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BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:)
)
PROPOSED NEW 35 ILL.ADM.CODE PART 225) **PCB R06-25**
CONTROL OF EMISSIONS FROM) **Rulemaking - Air**
LARGE COMBUSTION SOURCES)

NOTICE OF FILING

To:

Dorothy Gunn, Clerk Illinois Pollution Control Board James R. Thompson Center Suite 11-500 100 West Randolph Chicago, Illinois 60601	Persons included on the **ATTACHED SERVICE LIST**

PLEASE TAKE NOTICE that we have today filed with the Office of the Clerk of the Pollution Control Board the **Testimony** of the following witnesses, copies of which are herewith served upon you: **Peter M. Chapman, Ph.D.; Gail Charnley, Ph.D., and Attached Exhibits; J.E. Cichanowicz; William DePriest and Attached Exhibits; James Marchetti; Richard D. McRanie; Ishwar Prasad Murarka, Ph.D.;** and **Krish Vijayaraghavan**.

/s/ Kathleen C. Bassi
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Dated: July 28, 2006

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TESTIMONY OF PETER M. CHAPMAN, Ph.D.

1.0 Qualifications

My name is Peter M. Chapman. I am an internationally recognized expert in the fields of aquatic ecology, ecotoxicology, and environmental risk assessment, with particular expertise and experience in the environmental fate and effects of metals including mercury. I have published over 150 scientific journal articles and book chapters, written over 200 technical reports, and made over 100 presentations at scientific meetings. I am Senior Editor of the international peer-reviewed journal, *Human and Ecological Risk Assessment*, a member of the Editorial Boards of two other international journals, editor of a popular, on-going series of scientific discourses, and have held advisory appointments with the National Research Councils of both Canada and the United States as well as with the USEPA Science Advisory Board. In 2001 the Society of Environmental Toxicology and Chemistry (SETAC) awarded me its Founders Award, their most prestigious award for an outstanding career and contributions to the environmental sciences. Since 1999 I have been part of the Natural Sciences and Research Council (NSERC)-funded network of university researchers originally titled “Metals in the Environment” [www.mite-rn.org] and now titled “Metals in the Holistic Environment” [www.mithe-rn.org]. My role in the Network is to integrate the work done by researchers and universities participating in the Network into a risk assessment framework for decision-making. My specific focus in this regard is metals including mercury in aquatic ecosystems. My curriculum vita is provided as Attachment 1.

2.0 Summary of Testimony

My testimony initially explains what happens to mercury when it is deposited from the atmosphere or other sources into aquatic environments. I then evaluate the possibility of a linkage between mercury emissions from coal-fired power plants in Illinois and mercury in fish in Illinois waters related to lifting impaired water restrictions.

The basis for Illinois EPA's proposed mercury rule is well summarized in the testimony of Jim Ross at page 5: "A key concept in understanding the need and methods for mercury control is that although mercury air emissions are the target for reductions, the ultimate goal is to reduce methyl mercury levels in water bodies and, hence, fish tissue." Accordingly, the focus of my testimony is this "key concept"; specifically, my testimony answers the following two key questions:

Question 1: *Will reducing inorganic mercury emissions from coal-fired power plants in Illinois under the proposed rule reduce organic (methyl) mercury concentrations in fish living in water bodies in Illinois to the same extent?*

Question 2: *Will reducing inorganic mercury emissions from coal-fired power plants in Illinois under the proposed rule ensure that impairment restrictions can be lifted for water bodies where fish have elevated mercury concentrations?*

The answer to both of these questions, as my testimony clearly demonstrates, is "No". ***The goal of the proposed rule, as summarized in Marcia Willhite's written testimony at page 4 ("In order to assure that 95% of largemouth bass in Illinois waters may be consumed in unlimited quantities by sensitive subpopulations, a 90% reduction of mercury in fish tissue is needed"), will not be achieved.***

3.0 Mercury in the Environment

The relationship between inorganic mercury emissions and organic mercury in the environment including fish is complex[1]. For instance, when mercury is emitted from coal-fired power plants it is as an inorganic substance – typically elemental mercury (Hg^0), divalent mercury (Hg^{2+}, also termed reactive gaseous mercury, or RGM), and particulate mercury[2], and can change form as it travels downwind[3]. Inorganic mercury is also emitted from a wide variety of other sources including motor vehicles, incinerators, crematoria, forest fires, deep sea vents, volcanoes, oceans, soils, etc[4]. Although estimates vary, about half the mercury emitted to the atmosphere is natural, and about half is due to human activities[5]. All states and countries have some level of mercury emissions; the greatest current levels of human emissions appear to be from China related to its rapid industrialization[6]. ***Contamination due to mercury is a world-wide problem[7].***

Mercury in the atmosphere can be deposited onto land or water via either dry deposition (e.g., dust) or wet deposition (e.g., rain, snow)[8]. Wet deposition can result in some forms of mercury coming down closer to emission sources than others. But mercury deposited to land or water may not remain there; mercury can be re-emitted back to the atmosphere where it is transported further. For instance, Dr. Keeler (one of Illinois EPA's witnesses) and his co-workers have shown that re-emission of dissolved gaseous mercury from Lake

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[1] Eisler R. 2006. Mercury Hazards to Living Organisms. Published by Taylor and Francis, Boca Raton, FL, USA.

[2] Marcia Willhite's verbal testimony on June 14, 2006: at page 32 of the transcript of that testimony.

[3] Lohman K, Seigneur C, Edgerton E, Jansen J. 2006. Modeling mercury in power plant plumes. Environ Sci Technol 40: 3848-54.

[4] Eisler 2006, op. cit.; also, written testimony of Gerald Keeler at page 3, indicates that motor vehicle sources contribute mercury to the atmosphere.

[5] USEPA. 2005. Mercury emissions: The global context. www.epa.gov/mercury/control_emissions/global.htm; also, Landis MS, Vette AF, Keeler GJ. 2002. Atmospheric mercury in the Lake Michigan basin: Influence of the Chicago/Gary urban area. Environ Sci Technol 36: 4508-17.

[6] Seigneur C, Vijayarghavan K, Lohman K, Karamchandani P, Scott C. 2004. Global source attribution for mercury deposited in the United States. Environ Sci Technol 38: 555-69; also, Jiang G-B, Shi J-B, Feng X-B. 2006. Mercury pollution in China. Environ Sci Technol 40: 3673-8; also, Gerald Keeler's verbal testimony on June 15, 2006: at page 17 of the transcript of that testimony.

[7] Eisler 2006, op. cit.; also, Gerald Keeler's verbal testimony on June 15, 2006: at page 17 of the transcript of that testimony.

[8] Dvonch JT, Graney JR, Keeler GJ, Stevens RK. 1999. Use of elemental tracers to source apportion mercury in south Florida precipitation. Environ Sci Technol 33: 4522-7.

Michigan is a process that significantly reduces net atmospheric deposition[9]. In fact, Dr. Keeler in testimony before the U.S. House of Representatives stated, "…previously deposited mercury can also undergo chemical transformations that convert it back to the elemental form that readily leaves the earth's surface (land and water) to re-enter the global background of mercury"[10]. Similarly, Illinois EPA's Technical Support Document (the "TSD") mentions mercury volatilizing from water back into the atmosphere. Thus, ***once mercury enters the atmosphere, it becomes part of a global cycle of mercury among land, water, and the atmosphere; past activities continue to affect current atmospheric mercury concentrations[11].***

The inorganic mercury that remains in water bodies (either from the atmosphere or from other sources) can undergo different biological and physico-chemical processes (Figure 1). The mercury cycle is a complex biogeochemical system involving both biotic and abiotic transformations of the different forms of mercury. Inorganic mercury species that are not reduced to form gaseous elemental mercury have an affinity for particulates and organic matter and thus will tend, if not re-emitted, to sink down to and accumulate in the sediments. The sediments of water bodies thus serve as both a sink and a reservoir for mercury contamination. They can also be a source of potential mercury pollution[12].

Although most inorganic mercury remains in this form in the sediments, a portion[13] of that mercury can be converted to an organic form of mercury, methyl mercury. This conversion occurs primarily by metabolism within sulphate- and iron-reducing bacteria living in anaerobic sediments, i.e., sediments without oxygen[14]. Mercury methylation

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[9] Landis MS, Keeler GJ. 2002. Atmospheric mercury deposition to Lake Michigan during the Lake Michigan mass balance study. Environ Sci Technol 36: 4518-24; Vette AF, Landis MS, Keeler GJ. 2002. Deposition and emission of gaseous mercury to and from Lake Michigan during the Lake Michigan mass balance study (July, 1994 – October, 1995). Environ Sci Technol 36: 4525-32.

[10] Keeler GJ. 2001. The problem of mercury. Testimony for the U.S. House of Representatives Committee on Science Hearing on Acid Rain: The State of the Science and Research Needs for the Future. May 3, 2001.

[11] Eisler 2006, op. cit.

[12] Eisler 2006, op. cit.

[13] Marcia Willhite's verbal testimony on June 14, 2006 states "it has been estimated that .7 to .0006 percent of total mercury in sediment is methylmercury": at page 40 of the transcript of that testimony.

