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Mercury Measurement and Its Control: What We Know, Have Learned, and Need to Further Investigate

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ABSTRACT

The U.S. Department of Energy (DOE), through the Federal Energy Technology Center (FETC), manages the largest funded program in the country for developing (1) an understanding of mercury emissions, (2) measurement of these emissions, and (3) control technology (-ies) for these emissions for the U.S. coal-fired electric generating industry. DOE has initiated, or has collaborated with other government and industrial organizations in, these and other efforts relating to mercury and other hazardous air pollutants (HAPs), also known as air toxics. One of DOE's first reports on trace elements in coal was conducted from 1976 through 1978 by researchers at DOE's Pittsburgh Energy Technology Center (PETC, now FETC) and the Pittsburgh Mining Operations of the Department of the Interior's Bureau of Mines. The report was completed less than two years after DOE was formed, and 13 years before Title III of the 1990 Clean Air Act Amendments was enacted (Cavallaro et al., March 1978).

This work was conducted at PETC facilities years before the terms "hazardous air pollutants" and "air toxics" came into vogue. The work indicated, from 10 different coal beds, that most of the trace elements of interest are concentrated in the heavier specific gravity fractions of the coal, and, therefore, are associated with the mineral matter. It was speculated that the removal of the mineral matter should result in significant trace element reductions ranging up to 88%. (Cavallaro et al., March 1978)

Since that time, many collaborative efforts on trace element research (focused on mercury) have been realized between DOE/FETC and EPA, the U.S. Geological Survey (USGS), the Electric Power Research Institute (EPRI), the utility industry, other government agencies at both the federal and state levels, and other U.S. and foreign research organizations. Most efforts in trace element research have been conducted in this decade, and many of the most important efforts in the understanding of mercury have been conducted during the last six years.

EPRI and DOE/FETC collaborated on the sampling and analyses of a possible 189 listed HAPs resulting from coal combustion and indicated by EPA as potentially impacting our ecosystems and human health. The combined EPRI and DOE/FETC efforts provided comprehensive HAPs assessments from over 30 different coal-fired power plants in the United States to the EPA for both of their congressionally mandated reports: the Mercury Study Report and the Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress (EPRI, 1994; U.S DOE, 1996).

Through an interagency government review process, DOE/FETC and DOE's Policy Office were also involved with some of the results of the data and conclusions contained in these two reports. With FETC managing the largest mercury control program, the Mercury Study Report stressed during the review period that for the promising technologies, "Given the relative low maturity level of these technologies, commercial deployment is still at least several years away, and will be strongly dependent on the results of the Phase II efforts." The EPA report also stated, "Before any of the technologies are fully realized for utility application, the fundamental mechanisms of the flue gas and mercury chemistries during the combustion and post-combustion conditions, along with the various interactions with the different types of fly ash must be understood" (Brown, T.D., 1997; EPA, 1997).

Phase II, as referred to in the above paragraph, is part of DOE/FETC's Advanced Emissions Control Technology "Mega PRDA Program" (PRDA is a Program Research and Development Announcement). During Phase I of the program, 11 of the 17 awarded contracts were related to mercury understanding and control. Work was initiated in October 1995 and completed in July 1997. The efforts encompassed two years of laboratory- and bench-scale testing and evaluation of several approaches for controlling the emission of mercury from coal-fired utility boilers. During a down-selection process, FETC selected six Phase II proposals (two-to three-year efforts) to further investigate and develop fine particulate and mercury control technologies and concepts. These research projects constitute the most comprehensive program both in the United States and worldwide regarding coal-fired utility boiler systems.

This research focuses on developing potential technologies for mercury emission reduction from utility plants and is aimed at either adding some type of sorbent technology to adsorb the mercury, improving the mercury capture effectiveness of existing pollution control technology, or using new technology for mercury control. There are other DOE/FETC initiatives that also address research areas related to mercury. The FETC in-house research and development (R&D) program conducts HAPs and mercury measurement and controls R&D for both conventional and advanced coal-fired power systems. The Small Business Innovative Research Program (SBIR), the University Coal Research Program (UCR), and the Jointly Sponsored Research Program (JSRP) at the University of North Dakota Energy and Environmental Research Center (UNDEERC or EERC) have many focused areas in mercury measurement and control R&D for the coal-fired utility industry.

Through interagency government review processes, DOE/FETC has also been involved with the review and comment on EPA initiatives regarding the Toxic Release Inventory (TRI) and the Information Collection Request (ICR) for mercury concentration determinations in the various coals utilized in the utility industry and for mercury flue gas speciation measurements, which represent a cross-section of the coal-fired utility industry. There are issues related to the reporting threshold limits EPA has indicated for cobalt, vanadium, mercury, and dioxin and furan compounds for the utility industry. FETC has been involved in all the aspects of the EPA ICR, from coal sampling for mercury concentrations to the quality assurance and quality control of both the coal and flue gas mercury measurements.

These and other programs and projects initiated by DOE/FETC, and in collaboration with outside participants, are detailed in this report. The information includes data from the initial comprehensive assessments of HAPs, mercury speciation method developments, and the efforts of DOE/FETC and their contractors regarding the understanding of mercury and its control across a highly variable coal-fired utility industry. This review describes

(1) the diversity in coal composition;
(2) the species of mercury in flue gas resulting from combustion;
(3) the ability to measure mercury speciation;
(4) factors influencing mercury speciation and adsorption or other capture mechanisms; and
(5) the technical and economic mercury issues for coal-fired utility boiler systems.

The technology breakthroughs made by the DOE/FETC contractors are detailed, along with the implications of these results on mercury control for the utility industry. In addition, research efforts conducted by other organizations are discussed. The report also examines the potential need for regulations and a schedule for recommending them before the ICR initiative is completed, before making determinations on mercury reporting thresholds under the TRI initiative, and, most importantly, before the National Academy of Sciences (NAS) has completed its study on the somewhat conclusive, but controversial, mercury-related health studies conducted on the inhabitants of the Faroe and Seychelles Islands. The NAS is mandated by Congress to provide a report on the human reference dose level for mercury.

The impact of existing flue gas cleanup systems and mercury concentrations in coal that is supplied to the electric utilities require improved understanding before any regulatory decision is made. The EPA ICR should elucidate many of the uncertainties. To illustrate instances where these knowledge gaps are closing, the following examples are provided. Data that would not require a 90% reduction of mercury emissions for individual plants and utilities. For instance, data collected by DOE/FETC and EPRI contractors are indicating that mercury removals for plants equipped with wet flue gas desulfurization (WFGD) systems are between 50 and 65% of the mercury, which includes the particulate-bound mercury. The vapor phase represents 80–95% of the oxidized mercury in the flue gas prior to scrubbing by the WFGD. The oxidized mercury gets into the environment sooner as a result of local deposition, but the plants with the highest concentrations of oxidized mercury in the flue gas utilize WFGD systems (e.g., Ohio Valley plants firing medium- to high-sulfur bituminous coals).

