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EVALUATION OF THE TECHNOLOGICAL AND ECONOMIC FEASIBILITY OF CONTROLLING AND ELIMINATING MERCURY EMISSIONS FROM THE COMBUSTION OF SOLID FOSSIL FUEL

Pursuant to 310 CMR 7.29 – Emissions Standards for Power Plants

December 2002

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EXECUTIVE SUMMARY

Purpose and Scope of This Report

Massachusetts' regulation 310 CMR 7.29, "Emissions Standards for Power Plants," which went into effect in May 2001, establishes emissions standards for sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and carbon dioxide (CO_2) from the six affected power plants and caps emissions of CO_2 from the facilities. It caps mercury emissions from solid-fuel-fired affected facilities by limiting annual mercury emissions to the average annual emissions calculated using the results of required stack tests. The regulation also provides a framework for establishing emission standards for mercury from the affected facilities by requiring that the Department of Environmental Protection (the Department), by December 1, 2002, "complete an evaluation of the technological and economic feasibility of controlling and eliminating emissions of mercury from the combustion of solid fossil fuel in Massachusetts." The regulation also states: "within 6 months of completing the feasibility evaluation, the Department shall propose emission standards for mercury." This document constitutes the evaluation of the technological and economic feasibility of controlling mercury emissions from power plants called for in the regulation.

Conclusions As to Feasibility of Mercury Control

Based on a wide range of research, data and experience, the Department has concluded that control of mercury emissions from solid-fossil-fuel fired facilities is indeed feasible. The Department plans, therefore, to proceed with the development of a proposed a mercury emissions standard for power plants within six months of the date of this report.

As discussed in the report, U.S. Environmental Protection Agency (EPA) data demonstrates that some coal-fired facilities are already removing 98% of mercury from flue gas. Data from the stack tests required at the affected Massachusetts facilities indicate that a number of these facilities are already removing close to 90% of flue gas mercury. EPA has also demonstrated the economic feasibility of mercury control at up to 90% removal rates. Based on this information, and on other factors discussed in the report, the Department believes that the removal of 85-90+% of mercury in flue gas has been demonstrated to be technologically and economically feasible. The Department will continue to discuss with stakeholders the appropriate level and form of the mercury standard that will be proposed. The Department has not concluded that removal of 85-90+% of mercury is technologically and economically feasible for any of the Massachusetts facilities.

This report provides important background for development of the standard by assessing the general availability and effectiveness of a range of control measures. However, the Department recognizes that the feasibility of mercury controls for a specific facility will depend on a range of facility characteristics including: type of coal used; configuration of the plant; existing pollution controls and proposed additional controls. The Department also recognizes that the feasibility of control at each facility will be influenced by the form and level of the standard ultimately adopted, the time frame for implementation, and the state of control technologies at the time that the facilities are required to meet the standard.

The Department will begin discussing how the background information presented in this report can and should be used when developing a standard for Massachusetts' facilities with stakeholders at a meeting to be held in January 2003. The Department anticipates holding additional public meetings prior to proposing a draft regulation with a mercury standard. At these meetings it will continue to address issues related to the applicability of the findings of this report to the affected facilities. This will include consideration of factors unique to the affected Massachusetts facilities including the technical feasibility of certain control measures at individual facilities and the costs of implementation of various measures at each facility.

Next Steps
The Department plans to propose standards for mercury emissions within six months of the issuance of this report, with a proposed compliance date of October 1, 2006, as required by 310 CMR 7.29. The proposed standards will be subject to a full regulation review process with a formal public comment period and a public hearing. At the January stakeholder meeting, as the first step in the development of a standard, the Department will take comment on this report as well as begin the discussion of the technological and economic feasibility of the control measures discussed in the report for specific Massachusetts facilities.

INTRODUCTION

On May 11, 2001, Massachusetts regulation 310 CMR 7.29, "Emissions Standards for Power Plants," went into effect. This regulation establishes emissions standards for sulfur dioxide (SO_2), oxides of nitrogen (NO_x) and carbon dioxide (CO_2) from the six affected power plants and caps emissions of CO_2 from the facilities. It also caps mercury emissions from solid-fuel-fired affected facilities by limiting annual mercury emissions to the average annual emissions calculated using the results of required stack tests. The regulation, at 310 CMR 7.29(5)(a)3, also provides a framework for establishing emission standards for mercury from the affected facilities by requiring that the Department of Environmental Protection (the Department or DEP), by December 1, 2002, "complete an evaluation of the technological and economic feasibility of controlling and eliminating emissions of mercury from the combustion of solid fossil fuel in Massachusetts in accordance with the Mercury Action Plan of the Conference of New England Governors and Eastern Canadian Premiers." The regulation also states: "within 6 months of completing the feasibility evaluation, the Department shall propose emission standards for mercury."

PURPOSE AND SCOPE OF REPORT

At the time that DEP promulgated 310 CMR 7.29, it had not compiled the technical data to support emission standards for mercury. The regulation, therefore, required that DEP evaluate the technical and economic feasibility of controlling mercury emissions from the combustion of solid fossil fuel and issue this evaluation prior to proposing mercury standards. This document constitutes the evaluation of the technological and economic feasibility of controlling mercury emissions from power plants called for in 310 CMR 7.29(5)(a)3.a.

The Department plans to propose standards for mercury emissions within 6 months of the issuance of this report, with a proposed compliance date of October 1, 2006, as required by 310 CMR 7.29. The proposed standards will be subject to a full regulation review process in accordance with Chapter 30A, with a formal public comment period and a public hearing. The Department will likely hold one or more informal rule review meetings prior to issuing a proposed rule for comment.

The Department conducted three public stakeholder meetings, on August 1, September 20 and October 11, 2002, to solicit input from interested parties prior to the creation of this report. The Department appreciates the participation of the parties who attended those meetings and has carefully considered the comments and suggestions that the participants offered.

Many points raised during those public meetings related to issues other than the technological and economic feasibility of controlling mercury emissions. This report addresses only issues directly related to the technological and economic feasibility of controlling mercury emissions. This report does not address issues that had already been resolved with the promulgation of 310 CMR 7.29, such as the need for DEP to propose a mercury standard, nor does this report address other points not directly related to the technological and economic feasibility of controlling mercury emissions, such as the form of a mercury standard, mercury transport from out-of-state sources, or health impacts related to mercury contamination.

DEP will use this final feasibility report as part of its technical support for the mercury standards to be proposed. The Department will accept comments on this final report, or additional information that interested persons would like the Department to consider as it develops the proposed standard, at any time. The Department will also accept comments on the content of this final report during the formal rule making for the proposed mercury standard.

BACKGROUND

Mercury is a persistent, bioaccumulative toxic metal that exists at trace levels in the earth's crust. It is released to the environment by airborne emissions, direct discharges to surface water and soil, accidental spills, and natural activities. Although all releases of mercury are of concern, air emissions play a significant role in the transport and dispersion of mercury. The health and environmental effects of mercury are well documented in other publications.[1]

Mercury is present as a naturally occurring trace element in coal. As coal is burned in electric utility boilers, the mercury (Hg) in the coal volatilizes to form gaseous elemental mercury (Hg^0). In the subsequent cooling of the combustion gases, interaction with other combustion products results in a portion of the elemental mercury being converted into gaseous oxidized forms of mercury (Hg^{2+}). A portion of Hg^0 and Hg^{2+} adsorbs onto particulate, forming particle-bound mercury (Hg_p). Thus, mercury exists in three different forms in coal combustion gas – elemental, oxidized, and particulate-bound – with the gaseous forms being the most prevalent in stack emissions. The form and amount of mercury emitted from specific coal-fired units is affected by coal type as well as numerous other factors, such as combustion variables and the presence of other chemicals in the coal.

The Department estimates that mercury emissions from the power plants covered under 310 CMR 7.29 are approximately two hundred pounds per year based on the stack test data that the facilities were required to collect and submit to DEP pursuant to 310 CMR 7.29.[2]

MERCURY REDUCTION INITIATIVES

Because there were no limits on air emissions of mercury from power plants in the U.S. prior to the adoption of 310 CMR 7.29, the electric utility industry has not had a strong incentive to control mercury emissions. However, there are currently a number of initiatives underway that are aimed at reducing mercury emissions from power plants, which, like the Massachusetts regulation, will provide incentive for further development of control technologies. These initiatives are outlined below.

EPA Utility MACT Development

In December 2000, EPA made a finding that the regulation of hazardous air pollutant emissions from electric utility steam generating units is necessary and that mercury is the hazardous air pollutant with the greatest potential concern for public health.[3] At that time, EPA added coal-and-oil-fired electric utility steam generating units to the list of source categories in section 112(c) of the Clean Air Act for which "maximum achievable control technology" (MACT) regulations must be developed. Pursuant to a settlement agreement, the utility MACT regulations are to be proposed by December 15, 2003 and promulgated by December 15, 2004 with a compliance date of December 15, 2007.

EPA indicates that it expects to propose and finalize a MACT regulation for power plants according to this timeframe. However, the Bush Administration has proposed legislation that would limit the emissions of SO_2, NO_x and mercury from power plants and replace the utility MACT rule requirement

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[1] See: U.S. Environmental Protection Agency. December 1997 Mercury Study: Report to Congress. U.S. EPA-452/R-97-0013 at: http://www.epa.gov/ttnatw01/112nmerc/volume1.pdf; Northeast States and Eastern Canadian Provinces Mercury Study: A Framework for Action, February 1998; Massachusetts Department of Environmental Protection. Mercury in Massachusetts: An Evaluation of Sources, Emissions, Impacts, and Controls. June 1996.

[2] From emission testing reports submitted to the Department to comply with 310 CMR 7.29(5)(a)3.d.

[3] See EPA Utility Air Toxics Study Report to Congress at: http://www.epa.gov/mercury/actions.htm#utility and EPA December 14, 2000 Fact Sheet at http://www.epa.gov/ttn/oarpg/t3/fact_sheets/fs_util.pdf.

with a nation-wide mercury cap and trade program. Other multi-pollutant legislative proposals that contain nation-wide caps for mercury emissions from power plants have also been introduced. The extent to which any of these proposals, if enacted, would reduce emissions from Massachusetts' power plants cannot be determined. Furthermore, the prospect of enactment of any of these legislative initiatives is uncertain as of the date of this report. In the face of these uncertain federal requirements, and as required by 310 CMR 7.29(5)(a)3.b, the Department plans to propose emission standards for mercury within six months of completing this feasibility evaluation, notwithstanding the federal MACT process.

In support of the MACT development process, EPA undertook an evaluation of the mercury control performance of various emission control technologies that are either currently in use on coal-fired units for pollutants other than mercury or that could be applied to such units for mercury control. DEP's review and assessment of available control technologies draws heavily on EPA's evaluation.

Other States

A number of other states are taking steps to address mercury emissions from power plants. New Hampshire's Clean Power Act, signed into law in May 2002, calls for a cap on mercury emissions to be recommended to the legislature by the Department of Environmental Services by early 2004. New Jersey's Mercury Task Force released a January 2002 report containing reduction recommendations for mercury emissions from numerous source categories, including power plants. North Carolina has recently passed legislation calling for a study of mercury emissions from power plants and the feasibility of controlling those emissions. Wisconsin has established a task force to study issues related to the control of mercury emissions from power plants.

New England Governors and Eastern Canadian Premiers Mercury Action Plan

The Conference of New England Governors and Eastern Canadian Premiers (NEG/ECP) adopted a Mercury Action Plan in 1998. Massachusetts is a signatory to this agreement. The NEG/ECP action plan established a long-term regional goal of virtual elimination of anthropogenic mercury emissions, with an interim goal of a 50% reduction in regional emissions by 2003. In 2001, after an evaluation of the interim goal, the NEG/ECP adopted another interim goal of an overall reduction of 75% or greater by 2010, with an evaluation in 2005 to allow for new information to be taken into account and to revise the target if necessary.[4]

The Mercury Action Plan includes commitments to establish mercury emissions limits for large municipal waste combustors and large medical waste incinerators, evaluating the feasibility of emission limits for municipal sludge incinerators, and implementing regional strategies to promote the maximum economically and technically feasible reduction in mercury emissions from electric generating facilities and other boilers in the Northeast.

With regard to electric generating facilities, the NEG/ECP Mercury Action Plan makes the following recommendations:[5]

- promote the establishment of national and international strategies to reduce mercury emissions from utility and non-utility boilers;
- identify mercury emission control options and regional emission reduction targets for these sources within one year, using best available information;

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[4] "Technology Recommendations for Reducing Mercury and Acid Rain Precursor Emissions from Boilers" (the "Joint Boiler Report"). http://www.scics.gc.ca/pdf/850084012_e.pdf

[5] Listed under Action Item 2.d for Utility and Non-Utility Boilers, recommendations 10, 11, and 12; and under Action Item 5 for Research, Analysis and Strategic Monitoring, recommendation 36.

- develop and implement strategies to promote maximum economically and technically feasible reductions in mercury emissions from utilities and other boilers in the northeast with an implementation target commencement date of 2003; and
- promote collection of more emissions test data for sources such as utility and non-utility boilers, mobile sources, and oil refineries.