[14] Fleming EJ, Mack EE, Green PG, Nelson DC. 2006. Mercury methylation from unexpected sources: Molybdate-inhibited freshwater sediments and an iron-reducing bacterium. Appl Environ Microbiol 72: 457-64; also, Jeremiason JD, Engstrom DR, Swain EB, Nater EA, Johnson BM, Almendinger JE, Monson

generally cannot occur in aerobic (oxygenated) environments; in the water column it can occur only when conditions are anoxic (there is no oxygen). Methyl mercury production occurs not just in recently deposited surface sediments but also in much older, deeper sediments where the mercury was deposited decades previously, even though "old" inorganic mercury in sediments tends to be less biologically available than "new" inorganic mercury in sediments[15]. Methyl mercury from these deeper sediments can reach organisms living in shallower sediments by a process called diagenesis, which typically occurs in sediments with low organic carbon content. There is a depth beyond which, absent unusual disturbances, the mercury in the sediments will not reach animals or plants, but burial to such a depth is typically a slow process under natural conditions. As noted in the Florida study there is "slow mobilization of historically deposited mercury from deeper sediment layers to the water column. Until buried below the active zone, this mercury can continue to cycle through the system"[16]. Thus, even when emissions of inorganic mercury are reduced, there will be a substantial lag phase before emission reductions can result in reductions in methyl mercury concentrations in fish.

Production of methyl mercury in sediments is not a readily predictable process and can be highly variable between water bodies[17] (Table 1). There is not a 1:1 relationship between inorganic mercury released to the atmosphere and deposited in water bodies and the level of methyl mercury found in water bodies and fish tissue. For instance, methyl mercury produced in water bodies from inorganic mercury deposition can be augmented by direct precipitation of methyl mercury from other sources, including: the atmosphere, runoff from land, or inputs from other water bodies such as wetlands[18].

BA, Kolka RK. 2006. Sulfate addition increases methylmercury production in an experimental wetland. Environ Sci Technol 40: 3800-6.

[15] Fleming et al. 2006, op. cit.

[16] Florida Dept of Environmental Protection. 2003. Integrating atmospheric mercury deposition with aquatic cycling in South Florida: An approach for conducting a total maximum daily load analysis for an atmospherically derived pollutant: at page iii.

[17] Marcia Willhite's verbal testimony on June 14, 2006 notes that the characteristics that impact mercury methylation are water body specific, can differ between water bodies, and that mercury methylation is highly dependent on water chemistry and biology, in particular pH, dissolved oxygen, dissolved organic carbon, nutrients, selenium concentrations, temperature, sulphate concentrations, drainage size to lake volume ratio, percentage of wetland and watershed, conductivity and water level flucturations: at pages 45 to 47 of the transcript of that testimony. She made similar comments elsewhere in her verbal testimony: e.g., at page 37 of the transcript of that testimony.

[18] Eisler 2006, op. cit.

Table 1
Example of Physico-Chemical Processes Affecting Mercury Methylation[19]

Physico-Chemical Condition	**Methylation**	
	Enhanced ↑	**Decreased ↓**
Low dissolved oxygen	***Yes***	
Low pH	***Yes*** (in water)	***Yes*** (in sediment)
Increased dissolved organic carbon	***Yes*** (in sediment)	***Yes*** (in water)
Increased conductivity or salinity		***Yes***
Increased nutrients	***Yes***	
Increased selenium		***Yes***
Increased temperature	***Yes***	
Increased sulphate or sulphide	***Yes***	

Point and non-point source discharges continue to contribute mercury to water bodies. For example, Marcia Willhite notes at page 144 of the transcript of her June 14, 2006 verbal testimony, that runoff may be a significant source of mercury in southern Illinois. Interestingly, at page 118 of the transcript of that same testimony, Ms Willhite notes that historical data suggest that the levels of mercury in fish are higher than expected in waters in the far southern end of the State.

The TSD indicates (at pages 68 and 69, including Table 4.7) that, at "maximum" discharge levels, the 137 wastewater point sources in Illinois would discharge approximately 1.5 tons of mercury per year compared to 45 pounds at an "average" discharge level. Marcia Willhite confirmed in her testimony (June 14, 2006, at pages 288-290 of the transcript) that the "maximum" load or discharge level was based on actual measured maximum flow and maximum mercury concentrations in the flow, which would comprise approximately 1.5 tons, or about half of the mercury air emissions from coal-fired power plants as indicated in the TSD (3 tons at page 60). Other un-measured sources of mercury exist including combined sewer overflows, which Illinois EPA does not sample for mercury but which contain mercury[20]. Thus other local sources of mercury

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[19] Developed based on information contained in Eisler 2006, op. cit.

[20] Available data on mercury related to combined sewer overflow discharges for the Metropolitan Water Reclamation District of Greater Chicago reviewed by Dr. Chapman suggest that inputs can be on the order of tens of pounds per year.

(as well as sources outside the State) will have inputs to different water bodies that likely are, in some cases, greater than those from coal-fired power plants.

Similarly, production of methyl mercury in the sediments of water bodies is governed by: microbial community composition, geochemical conditions that affect the activity of methylating bacteria (e.g., availability of carbon, abundance of electron acceptors such as sulphate), and availability of inorganic mercury in a suitable (bioavailable) form for methylation. Availability of carbon and the cycling of sulphur are major constraints on the process of mercury methylation. For instance, although sulphate is essential for the methylation process, excessive amounts of sulphate can actually poison the mercury methylation process by limiting the availability of mercury to methylating bacteria. The key Florida study cited in the TSD notes, "Sulfate is an important influence on the production of methylmercury, affecting not only mercury transformations, but also the biological availability of mercury for uptake….[sulphate] is an important cofactor controlling the severity of the mercury problem at any given site"[21]. Methyl mercury concentrations in fresh water bodies in the U.S. may have increased historically due to increases in atmospheric sulphate deposition. ***Decreases in sulphate deposition alone, with no change in mercury inputs, could result in lower methyl mercury levels in freshwater fish***[22]. It is thus entirely possible that reductions in sulphate deposition rates resulting from the Acid Deposition Program were at least partly responsible for decreased methyl mercury concentrations seen, for instance, in Massachusetts from 1999 to 2004.

In addition, demethylation can occur in sediments (Figure 2), also mediated by naturally occurring microbes – possibly as a defense against mercury toxicity[23]. In most, but not all anaerobic systems, mercury methylation rates are greater than demethylation rates. However, ***methyl mercury concentrations and production rates vary more than do inorganic mercury deposition rates***. For instance, a simple change in bacterial activity alone could "cause an increase in fish mercury concentrations even as atmospheric

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[21] Florida Dept of Environmental Protection 2003, op. cit., at page vi.
[22] Jeremiason et al. 2006, op. cit.
[23] Eisler 2006, op. cit.

deposition [from industrial mercury emissions] decreases"[24]. Thus there can be, for instance, freshwater systems containing relatively high concentrations of inorganic mercury but relatively low concentrations of methyl mercury because conditions are either less than optimum for mercury methylation, or demethylation is the predominant process. And the reverse can also occur. Thus, it is not surprising that the TSD reports that Illinois lakes with the highest mercury concentrations were not the same lakes as had fish with the highest mercury concentrations.

When the organic form of mercury, methyl mercury, is present in a water body, this organic form can biomagnify through food chains via the diet. Biomagnification is the process by which a few organic chemicals (methyl mercury is one, PCBs are another) increase in concentrations through successive levels of the food chain as a result of dietary uptake. Fish absorb methyl mercury when they eat smaller aquatic organisms. Larger and older fish absorb more methyl mercury as they eat other fish. Aside from the concentrations of methyl mercury in the water body and sediment, which depend on the factors discussed above, the level of mercury contamination in fish can be affected by factors such as changing water levels[25] and dissolved organic matter[26]. In this way, the amount of methyl mercury builds up as it passes through the food chain. Methyl mercury generally reaches the highest levels in predatory (piscivorous [fish-eating]) fish at the top of the aquatic food chain.

Some of the highest recorded mercury levels found in fish are in marine fish such as tuna and swordfish, which are commonly found in supermarkets in Illinois[27]. Mercury levels are also higher in older than in younger fish because older fish have had more time to accumulate higher levels of mercury. In fresh water environments piscivorous fish such as walleye and northern pike, found at the top of the food chain, tend to have the highest

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[24] Mason RP, Abbott ML, Bodaly RA, Bullock OR Jr, Driscoll CT, Evers D, Lindberg SE, Murray M, Swain EB. 2005. Monitoring the response to changing mercury deposition. Environ Sci Technol 39: 14A-21A.

[25] Sorensen JA, Kallemeyn LW, Sydor M. 2005. Relationship between mercury accumulation in young-of-the-year yellow perch and water-level fluctuations. Environ Sci Technol 39: 9237-43.

[26] Ravichandran M. 2004. Interactions between mercury and dissolved organic matter – a review. Chemosphere 55: 319-31.

[27] Burger J, Gochfeld M. 2006. Mercury in fish available in supermarkets in Illinois: Are there regional differences. Sci Total Environment: in press.

mercury levels in their tissues. Most of the mercury in fish is in the form of methyl mercury, which can be excreted by fish, but more slowly than inorganic mercury. Thus, if fish are not exposed to new sources of methyl mercury in their diet they will begin to rid themselves of the methyl mercury in their bodies. This is not a fast process, but it does occur faster at higher temperatures than at lower temperatures[28].

4.0 Mercury in Illinois Water Bodies and Fish

As noted at page 61 of the TDS "Mercury TMDLs are complicated. The mechanisms controlling mercury accumulation in fish tissue are variable and difficult to model, resulting in questionable values…sources may be outside the watershed, state or nation." However, the key issue related to the proposed rule is, as previously noted, the relationship between inorganic mercury emitted from coal-fired power plants in Illinois and organic (methyl) mercury in fish in Illinois waters.