The EPA ICR will provide additional data on mercury removal from WFGD systems and from other air pollution control devices used in the utility industry. On a mass basis, over one-third of the coal utilized in this country is from the Powder River Basin (PRB) and other subbituminous coals. Many full-scale characterization studies conducted by DOE/FETC contractors on power plants firing PRB coal indicate between 20 and 30% mercury capture associated with electrostatic precipitators; and on average 50–60% mercury capture at plants equipped with baghouses, with 90% mercury capture being observed.

A sensitivity analysis for mercury emission control has been performed to examine how control options may impact the diverse U.S. power plant population. The first option, shown in Figure ES-1, considers setting a cap on emissions of 0.03 tons of mercury emitted per million tons of coal consumed. At this level of control, about 10% of the U.S. power plants that have low mercury emissions come under the cap with little or no additional controls needed. For about half of the total coal consumption, less than 40% additional control would be required. On about 10% of the total coal consumption, fairly significant control would be required, ranging from 66 to 85% reduction from the existing emissions level.

The remaining 30% of power plants would require approximately 40 to 67% mercury emissions reduction. The overall reduction in mercury emissions from the national mercury emissions inventory estimate for the reference year of 1996 is about 50%.

In the second option, a 90% reduction of mercury contained in the mined coal is considered. This scenario credits mercury removal from coal preparation and existing power plant controls toward an overall 90% reduction goal. Approximately 60% of the coal consumed would require controlled reduction between 80 and 90%. Nearly 98% of the coal consumed would require reductions of at least 50%. The overall reduction in mercury emissions from the national mercury emissions inventory estimate for the reference year of 1996 is about 80%.

This sensitivity analysis demonstrates that mercury control options are highly dependent on the existing power plant's operating characteristics and design. As stricter control options are considered, the flexibility to achieve these reductions begins to diminish.

Mercury control technology availability should not be the driving force behind any regulatory decision for mercury emissions from coal-fired power plants. Control technology availability has an impact, but the need for control, based on health impacts, must be a driver. The Seychelles studies provided data to calculate a mercury reference dose (MRD) of 0.5 μg Hg/kg-bw/day (grams of mercury per kilogram of body weight per day). This is in comparison to EPA's calculated 0.1 μg Hg/kg-bw/day MRD, from the acute exposure with the Iraqi contaminated grain incident. The Agency for Toxic Substances and Disease Registry (ATSDR) has recently indicated a mercury reference dose (MRD) or mercury risk level (MRL) of 0.3 μg Hg /kg-bw/day based upon the Seychelles Island studies. If an MRL of 0.3 μg Hg /kg-bw/day limit was indicated by NAS from their 18-month study, it is estimated that 90% or more of the state fish advisories would not be required. This alone may be the most dramatic factor impacting the level of control required under any regulatory determination process.

The NAS study and the agency's subsequent submission of a report should provide information on the reference dose level. DOE/FETC and EPRI support of industry's progress in advancing the state-of-the art understanding of mercury measurements and control in the utility industry, is thought to enhance any future regulatory process or requirement by the sound science achieved through these investigations.

DOE/FETC, in collaboration with EPA, EPRI, and USGS, is developing a program to demonstrate the most promising mercury control technologies at larger- or full-scale at different coal-fired utilities. DOE will issue a solicitation before the end of fiscal year 1999 (September 30, 1999). The solicitation will ask for proposals to scale up the promising technologies and will require contractor and industrial cost sharing. These demonstrations need to be completed before any regulatory

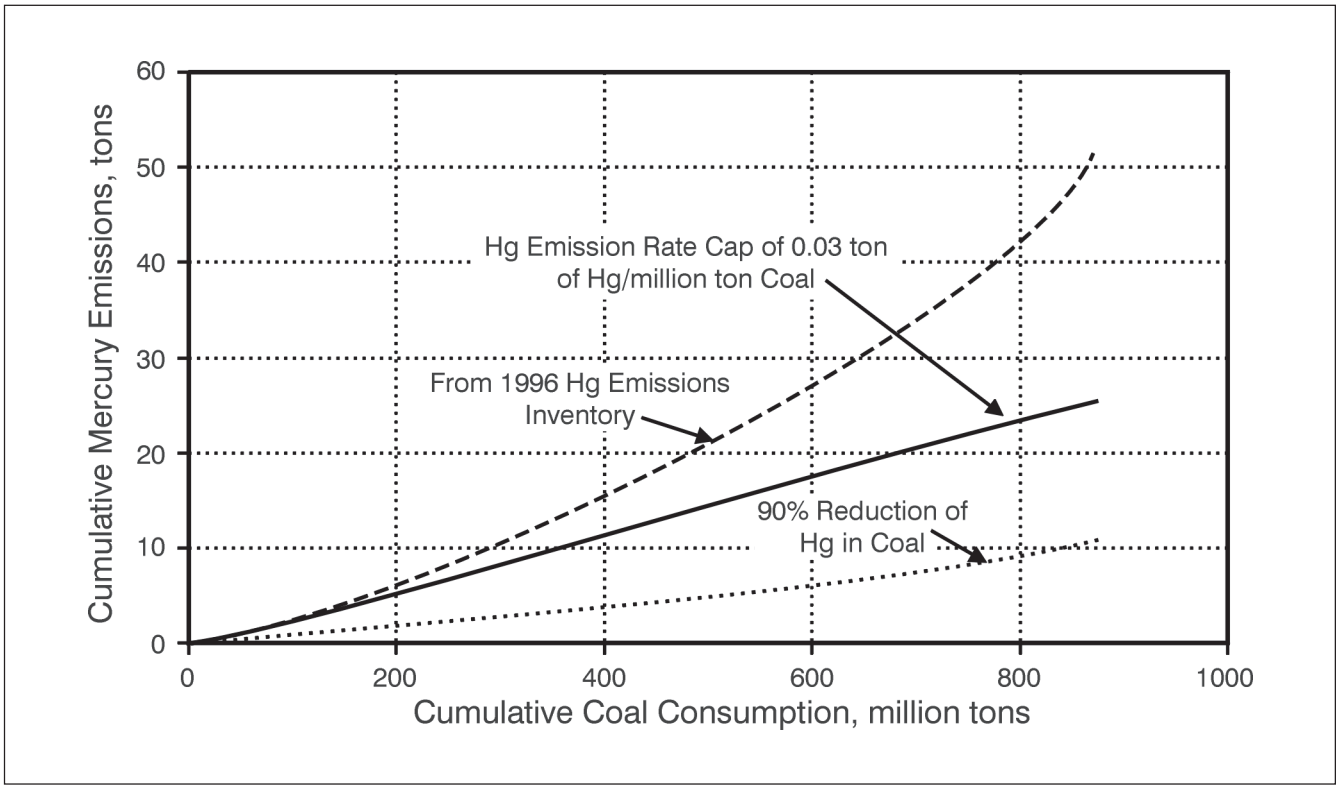

Figure ES-1. 1996 mercury emissions and control scenarios (Smith, D.N., 1999).

decisions can be made based on sound science. There are many engineering and technical issues that need to be addressed before mercury control is implemented in the utility industry.

