CMR 7.29, i.e., Brayton Point unit 1 and Salem Harbor unit 1. This study is being conducted by ADA Environmental Solutions (ADA-ES), LLC, with primary funding from DOE and additional funding from ADA-ES, EPRI, facility owners (PG&E National Energy Group in the case of Brayton Point and Salem Harbor Stations), and others. The goals of the study are:

- to perform the first full-scale evaluations of mercury control on coal-fired boilers (up to 150 MW equivalent),
- to evaluate effectiveness of sorbent-based mercury control (i.e., activated carbon),
- to test several different power plant configurations, and
- to document all costs associated with mercury control.

Testing was conducted at Gaston in Spring 2001, Pleasant Prairie in Fall 2001, Brayton Point in Summer 2002, and testing at Salem Harbor Station is to be completed in November 2002. ADA-ES has indicated that the final report on all four facilities will not be ready before summer 2003, however, some preliminary data is available, as discussed for each facility below.

At each facility, ADA-ES conducts Baseline, Parametric and Long-term testing. Baseline testing documents mercury concentrations with no Activated Carbon Injection, using Ontario Hydro testing and a semi-continuous emission monitor (S-CEM). Parametric testing consists of a series of 8 hour tests over three weeks at different parametric conditions (i.e., sorbent, feedrate, and operating conditions); mercury concentrations are documented using a S-CEM only. Long-term testing consists of a ten day run at constant conditions using optimum sorbent and feedrate; mercury concentrations are documented using Ontario Hydro testing and a S-CEM.

The Apogee Scientific semi-continuous emission monitor (S-CEM) used to measure mercury concentrations is a research prototype analyzer that requires a skilled operator. It determines total vapor phase mercury measurements, converting all non-elemental vapor-phase mercury in the flue gas to elemental mercury and measuring using cold vapor atomic absorption spectrometer with a gold amalgamation system. Particulate is separated from the gas sample by a filter. Baseline data collection is performed to compare the accuracy of the S-CEM against the Ontario Hydro test method and to determine baseline Hg concentrations. At Brayton Point, the S-CEMs were placed before the old ESP, before and after the new ESP, and at the stack. At Salem Harbor, the S-CEMs were placed at the economizer/Air Pre-Heater exit, the ESP inlet, and the ESP outlet (ID fan inlet).

Gaston testing

Gaston's Unit 3 is a 270 MW wall-fired boiler that burns washed eastern US low sulfur bituminous coal. Particulate matter emissions are controlled by a Research Cottrell hot-side (i.e., before the air preheater) ESP followed by a Hamon Research-Cottrell COmpact Hybrid PARticulate Collector (COHPAC) baghouse. This unit was chosen for testing because the COHPAC represents a cost effective retrofit solution for utilities with existing ESPs. The sorbent was injected downstream of the ESP and the air preheater and upstream of the baghouse. A comparison of the Gaston results with those of the other two completed sites, Pleasant Prairie and Brayton Point, indicated that Gaston showed the highest percentage of mercury removal (i.e., 90+% removal) at the lowest concentration of sorbent injected (i.e., less than 5 lb/million actual cubic feet (lb/MMacf)) of the three units tested to date. This result is also reflected in

cost data indicating Gaston has the highest mercury removal (i.e., 90+% removal) with the lowest sorbent costs at that removal level (i.e., under 0.5 mills/kWh). ADA-ES would like to perform longer-term powdered activated carbon testing on Gaston's Unit 3 in 2002-2003.

Pleasant Prairie testing

Pleasant Prairie unit 2 is a 600 MW turbo fired boiler equipped with a cold-side (i.e., after the air preheater) ESP and a Wahlco SO₃ system for fly ash resistivity control. This facility burns Powder River Basin (PRB) subbituminous coal, unlike any other facility in the test program, and unlike any Massachusetts facility subject to 310 CMR 7.29. The facility was selected to include a PRB-fired unit, but the results may not be directly applicable to Massachusetts facilities that do not burn PRB. The best preliminary data from this unit indicate a 73% mercury removal upon injection of sorbent, an increase from the 5.3% removal seen without sorbent injection. The results indicated a clear "plateau" of mercury removal, in which no further mercury removal is seen even upon increasing the sorbent injection rate. Likewise, the sorbent costs at this facility increase at higher sorbent injection rates, for no further addition in mercury removal. Sorbent costs of approximately 0.5 mills/kWh achieve mercury control of approximately 58%, while a doubling of sorbent cost to 1 mill/kWh only achieves mercury control of approximately 60%.