As noted above, the pathway for inorganic mercury from the power plants reaching the fish would be via atmospheric deposition into water bodies containing those fish. The mercury would then have to accumulate in the sediments where some of it would be transformed into the organic (methylated) form which would then accumulate in fish via dietary uptake. Further, to have any possible health impact on an Illinois resident, that resident would need to eat such fish. Whether or not consumption of fish with elevated mercury concentrations will impact the health of human consumers requires consideration of factors including the protective effects of selenium in tissues[29].

The relationship between the power plant mercury emissions and mercury in fish in Illinois can be assessed using two key pieces of information: sediment mercury data, and fish mercury data. To obtain this information, Illinois mercury sediment and fish tissue data for the past 30 years were downloaded from the USEPA's STORET data base. The specific focus was on waters where fish had total mercury concentrations above threshold values of 0.1 and 0.23 ppm (mg/kg wet weight). The State of Illinois uses an initial

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[28] Eisler 2006, op. cit.

[29] Raymond LJ, Ralston NVC. 2004. Mercury:selenium interactions and health implications. Seychelles Med Dental J 7: 72-7.

threshold value of 0.06 ppm for advising no more than one meal per week of fish (range of 0.06 to 0.22 ppm); however, because this value has been close to or below the detection limits used by some chemical analytical laboratories, a value of 0.1 ppm was used to provide more dependable data for comparison purposes[30]. Fish mercury values of 0.23 ppm and above are subject to the special mercury advisory[31]. Tables 2 and 3 summarize these data, and Figures 3 and 4 present these data in graphical form. The mercury sediment concentrations were at times both higher and lower than the fish concentrations. ***Thus, there is no consistent relationship between total mercury concentrations in sediments and mercury concentrations (primarily methyl mercury) in fish tissues of impaired waters.***

Power plant locations and Illinois impaired waters are also shown in Figures 2 and 3. Exceedances of 0.1 and 0.23 ppm total mercury levels in fish were not always found at sites in close proximity to power plants, nor were impaired waters always associated with power plants. Moreover, given that the winds in Illinois are primarily south, southwest and north, northwest in the winter[32], emissions from power plants do not appear to be responsible for all waters in Illinois impaired due to mercury (e.g., Rock River). Thus, ***there is no clear and consistent relationship between Illinois coal-fired power plants and methyl mercury concentrations in fish in Illinois waters.*** This finding is not unexpected given the complexity of the global mercury cycle. Although there is no question that coal-fired power plants are significant sources of mercury to the atmosphere, they are not the largest sources of mercury deposited in Illinois[33]. These emissions cannot be directly related to mercury concentrations in fish collected from

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[30] Illinois EPA, in the TSD, assumes that if mercury is not detected, it is present at 50% of the detection limits [cf Marcia Willhite's verbal testimony of June 14, 2006: e.g., at pages 84-85 and pages 158-160 of the transcript of that testimony]. However, this practice is questionable given that it means that mercury is assumed to be present when it may not be. Better methods exist for dealing with values below detection limits: e.g., Shumway RN, Azari RS, Kayhanian M. 2002. Statistical approaches to estimating mean water quality concentrations with detection limits. Environ Sci Technol 36: 3345-53; also, Helsel DR. 2005. More than obvious: Better methods for interpreting nondetect data. Environ Sci Technol October 15, 2005: 419A-23A.

[31] Clarification regarding the 0.06 and 0.23 ppm mercury values was provided by Dr. Hornshaw in verbal testimony on June 14, 2006: at pages 25 and 26 of the transcript of that testimony.

[32] Gerald Keeler's verbal testimony of June 15, 2006: at page 32 of the transcript of that testimony.

[33] K Vijayaraghavan in his testimony at page 7 estimates "U.S. coal-fired power plants are calculated to contribute 19% of mercury deposition in Illinois in 2006."; also, see Section 3.0, page 4 of the present document (Testimony of Peter M. Chapman)

nearby water bodies. Further, Illinois' proposed rule would only result in a 4% reduction in depositions in Illinois from Illinois coal-fired power plant mercury emissions compared to the CAMR[34], which would likely not result in a measurable decrease in mercury concentrations in fish in Illinois water bodies compared to the CAMR. As noted at page 3 of Gerald Keeler's testimony, "The relationship between the emissions of mercury to the atmosphere from any one plant and the amount received at any receptor is complex." Interestingly, as noted by Thomas Hornshaw in his verbal testimony of June 16, 2006 (at pages 84-85 of the transcript), Illinois fish tissue mercury levels are lower than in some other Great Lakes States.

The discussion above explains the "no" answer to Question 1 (Section 2.0). The discussion below explains the "no" answer to Question 2 (Section 2.0).

The Illinois 2004 Section 303(d) List[35] was reviewed, to identify water bodies considered impaired by the State due to mercury and/or PCB concentrations. Table 4[36] summarizes these sites, listing water body name, site name, and whether the site is impaired due to levels of mercury and/or PCBs. Fifty-five of the 74 sites (74%) in Illinois listed as impaired due to mercury would continue to be impaired even if full compliance with the proposed rule were achieved and the projected fish mercury reductions were achieved. The presence of PCBs renders the proposed rule ineffective at removing impairment restrictions. Thus, even if fish mercury levels were to drop below the State mercury threshold for impaired waters, which is highly unlikely as noted previously, the classification of these sites as impaired would not change.

5.0 Florida, Massachusetts and Ohio Studies: Relevance to Illinois

We have found no published studies that specifically evaluate coal-fired power plant mercury emissions and trends in methyl mercury levels in fish. The TSD relies on data from Florida and Massachusetts to support its conclusion that reducing local coal-fired power plant inorganic mercury emissions will similarly reduce local fish methyl mercury

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[34] Testimony of K. Vijayaraghavan at page 7.

[35] Illinois Environmental Protection Agency, IEPA/BOW/04-005.

[36] Source: Appendix A of the IEPA 2004 document.

levels. A study in Ohio is also mentioned in testimony by IEPA witness Dr. Keeler, however complete details of this study (i.e., the full report) have not been provided by Dr. Keeler.

As noted in the TSD, Massachusetts has implemented mercury reduction programs, but has not specifically focused on coal-fired power plants. The Massachusetts study[37] monitored mercury concentrations in Largemouth bass (LMB) and yellow perch (YP) from 1999 to 2004. The authors noted at page viii that "Over this period consistent and substantial statistically significant decreases in YP and LMB fish tissue mercury concentrations occurred in most lakes sampled." However, decreases did not occur in all lakes (about 24% showed no decreases for YP and about 35% showed no decreases for LMB), the level of decrease was variable, and there were some inconsistencies (e.g., at page 7, "an apparent large temporal increase in tissue mercury concentrations between 1999 and 2004" in one lake and "a slight increase over the 1999 value" for 2004 fish tissue data from another lake). It was estimated (at page viii) that mercury emissions in the main deposition area identified in the TSD "decreased by about 87% between the late 1990's and 2004 due to new pollution controls on municipal solid waste combustors (MSWC) and the closure of medical waste incinerators (MWIs) and a MSWC in the area." But there was far from a 1:1 relationship between decreased emissions and decreased methyl mercury concentrations in fish; in fact, the Massachusetts study[38] concluded that "…significant reductions from out-of-state mercury sources will likely be needed to achieve water quality and public health objectives in Massachusetts." The page and a half in the TSD dedicated to the Massachusetts study provides an overly simplified summary of this complex study, as does Marcia Willhite's testimony.

Similarly, the TSD does not deal fully with the Florida study, which is a modeling study that makes predictions that do not appear to be supported by available data. Marcia Willhite, in her testimony, also simplifies the findings of the Florida study. Just a few of

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[37] Massachusetts Dept of Environmental Protection. 2006. Massachusetts Fish Tissue Mercury Studies: Long-Term Monitoring Results, 1999-2004.

[38] Massachusetts Dept of Environmental Protection. 2006. op. cit., at page viii.

the caveats noted at page v of the Florida study report include[39]: the major assumption that all mercury deposited via wet deposition was from local sources which cannot be the case given global cycling of mercury; the acknowledgment that mercury cycling cannot yet be fully modelled; and the fact that different areas might respond differently due to site-specific differences (e.g., different habitat, food web dynamics and water quality). Of note, Figure 5.7 in the TSD is labeled "Relation between Atmospheric Mercury Load and Body Burden in Largemouth Bass", whereas in the original Florida study (Figure 9, at page 40) it is labelled "Predicted Hg concentrations in age 3 largemouth bass as a function of different long term constant annual rates of wet and dry Hg(II) deposition." The fact this is a prediction rather than reality is not mentioned in the TSD.