INTRODUCTION

The 1990 Clean Air Act Amendments (CAAAs) brought about a new awareness regarding the potential impact or health effects of stationary source emissions. A possible 189 pollutants were identified as hazardous or toxic; these pollutants have collectively become known as "air toxics." Of the 11 titles contained in the CAAAs, Title III, Hazardous Air Pollutants (HAPs), has promoted some of the most interesting and exciting research, as well as eventual development of many databases on air toxic emissions from all industrial stationary sources in the United States.

The specific provisions under Title III of the CAAAs regarding electric steam generating units were comprehensively addressed by DOE/FETC and EPRI in their collaborative air toxic characterization programs. Their work concluded that many of the air toxics from coal-fired utilities are "*not a concern to the environment and human health.*" There still exist, however, uncertainties regarding arsenic, chromium, nickel, dioxin, and furan compounds, and most importantly, mercury emissions from coal-fired utility boilers. (U.S. EPA HAPs Report, 1998)

The work, initiated by DOE/FETC and EPRI in 1990 and continued through 1997, provided most of the data used as the basis for EPA's conclusions regarding air toxic emissions from coal-fired utility boilers. The results of the studies and the input to the knowledge base regarding these emissions are discussed below. The assessment of toxic emissions, with a focus on mercury, has continued since 1993.

Conventional particulate control devices used in the utility industry capture the majority of the trace elements (Sb, Be, Cd, Cr, Co, Pb, Mn, Ni, and, in most cases, As) and compounds of these elements indicated on the CAAA HAPs list to levels exceeding 95% and as high as 99.99%. The obvious elements not collected at high efficiencies were Hg, Se, and, in some cases, As. Approximately 65% of the utility power plants only utilize an electrostatic precipitator (ESP); 10% utilize only a fabric filter (FF); and the remaining 25% utilize a combination of an ESP and wet FGD systems.

It has been determined that the high removal of the trace elements/compounds is independent of coal rank, boiler configuration, concentrations in the coal and subsequent flue gas, and conditions before and within the air pollution control devices (APCDs). The nonvolatile nature of these elements augments their association with the particulate matter being collected from 99.0 to 99.99% in the various particulate control devices (ESPs and FFs). The remaining low levels of particulate matter and associated trace elements are effectively removed across wet FGD systems. (EPRI, 1994; U.S. DOE Report, 1996) Table 1 gives the emission factors of these elements from the DOE/FETC program from 1993 and the results from past studies on trace element emissions from coal-fired boilers.

A detailed examination of the available data from coal-fired power plants was conducted recently. (Senior, C. L., et al., 1997) Data reviewed included the EPRI and DOE-sponsored studies as well as data from the scientific literature. Again, most of the HAPs (Cd, Co, Cr, Ni, Pb, Be, Mn, and Sb) showed uniformly high capture efficiency in all types of APCDs studied to date. Not only was the capture efficiency for these elements high, but it fell within 2 standard deviations of the average particulate matter capture efficiency for the particular device.

Three elements (As, Se, and Hg) exhibited capture efficiencies in the air pollution control devices that were significantly less than the particulate matter collection efficiency. An in-depth look at the data suggests that this is because these elements either are concentrated in the sub-micron particulate or are in a gaseous form.

Both the type of coal and the type of APCD seemed to have an impact on arsenic and selenium capture in coal-fired power plants. Subbituminous coals and lignite coal have large amounts of calcium in the ash that can react with arsenic and selenium. Average capture efficiencies for arsenic depended on coal type: 98.9% for subbituminous coals, 99.6% for lignite coals, and 96.3% for bituminous coals. Selenium is a volatile element in the flame and shows low-capture efficiencies in coal-fired power plants. Average capture efficiencies were strongly dependent on coal type: 98% for subbituminous coals, 62% for lignite coals, and 44% for bituminous coals. For both elements, the amount captured in ESPs was significantly less than that in fabric filters. This points to an interaction between arsenic, selenium, and calcium in the large fly ash particles in sub-bituminous coals and lignites. A significant fraction of selenium may be emitted in the

Table 1. Emission factors (lbs/trillion Btu).

Trace Element	DOE	Literature
Antimony	0.1– 2.4	NA
Arsenic	0.1– 42	1–860
Beryllium	0.1–1.4	1–32
Cadmium	0.1–3.0	1–490
Chromium	0.1–51	10–5000
Manganese	1.1–22	30–2400
Mercury	0.5–14	1–22
Nickel	0.3–40	1–2500

gas phase as suggested by the low capture efficiency (35% on average) for selenium in plants burning bituminous coals and employing ESPs.

Improvements to the conventional particulate control devices have increased the collection of the particulate even for particles less than 2.5 μm and have further reduced the trace elements/compounds well below the detection limits of the state-of-the-art multi-metals sampling and analytical technique (EPA Method 29). In addition, the development of new retrofit and novel particulate control devices for new installations have also shown the improvement in the collection efficiencies of the particles less than 2.5 μm, with a corresponding reduction of the potentially hazardous trace elements. Based on DOE/FETC and EPRI findigs from their comprehensive HAPs measurements, Table 2 indicates lower calculated emissions or reduction of trace elements of concern as particulate collection efficiency is increased.

For the reference year of 1997, the uncontrolled emissions from U.S. coal-fired power plants was calculated to be 105,000 tons. However, on average, the particulate matter capture efficiency on a mass basis for the utility industry was estimated to be 99%. Therefore, it was calculated that the coal-fired utility industry removes more than 103,900 tons of trace elements with the fly ash. Trace element removals associated with higher particulate removals for a 600-MWe coal-fired power plant are also presented in Table 2. This is extremely important for the toxic release inventory (TRI) that the utilities must compile. The TRI is a public database that may cause some concern owing to the high levels of trace elements from coal combustion (i.e., fly ash being landfilled). Of course, utilities with fabric filters will remove more of the trace elements with the increase in particulate collection efficiency. Figure 1 compares field data on the distribution of trace elements/compounds of these elements for a fabric filter and an ESP installed on the boilers firing a subbituminous and bituminous coal, respectively. While the trace elements found in the two boilers are different, the higher efficiency particle collector (i.e., fabric filter) has the lowest emission rates for the trace elements. While mercury is a small percentage of the air toxic generated in the combustion process and only represents a small fraction of the emissions, some consider mercury an issue owing to its persistence and propensity for bioaccumulation.

Table 2. Calculated effect of control level on emissions (lbs/trillion Btu).

Control Level	1997 Total United States, 900 million tons of coal, dry basis	600-MW Plant 3 million tons
Uncontrolled Emissions	105,000 tons[a]	353 tons
99% Control	1,050 tons	3.5 tons
99.9% Control	105 tons	700 lb
99.99% Control	10.5 tons	70 lb
99.999% Control	1.05 tons	7 lb

[a]Assuming 117 μg/g total nonvolatile trace elements in coal, including Sb, As, Be, Cd, Co, Cr, Pb, Mn, and Ni. Mean value from 1993 DOE Study.