Brayton Point testing

Brayton Point Station's Unit 1 is a tangentially fired boiler converted from oil to coal and rated at 245 MW. The flue gas stream divides into two sides and remains divided as it passes through the electrostatic precipitators (ESPs). Testing was performed only on the east side of the gas stream, thus representing approximately 122 MW. Unit 1 has two cold-side (i.e., after the air preheater) ESPs, in series, with the second being newer and larger than the first. Sorbents were injected into the east side of Unit 1 ductwork between the old and the new precipitators; therefore capture of sorbents was accomplished by the second precipitator. The unit burned West Virginia low-sulfur bituminous coal during the testing. The hopper ash from both precipitators is combined and processed by an on-site carbon separation system. The processed ash is sold as base for concrete and the remainder of the higher carbon ash is disposed of as waste. The unit has an EPRICON flue gas conditioning system that uses SO₃ for fly ash resistivity control.

The Parametric Tests consisted of a series of eight-hour tests conducted at different sorbent, feedrate and operating conditions and were performed at full load. The areas of interest included mercury removal as a function of injection rate, the effect of operational conditions with and without carbon injection on mercury removal, and performance of "alternative" sorbents to the baseline sorbent "Norit FGD." Results from screening tests done in February 2002 indicated that the presence of SO₃ in the flue gas from the EPRICON system decreased the adsorption capacity of a few candidate sorbents by a factor of at least 2. Five sorbents were chosen for the Parametric Tests based on the screening tests and various sorbent selection criteria. The sorbents and injection rates used during the parametric tests consisted of Norit Americas, Inc. FGD at 1, 3, 10, and 20 lb/MMacf, and Superior Adsorbents, Inc., CarboChem, Donau Carbon, and EPRI sorbents at 3 and 10 lb/MMacf. The parametric tests ended with tests of the Norit FGD sorbent at 10 and 20 lb/MMacf with the EPRICON system off and on.

Norit America's Inc. FGD was the sorbent used for the Long Term full-scale testing. The Long Term Test was a ten-day run at constant conditions using optimum sorbent and feedrate. Ontario Hydro testing was performed during two of these days in order to check the S-CEM analyzer values. The powdered activated carbon was to be injected at 10 lbs/MMacf, although if the carbon content of the ash was under acceptable limits, testing was to proceed at 20 lbs/MMacf with the carbon content in the ash being closely monitored.

The Brayton Point Parametric Test results indicate that the higher the concentration of sorbent injected, the more mercury removed. Removal values range from 0 – 50% at 3 lb/MMacf and 75 – 95% at the highest sorbent injection rate of 20 lb/MMacf.

Both the removal trend and the sorbent costs preliminary results indicate that Brayton Point does not exhibit a sorbent injection level at which further injection of sorbent provides no further mercury removal. Instead, addition of more sorbent results in additional mercury reductions over the range of sorbent injection levels tested, with an approximately linear trend. This result is different from that seen at the two other facilities at which ADA-ES has completed testing, in that the other facilities showed definitive injection rates above which increased sorbent injection achieved little additional mercury removal. ADA-ES believes Brayton Point was different from the other two sites at which testing has been completed in that:

- flue gas conditions presented measurement challenges for the S-CEMs,
- Brayton Point's two ESPs in series is an unusual configuration,
- Brayton Point's second ESP is larger than most, and
- documented variability in day to day performance.

The results of the Brayton Point Long Term Test are not yet fully analyzed, nor are the coal, ash and economic analyses complete.

Salem Harbor testing

Salem Harbor Station's Unit 1 is a single-wall-fired boiler rated at 88 MW. The flue gas stream divides into two sides and remains divided as it passes through the electrostatic precipitator (ESP). Testing will be performed only on one side of the gas stream, thus representing approximately 42 MW. The unit fires a low sulfur, bituminous coal and uses oil for startup. The particular characteristics of the unit that make it of interest are: use of a urea-based Selective Non-Catalytic Reduction (SNCR) system for NO_x control, high ash carbon content (i.e., LOI) of 25%, and a low ESP operating temperature of 255°F.

As indicated in the test protocol, the primary objective of the testing at Salem Harbor is to find out whether sorbent injection can enhance mercury removal beyond the baseline removal by flyash. The secondary objective is to better understand the cause of the existing high mercury removal baseline (initially discovered during EPA's 1999 Mercury Information Collection Request), to be accomplished by varying process conditions. Variables that may contribute to the high removals include low ESP operating temperatures, high ash carbon content, and the operation of the SNCR. A single sorbent will be injected, specifically Norit America's "Darco FGD." The native fly ash at Salem Harbor is viewed as a second sorbent, since this ash already is proven to have close to 90% removal. The testing at Salem Harbor was not complete at the writing of this report.

Summary of ADA-ES testing

ADA-ES's preliminary results based on testing at three facilities are:

- PAC injection can capture elemental and oxidized mercury from both bituminous and subbituminous coals,
- additional field tests and long-term demonstrations are necessary to continue to mature the technology,
- fabric filters provide better contact between the sorbent and mercury than ESPs resulting in higher removal levels at lower sorbent costs,
- coal characteristics appear to affect ACI performance with an ESP, and
- small amounts of carbon in fly ash can limit use as a cement admixture, potentially affecting overall costs.

ADA-ES has indicated that the final report on all four facilities will not be ready before summer 2003.