The actual field data reported in the Florida study do show some correlations between reducing emissions and decreases in methyl mercury concentrations in some biota at some locations, which is not unexpected. However, the actual data do not show a 1:1 relationship and in some locations show no correlation, which is also not surprising given the simplifications made by the model which the authors of the Florida study acknowledge but which the TSD does not mention. There are several examples in the Florida study of differences between the 1:1 prediction and the reality. For example, although emissions showed a declining trend from 1994 to 2000, mercury wet deposition for this same time period remained relatively constant (Figure 24 at page 81 of the Florida study report). The Florida study report at pages 81-82 assessed trends in mercury concentrations in biota based on levels in Largemouth bass from 12 sites across Florida, 9 of which were in the Everglades and at least 3 of which were in the study area. There were enough data in only a little over half of the available data sets to conduct statistical tests for significance. The two sites with the most consistent declines are shown in the TSD (Figure 5.5, basically the same figure as Figure 25, at page 83 in the Florida study report). What is not mentioned in the TSD is that there were also examples of no declines as well as of increases in fish methyl mercury concentrations. In fact, as noted in the Florida study report (at page 81) and as confirmed by Gerald Keeler in his verbal testimony on June 15, 2006 (at page 13 of the transcript), about half the cohorts in the

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[39] Florida Dept of Environmental Protection, op. cit.

study area showed no change. The “bottom line” is that, although the Florida modeling suggests a 1:1 relationship between inorganic mercury emissions and methyl mercury concentrations in fish, this relationship is not supported by actual data and, given the simplifications inherent in the model, is highly unlikely to reflect the “real-life” situation.

6.0 Conclusions

At the start of my testimony (Section 2.0) I asked and answered “no” to two key questions, below:

Question 1: *Will reducing inorganic mercury emissions from coal-fired power plants in Illinois under the proposed rule reduce organic (methyl) mercury concentrations in fish living in water bodies in Illinois to the same extent?*

Question 2: *Will reducing inorganic mercury emissions from coal-fired power plants in Illinois under the proposed rule ensure that impairment restrictions can be lifted for water bodies where fish have elevated mercury concentrations?*

The reasons for my answers follow from my detailed testimony above. Reducing inorganic mercury emissions from coal-fired power plants will result in a decreased level of inorganic mercury deposition. However, even if reductions in mercury depositions were to occur in Illinois, reductions in methyl mercury concentrations in local fish will not occur to the same level as the emission reductions. Mercury is a global problem, not just a local problem, and the pathways from inorganic mercury emissions to methyl mercury in fish are complex and governed by site-specific differences that are not readily predictable[40]. Generalizations such as a 1:1 relationship do not reflect reality. ***The amount of methyl mercury in fish is site specific, as confirmed by Marcia Willhite (see footnote 18), and is not related simply to the amount of inorganic mercury that is deposited to a water body.*** Moreover, even if mercury levels in Illinois water bodies were reduced below levels of potential concern, elevated levels of PCBs would still result in an “impaired” designation for the vast majority of those water bodies.

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[40] Eisler 2006, op. cit.

The goal of the proposed rule, as summarized in Marcia Willhite's written testimony at page 4 ("In order to assure that 95% of largemouth bass in Illinois waters may be consumed in unlimited quantities by sensitive subpopulations, a 90% reduction of mercury in fish tissue is needed"), will not be achieved.

Table 2

Relationship between total mercury concentrations in sediments (mg/kg dry weight) and fish tissues (mg/kg wet weight). Source: USEPA's STORET data base. Values represent sites with fish tissue mercury levels at or above 0.1 mg/kg wet weight. Fish data for the year referenced; sediment data for samples collected within a 5-year period of the fish tissue data collection date (2.5 years before and after the date of the tissue collection). Sediment values shown are an average sediment concentration of these 5 years.

County	Total Mercury in Fish Tissue (mg/kg wet weight)	Total Mercury in Sediments (mg/kg dry weight)	Year Fish Data Collected
Jackson	0.185	0.052	1986
Jackson	0.15	0.052	1990
Jackson	0.167	0.115	1988
Jackson	0.167	0.077	1988
Fayette	0.184	0.03	1978
Fayette	0.184	0.04	1978
Fayette	0.13	0.04	1979
Fayette	0.1	0.03	1980
Fayette	0.1	0.035	1980
Fayette	0.205	0.03	1981
Fayette	0.205	0.04	1981
Fayette	0.205	0.035	1981
Fayette	0.205	0.035	1981
Fayette	0.1	0.035	1983
Macoupin	0.26	0.048	1990
Coles	0.21	0.1	1991
Coles	0.1	0.1	1991
Champaign	0.16	0.215	1981
Kankakee	0.12	0.04	1978
Kankakee	0.12	0.05	1978
Kankakee	0.14	0.53	1988
Kankakee	0.14	0.08	1988
Henry	0.22	0.055	1981
La Salle	0.13	0.14	1988
La Salle	0.12	0.029	1990
Henry	0.143	0.037	1978
Henry	0.143	0.03	1978
Cook	0.15	0.331	1974
Cook	0.47	0.061	1990
Cook	0.47	0.1	1990
Cook	0.273	0.1	1991
Cook	0.1	0.221	1990
Cook	0.46	0.091	1991
Cook	0.19	0.49	1981

Table 3

Relationship between total mercury concentrations in sediments (mg/kg dry weight) and fish tissues (mg/kg wet weight). Source: USEPA's STORET data base. Values represent sites with fish tissue mercury levels at or above 0.23 mg/kg wet weight. Fish data for the year referenced; sediment data for samples collected within a 5-year period of the fish tissue data collection date (2.5 years before and after the date of the tissue collection). Sediment values shown are an average sediment concentration of these 5 years.

COUNTY	Total Mercury in Sediments (mg/kg dry weight)	Total Mercury in Fish Tissue (mg/kg wet weight)	Year Fish Data Collected
Coles	0.113	0.23	1979
Coles	0.113	0.26	1979
Cook	0.49	0.24	1981
Cook	0.49	0.25	1981
Cook	0.49	0.27	1981
Cook	0.49	0.23	1981
Cook	0.061	0.61	1988
Cook	0.074	0.47	1990
Cook	0.1	0.26	1991
Cook	0.1	0.25	1992
Cook	0.1	0.31	1991
Cook	0.1	0.27	1992
Cook	0.221	1.4	1988
Cook	0.091	0.46	1991
Du Page	0.1	0.27	1998
Effingham	0.016	0.4	1989
Effingham	0.018	0.33	1989
Effingham	0.023	0.23	1989
Effingham	0.027	0.29	1989
Effingham	0.029	0.33	1989
Fayette	0.035	0.27	1978
Jackson	0.052	0.25	1986
Macoupin	0.048	0.26	1990
Clay	0.016	0.42	1989
Clay	0.024	0.81	1989
Clay	0.012	0.28	1989

Table 4

Summary of current information on waters listed as impaired due to mercury, PCBs, or both as documented in Appendix A of the Illinois 2004 303(d) List (IEPA/BOW/04-005). IEPA, 2004. Illinois 2004 Section 303(d) List. Bureau of Water, Watershed Management Section, Planning Unit. IEPA/BOW/04-005.

Water Body	Site Name	Size	Miles/ Acres	Hg Impaired?	PCB Impaired?	Could Reduction in Mercury Affect Impaired Listing?
Des Plaines	IL_G-15	3.47	miles	✓	✓	NO
	IL_G-22	4.14	miles	✓	✓	NO
	IL_G-26	3.32	miles	✓	✓	NO
	IL_G-28	8.82	miles	✓	✓	NO
	IL_G-30	5.14	miles	✓	✓	NO
	IL_G-32	6.08	miles	✓	✓	NO
	IL_G-35	5.1	miles	✓	✓	NO
	IL_G-36	6.92	miles	✓	✓	NO
	IL_G-03	15.08	miles	✓	✓	NO
	IL_G-11	5.17	miles	✓	✓	NO
	IL_G-23	2.65	miles	✓	✓	NO
	IL_G-39	11.12	miles	✓	✓	NO
	IL_G-07	10.22	miles	✓	✓	NO
	IL_G-08	0.77	miles	✓		YES
	IL_G-25	6.78	miles	✓		YES
	IL_G-26	3.32	miles	✓	✓	NO
	IL_G-01	2.71	miles	✓	✓	NO
	IL_G-12	8.35	miles	✓	✓	NO
	IL_G-14	4.87	miles	✓	✓	NO
Chicago River	IL_HCB-01	2.56	miles	✓	✓	NO
Devils Kitchen	IL_RNJ	810	acres	✓		YES
Little Grassy	IL_RNK	1000	acres	✓		YES
Campus	IL_RNZH	40	acres	✓	✓	NO
Marquette Park Lagoon	IL_RHE	40	acres	✓		YES
E. BR. DuPage R.	IL_GBL-08	5.53	miles	✓		YES
	IL_GBL-10	4.63	miles	✓		YES
Salt Creek	IL_GL	11.19	miles	✓	✓	NO
	IL_GL-03	10.38	miles	✓	✓	NO
	IL_GL-09	11.78	miles	✓	✓	NO
	IL_GL-10	3.64	miles	✓	✓	NO
	IL_GL-19	3.1	miles	✓	✓	NO

Table 4

Summary of current information on waters listed as impaired due to mercury, PCBs, or both as documented in Appendix A of the Illinois 2004 303(d) List (IEPA/BOW/04-005). IEPA, 2004. Illinois 2004 Section 303(d) List. Bureau of Water, Watershed Management Section, Planning Unit. IEPA/BOW/04-005.