In 2000, the NEG/ECP Joint Boiler Workgroup released a report (subsequently accepted by the NEG/ECP) recommending the goal of reducing mercury emissions from coal-fired utility boilers by 20%-50% by 2005 and by 60-90% by 2010. These reduction goals were based on the February 1998 regional inventory, which serves as a baseline for the Mercury Action Plan. In August 2002, the NEG/ECP Joint Boiler Workgroup issued a report finding that the reduction target range of 60-90% from the 1998 baseline for the longer-term 2010 goal is still valid, while achievable reductions for 2005 are more likely to fall in the lower part of the 20-50% target range.

The establishment of mercury emission standards for Massachusetts' power plants is consistent with the goals of the NEG/ECP Mercury Action Plan.

OVERVIEW OF MERCURY CONTROL METHODS AND TECHNOLOGIES

In general, there are two approaches for reducing mercury emissions from coal-fired utility boilers: 1) pollution prevention through fuel switching and/or coal cleaning; and 2) post combustion controls, which remove mercury from the flue gas.

Pollution Prevention

Fuel-switching. Mercury emissions can be reduced by switching to another fuel (such as natural gas) partially or completely, or installing new gas-fired units or integrated gasification combined cycle (IGCC) units. The mercury reduction is incremental and limited to the difference in the mercury emissions of the two fuels. Installation of new gas-fired units or IGCC units would result in significant reduction of Hg. Co-firing or switching to natural gas may be an option for some facilities. Major considerations in switching to natural gas are: the availability of natural gas, the differential cost of natural gas versus coal, and the configuration of the existing units.[6]

Coal cleaning. Certain types of coal are processed to remove mineral matter in order to meet combustion specifications and increase heating value. The coal cleaning processes already used for these purposes result in some reduction of mercury content. The affected Massachusetts facilities use bituminous coal, which typically is cleaned using current technologies. Advanced coal cleaning technologies are being developed and can achieve further reduction of mercury in coal but do not offer the potential of significant additional reductions in the near term.

Post Combustion Controls

Post-combustion, flue gas technologies employ three basic methods to capture mercury:

1) capture of particulate-bound mercury in particulate matter control devices;
2) adsorption of elemental and oxidized mercury onto sorbents for subsequent capture in particulate matter control devices; and

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[6] One Massachusetts facility, NRG Somerset, has received approval of its 310 CMR 7.29 Emissions Control Plan (ECP) application proposing natural gas reburn as a pollution control measure to comply with 310 CMR 7.29. See Appendix E for a summary of the ECP approvals for the four coal-fired facilities subject to 310 CMR 7.29.

3) removal of soluble oxidized mercury in wet scrubbers (including processes to convert elemental to oxidized mercury for subsequent capture in wet scrubbers).

It is also useful to categorize mercury control methods in terms of:

1) mercury capture by controls currently designed for the capture of pollutants other than mercury (NO_x, SO_2, and particulates);
2) new combinations of control devices used for these other pollutants specifically intended for increased mercury capture; and
3) new controls designed specifically for mercury capture.

Appendix A reviews multiple mercury control methods and technologies. Table 1 below summarizes a number of the mercury control approaches that are discussed in detail in Appendix A. For a more complete discussion, with references, see Appendix A

Table 1. A selection of approaches demonstrated or under investigation to control mercury. Some approaches could reasonably be considered to fall in more than one category.

Pollution Prevention approaches	Biomass Substitution Coal Cleaning Low Mercury Coal Natural Gas Substitution New Coal Plant (Integrated Gasification Combined Cycle) New Gas Plant
Traditional control technologies for pollutants other than Hg that provide some amount of Hg capture	Electro Static Precipitator (ESP), cold side and hotside Fabric Filter (FF)/baghouse Flue Gas Desulfurization, wet, semi-dry, and dry Particulate Scrubber Selective Catalytic Reduction Selective Non-Catalytic Reduction Sprat dryer Absorber (SDA)
New combinations of, and modifications to, traditional technologies	Activated Carbon (AC) Injection Prior to Existing ESP or FF Adding tubular wet ESP Add-on Compact Fabric Filter + AC Injection Add-on Polishing Fabric Filter Carbon Bags for FF Catalyst Bed Oxidizer + Scrubber Catalytic Bags for FF Chemical Oxidant + Scrubber Convert 1 ESP field to wet Convert 1 ESP field to pulse-jet FF Enhanced Coal Washing Spray Dry Calcium-Based Sorbent Injection
Technologies designed to control Hg (or to control multiple pollutants including Hg)	Alternative Sorbents (e.g., calcium-based, Sodium Tetrasulfide) for Injection, in furnace or SDA Duct Modifications/Contacting Bed Fixed Metal/Activated Carbon Catalyst Bed PowerSpan Electro Catalytic Oxidation

For reference, the pollution control measures included in the Emission Control Plan (ECP) approvals for the coal-fired Massachusetts facilities subject to 310 CMR 7.29, including control devices currently installed and control devices expected to be installed at those facilities to comply with the 310 CMR 7.29 NO_x and SO_2 requirements, are summarized in Appendix E.

TECHNOLOGICAL FEASIBILITY OF MERCURY CONTROLS

The Department is relying on a wide range of research, data and experience to assess the technological and economic feasibility of mercury control. Based on the following, the Department concludes that the capture of at least 85-90+% of flue gas mercury is technologically feasible.

EPA's Mercury Information Collection Request (ICR) Data

To demonstrate the feasibility of mercury control, the Department points to data collected by EPA in 1999 as part of a nation-wide effort to develop a database to support EPA's development of a MACT standard for power plants. The data collection effort, referred to as EPA's Mercury Information Collection Request (ICR), was designed to gather emissions data from plants representative of the US coal-fired power plant fleet. The US fleet was categorized by 1) combustion technology utilized, 2) type of coals combusted, and 3) control devices installed for PM, NO_x, and SO_2.

The Massachusetts coal-fired units subject to 310 CMR 7.29 employ pulverized coal combustion technology. A summary of EPA's Mercury ICR data from pulverized coal fired boilers is listed below in Table 2. The table further breaks down the results from pulverized coal boilers by the type of coal combusted[7] and by the type of emissions controls installed.[8] The figures represent the three-run average percentage of mercury captured by the installed control devices, calculated from the difference in mercury measured before and after the control devices. The results document that there are US facilities that currently achieve up to 98% removal of mercury from bituminous coal, the kind used by affected facilities.

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[7] The coal-fired Massachusetts facilities subject to 310 CMR 7.29 combust bituminous coal.

[8] The pollution control measures included in the ECP approvals for the coal-fired Massachusetts facilities subject to 310 CMR 7.29, including control devices currently installed and control devices expected to be installed at those facilities to comply with the 310 CMR 7.29 NO_x and SO_2 requirements, are summarized in Appendix E.

Table 2. Mean mercury reduction for pulverized-coal-fired boilers.[9]

Post-combustion Emission Controls Used for Pulverized Coal Boiler		Average Total Mercury Emission Reduction (%)[(a)]		
		Bituminous Coal	Subbituminous Coal	Lignite Coal
PM Control Only	CS-ESP	36 %	3 %	-4 %
	HS-ESP	9 %	6 %	not tested
	FF	90 %	72 %	not tested
	PS	not tested	9 %	not tested
PM Control and Spray Dryer Adsorber	SDA + ESP	not tested	35 %	not tested
	SDA + FF	98 %	24 %	0 %
	SDA + FF + SCR	98 %	not tested	not tested
PM Control and Wet FGD System	PS + FGD	12 %	-8 %	33 %
	CS-ESP + FGD	75 %	29 %	44 %
	HS-ESP + FGD	49 %	29 %	not tested
	FF + FGD	98 %	not tested	not tested

Key: (a) Mean reduction from 3-run averages for each pulverized coal boiler unit in Phase III EPA ICR database.
CS – cold side; ESP – electrostatic precipitator; FF – fabric filter; FGD – flue gas desulfurization; HS – hot side; PM – particulate matter; PS – particulate scrubber; SDA – spray dryer absorber; SCR – selective catalytic reduction

Massachusetts' Test Data
To demonstrate the feasibility of mercury control, the Department points to preliminary results of testing required by 310 CMR 7.29,[10] which indicate that some Massachusetts coal-fired units are achieving mercury capture rates approaching 90% due to existing emission controls and operating conditions.

The regulation required that each of the affected solid-fossil-fuel-fired facilities perform three sets of tests for mercury concentrations and species at two different points in the exhaust stream: 1) before all add-on air pollution control equipment (inlet), and 2) after add-on air pollution control equipment (outlet). This data is a snapshot of actual mercury emissions from each unit tested for the time period covered by the test (generally 2-3 days). Each of the three test sets consists of three runs, for a total of nine runs. The nine-run average amount of total mercury measured at the two required points and the calculated percentage of mercury captured by the installed control devices at Massachusetts coal-fired units subject to 310 CMR 7.29 is shown below in Chart 1. The results document that some Massachusetts coal-fired units are achieving mercury capture rates approaching 90% with the existing emissions controls at the facility.

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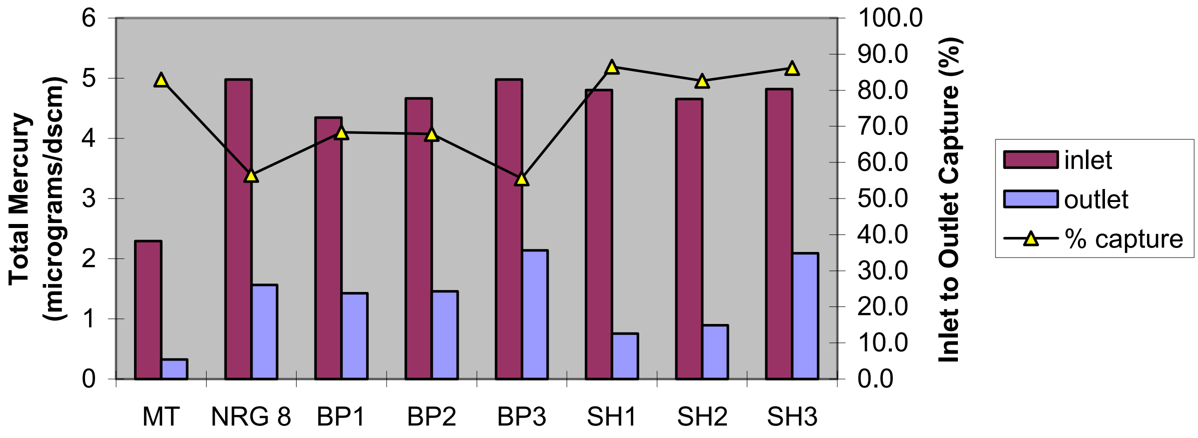
[9] Table from Office of Air Quality Planning and Standards, US EPA: Research and Development, "Control of Mercury Emissions From Coal-Fired Electric Utility Boilers: Interim Report Including Errata Dated 3-21-02," prepared by National Risk Management Research Laboratory, April 2002, EPA-600/R-01-109, pp. ES-10.

[10] From emissions testing reports submitted to the Department to comply with 310 CMR 7.29(5)(a)3.d.

Chart 1. Average Total Mercury in Flue Gas by Unit



Key: MT – Mount Tom Station; NRG – NRG Somerset Station; BP – Brayton Point Station; SH – Salem Harbor Station

Expected Emissions Controls on Massachusetts Coal-fired Units

To demonstrate the feasibility of mercury control at Massachusetts' facilities beyond the level of control currently achieved, the Department points to the 310 CMR 7.29 Emission Control Plan (ECP) approvals issued by the Department for each of the facilities subject to the regulation.[11] The facilities affected by 310 CMR 7.29 have proposed to comply with the NO_x, SO_2 and CO_2 standards in the regulation by employing a variety of strategies that will also achieve further mercury reductions.

In particular, wet Flue Gas Desulfurization (FGD) is to be installed on Brayton Point unit 3; dry FGD and fabric filters are to be installed on Salem Harbor units 1 and 3; Selective Catalytic Reduction (SCR) is to be installed on Brayton Point units 1 and 3 and Salem Harbor units 1, 2, and 3; and Selective Non-Catalytic Reduction (SNCR) is to be installed on Mt. Tom unit 1. As illustrated in Table 2, mercury capture increases with installation of additional controls. This same result can be expected in Massachusetts facilities that are proposing to install additional controls.[12] Because the facility owners proposed use of these control devices, it is self-evident that these specific control devices are technologically feasible at these specific facilities.

Field Tests of Mercury Specific Controls

To demonstrate the feasibility of mercury control using mercury-specific control technology, the Department points to the full scale pilot tests of sorbent-injection mercury control systems at Brayton Point Station and Alabama Power's Gaston facility, which have produced preliminary results of at least 90% mercury capture.[13]

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

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[11] See Appendix E for a summary of the pollution control measures included in the ECP approvals for the coal-fired facilities subject to 310 CMR 7.29.

[12] See Appendix A for a discussion of the details of the physical and chemical mechanisms exploited by various mercury control strategies.