Capture efficiency for particulate of 99.0 to 99.99% is achievable in the utility industry with fabric filters, while 99.999% is possible with new technologies developed under DOE funding (e.g., ADA Technologies additives; UNDEERC Advanced Hybrid Particle Collector; ABB's modifications to ESPs, including flue gas cooling in conjunction with pulsed energization; Environmental Element's Laminar Flow ESP; and Particle Agglomerator) (Durham et al., 1997. Miller, 1997; ABB et al., 1997; Feldman, P., et al., 1997; and Helfritch et al., 1997). EPRI's Compact Hybrid Particulate Collector (COHPAC), a high air-to-cloth-ratio, pulse-jet fabric filter downstream of an underperforming ESP, also can collect particles at 99.99% when combined with an ESP (Miller, R.L., et al., 1997; Browning et al., 1997).

The improvements and enhancements to conventional particulate control devices and novel concepts will enable effective collection of particles below 2.5 μm. The effective collection below this size also enables high efficiency collection of the trace elements and compounds (As and Se) and other HAPs associated with this particle size range. Work continues on reducing emissions of primary fine particulate below 2.5 μm through the many projects sponsored by DOE, EPRI, and EPA.

Most of the recent focus of these institutions involves developing an understanding of mercury and its various forms, while funding and performing research and development for technologies or strategies for controlling mercury in coal-fired utility boilers in case regulations are required.

Based on the available evidence of health effects, EPA has been evaluating the need to regulate mercury releases to the environment and has issued the Mercury Study and the Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units reports. In spite of the enormous effort represented by these reports, as well as the efforts of both the DOE/FETC and EPRI, in conducting the field measurement programs that form the basis for these reports, a definitive answer on the need for mercury regulation has not been found. However, EPA, as well as other regulatory agencies and health researchers, have suggested a *"plausible link"* between anthropogenic sources emitting mercury and the methylation, bioaccumulation in the food chain, and adverse health effects in humans and wildlife.

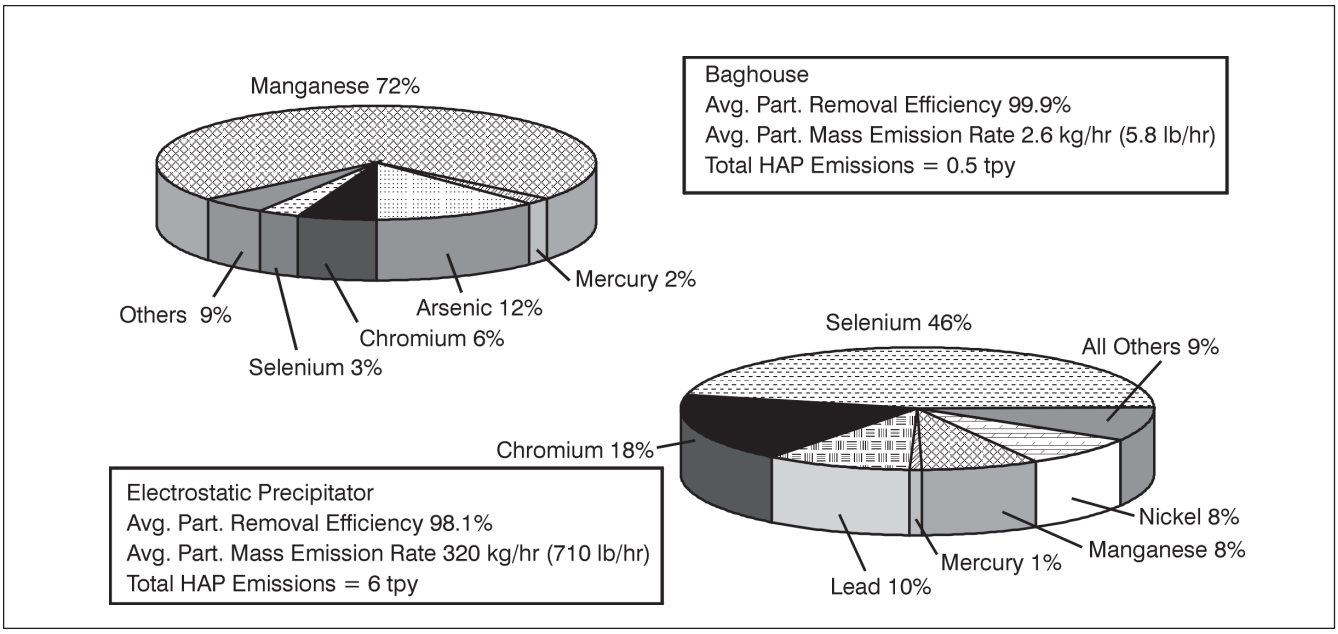

Figure 1. Distribution of trace elements identified as HAPs (U.S DOE, 1996).

Policy-makers have recognized that regulations must be based on good science and also that a number of issues still remain. These issues can generally be grouped into four main categories: emissions inventory, control technology, fate of releases, and health effects. Add a space As previously stated, this review will discuss recent, ongoing, and planned studies to address the remaining issues regarding the presence of mercury in the environment, with an emphasis on those studies that are directly related to the DOE/FETC's programmatic effort.

The emissions inventory contained in the EPA Mercury Study Report addresses known anthropogenic sources of mercury to the environment for 1994 through 1995. Emissions from combustion are the largest single source category. Within this source category, combustion of coal accounts for the largest fraction. While DOE/FETC does not necessarily agree with all the assumptions made in the EPA estimate, it is obvious that coal combustion is a significant source of mercury. In fact, the data used to estimate coal combustion emissions were based largely on field studies conducted under the DOE and EPRI programs. In conducting these studies, individual sites were selected to give a good cross-section of the U.S. boiler population, conventional control equipment, and coal types. Issues related to the development of an accurate inventory are discussed here, along with two new data-collection initiatives by the EPA: the Toxic Release Inventory (TRI) and Information Collection Request (ICR).

Developing effective mercury control technologies in coal-fired utility applications is extremely difficult if researchers can not determine the amount, vapor phase speciation (elemental versus oxidized mercury), and particulate-bound mercury. Total mercury (Hg) concentrations in coal, based on data collected since 1993, are relatively constant across the U.S. (20 to 120 parts per billion on a weight basis, or ppbw) with more than 75% of the coals having concentrations below 100 ppbw. There are a few exceptions with some concentrations being between 200 and 300 ppbw. However, when the different ranks of coal are fired in utility boilers, there is substantial variation in the concentrations of elemental mercury (Hg^0) versus oxidized mercury (Hg^{2+}) as measured at the inlet to the particulate control device. The percentage of Hg^0 varies from 10 to >90% indicating that speciation is very dependent on coal type. The chemical species of Hg formed during the combustion process and post-combustion conditions vary significantly from one plant to another, exacerbating the effective control of Hg across the utility industry.

While combustion conditions vary, the subsequent fly ash, carbon in the ash, and vapor-phase constituents can also play a major role in determining the percentage of the Hg chemical species formed. Understanding the rate-controlling mechanisms (i.e., transport, equilibrium, and kinetics) will not only aid in predicting the Hg species formed, but, eventually, will aid in optimizing existing air pollution control devices (APCDs) for Hg removal. Kinetics may play more of a role on the form of Hg than anticipated. Effective removal is dependent on the species of Hg present in the flue gas. For example, Hg^{2+} is water soluble and is less volatile compared to Hg^0. Reducing the temperature of the flue gas and utilizing wet scrubbing could result in increased Hg^{2+} removal.