Water Body	Site Name	Size	Miles/ Acres	Hg Impaired?	PCB Impaired?	Could Reduction in Mercury Affect Impaired Listing?
Cedar (Jackson)	IL_RNE	1800	acres	✓		YES
Calumet-Sag Channel	IL_H-02	10.35	miles	✓	✓	NO
Little Calumet R. N.	IL_HA-05	5.06	miles	✓	✓	NO
Little Calumet R. S.	IL-HB-01	8.6	miles	✓		YES
	IL_HB-42	406	miles	✓		YES
Arrowhead (Cook)	IL_RHZE	14	acres	✓		YES
Midlothian Reservoir	IL_RHZI	25	acres	✓	✓	NO
Petticone Creek	IL_QA-C4	0.27	miles	✓	✓	NO
Lake-In-The-Hills 1W	IL_RTZZ	54	acres	✓		YES
Rock River	IL_P-14	10.91	miles	✓	✓	NO
	IL_P-20	13.62	miles	✓	✓	NO
	IL_P-23	0.96	miles	✓	✓	NO
	IL_P-15	21.19	miles	✓	✓	NO
	IL_P-06	8.57	miles	✓	✓	NO
	IL_P-21	18.36	miles	✓	✓	NO
	IL_P-04	19.54	miles	✓	✓	NO
	IL_P-06	8.57	miles	✓	✓	NO
	IL_P-24	25.18	miles	✓	✓	NO
	IL_P-25	15.13	miles	✓	✓	NO
	IL_P-09	5.62	miles	✓	✓	NO
Illinois River	IL_D-31	25.49	miles	✓	✓	NO
	IL_D-32	13.89	miles	✓	✓	NO
	IL_D-16	6.58	miles	✓	✓	NO
	IL_D-09	20.09	miles	✓	✓	NO
	IL_D-01	35.09	miles	✓	✓	NO
	IL_D-20	1.17	miles	✓	✓	NO
	IL_D-23	10.52	miles	✓	✓	NO
	IL_D-05	12.19	miles	✓	✓	NO
	IL_D-10	9.38	miles	✓	✓	NO
	IL_D-30	19.92	miles	✓	✓	NO

Table 4

Summary of current information on waters listed as impaired due to mercury, PCBs, or both as documented in Appendix A of the Illinois 2004 303(d) List (IEPA/BOW/04-005). IEPA, 2004. Illinois 2004 Section 303(d) List. Bureau of Water, Watershed Management Section, Planning Unit. IEPA/BOW/04-005.

Water Body	Site Name	Size	Miles/ Acres	Hg Impaired?	PCB Impaired?	Could Reduction in Mercury Affect Impaired Listing?
Kankakee River	IL_F-01	11.54	miles	✓		YES
	IL_F-04	10.04	miles	✓		YES
	IL_F-12	1.76	miles	✓		YES
	IL_F-16	9.57	miles	✓		YES
	IL_F-02	13.46	miles	✓		YES
	IL_F-03	1.97	miles	✓		YES
Kinkaid	IL_RNC	3475	acres	✓	✓	NO
Wabash River	IL_B-01	4.73	miles	✓	✓	NO
	IL_B-06	7.51	miles	✓	✓	NO
	IL_B-03	15.21	miles	✓	✓	NO
Monee Reservoir	IL_RFH	46	acres	✓		YES
Big Bureau Creek	IL_DQ-03	5.31	miles	✓	✓	NO
Bracken	IL_SDZA	172	acres	✓	✓	NO