[13] "Mercury Control Pilot Testing at Brayton Point Station," presentation at the Mercury Standards Technology Feasibility Meeting, Massachusetts Department of Environmental Protection, Boston, MA September 20, 2002, Richard Schlager, ADA Environmental Solutions.

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. The goals of the study are to:

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

The final report on all four facilities will not be ready before summer 2003; however, some preliminary data are available.

A comparison of the Gaston, Pleasant Prairie, and Brayton Point results shown in Chart 2 below indicates 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 pounds of sorbent per million actual cubic feet of flue gas (lb/MMacf)) for those three units for which preliminary data are available. 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). Gaston's impressive cost results are due in part to a PM control device (COHPAC, to be discussed in the next two sections) that requires less sorbent be injected to achieve a given mercury removal level than does a facility equipped only with an ESP. Gaston was selected for the DOE sorbent-injection tests specifically because COHPAC represents a cost effective retrofit solution to improve particulate matter collection for utilities with existing ESPs.

With respect to both the removal trend and the sorbent costs, preliminary results for Brayton Point indicate that the higher the amount of sorbent injected, the more mercury removed, with the highest removal values during long term tests ranging from 90-93% at the highest sorbent injection rate of 20 lb/MMacf. In contrast to the other two facilities for which data are available, 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.

These results are preliminary, and DOE's prime contractor in this study has indicated that extended operation of the sorbent-injection-based system would be needed to determine if there are negative impacts of sorbent injection on downstream hardware. DOE's contractor has estimated that the "first commercial installations at a few early adopters" could occur in 2005-2007.[14] These preliminary results of DOE-funded field tests demonstrate successful application of mercury-specific control technology at mercury removal levels greater than 90%; thus, control of mercury using mercury-specific control technology is technologically feasible.

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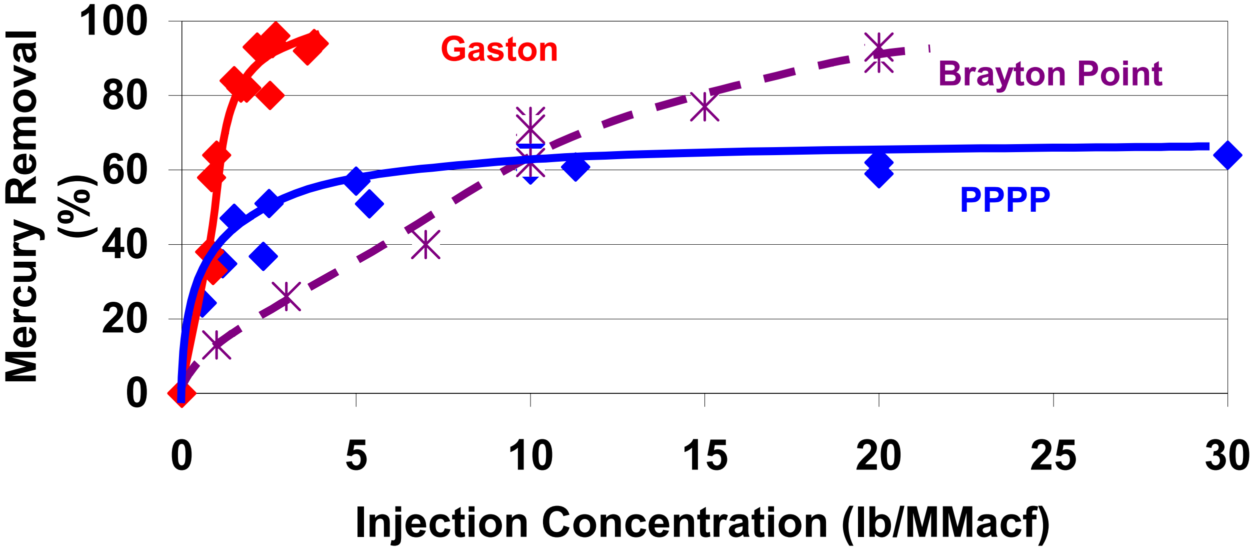
[14] "Status of Sorbent Injection Mercury Control Technology," Testimony before the US Senate Committee on Environment and Public Works, Michael D. Durham, ADA Environmental Solutions, January 29, 2002.

Chart 2. Mercury Removal Trends With Sorbent Injection



COHPAC Experience

Further demonstration of the feasibility of mercury control comes from the experience with fabric filter technology (in particular the Electric Power Research Institute's patented COmpact Hybrid PArticulate Collector (COHPAC) baghouse system). Because mercury adsorbs onto particulate matter, mercury capture can be improved by collecting a larger portion of flue gas particulate matter. As can be seen in the upper portion of Table 2 on page 14, a fabric filter typically captures far more mercury than an electrostatic precipitator; this is due to: 1) increased contact between flue gas and particulate matter on the filter itself, providing additional opportunity for flue gas mercury to adsorb onto particulate matter, and 2) increased collection of the particulates to which mercury has adsorbed.

The SEMASS Municipal Waste Combustor (MWC) facility in Rochester, Massachusetts conducted pilot scale testing of COHPAC for a year starting in April 1998 and subsequently installed COHPAC on units 1 and 2 in order to achieve the standards established by the Massachusetts MWC regulation 310 CMR 7.08(2). The pilot testing was initially intended only to assess particulate capture, but the scope was ultimately enlarged to evaluate carbon injection at two boiler locations. Installation of COHPAC saved the municipalities contracting with the MWC for trash disposal an estimated $10,000,000[15] by avoiding the installation of conventional baghouses on units 1 and 2.

The COHPAC technology has been in use to control opacity on two units at Alabama Power's Gaston facility[16] (since December 1996 on unit 3 and since June 1999 on unit 2), showing that the technology has been successfully transferred to the electric power industry. A "sorbent injection plus COHPAC" configuration was also used at Alabama Power's Gaston station during DOE-funded sorbent-injection tests as discussed above in "Field Tests of Mercury Controls." The increased contact between flue gas mercury and sorbent provided by sorbent caught on the fabric filter means that less sorbent must be

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[15] SEMASS estimate.

[16] "COHPAC (COmpact Hybrid PArticulate Collector): The Next Generation in Particulate Control Technology, Alabama Power Company's E.C. Gaston Units #2 and #3, 'A Success Story'" Miller, Richard et al.

injected to achieve a given level of mercury control than is required for a facility equipped only with an ESP, thereby reducing costs.

Fabric filter-based particulate control technology, which will increase mercury capture, has been successfully transferred to the electric power industry; thus, control of mercury at power plants using equipment originally designed for particulate capture is technologically feasible.

MWC Source Sector Mercury Reductions

Massachusetts' experience with Municipal Waste Combustors (MWCs) further demonstrates the feasibility of mercury control. Although the MWCs have characteristics that make them operationally different from power plants,[17] they are an example of another industry sector that has achieved 90% control through the application of a mercury control technology that holds promise for power plants.

The Department established MWC regulation 310 CMR 7.08(2) in 1998 requiring compliance with an annual mercury emissions limit based on the rolling average of four quarterly stack tests. Facilities are complying with the standard and achieving greater than 90% reduction in mercury emissions, using a variety of controls (including PM, SO_2, and NO_x controls), and carbon injection to reduce emissions of both mercury and organics (e.g., dioxins/furans). Gaseous mercury adsorbs onto injected carbon, and the particulate matter is then removed in the PM control device. The MWCs were required to optimize the level of carbon injection by selecting a carbon injection rate above which additional amounts of carbon injection would achieve limited additional mercury control. For reference, certain MA MWC units have mercury stack emissions at the same levels as MA coal-fired units, while other MWC units have mercury stack emissions an order of magnitude higher than MA coal-fired units.[18]

The MA MWC, SEMASS, using the COHPAC baghouse technology injects carbon to achieve control of mercury and organics in a "sorbent injection plus COHPAC" configuration. That MWC has a consistent record of demonstrating compliance with the MWC emissions standards.

Carbon injection systems are widely used to achieve 90% mercury capture on MWCs in Massachusetts and other states, providing a wide base of practical experience with manufacture of sorbents, installation, and material handling, demonstrating that this mercury-specific control technology is technologically feasible.

Mercury Control Research Activities

To demonstrate the feasibility of mercury control, the Department has completed a literature review, summarizing an extensive amount of research activity in the field of mercury control and considerable progress by the private sector towards the commercialization of various mercury controls. Appendix A is an extensive review of technical approaches at various stages of development that could be used to reduce mercury emissions from coal-fired power plants.

Mercury control is the focus of numerous research programs in the United States, that together constitute a multi-million dollar research effort.[19] Public agencies (such as DOE and EPA) and private agencies (such as the Electric Power Research Institute and the Southern Research Institute) have joined with equipment vendors (such as ADA Environmental Solutions, Babcock and Wilcox McDermott

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[17] A major difference being the much larger volume of stack gas released from large power plants; other differences include the constituents of the stack gas, temperatures, and fuels.

[18] From emissions testing reports submitted to the Department to comply with 310 CMR 7.29(5)(a)3.d. and 310 CMR 7.08(2).

[19] Please see http://www.fossil.energy.gov/coal_power/existingplants/mercurycontrol_fs.shtml for an overview of the mercury control research that has been undertaken with financial support from the US DOE.

Technology, Powerspan, Consol, Apogee Scientific and others), universities (such as the University of North Dakota) and a large number of power plant owners to support research activities adding to the information base on control of mercury emissions from power plants. The research areas range from improving traditional control devices to development of new technologies; from the measurement of mercury to creation of more economical sorbent materials. The Department is aware that new results of these research efforts are being released as they become available and will continue to track these developments.

The research underway makes it likely that technologies currently considered experimental will become commercially available, and that new experimental technologies will start down the path to commercialization within the next few years.

Regulatory Drivers

The Department believes that its adoption of mercury emission standards will provide incentives for further research, broader commercialization of existing technologies, and more cost-effective technologies. The ability of regulations to serve as a driver for technology is documented in a September 2000 Report by the New England States for Coordinated Air Use Management (NESCAUM).[20] The NESCAUM report relies on case studies related to the development of technologies for control of: 1) NO_x emissions from power plants, 2) SO_2 emissions from power plants, and 3) the evolution of motor vehicle controls to support the following findings:

- a strong link between regulatory drivers and technological innovation;
- technological improvements and reductions in control costs follow the adoption of regulations; and
- technological improvements and cost reductions have occurred even when control options were limited or largely untested when the regulations were introduced.

The Department believes that past experience, as documented in the NESCAUM report, supports the view that the adoption of a regulatory mercury standard for coal-fired power plants will serve as a strong incentive for the development of additional cost-effective technologies and lead to greater cost-effectiveness of existing technologies. As stated in the NESCAUM report:

> Viewed in the context of the case studies … the present status of mercury controls clearly does not preclude near-term regulation. On the contrary, past experience strongly suggests that the impetus of regulatory drivers is all that is lacking to advance these technologies to full-scale commercial application." (Executive Summary, page 2.)

Demonstration of Compliance with a Mercury Standard

The Department also evaluated options that might be used by facilities to demonstrate compliance with a mercury emission standard. Detailed discussion can be found in Appendix C. There are approaches commercially available now to allow facilities to demonstrate compliance with a mercury emission standard, including fuel and emissions sampling. The specific compliance demonstration technique that would be required must be selected in concert with the form of the emissions limit in the standard. This topic will be considered during development of the Department's proposed standard.

Elimination of Mercury Emissions

With respect to the <u>elimination</u> of mercury emissions, the Department is aware of no pre-treatment or add-on control technology that would eliminate mercury emissions from the combustion of solid fossil

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[20] "Environmental Regulation and Technology Innovation: Controlling Mercury Emissions from Coal-Fired Boilers." NESCAUM, September 2000.

fuel. Eliminating mercury emissions would be possible only by switching to a fuel that does not emit mercury (i.e., wind, solar, nuclear, natural gas), but the technological and economic feasibility of such a switch would be dependent on the specific situation at a facility, including the availability of the alternate fuel source.

ECONOMIC FEASIBILITY OF MERCURY CONTROLS

The Department concludes that mercury control is economically feasible for coal-fired power plants and relies on the points set forth below to support this conclusion. More detailed discussion relating to the costs of mercury controls and the following points is included in Appendix B.

- EPA has demonstrated that various levels of mercury control are economically feasible, including a 90% control level. EPA's projected costs for sorbent-injection based systems, which most likely will reach commercialization for mercury control before other technologies, are similar to those seen and accepted for control of NO_x in the electric power industry.

- Future costs for mercury controls are expected to decline for a number of reasons, including the following:

    - The development of more cost-effective particulate control devices, such as COHPAC;

    - Development of more effective sorbents, such as composite powdered activated carbon (PAC) lime;

    - Economies of scale related to more widespread use of sorbents;

    - Development of cheaper raw materials for the manufacture of sorbents; and

    - Use of ultra fine sorbents with a higher surface area, which allow for use of less sorbent.

- Mercury controls in the context of a multi-pollutant regulation, such as 310 CMR 7.29, allow for improved cost-effectiveness due to co-benefits realized through the implementation of controls that reduce emissions of more than one pollutant.