The discussion of mercury control technology begins with a review of data on mercury removal in conventional pollution control equipment [electrostatic precipitators

(ESPs), fabric filters, wet and dry flue gas desulfurization (FGD) scrubbers], and NO_x control systems. Fuel switching, used as an SO_2 compliance strategy, can also have an effect on mercury emissions. Next, optimization/modification of conventional control equipment for mercury removal efficiency (e.g., converting elemental mercury to oxidized mercury followed by scrubbing) is reviewed. Finally, new technologies being developed at the pilot-scale specifically designed for mercury removal are discussed, along with a comparison of costs for mercury control.

This year's Critical Review addresses mercury speciation, mercury measurement, mercury emissions inventory, and mercury control technology development in the following sections:

Emissions Inventory
Mercury Measurement and Mercury Control Technology Development
Mercury and Its Speciation
Mercury Speciation and Its Measurement
Factors Influencing Mercury Speciation and Adsorption
Control Technology Investigations and Development for Coal-Fired Utility Applications
Mercury Control Sensitivity
Recent R&D and Emerging Mercury Control Technologies for Coal-Fired Utility Boiler Systems
Coal Preparation or Coal Cleaning
Activated Carbon and other Sorbent Injection Technologies for Mercury Capture
Enhancing Mercury Capture in Flue-Gas from Utility Wet Desulfurization (WFGD)
Other Innovative Approaches for Mercury Control in the Coal-Fired Utility Industry
Cost of Mercury Control
Conclusions and Recommendations

CONCLUSIONS AND RECOMMENDATIONS

Mercury emission inventory estimates continue to be refined as better information becomes available. EPA's recent Information Collection Request (ICR) for mercury measurements at coal-fired power plants is expected to provide an improved understanding of mercury concentration in "as-received" coal at electric utilities. More reliable relationships between the mercury concentrations in coal "as-mined" and "as-received" can be sought from this new information so that future mercury emissions can be estimated with greater certainty.

Additionally, the ICR will gather information on stack emissions of mercury for a segment of the coal-fired electric utility industry. The new data will add to our understanding of mercury partitioning in flue gas from full-scale operations. This, in turn, will improve the reliability of emission modification factors and the efficacy of mercury emission control options.

Based on recent findings and analysis pertaining to the national mercury emissions inventory, model parameters (such as coal cleaning factor and emission modification factor for FGD scrubbing) require further validation to support the reliability of the inventory estimate.

Research at the fundamental level continues to be conducted to determine the mechanisms involved with both gas-phase Hg transformations and gas-solid interactions. Attempts have been made to use thermochemical equilibrium calculations to predict the Hg species in coal combustion flue gas. The assumption of gas-phase equilibrium for mercury-containing species in coal-fired power plant exhaust is not valid. Preliminary evidence suggests that the oxidation of Hg^0 to Hg^{2+} in the flue gas is quenched when the gas cools below 750-900 K. Again, kinetic calculations on the formation of Cl_2, which is highly reactive with Hg^0, indicate that the conversion of HCl to Cl_2 does not attain equilibrium given the time temperature-history of flue gas in a power plant. The calculated results lend support to the conclusion of quenched equilibrium for Hg oxidation.

Equilibrium calculations indicate that Hg may condense as HgO, $HgCl_2$, or $HgSO_4$, but nitrates and other forms may also occur as intermediates. Equilibrium predicts a complete conversion of Hg^0 to Hg^{2+} at air preheater outlet temperatures, but measurements of boiler emissions indicate only 10 to <90% as Hg^{2+}, suggesting that kinetic limitations are the controlling mechanisms. Recent research has speculated that the major kinetic pathway for the formation of $HgCl_2$ involves the reaction of atomic chlorine with Hg^0. Kinetic simulations predict that the concentration of atomic chlorine in a cooling combustion gas is rapidly reduced by interconversion with HCl and Cl_2, and possibly Cl and Cl_2.

Understanding gas-phase speciation of Hg in coal-fired power plant flue gas is not sufficient to describe the transformations of Hg in the combustion system. To understand the capture of Hg in APCDs and the effectiveness of sorbents for Hg capture, a better understanding of the gas-to-particle conversion is needed, particularly the relationship(s) between fly ash properties and oxidation and adsorption of Hg.

Two key questions have been postulated: first, "What are the processes/mechanisms by which fly ashes (and certain other solids) seem to catalyze the transformation of gaseous Hg^0 to "oxidized forms?" and second, "What Hg species are adsorbed on fly ash?" Answering these questions will require a detailed look at the constituents of the fly ash and how they interact with $Hg_{(g)}$ at temperatures characteristic of the flue gas (400–600 K) as it enters the APCD. Studies conducted under federal

and private funding are designed to answer these questions. Again, the EPA ICR could possibly add to the existing databases.

Investigations at both bench and laboratory scales with simulated flue gas have indicated certain bituminous coal fly ash and vapor-phase constituents play a role in the oxidization of Hg^0. Powder River Basin (PRB) subbituminous coal fly ashes show high adsorption capacities compared to the bituminous coal fly ashes, but indicate, in most cases, very little oxidation. Generally, the adsorption rate increases as the temperature in the flue gas decreases. Work is continuing to investigate these observations and determine the mechanisms responsible for both oxidation and adsorption of Hg by various fly ashes.

It has been speculated that the oxidized form of Hg in flue gas from coal combustion is mercuric chloride ($HgCl_2$). The existence of Cl_2 at temperatures measured near the first APCD of coal-fired power plants has been postulated. Kinetic calculations also showed that the chlorine atoms combine to form primarily HCl with minor amounts of molecular chlorine (Cl_2). If small concentrations of Cl_2 are present in the flue gas streams exiting the air preheater, then reactions could be occurring with the Hg^0 to subsequently form $HgCl_2$. Alternatively, mercury could react with other vapor-phase compounds and/or fly ash constituents to form other oxidized mercury compounds.

The affinity of fly ash from PRB coals for mercury sorption needs to be better understood. Initial work has identified the effects of HCl, CaO, and carbon on sorption capacity and reactivity. More work is needed to understand the mechanism for the mercury interactions with the fly ash components. Fundamental studies under controlled bench-scale conditions are needed to correlate with full-scale measurements. This should be combined with analysis of the fly ash by XAFS to identify the mercury compounds. Mechanistic models could then be developed and tested. Pilot-scale studies could then build on the fundamental design information to seek optimum conditions for mercury sorption and economic control configurations.

Research is ongoing to identify promising catalysts to promote oxidation of elemental mercury for subsequent capture by flue gas scrubbers. Similar to the studies on PRB coals, these catalysts should be studied under bench-scale conditions and mechanistic models for the reactions should be developed.

One of the most important breakthroughs was realized after the numerous pilot-scale and field studies and subsequent validation at both scales of the Ontario Hydro Mercury Speciation Method. It is recommended as the best method to measure the distribution between Hg^0 and Hg^{2+}in coal-fired combustion systems by EPA, DOE, and EPRI. The method has been proven to provide good precision, low bias, and accurate spiked Hg recoveries.