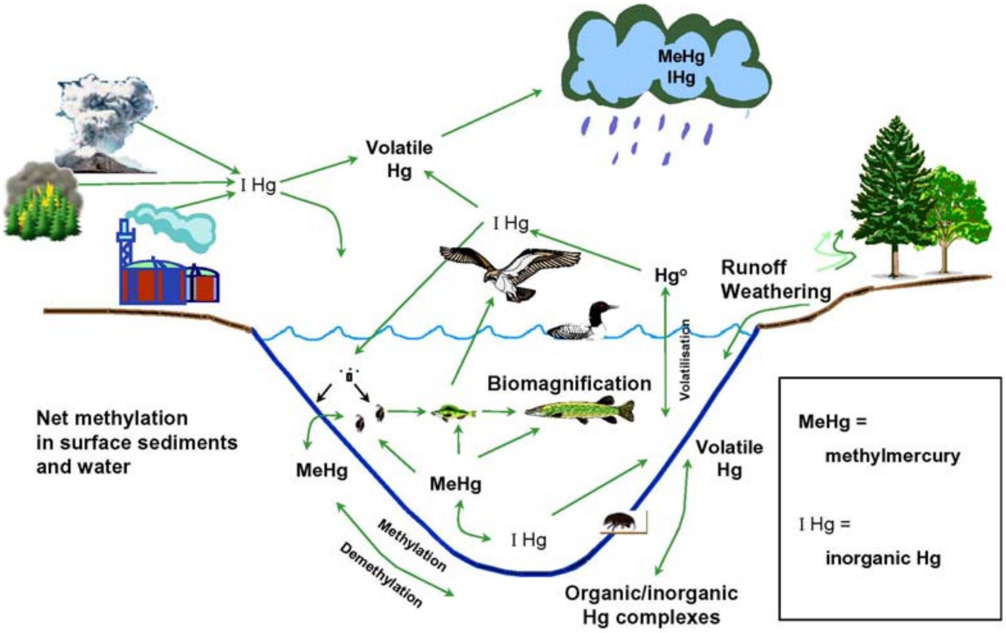

Figure 1
The Mercury Cycle

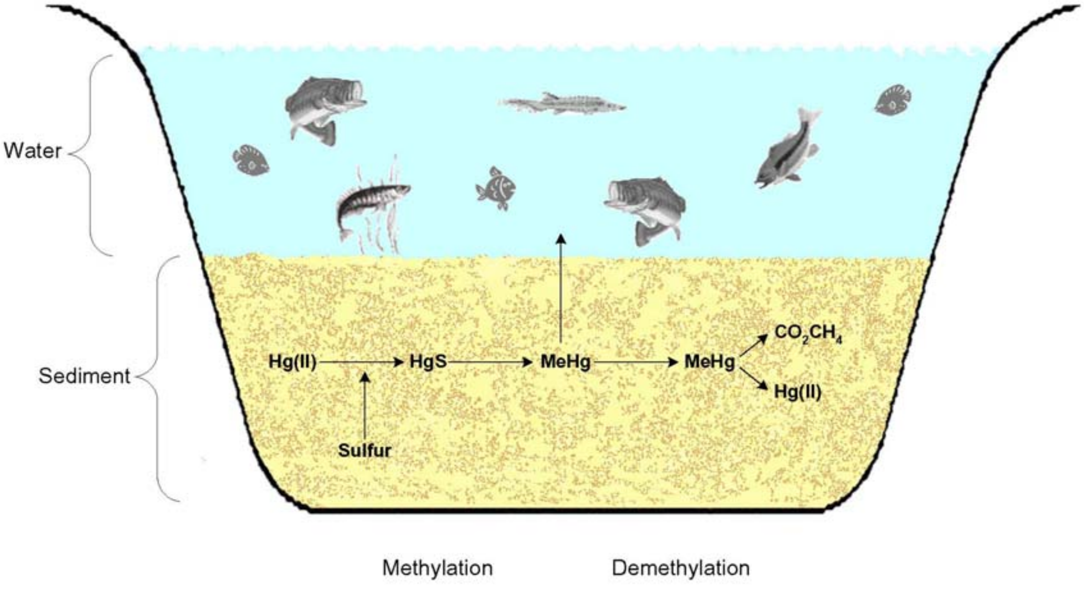

Figure 2
Mercury Methylation

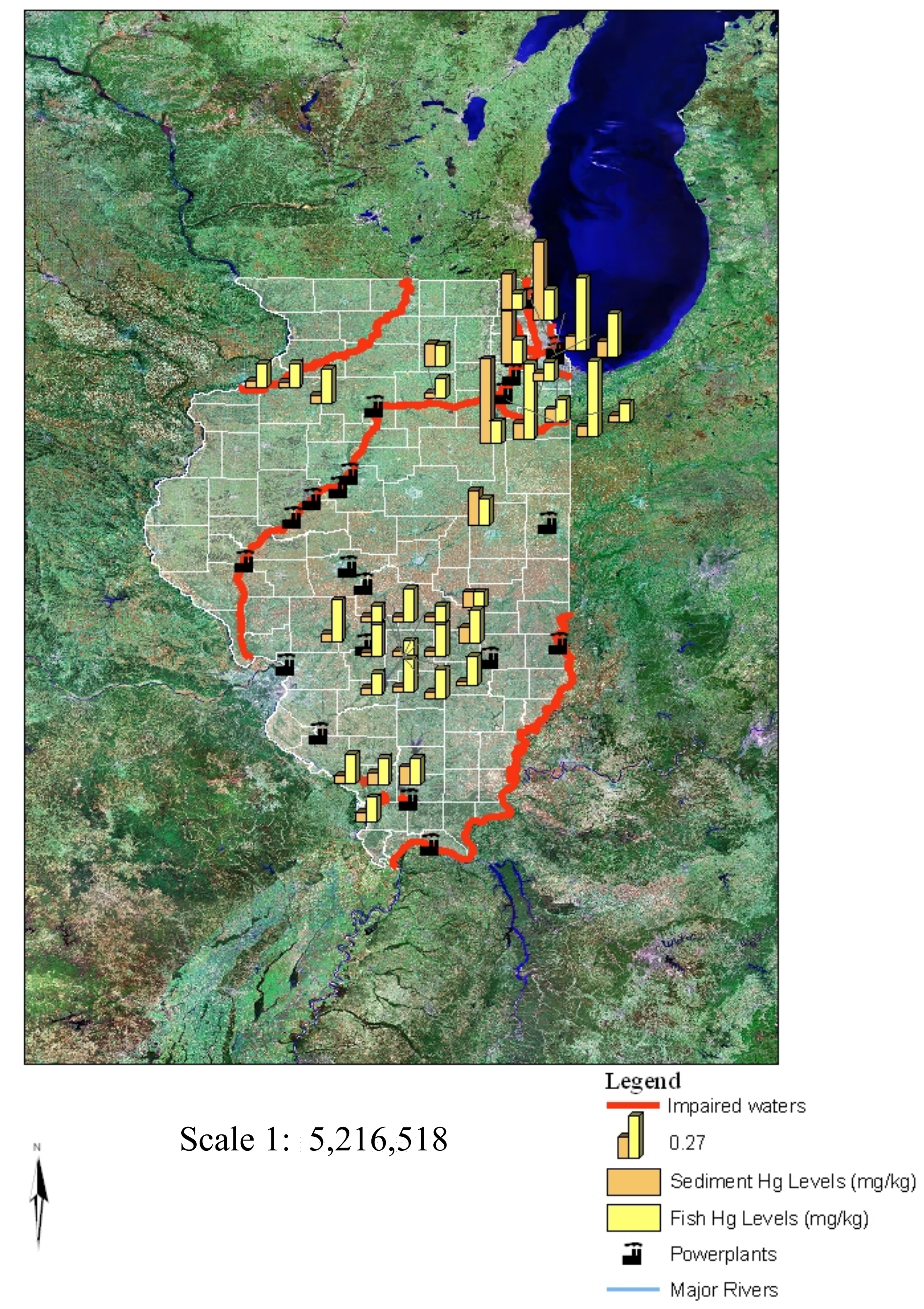

Figure 3
Relationship Between Total Mercury Concentrations in Sediments (mg/kg dry weight) and Fish Tissue Concentrations (mg/kg wet weight) Greater Than or Equal to 0.1 and Their Proximity to Listed Impaired Waters and Coal-Fired Power Plants in Illinois. Note: the information plotted comprises locations with sediment and tissue data collected from the same site within a 5-year period.

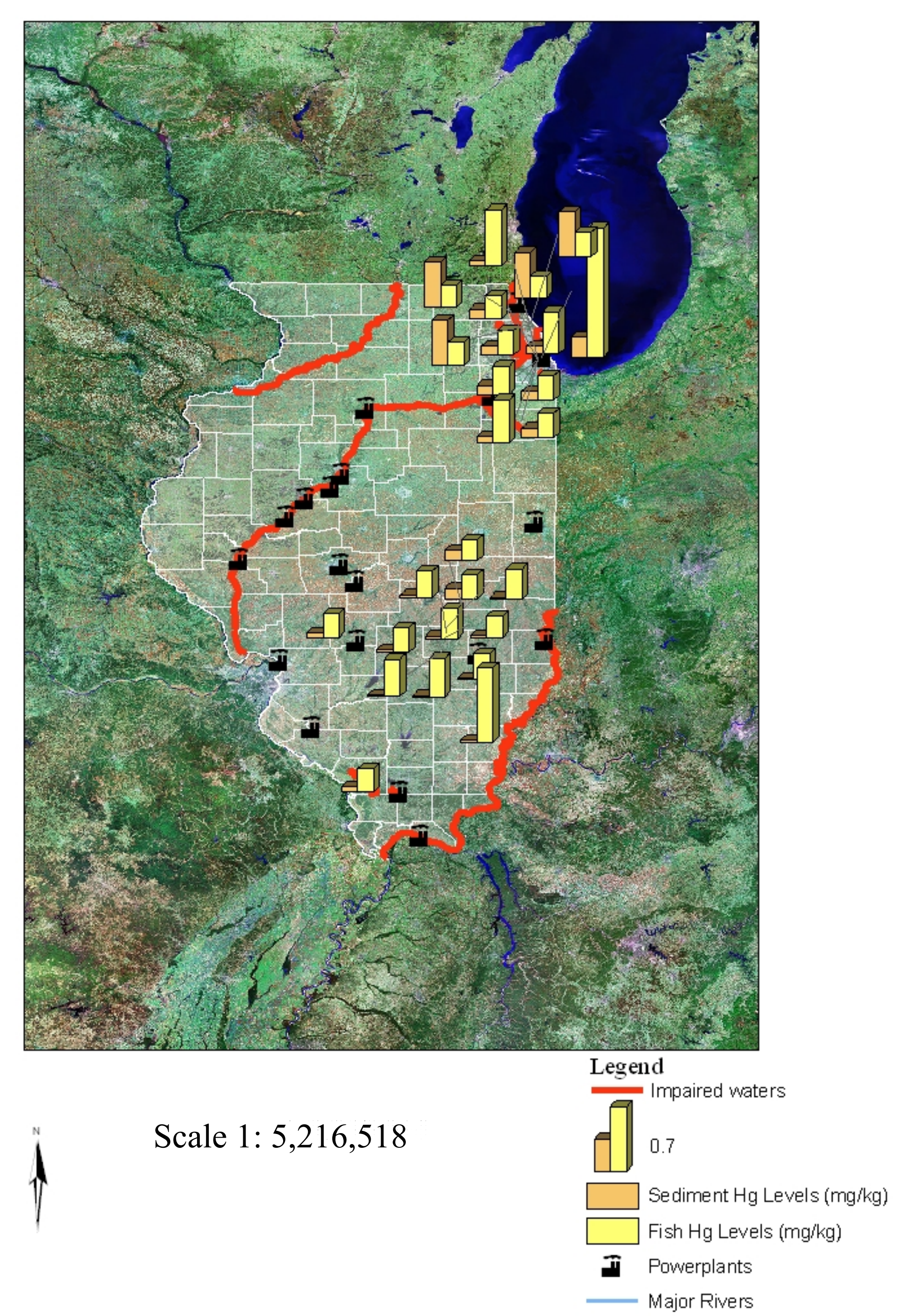

Figure 4
Relationship Between Total Mercury Concentrations in Sediments (mg/kg dry weight) and Fish Tissue Concentrations (mg/kg wet weight) Greater Than or Equal to 0.23 and Their Proximity to Listed Impaired Waters and Coal-Fired Power Plants in Illinois. Note: the information plotted comprises locations with sediment and tissue data collected from the same site within a 5-year period.

Education:
Ph.D., Benthic Ecology, University of Victoria, Victoria, BC, 1979
M.Sc., Biological Oceanography, 1976
B.Sc., Marine Biology, 1974

Affiliations:
Member, American Water Works Association
Member, North American Benthological Society
Member, American Society for Testing and Materials
Charter Member, Estuarine Research Federation
Member, Society of Environmental Toxicology and Chemistry (SETAC)
Member, Water Environment Federation

Awards:
Founders Award, Society of Environmental Toxicology and Chemistry, 2001
Region 10 award for resolving environmental issues, Port Valdez, Alaska, 1996

Languages: English and Spanish

Publications:
Over 150 journal articles and book chapters
Over 200 technical reports
Over 100 presentations at meetings

Experience:

2004 – Present **Golder Associates Ltd.** **North Vancouver, BC**
Senior Environmental Scientist, Principal
Responsibilities include directing, designing, and managing environmental studies in Arctic, temperate, and tropical ecosystems. Primary areas of expertise and responsibilities are in ecotoxicology, risk assessment, and aquatic ecology. Areas of specialisation include weight of evidence assessments and metals fate and effects, especially selenium.

1979 – 2004 **EVS Environmental Consultants** **North Vancouver, BC**
Senior Environmental Scientist/Principal
Responsibilities included directing, designing, and managing environmental studies in Arctic, temperate, and tropical ecosystems. Primary areas of expertise and responsibilities were ecotoxicology, risk assessment, and aquatic ecology. Areas of specialisation included weight of evidence assessments and metals.

1977 – 1979 **Environment Canada/Dept. Fisheries and Oceans** **Victoria, BC**
Independent Contractor
Conducted independent research on aquatic oligochaete distributions in the Fraser River and assessed metal body burdens in aquatic benthos from various areas. Published several papers and one book chapter based on this work.

1976 – 1979 **University of Victoria** **Victoria, BC**
Teaching and Research Assistant
Prepared laboratories for undergraduate classes and provided lectures during laboratory classes. Involvement in research activities included species collections (terrestrial and aquatic), laboratory and field studies.

PROJECT RELATED EXPERIENCE – ECOTOXICOLOGY/TOXICITY TESTING

Ecotoxicology North and South America, Europe, Australasia

- Directed development and source evaluation studies of chemical contaminants in water and sediment.
- Designed, directed and conducted studies involving sewage treatment plants, mining, manufacturing, pulp and paper, wood processing, hazardous waste disposal, landfill operations, oil and gas, smelting and food processing.
- Conducted pioneering toxicity studies in Arctic, temperate, and tropical ecosystems.

Toxicity Testing North and South America, Europe, Australasia

- Nationally and internationally recognised expert in ecotoxicology.
- Developed and verified national and international bioassessment protocols for measuring/predicting toxicity and bioaccumulation.

Example Publications International Peer-Reviewed Literature

Chapman, P.M. and J. Anderson. 2005. A decision-making framework for sediment contamination. Integr. Environ. Assess. Manage. 1: 163-173.

Chapman, P.M. and M.J. Riddle. 2005. Toxic effects of contaminants in polar marine environments. Environ. Sci. Technol. 38: 200A-207A.