- Improved methods for controlling mercury and multi-pollutant emissions are under development by DOE, EPA, EPRI, the electric industry, and control technology vendors. (See Appendix A.) As a result of these research and development activities, mercury and multi-pollutant control options are expected to become available with improved cost-effectiveness in the next few years.

- Prior experience indicates that regulations can provide the impetus for more cost-effective pollution control technologies.

The Department recognizes that the actual costs to any facility will be highly dependent on the stringency of the standards ultimately adopted as well as the characteristics of the facility. This report does not attempt to assess the actual costs of mercury reduction at any of the affected facilities. A determination of actual costs to any facility would require an analysis of the applicability of various technologies at a specific facility in concert with a specific emission standard. That analysis is beyond the scope of this report.

WASTE ISSUES RELATED TO MERCURY CONTROL

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 physical properties of the wastes produced, including the chemical availability of mercury. The Department believes that there are currently, and will continue to be, safe options for the disposal and/or management of waste generated from coal-fired power plants. The Department will consider issues such as landfill capacity and ultimate fate of mercury, including water quality and coal ash re-use options, as it proceeds with developing a mercury standard. A more detailed discussion of these issues can be found in Appendix D.

SUMMARY

The Department plans, pursuant to the requirements of 310 CMR 7.29, to propose a mercury emissions standard for power plants within six months of the date of this report. In doing so, it will rely, in part, on the technical information presented herein. The Department has completed a review of the scientific and technological research relating to mercury control in order to assess the current state of methods and technologies for reducing mercury emissions. While the Department's review is not exhaustive as to either the current research or the applicability of all technologies to the affected facilities, the Department's thorough review of an extensive number of studies and reports has allowed it to draw conclusions relating to the feasibility of mercury emission reduction and controls.

There is substantial evidence that some technologies are currently available and that additional technologies will be available for implementation at the affected facilities in order to meet the proposed compliance date of October 1, 2006. The Department believes that there is strong evidence to conclude that the capture of at least 85-90+% of flue gas mercury is technologically and economically feasible for coal-fired power plants at the present time. The Department is not concluding that each of the affected facilities will be required to achieve 85-90+% capture of flue gas mercury; nor is the Department making any determination as to the appropriate level or form of the mercury standard that will be proposed. The Department will consider multiple factors, including the contents of this report, when it proposes standards for mercury emissions from Massachusetts' power plants.

UNITS AND ACRONYMS

AC – activated carbon
ADA-ES – ADA Environmental Solutions, LLC
ADP – acid dew point
AECDP – Advanced Emissions Control Development Program
APCD – Air Pollution Control Device
BUD – Beneficial Use Determination
°C – degrees Celsius
Ca – calcium
$CaSO_4$ – calcium sulfate
CCR – Coal Combustion Residue
CEMS – Continuous Emissions Monitoring System
CFBA – circulating fluidized-bed absorber
Cl – chlorine
CMR – Code of Massachusetts Regulations
CO_2 – carbon dioxide
COALQUAL – National Coal Resources Data System, US Coal Quality Database
COHPAC – compact hybrid particulate collector
CS-ESP – cold-side electrostatic precipitator
CVAAS – Cold Vapor Atomic Abortion Spectroscopy
DEP – Massachusetts Department of Environmental Protection
DOE – Department of Energy
DOE/NETL – DOE National Energy Technology Laboratory
DSI – dry sorbent injection
E-beam – electron beam radiation
ECP – Eastern Canadian Premiers, Emission Control Plan
EDTA – ethylene diamine tetra-acetic acid
EPA – Environmental Protection Agency
EPRI – Electric Power Research Institute
ESP – electrostatic precipitator
ETV – Environmental Technology Verification
°F – degrees Fahrenheit
FF – fabric filter
FGD – flue gas desulfurization
FGR – flue gas recirculation
g – gram
H_2S – hydrogen sulfide
H_2SO_4 – sulfuric acid
HCl – hydrochloric acid
Hg – mercury
Hg^0 – gaseous elemental mercury
Hg^{2+} – gaseous oxidized mercury
Hg_p – particle-bound mercury
Hg_T – total mercury
$HgCl_2$ – mercury chloride
HNO_3 – nitric acid
HS-ESP – hot-side electrostatic precipitator
ICR – information collection request
IGCC – integrated gasification combined cycle
kW – kilowatt

lbs/hr – pounds per hour
LNB – Low NO_x Burners
LOI – Loss On Injection
MA – Massachusetts
MACT – Maximum Achievable Control Technology
µg – microgram
mg/L – milligrams per liter
MW – megawatt
MWC – municipal waste combustor
MWe – megawatt electrical
N_2 – nitrogen
NAS – National Academy of Sciences
NEG – New England Governors
NESCAUM – Northeast States for Coordinated Air Use Management
NH_3 – ammonia
NO – nitric oxide
NO_2 – nitrogen dioxide
N_2O_4 – nitrogen tetroxide
N_2O_5 – nitrogen pentoxide
NO_x – oxides of nitrogen
O_2 – oxygen
O_3 – ozone
OH – Ontario Hydro method
P2 – pollution prevention
PAC – powdered activated carbon
PC – pulverized coal
PCD – pollution control device
PM – particulate matter
ppm – parts per million
PRB – Powder River Basin coal
PS – particulate scrubber
RA – Relative Accuracy
RACT – Reasonably Available Control Technology
RATA – Relative Accuracy Test Audit
RCRA – Resource Conservation and Recovery Act
SC – spray cooling
SCR – selective catalytic reduction
SDA – spray dryer absorber, semi-dry absorption
SNCR – selective non-catalytic reduction
SNO_x – trade name emission control technique
SO_2 – sulfur dioxide
SO_3 – sulfur trioxide
TCLP – EPA Toxicity Characteristic Leaching Procedure
US – United States
USGS – United States Geological Survey
WFGDS – wet flue gas desulfurization system

APPENDIX A: MERCURY CONTROL AND CONTROL TECHNOLOGIES

1. Introduction

The Department has reviewed the scientific and technological research relating to mercury control in order to assess the current state of methods and technologies for reducing mercury emissions. While the Department's review is not exhaustive as to either the current research or the applicability of all technologies to the affected facilities, the Department's thorough review of an extensive number of studies and reports has allowed it to draw conclusions relating to the feasibility of mercury emission reduction and controls.

2. Background

Mercury is a naturally occurring impurity in coal in trace amounts. It generally occurs in several forms and is associated with both inorganic minerals in coal (i.e., the materials that generate ash when the coal is burned) as well as with the organic fraction in coal (i.e., the carbon portion of the coal that generates heat).

2.1 Coal Types and Coal Preparation

In the United States, coals are classified based on the geological age of the coal and the conditions under which the coal was formed (i.e., the degree of metamorphism), and are divided into four major categories called "ranks." Each rank is further subdivided into groups. The basic classification criteria are coal heating value, volatile matter content, carbon content, and agglomerating behavior. These coal ranks are: anthracite, bituminous, subbituminous, and lignite. The combustion properties and the characteristics of the coal combustion byproducts depend on coal properties. The Massachusetts coal-fired facilities subject to 310 CMR 7.29 burn bituminous coal.

According to a study that evaluated the Hg content of coals representing major coal producing regions in the United States (using the USGS COALQUAL database), the average concentration of Hg in the (in-ground) coal samples ranged from 0.08 to 0.22 μg/g. The data show that the Hg content of coals is not constant but varies depending on the coal deposit. Also, the Hg content of the coal is not a function of the coal rank.

The Hg concentrations in different coals cannot be directly related to the amount of Hg emitted from boilers burning these coals. In other words, one cannot conclude that burning a coal with higher as-mined Hg concentration will necessarily result in higher Hg emissions from a coal-fired electric utility boiler in the absence of applying any Hg emissions controls. Other coal properties as well as how the coal is prepared prior to firing in a boiler (i.e., coal cleaning) affect the theoretical potential level of Hg emissions.

After coal is mined, it is often first processed at a coal preparation plant to remove mineral matter (i.e., a source of coal combustion ash) and mineral bound sulfur (pyrite). This "coal cleaning" increases the heating value of coal and produces a coal with certain combustion specifications. A portion of mercury and other trace metals that are associated with the mineral fraction of the coal are also removed by the coal cleaning process.

Mercury reduction in the coal cleaning process is believed to be a function of the type of process used to clean a given coal and the proportion of Hg in the coal that is present in combination with pyrite. The existing commercially available coal cleaning methods remove only a portion of the Hg associated with the non-combustible mineral matter in the coal; they do not remove the Hg associated with the organic carbon structure of the coal (i.e., the material that generates the heat during the combustion process). In some coals, large portions of Hg are associated with the organic fraction of the coal. Hg removal in these cases is expected to be substantially lower.

2.2 Mercury Speciation in Coal Combustion Systems

As coal is burned in an electric utility boiler, due to the high temperatures in the coal combustion process, mercury (Hg) contained in coal volatilizes[21] to form gaseous elemental mercury (Hg^0). In the subsequent cooling of the combustion gases, the interaction of the elemental mercury with other combustion products results in a portion of the mercury being converted into gaseous oxidized forms[22] of mercury (Hg^{2+}) and particle-bound mercury (Hg_p).[23] Thus, mercury exists in elemental, oxidized, and particulate-bound forms in coal combustion gas. The term *speciation* is used to denote the existence of mercury in various forms and the relative amounts of these three forms of mercury in the flue gas. The total mercury in flue gas (Hg_T) is the sum of Hg_p, Hg^{2+}, and Hg^0.

The particulate-bound form of mercury can be readily captured in the particulate matter (PM) control devices, i.e., electrostatic precipitators (ESPs) and fabric filters (FFs). The predominant oxidized mercury compounds in coal flue gas are water-soluble, and the more soluble species can be generally captured in wet flue gas desulfurization (WFGD) scrubbers. Elemental mercury is insoluble in water and cannot be captured in wet scrubbers. Both elemental and oxidized mercury adsorb onto porous solids such as fly ash, powdered activated carbons (PAC), or calcium-based acid gas sorbents for subsequent collection in a PM control device. Oxidized mercury is generally easier to capture by adsorption than elemental mercury.

The control of flue gas mercury depends on mercury speciation. Factors that affect the speciation and capture of mercury in coal-fired combustion systems include: the type and properties of coal, the combustion conditions, the types of flue gas cleaning technologies employed, and the temperatures at which the flue gas cleaning systems operate.

2.3 Other Factors Affecting Hg Speciation

The amount of mercury present in the flue gas and its speciation depends on the coal type and its properties. In addition to different levels of mercury, different coals contain different levels of other trace elements and chemical constituents. Chlorine, calcium oxide/carbonate, and iron oxide content of coal can affect mercury oxidization.[24] Additionally, the quality of the fly ash (such as pore structure and carbon content) and its mercury adsorption capacity depend on the type of coal. Combustion and the operational conditions, as well as the gas cleaning technologies employed, affect the physical and chemical properties of the system and thus influence mercury speciation. The level of unburned carbon left in the fly ash, the temperature and residence time of the exhaust gas in the particulate control device, and the presence of oxygen (O_2), ozone (O_3), and acid gases (HCl, SO_2, NO, NO_2) in the flue gas are among factors that impact mercury speciation.

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[21] Essentially most of the mercury in coal is volatilized (as elemental mercury) and negligible amounts are left in the solid residue from the gasification process (i.e., bottom ash).

[22] The extent of oxidation varies and has a broad range, and can vary from <10% to as high as 70% of the total mercury upstream of the control device (Ref. 1).

[23] Both oxidized and elemental forms of mercury may be adsorbed onto the particulates present in the combustion gases to form particulate-bound mercury. In this document, oxidized and elemental mercury refer to their vapor-phase forms unless specifically stated otherwise.

[24] It is believed that calcium oxide/carbonate reduces mercury oxidation.

Many basic physical and chemical phenomena affecting mercury speciation and adsorption are not well understood yet. However, basic and applied research to develop insight into these fundamental processes has been undertaken and is in progress.

2.4 Overview of Control Strategies

The pollution control devices (PCDs) that are utilized on coal-fired utility boilers for reducing NO_x, SO_2, and PM affect mercury speciation and are effective in reducing mercury emissions to varying extents. New technologies that specifically aim at addressing mercury emissions have recently been under investigation and development. Additionally, certain conventional air pollution technologies that have not been traditionally employed in control of emissions from coal-fired utility boilers (such as wet electrostatic precipitators) have recently received attention and are under evaluation for their potential in application to mercury emissions reduction. The mercury control issues, the different approaches to reducing mercury emissions, and the various control technologies are further discussed in the following sections.

2.5 Challenges in Control Of Mercury Emissions

Control of mercury emissions from coal-fired utility boiler flue gas poses a more challenging problem compared to SO_2 and NO_x due to the following factors:

- Low concentration – Mercury concentrations in utility boiler flue gas are significantly (4-5 orders of magnitude) (typically 0.01 vs. 100+ ppm) lower compared to concentrations of SO_2 or NO_x (Ref. 2, 3). The interaction of mercury with sorbents is essentially limited by mass transfer.[25] Addressing this issue has proved technically challenging.