The method has been submitted to the American Society for Testing and Materials (ASTM) for review, evaluation, and acceptance as a standard reference method. In addition, EPA has recommended the Ontario Hydro Method as the method of choice for their Information Collection Request (ICR) for mercury speciation data from approximately 75 coal-fired utilities.

Validation of the Ontario Hydro Method has provided researchers with a valuable tool to measure, within ±10%, the distribution between Hg^0 and Hg^{2+}, along with total Hg in flue gas from coal combustion. This method has aided in the understanding of the different forms of Hg and which form is captured or emitted. Many researchers have modified this method and have been using it in a semi-continuous mode for their respective bench- and laboratory-scale Hg sorbent evaluation and development projects.

Numerous mercury sampling effort utilizing the Ontario Hydro Method at both pilot- and full-scale combustion systems indicate a wide range of Hg^{2+} percentages while firing coals of various ranks: bituminous coal(s) indicating Hg^{2+} values from 70 to 88%; Powder River Basin (PRB)/subbituminous coal(s) indicating Hg^{2+} values from 15 to 50%; and lignite coal(s) being highly variable indicating Hg^{2+} values from 10 to 30%, but as high as 50%.

A key measurement in all these studies, at least for those at pilot and full scale, is the solid-vapor distribution. Currently, no method for ensures that the solid-vapor distribution measured by the sampling train is the same as the distribution as it exists in the flue gas duct, especially upstream from a particulate control device. Similarly, the effect of passing the vapor through the filtered solids on the mercury speciation can not be accurately quantified. The solids are suspected to give bias to the oxidized fraction. A method is needed to separate the solid and vapor fractions without the intimate contact caused by a sample filter.

While there has been some success in using the impinger solutions of the Ontario Hydro Method in a semi-continuous mode, more development and evaluation, with subsequent validation of Hg continuous emissions monitors (CEMs) at coal-fired utilities, needs to be completed. The Ontario Hydro Method can now be utilized as a standard for the testing and possible validation of the promising CEMs.

Real-time data on total and speciated Hg are needed to fully evaluate the developing control technologies being funded. Correlating APCD operating parameters (i.e., sorbent and additive injection rates and temperature effects) with real-time monitoring is critical to the development of low-cost Hg control technologies. DOE has

been funding researchers to develop a Hg CEM as a research tool to aid in the evaluation of the promising control technologies for Hg control in coal-fired utilities.

Coal mercury concentrations and the distribution between elemental (Hg^0) and oxidized mercury (Hg^{2+}) vary considerably while firing the different ranks of coal. Nearly 90% of all coals, regardless of rank, have less than 100 ppbw of mercury and subsequently have less than 10 μg/Nm^3 of vapor-phase mercury with varying levels of Hg^{2+} resulting in the flue gas. The range of Hg^{2+} varies from <10% to as high as 70% of the total mercury. The actual mercury control or removal level varies from plant to plant, with one scenario indicating over 90% of the plants requiring capture efficiency well below 90%.

Much of the mercury control research in the United States is being sponsored by four organizations: DOE/FETC, EPRI, EPA, and the U.S. Geological Survey. The research is designed to augment existing pre- and post-combustion technologies, with investigations studying different combustion conditions for possible mercury removal or mercury speciation modifications.

The post-combustion R&D focuses on the addition of some type of sorbent (including gas-phase additives) to adsorb mercury and/or convert the mercury to another form for higher mercury removals; augmenting existing air pollution devices (APCDs) in the utility industry; and using new technology for mercury control.

Given the relative maturity level of these technologies, their commercial deployment is at least several years away. Research continues on developing potential technologies for mercury emission reduction from utility plants. Before any of the technologies can be fully realized for utility application, the fundamental mechanisms of the flue gas and mercury chemistries during the combustion and post-combustion conditions, along with the various interactions with the different types of fly ash, must be understood.

Through many research efforts on modes of occurrence of mercury in coal, the majority of the data supports a predominate mercury-pyrite association in coal with some evidence suggesting that this relationship is responsible for up to 65 to 70% of the mercury in some coals. It is not unusual for up to 25 to 35% of the mercury in coal to be associated with the organic fraction.

Approximately 80% of Eastern and Midwestern U.S. bituminous coals are cleaned prior to combustion to increase their heating value, and reduce their ash, and sulfur content. From comparison of run-of-mine coal to clean coal samples from the same coal seams, it has been estimated that conventional coal cleaning results in an average mercury reduction of about 37%.

Advanced coal cleaning technologies can reduce the mercury concentration of coal (30 to greater than 60%), but the potential impact on post-combustion form and control of the remaining mercury has not been thoroughly investigated. In addition, the added costs for advanced coal cleaning separately, and in combination with post-combustion controls for mercury, have not been fully developed. None of the advanced coal cleaning concepts has yet achieved any significant degree of commercialization.

One existing APCD being investigated to enhance Hg^{2+} and Hg^0 removal is wet flue gas desulfurization (WFGD) systems designed primarily for SO_2 removal, while removing other acid gases (e.g., HCl and HF). Integrating retrofit technology options with WFGD systems offers lower system complexity and costs compared to other Hg control technologies.

Numerous mercury sampling efforts indicate the nominal Hg removal for WFGD systems on units firing bituminous coal(s) is approximately 55% ±10% of the total Hg, with an associated removal for Hg^{2+} of between 80 to 95%. These sampling efforts have indicated no appreciable Hg^0 removal across the WFGD systems owing to the very limited solubility of Hg^0.

It is important to note that the high removal percentages of Hg^{2+} across WFGD systems in plants firing bituminous coals prevent this form of Hg from entering the local ecosystem(s). This represents approximately 50% (on a mass basis) of the 80 GWe of U.S. coal-fired capacity utilizing WFGD systems.

Many of the sampling efforts have indicated an apparent increase in a non-Hg^{2+}, possibly Hg^0, at the outlet of WFGD system(s) from 7 to 40%. Results from testing additives upstream and within a pilot-scale WFGD system indicated no appreciable increase in the Hg^0 compared without the additives.

Research is being conducted to further investigate the catalytic conversion of Hg^0 to Hg^{2+} upstream of WFGD inlets, the conversion through novel additives injected in the flue gas upstream of and directly into the WFGD systems, and the reduction in the re-emission of Hg from WFGD systems.

Stability tests were conducted on unfixated and fixated WFGD solids from a full-scale coal-fired power plant. The solid samples were subjected to the EPA Toxicity Characterization Leaching Procedure (TCLP) leaching procedures. In addition, the samples were heated to determine whether the captured Hg could be desorbed or re-emitted (volatilized).

Mercury concentrations of the unfixated and fixated WFGD samples were the same after the TCLP tests, with the mercury being below the analytical detection limit of 0.01 mg/L. For comparison, the Resource Conservation and Recovery Act (RCRA) limit for Hg is 0.20 mg/L and based on this criteria, both WFGD materials would be classified

as non-hazardous. Based on the EPA TCLP method, it was concluded that Hg contained in the solids is in a non-leachable form (e.g., chemically bound possibly with $CaSO_4$).