Wang, F., R. Goulet, and P.M. Chapman. 2004. A critique of testing sediment biological effects with the freshwater amphipod *Hyalella azteca*. Chemosphere 57: 1713-1724.

McDonald, B.G. and P.M. Chapman. 2002. PAH phototoxicity – An ecologically irrelevant phenomenon? Mar. Pollut. Bull. 44: 1321-1326.

Chapman, P.M., H. Bailey, and E. Canaria. 2000. Toxicity of total dissolved solids (TDS) from two mine effluents to chironomid larvae and early life stages of rainbow trout. Environ. Toxicol. Chem. 19: 210-214.

Wang, F. and P.M. Chapman. 1999. The biological implications of sulfide in sediment - a review focusing on sediment toxicity. Environ. Toxicol. Chem. 18: 2526-2532.

Chapman, P.M. 1998. New and emerging issues in ecotoxicology - the shape of testing to come? Austral. J. Ecotox. 4:1-7.

Chapman, P.M. 1997. Acid volatile sulfides, equilibrium partitioning, and hazardous waste site sediments. Environ. Manage. 21: 197-202.

Chapman, P.M. 1990. The Sediment Quality Triad approach to determining pollution-induced degradation. Sci. Tot. Environ. 97-8: 815-825.

PROJECT RELATED EXPERIENCE – ENVIRONMENTAL RISK ASSESSMENT

Various Projects — North and South America, Europe, Australasia

- Involved in ecological risk assessment since this process was formalised in the 1980s.
- Conducted ecological risk assessments for government and industry.
- Served, at the request of the U.S. Environmental Protection Agency Risk Assessment Forum, as a peer reviewer for various agency guidance documents.
- Published extensively on ecological risk assessment.

Global Experience — South America, Europe, Australasia

- Senior Editor of the international peer-reviewed journal, Human and Ecological Risk Assessment.
- Advisory and consulting services to the governments of Australia, Peru, Indonesia, Hong Kong, ASEAN (Association of South East Asian Nations).
- Helped set up the first Master's degree in Ecotoxicology in Portugal.
- Conducted pioneering toxicity testing studies in the Arctic, North Sea, and Venice lagoons.
- Lectured, taught, and worked extensively in Europe, South East Asia, Australia, and South America (fluent in Spanish).
- Independent, external examiner for Ph.D. dissertations in Spain, Finland, Canada, the U.S., Denmark, and Australia.
- Numerous lectures and presentations to the public, high school and university classes, business and professional groups.

Large-Project Expertise — North and South America, Europe, Australasia

- Responsible for synthesis of all studies conducted through NSERC (Natural Sciences and Engineering Research Council) under the Metals in the Environment Research Network (MITE-RN; www.mite-rn.org). MITE-RN ran for 5 years and involved 7 major Canadian Universities and over 20 Principal Investigators from those Universities plus graduate students and other collaborators.
- Currently providing similar services to the successor of MITE-RN, the Metals in the Holistic Environment Research Network (MITHE-RN); www.mithe-rn.org.
- Directed regional-scale risk assessments in Alaska (Port Valdez), Papua New Guinea, Irian Jaya, Chile, and Peru.

Example Publications — International Peer-Reviewed Literature

Campbell, P.G.C., P.M. Chapman, and B. Hale. 2006. Risk assessment of metals in the environment. pp 102-131, In: Hester, R. E. and R. M. Harrison (eds.), Chemicals in the Environment: Assessing and Managing Risk. Issues in Environmental Science and Technology Volume 22, Royal Society of Chemistry, Cambridge, UK.

Chapman, P.M., F. Wang, C. Janssen, R.R. Goulet, and C.N. Kamunde. 2003. Conducting ecological risk assessments of inorganic metals and metalloids – Current status. Human Ecol Risk Assess 9: 641-697. ***[This paper was selected as the Ecological Risk Assessment Paper of the Year 2003]***

Chapman, P.M., B.G. McDonald, and G.S. Lawrence. 2002. Weight of evidence frameworks for sediment quality and other assessments. Human Ecol. Risk Assess. 8: 1489-1515.

Chapman, P.M. 2002. Ecological risk assessment (ERA) and hormesis. Sci. Tot. Environ.288: 131-140.

PROJECT RELATED EXPERIENCE – ENVIRONMENTAL QUALITY MANAGEMENT/AQUATIC POLLUTION ASSESSMENT

Environmental Quality North and South America, Europe, Australasia, Arctic

- Intimately involved in the process and methods for developing environmental quality guidelines, both nationally and internationally.
- Advisor to the federal governments of both the United States and Canada for environmental toxicology and biomonitoring assessment policy and protocols.
- Participated in and led aspects of international (South American, European, and Australasian) monitoring development projects.
- Published extensively on the subject of environmental quality guidelines.
- Member of the International Standards Organization, representing Canada.

Pollution Assessment North and South America, Europe, Australasia, Arctic

- Developed the internationally recognised and accepted Sediment Quality Triad concept for determining pollution-induced degradation in aquatic habitats.
- Directed projects (for government and industry) for various studies involving biological monitoring; assessment of toxicant levels (including Priority Pollutants) in tissues, sediments, and water; ecological surveys; literature reviews for ranking environmental contaminants; and bioassessment (e.g., toxicity testing).

Dredging/Sediment Projects USA, Canada, and elsewhere

- Peer reviewed the U.S. Environmental Protection Agency/Army Corps of Engineers [USEPA/USACE] "Green Book" on ocean disposal.
- Contracted author for the EPA/USACE Inland Testing Manual for Waters of the U.S.
- Designed and implemented monitoring and assessment projects for aquatic dredging in fresh, marine, and estuarine waters world-wide.

Example Publications International Peer-Reviewed Literature

Chapman, P.M., W.S. Douglas, M.C. Harrass, R.M. Burgess, D.D. Reible, W.H. Clements, A.H. Ringwood, C. Hogstrand, and W.J. Birge. 2005. Workgroup summary report on the role of SQGs and other tools in different aquatic habitats. In: Wenning, R., C. Ingersoll, G. Batley, and M. Moore (eds.), Use of Sediment Quality Guidelines (SQGs) and Related Tools for the Assessment of Contaminated Sediments. SETAC Press, Pensacola, FL, USA.

Chapman, P.M., F. Wang, D.D. Germano, and G. Batley. 2002. Porewater testing and analysis: The good, the bad and the ugly. Mar. Pollut. Bull. 44: 359-366.

Chapman, P.M. 2001. Utility and relevance of aquatic oligochaetes in ecological risk assessment. Hydrobiologia 463:149-169.

Chapman, P.M., F. Wang, W. Adams, and A. Green. 1999. Appropriate uses of sediment quality values for metals and metalloids. Environ. Sci. Technol. 33: 3937-3941.

Chapman, P.M., P.J. Allard, and G.A. Vigers. 1999. Development of sediment quality values for Hong Kong Special Administrative Region: a possible model for other jurisdictions. Mar. Pollut. Bull. 38: 161-169.

PROJECT RELATED EXPERIENCE – EXPERT WITNESS AND PEER REVIEW

Expert Witness — USA and Canada

- Four trials with testimony.
- Two trials with attendance but no testimony as cases settled.
- Two depositions (one videotaped).
- One pending trial.
- Appeared as an expert witness on eight occasions before the Northwest Territories (Canada) Water Board, and on one occasion before the Nunavut (Canada) Water Board.
- Provided expert advice, but not testimony, during five judicial or quasi-judicial Hearings in Canada.
- Clients include both government (e.g., U.S. Department of Justice) and industry.

Peer Reviewer — USA, Canada, Australasia, Europe

Currently:

- Peer reviewer for over 20 international scientific journals.
- Peer reviewer for American, Canadian, Australian, New Zealand, and European granting agencies.
- Senior Editor for Debates/Commentaries and Perspectives for the international, peer-reviewed journal, Human and Ecological Risk Assessment.
- Editor of the Learned Discourses in the Society of Environmental Toxicology and Chemistry (SETAC) Globe.
- Editorial Board of the international journal, Marine Pollution Bulletin.
- Editorial Board of the international journal, Environmental Toxicology and Chemistry.

Previously:

- Member, U.S. Environmental Protection Agency, Science Advisory Board (SAB), Sediment Criteria Subcommittee.
- Member, Washington State Biomonitoring Science Advisory Board (BSAB).
- Member, Canadian Environmental Advisory Council (advised four different Canadian Ministers of Environment).
- Member, NRC Committee on the Bioavailability of Metals in Sediments.
- Member, U.S. Environmental Protection Agency, Science Advisory Board, Global Climate Change Subcommittee.
- Member, Editorial Board, Chemosphere.
- Member, Sewage Treatment Review Panel.
- Member, International Technical Advisory Panel on Ecotoxicity.

PROJECT RELATED EXPERIENCE – METALS AND METALLOIDS

Metals and Metalloids North and South America, Europe, Australasia, Arctic

- Past member of the International Technical Advisory Panel on Ecotoxicology, for nonferrous metals.
- Participated in an OECD Expert Workshop on Toxicity Testing of Metals and Metalloids as Chair of an International Expert Group.
- Participated in a Canada/European Union Expert Workshop on Persistence and Bioaccumulation of Metals and Metalloids as a speaker and workshop rapporteur.
- Participated in a World Health Organization Expert Workshop on Global Criteria for Zinc.
- Extensive experience and expertise with metals from sources including mining, smelters, sewage, and landfills.
- Extensive publications regarding metals fate and effects in the environment.