- Presence of chemical speciation and different physical forms – In contrast to NO_x and SO_2, which are mostly present in gaseous form in the flue gas, mercury exists both in vapor (as elemental and ionic mercury) and particulate forms. Because current control technologies and technologies under development do not have the same capture efficacy on different mercury forms, an understanding of the physical and chemical apportionment of mercury in the system is essential in development and deployment of control systems. It is also important to understand physical and chemical interactions of mercury at various points in the boiler unit.

These issues have been under investigation by researchers and are being addressed in the development of mercury control technologies.

3. Pollution Control Options

In general, two approaches can be adopted to reducing mercury emissions from coal-fired utility boilers: pollution prevention[26] (P2) and post combustion pollution control. Pollution prevention, in some cases, involves commercially available technologies, which do not require capital investment (e.g., using cleaned coal with lower mercury content, or fuel-blending in place of using coal alone for facilities that allow this option). Pollution prevention has been cost effective in SO_2 control for some facilities and this may be the case for mercury control as well.

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[25] Mass transfer refers to the ability of the sorbent particles to contact the Hg in the flue gas.

[26] Pollution prevention aims at reducing or eliminating the pollutant at the source. Options such as energy efficiency and power plant production efficiency improvement fall under pollution prevention approach but are not specifically discussed in this document.

Many of the conventional post combustion control technologies used on coal-fired power plants to control SO_2, and PM have the co-benefit of reducing Hg emissions. Certain NO_x control technologies (such as Low-NO_x burners (LNB) and selective catalytic reduction (SCR) in certain plant configurations) enhance mercury removal. A combination of some of these control devices[27] can achieve high (above 95%) mercury control.

A number of mercury-specific control technologies are under investigation and several of these have reached more advanced stages of testing (i.e., pilot- and full-scale tests in coal-fired utility plants) and development. At least one mercury-specific control technology (powdered activated carbon injection) has the potential for commercialization in the near future. Additionally, several post combustion multi-pollutant technologies are being developed. Several of these multi-pollutant technologies have been tested in pilot-scale tests. One multi-pollutant technology (Electron Beam Irradiation) has been commercially available since the 1980s and is currently used in Japan and China. The commercial demonstration of another multi-pollutant technology (Power Span's ECO^{TM}) has been planned.

In the following sections, the pollution prevention options and post combustion control technologies for mercury control are presented. The status of each technology with regards to its testing and demonstration has been noted in these discussions.

3.1. Pollution Prevention

Two pollution prevention options are available: fuel switching, and additional coal cleaning. Advanced coal cleaning technologies are available and can achieve further reduction of mercury in coal (30% to >60% reduction in mercury content of coal). However, depending on the required level of mercury control, coal cleaning alone may not be sufficient to achieve the mercury emissions reduction objectives of a facility. Use of post-combustion control technologies may be necessary in conjunction with coal cleaning. Fuel switching/blending has the potential to reduce other pollutants in addition to mercury. Improvements in generation and power plant efficiency can also reduce the mercury emission rate per unit of power generated, and should be explored, although these options will not be discussed here in detail.

Fuel Switching

Mercury emissions can be reduced by limited fuel switching (generally not more than 10 to 20% of fuel) or installation of new gas-fired units or integrated gasification combined cycle (IGCC) units. The mercury reduction is incremental and limited to the difference in the mercury emissions of the two fuels. Installation of new gas-fired units or IGCC units would result in significant reduction of Hg and co-benefits in reductions of other pollutants. Co-firing or switching to natural gas may be an option for some facilities. Major considerations in switching to natural gas are: the availability of natural gas, the differential cost of natural gas versus coal, and the configuration of the existing units.

Coal Cleaning

Reducing the amount of mercury in the coal that is burned in electric utility boilers reduces the level of mercury emissions from these boilers. Also, for two coals with the same mercury content but different heating values, burning the coal that has a higher heating value would reduce the mercury emitted in boiler combustion gases per unit of electricity output because less coal would be burned in the boiler on a mass basis to produce a given electricity output. However, most coal-fired plants have a limited range of

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[27] Such as a combination of SCR (for NO_x control) and WFGD (for SO_2 control) systems.

fuel properties (e.g., heating value, ash content, sulfur) that are acceptable. Consequently, replacing the coal type may not be feasible in all cases.

Coal cleaning can reduce the Hg content of the coal fired in the boiler. Approximately 80% of bituminous coals from mines in the Eastern and Midwestern United States are cleaned prior to shipment to an electric utility power plant. The subbituminous and lignite coals from mines in the Western United States are not routinely cleaned; however, these types of coals can also be cleaned. Currently, the available data on the level of Hg removed by conventional coal cleaning methods is limited. It has been estimated that conventional coal cleaning results in an average mercury reduction of about 37 percent (Ref. 1).

Mercury concentration of the coal can be further reduced by advanced coal cleaning technologies (30 to greater than 60 percent (Ref. 1). The combination of conventional with advanced coal cleaning technologies removes from 40 to 82 percent of the Hg contained in samples of raw coal according to the results of bench scale studies (Ref. 2).

In the conventional coal cleaning processes, separation of the organic fraction of the coal from the mineral materials is based on the density or surface characteristics of the different materials. Several advanced physical coal cleaning processes are now being developed that use selective agglomeration or column froth flotation.

Microcel™ and Ken-Flote™ are two types of commercially available new coal cleaning technologies that are based on column froth flotation techniques. Microcel™ is available through ICF Kaiser and Control International and has been sold for commercial operation in Virginia, West Virginia, and Kentucky.

Under DOE-funded bench scale studies, advanced coal cleaning processes that use naturally occurring microbes and mild chemical treatments to reduce the mercury content of coal have been investigated and indicate potential for further reduction of mercury. However, DOE has viewed these processes as potentially high-cost control technologies and is not currently funding development of these types of coal cleaning technologies (Ref. 2).

In the near-term, some reduction of the Hg content in certain coals is achieved by physical coal cleaning processes. As mentioned previously, the extent of mercury removed from coal in the cleaning process depends not only on the process used to clean a given coal but also on the proportion of Hg in the coal that is present in combination with mineral matter (pyrite). Because there is a variation in mercury content and its form of association in the coals of even the same rank, coal deposits or coal types that would reliably benefit from cleaning with respect to reducing Hg content cannot be easily identified. Additionally, significant quantities of Hg will remain in the coal after cleaning. Consequently, although coal cleaning can be used as a mercury reduction technique, it is very probable that use of post combustion control techniques would be necessary to achieve additional levels of reduction in mercury emissions. Advanced coal cleaning technologies are being developed and can achieve further reduction of mercury in coal but do not offer the potential of significant additional reductions in the near term.

The coal cleaning processes transfer the mercury that is removed from coal to the coal cleaning wastes. Proper management of the mercury in this waste is necessary. Waste issues are addressed later in this document.

3.2. Post Combustion Control Options

Flue gas cleaning technologies that are applied on combustion sources employ three basic methods to capture mercury:

- Capture of particulate-bound mercury in particulate matter control devices,
- Adsorption of elemental and oxidized mercury onto entrained sorbents for subsequent capture in particulate matter control devices; and
- Solvation of oxidized mercury in wet scrubbers.

Most of the new technologies under development use measures to enhance mercury capture through one of these methods or a combination of them. The currently available (conventional) air pollution control technologies and their impacts on mercury reduction, the new technologies under development specifically for mercury control, and the technologies aimed at multi-pollutant control are discussed below.

3.2.1. Conventional Control Technologies

The pollution control devices that are commercially available and can be utilized on coal-fired utility boilers for reducing sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM) affect mercury speciation and emissions. A number of these control systems (alone or in combination) can significantly reduce mercury emissions (in some cases above 95%).

The extent to which an existing post combustion control device is effective in mercury capture depends on mercury speciation at the inlet to the control device and the type of technology used in that device. In general, various types of coal, owing to the variation in their constituents, generate combustion gases with different levels of oxidized mercury and coal ashes with different mercury adsorption capabilities. A control device can itself affect the speciation of mercury. Consequently, the overall level of mercury control in a system depends on the combination of the control devices used as well as on the boiler and the coal type effects.

Combustion of bituminous coal results in a flue gas that contains moderate to high levels of Hg^{2+}. In contrast, subbituminous and lignite coals typically generate relatively low concentrations of Hg^{2+} and high concentrations of Hg^0 in the flue gas. The bituminous coals contain relatively high concentrations of chlorine and lower amounts of alkaline material (calcium and sodium) compared to both subbituminous and lignite coals. The high chlorine concentration in the bituminous coal is believed to result in the oxidization of Hg^0 to form Hg^{2+}, primarily $HgCl_2$. The flue gas from combustion of subbituminous and lignite coals tends to have relatively low concentrations of Hg^{2+} because chlorine in the flue gas of these coals tends to react with the alkaline materials resulting in little, if any, chlorine being available for the oxidization of Hg.

The oxidization of Hg^0 can occur from gas-phase reactions or gas/solid reactions with fly ash (and sorbents when these are injected into the system) or surface deposits in power plants. The unburned carbon in fly ash can oxidize Hg^0 or adsorb gas-phase Hg.[28] $Hg^{2+}$is believed to be more readily captured by adsorption than Hg^0.

As a result of US EPA's coal-fired utility boiler Information Collection Request (ICR), which was undertaken in anticipation of the utility MACT standards development by EPA, certain mercury related data has been collected from a number of coal-fired utility boilers. The average total mercury emission reductions obtained from the EPA ICR data for boiler units with pulverized coal type burner and various conventional post combustion control technologies are summarized in the following table.

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[28] The properties of the ash, which are dependent on the coal type, affect this oxidization and adsorption. The fly ash from lignite and subbituminous coals is more effective in this oxidization/adsorption process.

Table A-1. Mean mercury reduction for pulverized-coal-fired boilers.[29]

Post-combustion Emission Controls Used for Pulverized Coal Boiler		Average Total Mercury Emission Reduction (%)[(a)]		
		Bituminous Coal	Subbituminous Coal	Lignite Coal
PM Control Only	CS-ESP	36 %	3 %	-4 %
	HS-ESP	9 %	6 %	not tested
	FF	90 %	72 %	not tested
	PS	not tested	9 %	not tested
PM Control and Spray Dryer Adsorber	SDA + ESP	not tested	35 %	not tested
	SDA + FF	98 %	24 %	0 %
	SDA + FF + SCR	98 %	not tested	not tested
PM Control and Wet FGD System	PS + FGD	12 %	-8 %	33 %
	CS-ESP + FGD	75 %	29 %	44 %
	HS-ESP + FGD	49 %	29 %	not tested
	FF + FGD	98 %	not tested	not tested

Key: (a) Mean reduction from test 3-run averages for each PC boiler unit in Phase III EPA ICR database.
CS – cold side; ESP – electrostatic precipitator; FF – fabric filter; FGD – flue gas desulfurization; HS – hot side; PM – particulate matter; PS – particulate scrubber; SDA – spray dryer absorber; SCR – selective catalytic reduction.

Massachusetts coal-fired utility boiler units that are subject to the provisions of 310 CMR 7.29 regulations have pulverized coal boilers and burn bituminous coal. These facilities do not currently have, and are not expect to deploy in future, HS-ESP and/or PS particulate control devices (due to lower control efficiencies of these systems). The ICR data indicates that, for pulverized coal boilers burning bituminous coal and excluding units with the PS and HS-ESP control systems, the emission reductions averages range from 36% to 98% nationwide. The different types of post-combustion air pollution control devices (for PM, SO_2, and NO_x) and their impacts on mercury capture are discussed below.

3.2.1.a. PM Control Devices

Particulate control devices are used to capture particulate matter and reduce the opacity of air emissions from utility boilers. A PM control device can readily capture the particulate-bound form of mercury. Gaseous mercury (both Hg^0 and Hg^{2+}) can potentially be adsorbed on fly ash and subsequently be collected in a PM device. The level of this adsorption depends on the speciation of mercury, the flue gas concentration of fly ash, and the properties of fly ash. It is currently believed that mercury is primarily adsorbed onto the unburned carbon in fly ash (Ref. 2). The concentration of the unburned carbon in the fly ash depends on the type of the coal fired and the coal burner type. The use of low NO_x burners tends to increase the amount of unburned carbon and the potential for capturing gas-phase Hg. The amount of Hg captured in a PM control device is higher for bituminous coal than for either subbituminous coal or lignite, because as mentioned above, the bituminous coal flue gas contains higher levels of Hg^{2+} and fly ash with unburned carbon (Ref. 2).

The conventional particulate matter control technologies currently used in control of utility boiler emissions include electrostatic precipitators (ESPs), fabric filters (FFs) (also called “baghouses”), and particulate scrubbers (PS). Generally, FFs are the most effective PM control systems for mercury reduction because they can achieve a higher level of particulate control. Two factors contribute to the relative higher capture efficiency of FFs. The first factor is that generally a fabric filter can capture a higher level of fine particulates compared to other PM control devices. The second factor is that in a FF, when the gaseous mercury passes through the filter cake, the filter cake can adsorb (and also oxidize) the

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[29] Table from the Reference (2) of the Reference list for this section, pp. ES-10.

mercury that has not already been adsorbed on the entrained fly ash upstream of the device. Mercury control capability has been shown to be respectively lower for units with ESPs, PS, and mechanical collectors.