During volatilization tests, both WFGD wastes were exposed to elevated temperatures for 11 weeks with the most stringent case at 140°F (60 °C). Analyses conducted at the end of the exposure period showed no loss of Hg. It was concluded from these tests that Hg did not re-volatilize when exposed to temperatures up to 140 °F.

While the conversion of Hg^0 to Hg^{2+} has been demonstrated in both laboratory- and small pilot-scale tests and the decrease in the re-emission of Hg from a pilot-scale WFGD system, there is a need for longer term catalysts tests, and demonstration of additive injection at full scale. This also applies for the stability of the Hg associated with WFGD wastes. Injection rates of the additives for increased Hg^0 across WFGD systems must be optimized to provide lower cost options.

No individual mercury technology being investigated can be universally realized for the utility industry. Activated carbon injection for mercury capture has been extensively tested at the bench, laboratory, and pilot scales for possible coal-fired utility applications. Investigations involved the potential use of adsorbents for 75% of the utility industry having fine particulate control as the only APCD (65% ESPs and 10% baghouses). Activated carbon in parallel with the capture of mercury with native fly ashes, and with enhancements for particle collection, has potential application for these utility boiler systems.

Activated carbon injection is successfully utilized in the municipal waste combustor industry and is capable of removing >90% of the mercury at very modest carbon-to-mercury ratios. A fraction of a pound increase in carbon injection rate can mean as much as 30% more removal of the flue gas mercury. Activated carbon technology is not directly applicable, or can have only limited application, to the coal-fired steam generating utility industry for several reasons:

(1) Low concentrations of mercury present in the relatively high volumes of flue gas [(one ppbv of Hg with two different forms in flue gas volumes ranging from 500,000 to 5,000,000 actual cubic feet per minute (acfm)].
(2) Mercury speciation is highly variable across the boiler population.
(3) Higher concentrations of competing species occupying the active sites of the carbon.
(4) Flue gas residence time upstream of an ESP is nominally one second or less with flue gas velocities in the range of 50 to 60 ft/sec at 300 °F (149 °C).
(5) Compounding these factors are possible mass transfer limitations of the injected sorbents and the decrease in the carbon reactivity and equilibrium sorption capacity at this nominal temperature of 300 °F (149 °C).
(6) High levels of sulfur dioxide up to and >1600 ppmv, with 50 ppmv HCl, have a profound negative impact on the equilibrium adsorption capacity of certain virgin activated carbons for both Hg^0 and Hg^{2+}.
(7) Removal of HCl does not impact the Hg^{2+} equilibrium adsorption capacity, but does prevent the carbon from adsorbing Hg^0.
(8) Significant interactions between SO_2 and NO_2 gases and activated carbon(s) caused rapid breakthrough of mercury as well as conversion of the mercury to a volatile oxidized form. This effect occurred at both 225 and 325 °F (107 and 163 °C) and with or without the presence of HCl and NO.
(9) In the presence of four typical acid gases, SO_2, HCl, NO, and NO_2, in flue gas from coal combustion, rapid breakthrough and oxidation of the mercury occurred at both 225 °F (107 °C) and 325 °F (163 °C).

The interaction of NO_2 and SO_2 with activated carbon produced poor sorbent performance. This is likely to occur over a variety conditions typical of coal-fired boilers, and represents a hurdle that must be overcome to achieve effective mercury control by this control method. Understanding these factors enhancing or decreasing mercury capture with activated carbon and novel adsorbents will allow for potential low-cost technologies for mercury control, if required, for the utility industry. Particle size of the activated carbon can also impact the mercury capture.

Activated carbon injection is a promising technology, but further research is needed to provide the best sorbent providing effective capture at a low cost. Equilibrium sorption capacity may not be the driving force for better sorbent performance, while the reactivity with the basic forms of mercury (Hg^0, and Hg^{2+}) may be the critical factor.

Different sorbent injection options being investigated at the pilot-scale are as follows:

Option A: Sorbent or carbon injection upstream of the existing ESP;
Option B: Sorbent or carbon injection downstream of the existing ESP associated with a down stream fabric filter, with and without flue gas cooling; and
Option C: Sorbent or carbon injection upstream of the existing ESP, with flue gas cooling.

The utilization of activated carbon injection with reduced flue gas temperatures (i.e., spray cooling or use of heat exchangers) has promoted higher capture efficiencies of

mercury. This may be an appropriate application for low-sulfur PRB and other subbituminous coals, but not necessarily for facilities utilizing high- or low-sulfur bituminous coals.

DOE/PETC (now FETC) conducted a "Boiler Duct Configuration Survey" of targeted electric utility boilers to gather information on the general design basis for existing duct configurations upstream of fine particulate control devices. (U.S. DOE, August 1988; and October 1993) The survey was conducted to allow for the prediction of optimum operating conditions and component designs needed to determine the applicability of duct injection technologies for SO_2 reductions where WFGD systems may not be as cost effective.

Approximately 87 GWe of net generating capacity was surveyed in 1986 and 1987, to identify the parameter ranges for future R&D efforts, and provide the information to design engineers, if duct injection was commercially available. The information gathered under this survey is directly applicable to the various options utilizing sorbent injection, with and without flue gas cooling, for mercury capture. It was determined, based on the survey of current duct parameters, that a lower drying time for the injected sorbent slurries of 1 to 1.5 seconds would be needed, while an increase in sorbent reactivity for optimum SO_2 capture was also needed.

At 100% load through the longest straight runs, velocity of the flue gases representing 72% of the generating capacity, has a nominal velocity of 50 ft/sec. The corresponding nominal flue gas temperature at 100% load in the straight run was 290 °F (143 °C). The most critical factor for highly efficient capture of mercury with activated carbon is residence time of carbon in the flue gas within the ducts at a lower temperature, prior to entering the particulate collector (in this case, an ESP). The survey indicated a nominal residence time at the above conditions to be in the range of <0.5 to 1 second. Even though there is an increase in flue gas residence time with decreasing temperature, effective residence times may not be realized.

As a reference point, optimum conditions for duct injection resulting for SO_2 control is typically achieved with a 20 to 30 °F (11 to 17 °C) approach to the adiabatic saturation temperature [approximately 127 °F (63 °C)]. These conditions were achieved in the Coolside sorbent injection demostration as part of the Clean Coal Technology demonstration program (U.S. DOE, September 1990). The residence time of the duct injection humidification chamber was about 2 seconds at full load—at the high end of residence time available in straight length ducts at existing power plants.

Residence time is one of the most critical parameters for any sorbent technology including activated carbon injection for mercury capture, owing to (1) the amount of time the injected activated carbon has in the flue gas before collection in the ESPs, since mercury is not captured by activated carbon in the ESP; and (2) the amount of time needed to sufficiently reduce the flue gas temperature for optimum mercury capture by the injected activated carbon.

In addition, facilities utilizing bituminous coals may not effectively utilize humidification for flue gas cooling to enhance mercury control as a result of the formation of sub-micron sulfuric acid mist from sulfur trioxide (SO_3) condensing at or below the acid dew point of the flue gas. The sulfuric acid dew point for high moisture content in the flue gas is nominally in the 230 to 270 °F (110 to 132 °C) temperature range. (U.S. DOE, March 1998) The SO_3 may be a result of coal combustion or injected separately or in combination with ammonia for enhancing fine particle collection (mainly PRB and other subbituminous coals). In addition, 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. This conversion could dramatically reduce the bag life of the baghouse system.