ESPs and FFs fall into two classifications, coldside (CS) or hotside (HS), depending on whether they are installed after an air heater, where flue gas temperatures range from 284 to 320ºF (140 to 160°C), or before an air heater, where flue gas temperatures range from 662 to 842ºF (350 to 450°C). Currently available data indicate that mercury capture in HS-ESPs is very low.

PS systems, primarily venturi scrubbers, are used on some boiler units to control PM emissions. Only soluble Hg compounds such as $HgCl_2$ can be captured in such systems. Because PS systems typically do not collect fine PM effectively, capture of mercury associated with fine PM is poor in such scrubbers. Since Hg^0 is insoluble in water, it will not typically be captured by the scrubber. Hg^{2+} can be captured in the wet scrubbers, but the scrubber chemistry, and the manner in which the scrubber is operated, will determine whether it is effectively removed and/or stripped from the scrubbing liquor. Hg^{2+} can be stripped if it is not adsorbed on the particles, or reacted chemically with liquid-phase reactants within the scrubber.

Mechanical collectors such as cyclones are poor fine PM control devices. Mercury capture in these control devices is generally limited to the Hg_p associated with particles larger than 10 µm.

According to the ICR data, the average Hg emission reductions for plants that employ only post-combustion PM controls range from 0 to 90 percent. For bituminous coal (i.e., the type of coal currently used in the Massachusetts coal-fired utility boiler units subject to 310 CMR 7.29 regulations) and excluding the PS and HS-ESP systems (i.e., PM control system types that do not currently exist, and are not expected to be deployed in the future, at the affected coal-fired facilities), the emission reductions average for plants that employ only post-combustion PM controls ranges from 36% to 90% according to the ICR data.

Research is ongoing in improving particulate control efficiency and devices. A number of new systems have been developed that are based on the currently available particulate device control technologies and concepts, such as pulsed FFs, and hybrid ESP/FFs. Certain PM control systems such as wet ESPs (horizontal as well as tubular wet ESPs) that have been used in other industries (e.g., chemical processing) have been under evaluation and optimization for use in coal-fired boiler systems. Already progress has been made in improving PM control efficiency and several of these new technologies and new applications seem promising. Improvements in PM control efficiency, and especially improvements in fine PM control efficiency, will result in significant improvements in mercury control.

3.2.1.b. SO_2 Control Devices

SO_2 control may be achieved through pollution prevention (P2) and/or post-combustion methods. Using coal with lower sulfur content (a P2 approach) has been cost-effective for many facilities in achieving their SO_2 reduction goals. SO_2 post-combustion control technologies fall into three classifications: wet, semi-dry, or dry systems. An SO_2 control system always operates in conjunction with a PM control device.

The wet flue gas desulfurization (FGD) scrubbers remove SO_2 by dissolving it in a solution. A PM control device is always installed upstream of (i.e., prior to) a wet scrubber to reduce the solids in the scrubbing solution and prevent chemistry problems that may be associated with fly ash. PM devices that may be used with wet FGD scrubbers include a FF, CS-ESP, HS-ESP, or PS.

Semi-dry scrubbers include spray dryer absorbers (SDA). In these systems, a wet slurry is sprayed into the flue gas prior to the particulate control device. The SO_2 is adsorbed on the slurry sorbent, which is dried prior to collection by a PM control device.

In dry sorbent injection (DSI) systems, a dry powdered sorbent such as lime is directly injected into the flue gas. In many cases, water is injected upstream of the sorbent injection location to increase the flue gas moisture, which reduces the flue gas temperature and increases sorbent reactivity. An ESP or a FF is always installed downstream of a semi-dry scrubber or dry injection point to remove the sorbent from the flue gas.

The conventional SO_2 control devices achieve some level of mercury reduction. In certain cases, the Hg reduction levels can be quite high (98%). Table A-1 shows the average efficiency ranges for these devices obtained from the ICR data. SO_2 control systems in conjunction with sorbent injection and other possible modifications (such as addition of oxidant materials to the slurry) can provide further Hg reductions.

Wet Flue Gas Desulfurization Systems (WFGD)

In wet scrubbers, the gaseous species that must be removed are mixed with a liquid in which they are soluble; the solution is then removed and treated for disposal. WFGD scrubbers use a caustic slurry, typically water and limestone or water and lime, for SO_2 adsorption.[30]

The level of mercury capture in WFGD systems depends on the relative level of Hg^{2+} present in the flue gas that enters the FGD system. The gaseous Hg^0 is insoluble in water and therefore does not absorb in such slurries. The majority of Hg^{2+} species in the flue gas are soluble in water. After they are dissolved in the FGD solution, these mercury compounds are believed to react with dissolved sulfides from the flue gas, such as H_2S, to form mercuric sulfide (HgS), which precipitates from the liquid solution as sludge (Ref. 2). The adsorption of oxidized mercury in WFGD appears to be strongly correlated with the mass-transfer of gas to liquid in the scrubber and weakly dependent on the pH of the scrubber solution (Ref. 4).

When sufficient sulfides are not present in the liquid solution, a competing reaction that reduces/converts dissolved Hg^{2+} to Hg^0 is believed to take place. This newly formed (insoluble) Hg^0 is transferred to the flue gas passing through the wet FGD system, increasing the concentration of gaseous Hg^0 in the flue gas exiting the wet FGD compared to that entering. Transition metals in the slurry (originating from the flue gas) are believed to play an active role in this conversion reaction since they can act as catalysts and/or reactants for reducing oxidized species (Ref. 2). In many of the samples taken at the outlet of WFDG systems, an apparent increase from 7 to 40% in a non-Hg^{2+}, possibly Hg^0, has been indicated (Ref. 1).[31]

The level of Hg^{2+} that enters the WFGD system depends on the flue gas as well as the control systems upstream of the WFGD system (for example a FF and a SCR, used for NO_x control, oxidize the elemental mercury). A PM control device always precedes a wet FGD scrubber. Four types of PM control devices are commonly used upstream of the WFGD systems: FFs, CS-ESPs, HS-ESPs, and PM scrubbers (PS). In systems with a FF upstream of the FGD system, an increase in mercury reduction is observed across the FGD system due to the oxidization of elemental mercury that occurs on the fabric filter cake. Units equipped with FF+WFGD achieve the highest Hg reduction followed by units with CS-ESP, HS-ESP, and PS. Units with HS-ESPs operate at temperatures where the oxidization and capture of Hg is limited; therefore, a lower mercury reduction across the system is achieved. Systems with PS+WFGD have the

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[30] These scrubbers also eliminate other acid (e.g., hydrochloric and hydrofluoric) gases.

[31] Results from testing additives upstream and within a pilot-scale WFGD system has indicated no appreciable increase in the Hg^0 compared to tests with no additives.

lowest Hg removal efficiency (ICR data contains only a single test unit with a Hg_T capture of 12%) (Ref. 2).

According to the ICR data, average Hg captures in wet FGD scrubbers ranged from 23 percent (for a PC-fired HS-ESP+FGD unit burning subbituminous coal) to 97 percent (for a PC-fired FF + FGD unit burning bituminous coal) (Ref. 2).[32] According to the EPA-collected data, in the United States, generally more than 90% of the oxidized mercury that enters the wet limestone scrubbers for SO_2 control is captured. Total mercury reductions ranges from 20% to over 80% depending on the speciation of the Hg in the inlet flue gas (Ref. 2).

In general, the ability of SO_2 scrubbers to reduce total mercury is well established (Ref. 1, 2). However, it is difficult to generalize the effectiveness of the scrubbers for removing total mercury without an understanding of mercury speciation in the system. Increasing the oxidized mercury that reaches the inlet of the WFGD control device or modifying the liquid phase of the scrubber to cause oxidation to occur would result in an increase in mercury capture across WFGD. Currently research is being conducted to understand the conversion of Hg^0 to Hg^{2+} upstream of WFGD inlets, the conversion through injection of novel additives in the flue gas upstream of and directly into the WFGD systems, and the re-emission of Hg^0 from WFGD systems (for more information, please refer to the discussion under Capture of Mercury in WFGD Scrubbers in this report).

Conversion of Hg^0 to Hg^{2+} has been demonstrated in both laboratory- and small pilot-scale tests using catalysts. The decrease in the re-emission of Hg has been demonstrated in a pilot-scale WFGD system. Longer-term catalysts tests, and demonstration of additive injection at full scale is needed to further demonstrate viability and cost-effectiveness of these technologies (for more information, please refer to the discussion under Capture of Mercury in WFGD Scrubbers in this report).

Stability tests conducted on WFGD waste solids from a full-scale coal-fired power plant indicated that mercury concentrations of the WFGD samples remained below detection limits after the EPA Toxicity Characteristic Leaching Procedure (TCLP) tests,[33] with the mercury being below the analytical detection limit of 0.01 mg/L. Based on these tests, it has been concluded that Hg contained in the WFGD solids is in a non-leachable form (e.g., chemically bound possibly with $CaSO_4$). The WFGD materials would be classified as non-hazardous based on the Resource Conservation and Recovery Act (RCRA) criteria for mercury (i.e., a limit of 0.20 mg/L) (Ref. 1).

WFGD waste samples have also been tested to determine whether the captured Hg could be desorbed or re-emitted (volatilized). It has been concluded that Hg did not re-volatilize when exposed to temperatures up to 140°F.[34]

With further oxidization of the elemental Hg (as a result of new technologies which focus on this approach for mercury reduction) and higher capture of Hg^{2+} across the WFDG, the Hg in the WFGD solids would be increased. The increase in the Hg content of the WFGD waste may affect the stability of Hg in these wastes. Consequently, although the WFGD wastes can be currently considered stable under certain conditions (as discussed above), further research is needed to demonstrate the stability of the Hg associated with WFGD wastes for conditions other than those already tested (e.g., longer test periods) and

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[32] The nominal Hg removal for WFGD systems on units firing bituminous coal(s), based on mercury sampling results, is approximately 55% ±10% of the total Hg, with an associated removal for Hg^{2+} of between 80 to 95% (Ref. 1).

[33] TCLP test is used to assess whether the toxic substance can leach from the waste sample. If the toxic substance can leach, the waste would be considered as hazardous.

[34] The testing period was 11 weeks.

in situations when the wastes contain higher Hg levels. Suitability of these wastes for use in certain applications may be affected, if they could not be considered stable in those applications. Waste issues are further discussed under the Ash Issues section of this document.

Spray Dryer Adsorbers (SDA)

Spray Dryer Adsorber systems operate on the same basic principle as wet FGD systems. However the scrubbing agent (generally a fine mist of lime slurry) is sprayed into the flue gas and is mixed with the flue gas.[35] The SO_2 in flue gas is absorbed in the slurry and reacts with the hydrated lime reagent to form solid calcium sulfite and calcium sulfate. The high temperatures of the flue gas cause the water in the mist to evaporate, leaving dry solid particles of calcium sulfite and calcium sulfate. In some cases, water-soluble sodium-based sorbents are used instead of calcium-based sorbents. The PM control device (either an ESP or FF) downstream of the SDA captures the entrained particles (un-reacted sorbent particles, reaction products, and fly ash). Other dry sorbents for Hg control can be co-injected into the SDA systems (along with SO_2 control sorbents) for achieving multi-pollutant control.

The SDA systems on coal-fired boilers typically operate about 20°F (11°C) above the water vapor saturation temperature[36] in order to achieve optimal SO_2 reduction. This decrease in the flue gas temperature (compared to SDA inlet flue gas temperature) increases the potential for mercury capture, because mercury capture in general is dependent on temperature and increases with a decrease in temperature. The optimal flue gas temperature for SDA operation is determined by factors such as the buildup of moist fly ash deposits, which can plug the SDA reactor and coat downstream surfaces.

Both Hg^0 and Hg^{2+} can potentially be adsorbed on fly ash, calcium sulfite, or calcium sulfate particles in the SDA. Gaseous Hg^{2+} may also be absorbed in the slurry droplets and react with the calcium-based sorbents within the droplets. Hg^0 and Hg^{2+} can be adsorbed and captured as the flue gas passes through the PM control device (ESP or FF). Nearly all of the Hg_p can be captured in the downstream PM control device. When a FF is used, additional capture of gaseous mercury occurs as the flue gas passes through the bag filter cake.

Based on the limited test data available, mercury capture (i.e., percent reduction) in PC-fired units equipped with SDA seem to be similar to wet limestone scrubbers on a percentage reduction basis (Ref. 2). Further testing is needed to characterize the effects of fuel, combustion conditions, and APCD conditions on the speciation and capture of Hg.

Dry Sorbent Injection (DSI)

In this process dry powdered sorbent (lime or another suitable sorbent) is directly injected into the ductwork upstream of a PM control device. Some systems use spray humidification (for cooling of the flue gas) followed by dry injection. The SO_2 is adsorbed and reacts with the powdered sorbent. The entrained dry solids and the fly ash are collected by the downstream PM control device. The slurry production and handling equipment required for wet scrubbers and spray dryers is eliminated in this process. Additionally, the waste products of the process are dry and easier to manage for disposal. The SO_2 reduction efficiencies for the existing dry injection systems range from 40 to 60 percent. The dry sorbent injection systems also provide the opportunity for co-injection of sorbents for multi-pollutant control.