Based on the survey and other flue gas considerations, the configuration of ducts in the utility industry presents many limitations in providing effective reduction of the flue gas temperature from the survey average of 316 °F (158 °C) to temperatures at or below the acid dew point, 230 to 270 °F (110 to 132 °C) for optimum mercury capture with activated carbon. This alone may be the one limiting factor impacting the development of a low cost mercury control for the utility industry through activated carbon injection.

The above limitations in optimizing mercury capture associated with activated carbon impacts a majority of the utility population in the United States. These limitations would compromise lower activated carbon injection rates at lower temperatures, and could require carbon-to-mercury ratios between 50,000:1 to 100,000:1 upstream of an ESP. Caution must be taken when estimating possible carbon-to-mercury ratios for the 65% of the coal-fired utility industry utilizing an ESP as the only APCD. With multiple ducts, short straight duct lengths, and limited residence times, the technical and economic performance criteria of the control technology would be impacted. Future design and system performance modeling activities needs to properly account for these limitations. Possible power plant equipment that may require new or modified components include duct and chimney liners or new fabrications, fan upgrades, and particulate collection system upgrades.

A sensitivity analysis for mercury emission control has been performed to examine how control options may impact the diverse U.S. power plant population (see Figure ES-1). The first option considers setting an emissions cap of 0.03 tons of mercury emitted per million tons of coal consumed. Approximately 10% of the U.S. power plants fall under this cap with little or no need for additional control. Power plants

representing about half of the total coal consumption would require less than 40% additional control. Only a few utilities, representing about 10% of the total coal consumption, would require fairly significant control. Even for these utilities, the control would only range from two-thirds to 85% reduction from the existing emissions level. The remaining 30% of power plants would require approximately 40 to 67% mercury emissions reduction. The overall reduction in mercury emissions from the national mercury emissions inventory estimate for the reference year of 1996 is about 50%.

In the second option, 90% reduction of mercury contained in the mined coal is considered. This scenario credits mercury removal from coal preparation and existing power plant controls toward the overall goal. Utilities representing approximately 60% of the coal consumed in the United States would require reduction between 80 and 90%. Nearly all utilities would require reductions of at least 50%. The overall reduction in mercury emissions from the national mercury emissions inventory estimate for the reference year of 1996 is about 80%.

Mercury control options are highly dependent on the existing power plant's operating characteristics and design. As stricter control options are considered, the flexibility to achieve these reductions begins to diminish.

Appropriate environmental control measures for mercury emissions is undergoing scrutiny from a variety of perspectives. From a health perspective, the Agency for Toxic Substance and Disease Registry (ATSDR) announcement of a recommended mercury reference dose (MRD), or mercury risk level (MRL), of 0.3 μg Hg /kg-bw/day (gram of mercury per kilograms of body weight per day) indicates mercury levels in the United States ecosystems may be able to tolerate higher mercury levels. This recommendation is based upon the Seychelles Island studies compared to EPA's calculated 0.1μg Hg/kg-bw/day based upon acute exposure of eating mercury contaminated seeds in Iraq. If a MRL of 0.3μg Hg/kg-bw/day limit is adopted, it is estimated that 90% to 95% of the state fish advisories would not be required.

As our understanding of mercury behavior in coal-fired power plants improves, refinements to models of mercury emissions and control costs will likely be made. Some consideration for modeling improvements available from this review are recommended in the following.

(1) Incorporating the mercury speciation and total mercury measurements collected under the DOE/FETC and EPRI measurement programs conducted on coal-fired utilities with the Ontario Hydro Method.
   - Over 80% of the total mercury values exiting the boilers (preheater) are below 10 mg/Nm^3.
   - The ratio (speciation) between Hg^0 and Hg^{2+} in the flue gas varies from 90:10, and 10:90, with a nominal ratio of 70:30. There is less oxidized Hg than assumed in previous modeling efforts.

(2) Both Hg^0 and Hg^{2+} are capable of being captured with the fly ash in flue gas streams from coal-fired power plants.
   - 30% in-flight Hg capture associated with PRB coal fly ash, little to no capture in an downstream ESP, while as high as 90% of the Hg associated with fly ash is captured in a fabric filter. A nominal 60% is realized.
   - 10 to 20% in-flight Hg capture associated with lignite and bituminous coal fly ashes, with little to no Hg capture associated across the ESP.
   - 50 to 55% vapor-phase Hg capture across wet FGD systems, with a range from 85 to 95% of the Hg^{2+} being removed.
   - 60 to 66% total Hg capture in ESP/wet FGD systems while scrubbing flue gas from the combustion of medium- to high-sulfur eastern bituminous coals (~50% of the scrubbed capacity in the United States).

(3) With more than one-third of the utility industry utilizing PRB/subbituminous coals, there will be a considerable amount of mercury captured with the fly ash.

(4) Plants equipped with wet and dry FGD systems do remove Hg at high levels (Hg^{2+} and in dry FGD cases Hg^0). It should be noted that the high mercury removals are associated with power plants firing bituminous coals. Lower mercury removal levels have been measured across WFGD systems at plants firing either PRB/subbituminous or lignite coal. Even though more than 60% of the Hg^{2+} is removed, it only constitutes 10 to 30% of the total mercury.

(5) The impacts of low NO_x burners, selective catalytic and non-selective catalytic reduction of NO_x (SCR and SNCR, respectively) are currently being assessed for possible conversion of Hg^0 to Hg^{2+}, and possible mercury reductions.

The importance of properly accounting for mercury emissions from coal-fired power plants through understanding the complex behavior of mercury speciation and its interaction with flue gas and associated flue gas control equipment is amply described in the above documentation and analysis. Having placed these matters in context of our current understanding of mercury emissions, the U.S. coal-fired power generation industry's contribution to the global inventory can be more seriously debated as well as any considerations put forward to increase control levels beyond those currently realized with existing processes and equipment.

The EPA Information Collection Request (ICR) for mercury concentrations in coal and flue gas streams will

augment the previous DOE and EPRI measurements, and the findings on the distribution and fate of the Hg^0 and Hg^{2+} in utility boiler systems. DOE/FETC and EPRI support of industry's progress in advancing the state-of-the art understanding of mercury measurements and control in the utility industry, is thought to enhance any future regulatory process or requirement by the sound science achieved through these investigations. The on-going EPA ICR mercury data collection effort and the National Academy of Sciences (NAS) study will also be important factors in any regulatory decision.

DOE/FETC, in collaboration with EPA, EPRI, and USGS, is developing a program to demonstrate the most promising mercury control technologies at a larger scale or full-scale at different coal-fired utilities. DOE will issue a solicitation before the end of fiscal year 1999 (September 30, 1999). The solicitation, which will ask for proposals to scale up the promising technologies, will require contractor and industrial cost sharing. These demonstrations need to be completed through many collaborative efforts, before any regulatory decisions can be made based upon sound science. There are many engineering and technical issues that need to be addressed before mercury control is implemented in the utility industry.

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