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[35] In wet scrubbing system flue gas passes through a bulk liquid slurry.

[36] This is called a 20°F (i.e., 11°C) approach to saturation temperature.

Circulating fluidized-bed adsorber (CFBA)

A circulating fluidized-bed adsorber (CFBA) system is a type of sorbent injection system with simultaneous gas cooling, sorbent injection and recycle, and gas sorption by flash drying of wet sorbent reagent. By allowing the flue gas to flow upward and adjusting the gas flow rate to sufficiently support the particles, but not carry them out of the system, a fluid-like condition in the bed is produced. Characteristic high heat and mass transfer (due to high mixing rates and particle-to-gas contact) allow the sorbent particles to remove a sorbate from the gas stream with high effectiveness. The sorbent material can be treated before it is re-injected into the bed.

CFBAs are currently used with limestone and ash as sorbents for SO_2 control, but they can also be used for simultaneous control of several pollutants (by co-injecting sorbents). The SO_2 removal for CFBAs ranges from 80 to 98 percent (Ref. 2).

Owing to their improved sorbent utilization (by re-injection and recycle), and flash evaporative cooling, CFBAs are believed to have the potential for controlling Hg emissions at lower costs than those associated with use of DSIs. Utilization of advanced sorbents with these systems appears to be more favorable (Ref. 2).

3.2.1.c. NO_x Control Devices

Combustion and post-combustion control measures can be used to reduce NO_x. Combustion techniques for NO_x reduction employ modifications that reduce the peak temperatures and excess air in the furnace. More than one combustion technique[37] can be combined to reduce NO_x emissions. Certain combustion modification techniques increase the unburned carbon in fly ash and increase the adsorption of Hg onto collectable fly ash.

Nationally, a very small percentage (~ 3% in 1999) of boilers use post-combustion control technologies for NO_x reduction (Ref. 2). However, the application of these post-combustion NO_x controls will become more prevalent as EPA's SIP call for summertime NO_x control in 22 states takes effect. NO_x post-combustion control technologies include selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) processes. In both methods a reducing agent such as ammonia or urea is used to reduce NO_x to N_2 and H_2O. SCR operates at lower temperatures than SNCR and is more effective at reducing NO_x, but it is more expensive.

In the SCR process a catalyst (such as vanadium, titanium, platinum, or zeolite) is used in a bed reactor, and the NO_x reduction occurs at the surface of the catalyst bed with the help of a reducing agent (diluted ammonia or urea, which generates ammonia in the process). Ammonia dilution is achieved by introducing air or steam into the gas stream. The ammonia mixture is injected into the flue gas upstream of the metal catalyst bed reactor, which is located upstream of a PM or SO_2 control device (usually between the economizer outlet and air heater inlet, where temperatures range from 230 to 400°C, i.e., 450 to 750°F)(Ref. 2).

The SNCR process does not require the use of a catalyst to prompt the reduction reactions. However, the reduction can only occur in a specific temperature range (870 to 1090°C, i.e., 1,600 to 2,000°F) and the reducing agent can only be injected into the flue gas stream in a location that supports the temperature requirements. When the ammonia is injected above this temperature range, oxidation of the ammonia

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[37] These techniques include low NO_x burners, overfire air, off-stoichiometric firing, selective or biased burner firing, reburning, burners-out-of-service, flue gas recirculation (FGR), and staged combustion (also called air staging). Please see Reference (2) for more detail on these techniques.

forms more NO_x. At lower temperatures outside the optimum temperature window, the efficiency of the NO_x reduction process is significantly reduced. By adding hydrogen gas or other chemical enhancers, the reduction process can be sustained at lower temperatures (down to approximately 700°C, i.e.1300°F)[38] (Ref. 2).

ICR data regarding the potential effects of these post-combustion NO_x controls on Hg capture is limited. ICR data revealed that SCR application with SDA at one plant firing bituminous coal resulted in greater than 95 percent mercury removal. Recent pilot-scale tests indicate that SNCR and SCR systems may enhance Hg capture under some conditions by oxidizing Hg^0 (Ref. 2).

The effects of SNCR on mercury oxidization have not been documented in the open literature. Oxidation of elemental mercury in SCR systems has been documented in the literature (Ref. 5). EPRI has investigated mercury reactions in (actual) flue gas at conditions expected for certain NO_x processes including SCR (Ref. 6). Results indicate that some commercial SCR catalysts are capable of oxidizing elemental mercury. Oxidation is affected by the operating conditions and the flue gas properties. The effect of the ammonia on fly ash mercury reactions has also been investigated. Research is ongoing on the impacts of low NO_x burners, SCR, and SNCR on conversion of Hg^0 to Hg^{2+}, and possible mercury reductions (Ref. 6). In systems that burn bituminous coal, a combination of SCR and WFGD can achieve significant (above 95%) mercury reduction in certain cases (depending on several operational factors).[39]

3.2.2. Mercury-Specific Control Technologies

A number of technologies have been under development specifically to address mercury control and are in various stages of research, development, and testing. They include use of sorbents (processes that use injection and fixed-bed configurations), mercury oxidation materials, and mercury oxidation catalysts. A number of these technologies can be used in plants equipped with a PM control device (ESP and/or FF). The application of others requires a SO_2 scrubber. Certain technologies have been demonstrated at pilot- and full-scale applications and are closer to commercialization (such as activated carbon injection), while others are still in laboratory testing stage. A number of these technologies have indicated the potential to achieve mercury reduction levels above 90% (variation depends on the plant specifics such as other air pollution control devices already deployed, the type of coal fired, and the firing conditions). A brief explanation of these mercury-specific technologies follows.

3.2.2.a. Sorbents

Sorbents that can adsorb mercury can be injected into the duct in the form of a powder. An alternative approach that has been investigated is passing the gas through a fixed bed of a noble-metal-based sorbent.

Since 1995, EPRI has supported a sorbent development program for removal of Hg emissions from coal-fired electric utility power plants at several research organizations. The main objective of this program is development of effective sorbents that can be produced at lower costs (Ref. 2, 7, 8). Research has included investigation of preparation methods and the effects of sorbent properties. A number of promising low-cost sorbents have been further evaluated in actual flue gas at several full-scale coal-fired electric utility power plants.

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[38] Currently, two SNCR processes are commercially available: the THERMAL DeNOx and the NOxOUT.

[39] Research in this area and the operational factors that affect mercury oxidization by SCR is still on going.

3.2.2.a.i. Sorbent Injection

Mercury can be captured and removed from gas by injection of a sorbent into the exhaust system and subsequent collection of the particulates in a PM control device. Availability of low-cost and efficient sorbents and effective particulate collection are key in implementation of this type of mercury control. There is active research both in development and evaluation of mercury sorbents and enhancement of particulate collection methods (Ref. 2).

Certain physical and chemical sorbent characteristics affect its mercury adsorption capacity. These include surface area of the sorbent (especially surface area in the micro-pore structure of the sorbent for the removal in the part per billion mercury concentration range typical of coal combustion gases), pore size distribution, particle size distribution, and the sorbent content of certain chemicals (e.g., sulfur, iodine, chlorine, and water content of activated carbon), and certain chemical functional groups (e.g., carbonyls, carboxyl, phenol, etc.). Understanding these sorbent characteristics in the context of mercury adsorption would lead to development of better sorbents and is currently an active area of research.

Various types of sorbents have been under investigation. These include various types of activated carbon, calcium-based and sodium-based (trona) sorbents, various clays and zeolites, alkaline-earth sulfides, as well as lime and lime-silica multi-pollutant sorbents. Activated Carbon and calcium-based sorbents have been the most actively researched and tested sorbents. However, new classes of mercury sorbents and improvements in the mercury adsorption of the current sorbents can be expected because currently much research is taking place in this field.

In the near term, activated carbon seems the most likely technology to be commercialized for mercury control because there have been full-scale tests of this technology that have generated promising results. However, other sorbent technologies also offer certain advantages. A concern associated with use of activated carbon sorbents is the potential increase in the carbon content of the fly ash, which can affect the use of this waste in certain products (such as cement). Non-carbon-based sorbents eliminate this concern. Some of the non-carbon based sorbents (such as calcium-based sorbents) may prove cheaper than activated carbon.

Increased removal of mercury from gas has been demonstrated by co-injection of activated carbon and calcium-based sorbents in spray dryer adsorber systems in full-scale coal-fired power plants (Ref. 9), up stream of a baghouse in pilot tests (Ref. 10), and in a specialized fluidized bed reactor (Ref. 11). Activated carbon combined with hydrated lime has been shown to reduce the amount of carbon required by one half to one third compared to activated carbon alone (Ref. 1, 3). For eastern bituminous coals, injection of limestone into the furnace followed by a cyclone separator has shown good mercury removal in full-scale tests (Ref. 2, 12). A brief discussion of sorbents that have been under extensive investigation is given below.

Powdered Activated Carbon

Activated carbon (AC) has been the most extensively studied sorbent for mercury adsorption. Currently, AC seems to be the most likely candidate to reach commercialization for mercury removal in the near future. Mercury adsorption on activated carbon is affected by the following major factors: Temperature and composition of the gas (including the concentration of acid gases), the concentration of Hg in the gas exhaust system, the residence time in the duct and the dispersion of the sorbent in the gas, and the chemical and physical properties of the activated carbon (or the impregnated activated carbon). The effect of factors such as acid gases (SO_2) and temperature on adsorption of elemental and oxidized mercury is not identical (Ref. 2, 3). Sorption studies have suggested that it is more difficult to control Hg^0 emissions than $HgCl_2$ (Ref. 2).

Activated carbon has been successfully commercialized in municipal waste combustor (MWC) applications and is capable of removing >90% of the mercury at very modest carbon-to-mercury ratios, with a fraction of a pound increase in carbon injection rate increasing mercury removal from the gas by much as 30% (Ref. 1). However, differences between municipal and coal-fired utility boiler gases affect the performance of activated carbon in these two environments. These differences include a lower concentration of mercury, a higher concentration of acid gases, and a lower residence time (the time available for the mercury to contact the AC particle) in coal-fired utility boiler gas. Consequently, transfer of the AC technology commercialized for MWCs to utility boilers has required further investigation and optimization. Extensive tests have been performed at the bench, laboratory, pilot, and full scale for application of AC in the coal-fired utility boiler gas. The results of these tests will be discussed in the following section.

Modified activated carbons (i.e., doped with sulfur, iron, chlorine, and iodine), as well as activated carbon derived from a variety of materials (such as biomass, waste tire, carbon fibers, char produced from corn-to-ethanol production process byproducts, fly ash, and coal) have been studied. Preliminary evaluations have shown that activated carbon derived from some materials such as lignite coal fly ash and corn waste[40] may provide economic advantage compared to the currently commercially available activated carbon. Doped activated carbons can provide higher mercury adsorption capacity, but often have higher production costs that should be considered in the evaluation studies. As research in production and sorbent application methods continues, some of the cost issues associated with impregnated activated carbons may be addressed.

For example, it is believed that sulfur impregnation[41] increases the capacity of activated carbon for both elemental and oxidized mercury adsorption (Ref. 13). However, the cost of this material may be substantially higher than undoped available activated carbons. Research has been done on processes for impregnation and preparation of the sulfur-doped activated carbon because these processes affect the physical and chemical properties of the impregnated sorbent and its mercury adsorption capacity (Ref. 14). Due to higher production cost for sulfur-impregnated AC, the cost of mercury control using this type of powdered AC injection may be substantially higher compared to the undoped activated carbon. However, in an effort to investigate potential means of reducing costs associated with using this material, cloth made with activated carbon fiber was impregnated with sulfur and was tested for adsorption of mercury in simulated gas (Ref. 14). Bench-scale studies indicated a high capacity for Hg^0 capture, and a potential for the fabric filter to have a lower cost than the injection of activated carbon (Ref. 3).

Residence time and temperature of the flue gas prior to entering the particulate device control (where AC is injected) are two critical factors in improving the efficiency of the mercury capture with AC. Reducing gas temperatures (by spray cooling or use of heat exchangers) has promoted higher capture efficiencies of mercury with AC injection. However, operating at reduced temperatures may result in formation of sulfuric acid (and possibly hydrochloric acid) mist. Temperature reduction would not pose any operational concerns for facilities burning (low sulfur) subbituminous coals. For facilities that use coals with high sulfur content and humidification for flue gas cooling, formation of sub-micron sulfuric acid mist as a result of sulfur trioxide (SO_3) condensation at or below the acid dew point[42] (ADP) of the gas

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[40] The corn-derived activated carbon showed a Hg^0 adsorption capacity over twice that of the commercial activated carbon sorbent, after the char was activated (in CO_2 at 865°C for 3.5 hour) (Ref. 15).

[41] According to the document in Reference (2), the most effective sorbents were obtained by sulfur impregnation of activated carbons derived from waste material and carbon fibers (Ref. 2, 15).

[42] The acid due point (ADP) is the temperature of the flue gas at which the acidic components will condense.

can result in degradation of the ductwork and pollution control system. Formation of SO_3 may be a result of coal combustion, or sulfuric acid gas may be injected separately or in combination with ammonia for enhancing fine particle collection (this occurs mainly when PRB and other subbituminous coals are used). Also, pilot-scale tests have indicated that certain carbons convert SO_2 to SO_3 while the carbon is captured on the filter of the baghouse. Some options are available to address acid mist formation problem. In general, the system can be operated at a temperature above the ADP to avoid this problem.[43]

According to prior investigations, rather high carbon-to-mercury weight ratios are needed to achieve a high level of mercury removal. In order to reduce the carbon injection rates and the operating cost of the process, it is necessary to develop either a more efficient sorbent (i.e., lower carbon-to-mercury injection) or a lower-cost sorbent (or possibly both). Carbon impregnation and use of ultra fine activated carbon, as well as improvements in particulate collection have been investigated to address this issue.

A chlorine-impregnated activated carbon was produced and studied (Ref. 16). An inexpensive virgin activated carbon was used in a cost-effective impregnation process. Bench scale tests and cost analyses have shown that this Cl-impregnation process can produce a very efficient and cost effective activated carbon that can be used as a sorbent in ESP-equipped coal-fired boilers. Preliminary cost estimates have indicated 53 percent reduction in total annual cost of mercury control compared to using virgin activated carbon (with a removal efficiency of 80%). The Cl-impregnated AC will be investigated in a pilot-scale test (a 21-kW boiler fired with pulverized coal) (Ref. 2, 16).

Recent investigations have indicated that the composition of the flue gas affects the mercury adsorption capacities of the activated carbons. This is a result of complex interactions between the flue gas components, such as acid gases, and the surface characteristics and properties of the carbon sorbent. The observed varying effects of acid gases on Hg adsorption behavior of the carbon sorbents can be attributed to these complex physical and chemical interactions (Ref. 2, 8, 17).

The micropore surface area of sorbent is believed to be an important physical property for vapor-phase mercury adsorption. Recent research has indicated that relatively low surface area microporous activated carbon sorbents derived from bio-mass materials, such as pistachio nut shells and corn fibers, are as effective as the commercial (FGD activated carbon) sorbent for mercury adsorption (Ref. 8). It has been suggested that the presence of active surface functional groups (such as sulfur) in the micropores of the activated carbon are likely to provide the most reactive sites for Hg adsorption from the coal combustion flue gas (Ref. 18). Consequently, it is believed that sorbent-impregnation should focus on highly microporous sorbents.[44] The importance of active functional groups in micropores for vapor-phase Hg adsorption was demonstrated in an EPA study (Ref. 22) by treating the as-received activated carbon with sulfuric acid to increase its micropore functional groups. The Hg^0 adsorption capacity of the treated sorbent was much improved. Most of the commercial activated carbons have been developed for liquid-phase applications and contain large mesopore surface areas (in addition to micropores), which are less effective for adsorption of ppb levels of mercury from coal combustion gas (Ref. 2).

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[43] Often a temperature of ADP+10°C is adopted. A higher temperature may be necessary in some cases to prevent acid formation. Operating in a higher temperature range, based on the costs modeling studies, would result in increased total annual mercury control costs for plants firing bituminous coals and decreased costs for plants firing subbituminous coals (Ref. 2).

[44] It has been demonstrated that impregnation of activated carbon with heteroatoms such as sulfur and chloride is an effective method to improve the vapor-phase Hg adsorption capacities of AC (Ref. 2, 19, 20). Recently, EPA researchers have suggested that the Hg^0 adsorption capacity of an activated carbon is correlated with the concentration of the oxygen (another heteroatom) functional groups in the activated carbon (Ref. 21).

Research in understanding and improving mercury adsorption efficiency of activated carbons has been ongoing with the goal of improving carbon to mercury injection rates and reducing control costs. In general, the efficiency of sorbent use can also be increased by recycling and re-injecting sorbent and fly ash collected in the PM control device(s) located downstream of the injection point because sorbent capacity may be maximized through this recycling.

Successful implementation of full-scale tests for commercially available activated carbon has been demonstrated. Although these tests have had fairly short time frames and more extensive tests are needed for commercialization of this technology, the activated carbon injection technology appears to be promising. Issues such as potential increase in carbon content of the fly ash; SO_3 mist formation; and high carbon-to-mercury injections required for high levels of mercury reduction are being investigated and will potentially be addressed through measures such as sorbent modification (e.g., use of modified sorbents with higher capture efficiency), implementation of appropriately designed equipment (e.g., implementation of systems that can address SO_3 mist formation), and selection of the appropriate combination of APCD control devices (e.g., implementing an additional FF control device to reduce the carbon injection rate). In summary, activated carbon in conjunction with the capture of mercury by native fly ashes[45] and with enhancements for particle collection has potential application in coal-fired utility boilers to reduce mercury emissions (Ref. 2).

Field Demonstration of Mercury Control Using Activated Carbon Injection Control Technologies

Activated carbon injection technology has been demonstrated (under DOE-funded grants) in four coal-fired utility plants at pilot- and full-scale level tests. These tests were performed at the following plants: Pleasant Prairie Station (in Wisconsin), Alabama Power E.C. Gaston Station (in Alabama), Brayton Point Station (in Massachusetts), and Salem Harbor Station (in Massachusetts). In order to obtain AC injection technology performance data under various deployment conditions, facilities with different configurations and operational conditions were selected, and the tests were performed under varying testing conditions. The preliminary results of these field tests demonstrate successful application of mercury-specific control technology at mercury removal levels greater than 90% for boilers burning bituminous coals. Details on these field demonstration tests are discussed in Appendix F.

Calcium-Based Sorbents

Recent investigations of mechanisms involved in mercury adsorption of Ca-based sorbents have indicated the potential for efficient use of such sorbents in a range of applications (Ref. 23). It has been shown that injection of calcium-based sorbents into gas can result in significant removal of mercury (Ref 24, 25).[46,47] Other benefits associated with the use of limestone injection for mercury control include a high probability of SO_3 removal and an incremental SO_2 capture.[48] Relatively large quantities of Ca are required for SO_2 control at coal-fired utility boilers. The investigation results suggest that Ca-based sorbents, modified by reaction with fly ash, can be used to control total Hg and SO_2 emissions cost-effectively. Calcium-based sorbents that have significant pore volume (for elemental mercury capture)

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[45] The fly ash that is generated by any coal combustion process and enters into the flue gas.

[46] In a pilot-scale test, under high-temperature/short-gas-phase residence time for Illinois #6 coal, 77% of total mercury was removed from the gas (Ref.2).

[47] This work has been a collaboration between EPA and ARCADIS Geraghty & Miller, Inc (funded by the Illinois Clean Coal Institute).

[48] Additionally, injection of calcium-based sorbents eliminates the potential concern associated with use of AC sorbents. Injection of AC sorbents might in some cases increase the carbon content of the fly ash beyond what would be appropriate for its use in certain products such as cement.

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^{o}C) (Ref. 26). In these tests, oxidant-enriched, calcium based sorbents[49] have proved far superior to activated carbon in SO_2 uptake. The performance of these materials was also better than the baseline lime hydrates for NO_x and SO_2 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 Hg^0 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).

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[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 carbon[51] to investigate combined effects of sorbent injection for control of mercury and SO_2. The results of these two studies were not in agreement regarding the effect of the co-injection of alkaline materials (for SO_2 control) on mercury adsorption of activated carbon.

In one study (Ref. 28), activated carbon was co-injected with either sodium carbonate or lime for SO_2 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 NO_2 in the gas due to the sodium sorbent impacts. NO_2 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 Mercu-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 SO_2 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 Hg^{2+} to Hg^0 in the scrubber. Several scrubbing and flue gas additives are currently under development for: a) oxidization of the Hg^0, and b) preventing the conversion of adsorbed Hg^{2+} to gaseous Hg^0 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

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[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 ethylene-diamine-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 tests[52] (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 EDTA[54] 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/NERL[55] (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

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[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 (SO_3) 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 Hg^{2+} and reduce the conversion of the adsorbed Hg^{2+} to Hg^0. These studies indicate that the operating voltage of the ESP and the oxidation air of the WFGD influence the Hg^{2+} to Hg^0 conversion in the WFGD.[58] Liquid-to-gas ratios and the tower design of the WFGD unit affect adsorption of Hg^{2+} (Ref. 2).

3.2.3. Multi-Pollutant Control Technologies[59]

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 discharge[61] in the flue gas upstream of an ESP-WFGD system is under investigation for improving PM control. In this process, SO_2 and NO are converted to SO_3 and NO_2 (and subsequently to H_2SO_4 and HNO_3). Elemental mercury is oxidized by oxygen-carrying reactive species that are

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[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 Hg^{2+} to Hg^0.

[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 SO_3 helps oxidization of Hg^0 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 tests[62] 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 SO_2, NO_x, Hg, and fine PM. A dielectric barrier discharge is used to convert NO_x and SO_2 to acids and oxidize Hg^0. 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 tests[63] 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 construction[64] (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 (H_2SO_4, and HNO_3) 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).

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[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 $NO_2/N_2O_4/N_2O_5$ 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 Scrubber[66]

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 Toxecon™ 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

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[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 Hg^0 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 SO_2 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 SO_3 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 ESP[67] 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 required[68] when injecting sorbents upstream of a FF. There may be a need for more frequent cleaning with the additional sorbent loading.

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[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.

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[69] As discussed earlier, use of low NOx 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 SO_2, 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 matter[70] 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 SO_2, 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.

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[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 costs[71] 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 model[72] 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

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[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 appropriate[76] 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/Nm^3 were assumed.[77] An approach to acid dew point (ADP) of 10^{o}C (18^{o}F) was used for the retrofit system with spray cooling (SC) to operate above the ADP and avoid problems associated with acid mist (SO_3) 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^{o}F to ADP+ 40^{o}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]

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[76] For example, larger plants that use high sulfur bituminous coal tend to use a WFGD for SO_2 control; while in smaller plants that use high sulfur bituminous coal, use of both SDA + ESP/FF or WFGD for SO_2 control is common.

[77] This Hg concentration is in the range of mean concentrations (1.7-50.1 microgram/Nm^3) 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^{o}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 Hg^{2+} 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 study[83] 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.

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

[83] Published March 1999.

[84] EPA has derived the NOx 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) 0.035 - 1.915 (b)	0.183 - 2.270 (a) 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 here[89]).

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.

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[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-bed[90] 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

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[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 sorbents[93] (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 materials[94] 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/Nm^3, 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

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[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 systems[98] 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 technology[99] (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 EPA[100] 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 SO_2, can result in significant SO_2 removal (above the baseline reductions achieved with the currently used FGD calcium-based sorbents without optimizing the sorbent for SO_2 or NO_x control. The reductions for both SO_2 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, SO_2, and PM under federal requirements.[101] Under 310 CMR 7.29, these facilities are required to address their emissions of mercury and CO_2, as well as reduce the emissions of NO_x and SO_2. 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 (SO_2, NO_x, and particulates), major air toxics (especially mercury), CO_2 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.

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[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 NOx) and requirements for PM to meet federal opacity requirements. There are also state requirements for opacity.

SO_2 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 SO_2. However, a WFGD control system also generates additional emissions of CO_2 (by chemical reactions that capture the SO_2) 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 SO_2 into SO_3, 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 SO_2, NO_x, Hg and CO_2, multipollutant control strategies will be more cost-effective. During the SO_2 and NO_x emissions control planning and implementation, the effects of the SO_2 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

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[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 SO_2, 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 available[105]. For comparison, when CEMS were first used for pollutants such as NO_x and SO_2, 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 $\mu g/m^3$. Testing

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[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 $\mu g/m^3$ and oxidized mercury levels of approximately 1 to 1.5 $\mu g/m^3$.

- *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 $\mu g/m^3$. Testing showed relative accuracy of 50.2% for elemental mercury, and 99% for oxidized mercury, at elemental mercury levels of about 6 to 7 $\mu g/m^3$ and oxidized mercury levels of about 1 to 1.5 $\mu g/m^3$.
- *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 $\mu g/m^3$.
- *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 $\mu g/m^3$. 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 $\mu g/m^3$ and oxidized mercury levels of approximately 1 to 1.5 $\mu g/m^3$.

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 available[106]. 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 SO_2, 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

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[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 SO_2 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-volume[108] 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 SO_2 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.

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[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 SO_2 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 SO_2, 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 SO_2 than in a dry FGD, but with a greater volume of waste produced.

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[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 SO_2 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 Calculations[116]

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.

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[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

PG&E Brayton Point Station	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 – SO_2 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 – SO_2 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 CO_2 Reductions
NRG Somerset Station	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 SO_2 Early Reduction Credits SO_2 Acid Rain Allowances Off-site CO_2 Reductions On-site CO_2 Reductions

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 federate; 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 SO_3 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 SO_3 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.