Example Publications International Peer-Reviewed Literature

Adams, W. and P.M. Chapman (eds.), 2005. Assessing the Hazard of Metals and Inorganic Metal Substances in Aquatic and Terrestrial Systems. SETAC Press, Pensacola, FL.

Chapman, P.M. 2005. Inorganic metals and metalloids ERA – Recent advances and implications for LCIA. pp. 214-219. In: A.A. Dubreuil (ed.), Life Cycle Assessment of Metals – Issues and Research Directions. SETAC Press, Pensacola, FL.

Chapman, P.M. and C. McPherson. 2004. Possible selenium thresholds for trout. SETAC Globe 5(6): 22-25.

Chapman, P.M. and F. Wang. 2000. Issues in ecological risk assessment of inorganic metals and metalloids. Human Ecol. Risk Assess. 6: 965-988.

McPherson, C.A. and P.M. Chapman. 2000. Copper effects on potential sediment test organisms: the importance of appropriate sensitivity. Mar. Pollut. Bull. 40:656-665.

Chapman, P.M. 1999. Selenium - a potential time bomb or just another contaminant? Human Ecol. Risk Assess. 5: 1122-1137.

Wang, F., P.M. Chapman, and H. Allen. 1999. Misapplication of equilibrium partitioning coefficients to derive metals sediment quality values. Mar. Pollut. Bull. 38: 423-425.

Chapman, P.M., F. Wang, C. Janssen, G. Persoone, and H. Allen. 1998. Ecotoxicology of metals in aquatic sediments: binding and release, bioavailability, hazard, risk and remediation. Can. J. Fish. Aquat. Sci. 55: 2221-2243.

Chapman, P.M., H.E. Allen, K. Godtfredsen, and M.N. Z'Graggen. 1996. Evaluation of BCFs as measures for classifying and regulating metals. Environ. Sci. Technol. 30: 448-452.

PROJECT RELATED EXPERIENCE – SEWAGE EFFLUENT AND TREATMENT

Sewage — North and South America, Europe, Australasia, Arctic

- Extensive project experience assessing fate and effects of sewage effluents.
- Evaluations for cities with populations over 1,000,000 and small local discharges.
- Expert advice regarding design and placement of sewage discharges to minimise environmental concerns.
- Expert advice regarding levels of sewage treatment required relative to the receiving environment.
- Interpretative advice and studies regarding environmental effects and regulatory requirements.
- Member, Sewage Treatment Review Panel (Greater Vancouver Regional District).

Example Publications — International Peer-Reviewed Literature

Chapman, P.M. 2006. Determining when contamination is pollution – weight of evidence determinations for sediments and effluents. Environ. Intern. (in press).

Chapman, P.M., K. Ho, W. Munns, K. Solomon, and M.P. Weinstein. 2002. Issues in sediment toxicity and ecological risk assessment. Mar. Pollut. Bull. 44: 271-278.

McPherson, C.A., A.R. Tang, P.M. Chapman, and L.A. Taylor. 2002. Toxicity of 1,4-dichlorobenzene in sediments to juvenile polychaete worms. Mar. Pollut. Bull. 44: 1405-1414.

Chapman, P.M. 2000. Whole Effluent Toxicity (WET) Testing - usefulness, level of protection, and risk assessment. Environ. Toxicol. Chem. 19: 3-13.

Taylor, L.A., P.M. Chapman, R.A. Miller, and R.V. Pym. 1998. The effects of untreated municipal sewage discharge to the marine environment off Victoria, British Columbia, Canada. Water Sci. Technol. 38: 285-292.

McGroddy, S. and P.M. Chapman. 1997. Is mercury from dental amalgam an environmental problem? Environ. Toxicol. Chem. 16: 2213-2214.

Chapman, P.M., J. Downie, A. Maynard, and L. Taylor. 1996. Deodorizer residue and coal in marine sediments contaminants or pollutants? Environ. Toxicol. Chem. 15: 638-642.

Chapman, P.M., M.D. Paine, A.D. Arthur, and L.A. Taylor. 1996. A triad study of sediment quality associated with a major, relatively untreated marine sewage discharge. Mar. Pollut. Bull. 32: 47- 64.

Chapman, P.M. 1996. A test of sediment effects concentrations: DDT and PCB in the Southern California Bight. Environ. Toxicol. Chem. 15: 1197-1198.

Chapman, P.M., A.D. Arthur, M.D. Paine, and L.A. Taylor. 1994. Sediment studies provide key information on the need to treat sewage discharged to sea by a major Canadian city. Water Sci. Technol. 28: 255-261.

JOURNAL PUBLICATIONS
[* = Editorials or Letters to the Editor]

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BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
PROPOSED NEW 35 ILL.ADM.CODE PART 225	)	**PCB R06-25**
CONTROL OF EMISSIONS FROM	)	
LARGE COMBUSTION SOURCES	)	

TESTIMONY OF GAIL CHARNLEY, Ph.D.

My name is Dr. Gail Charnley. I am a recognized expert in the fields of toxicology and environmental health risk analysis. I received my PhD in Toxicology from the Massachusetts Institute of Technology in 1984 and my AB degree with honors in Molecular Biology from Wellesley College in 1977. I consult primarily in the areas of toxicology, risk assessment, and risk management policy. I have over 20 years of experience in the biological, chemical, and social policy aspects of environmental and public health protection. I have been the executive director of the Presidential/Congressional Commission on Risk Assessment and Risk Management and director of the Toxicology and Risk Assessment Program at the National Academy of Sciences. I currently serve on two National Academy of Sciences committees that focus on improving the scientific basis for limiting risks from chemical and radiological hazards. I am a fellow of the Society for Risk Analysis (and served as president of that society in 1998 and 1999) and am a member of the Society of Toxicology. I have been asked to address the topic of health issues associated with methylmercury in fish and coal-based power plant mercury emissions in general, and several related issues raised in the Illinois Environmental Protection Agency's *Technical Support Document for Reducing Mercury Emissions from Coal-Fired Electric Generating Units* (TSD) and in Dr. Deborah Rice's *Review of the nervous system and cardiovascular effects of methylmercury exposure* in particular.

Relationship between power plant mercury emissions and fish methylmercury concentrations

Much of what appears in the media about fish, mercury, and power plants implies that mercury comes directly out of power plants, falls directly onto nearby fish, turns into methylmercury, and threatens public health. The TSD also appears to reflect that thinking. The implication of such a scenario would be that reducing mercury emissions from power plants would lead directly to less methylmercury in fish and better public health. The TSD further implies that reducing power plant mercury emissions by a certain percentage would lead to the same percentage decrease in fish methylmercury levels. Such a simple and direct relationship between mercury emissions and local fish methylmercury levels is not supported scientifically.

The amount of methylmercury in fish is a function of many factors. Most of the mercury emitted from power plants in the US ends up in the global atmosphere and is deposited somewhere else. Most of the mercury that is deposited in the US comes from somewhere else. According to the US Environmental Protection Agency (US EPA), about half of global mercury emissions are naturally occurring, emitted from sources that include volcanoes, forest fires, oceans, and soils.[1] Mercury that is deposited into water bodies, whatever the source, has to be converted to methylmercury by microorganisms in the sediments. That methylmercury has to be taken up by fish and those fish have to be caught and eaten. The extent to which mercury deposited into water bodies—whether natural, global, local, and/or the result of human activities—actually turns into methylmercury and gets into fish is very site-specific, depending on factors like water chemistry, pH, temperature, sunlight, nutrient levels, and other site-specific characteristics.[2] As a result, the amount of methylmercury in fish is not related simply to the amount of mercury that is available. A lake with high mercury levels in its sediment can have fish with low methylmercury levels and a lake with lower mercury levels can have fish with higher methylmercury levels. In fact, the TSD reports that Illinois lakes with the highest mercury concentrations were not the same as the lakes containing fish with the highest mercury concentrations.

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[1] US Environmental Protection Agency (2005). *Mercury Emissions: The Global Context*. Washington, DC. http://www.epa.gov/mercury/control_emissions/global.htm

[2] Summarized in: Center for Science and Public Policy (2005). *Making Sense of State Fish Advisories*. Washington, DC. Page 54. http://ff.org/centers/csspp/pdf/20050228_hgfishadvisories.pdf

In a recent report from a workshop convened by the Society for Environmental Toxicology and Chemistry, scientists concluded,[3] "It is not clear whether changes in mercury input will result in a linear change in mercury methylation. Computer models, such as one developed for the Florida Everglades, tend to predict a linear response, but there are little data to support the predictions . . . [D]ecision makers need more than mercury concentrations to be able to ensure defensible interpretation of the indicators, such as methylmercury in fish. Other necessary information includes land use; food-web structure; the introduction of exotic species; point-source discharges; changes in climate, atmospheric chemistry, and acidic deposition; and hydrological regimes (e.g., retention time and water level fluctuation) . . . Other factors such as sulfate and organic matter that impact bacterial activity, could also possibly cause an increase in fish mercury concentration even as atmospheric deposition decreases."

Studies attempting to correlate trends in environmental mercury levels with trends in methylmercury levels in freshwater fish are limited. To my knowledge, there are no published studies specifically evaluating power plant mercury emissions and trends in fish methylmercury levels. The TSD relies on data reported in a Florida Department of Environmental Protection report[4] to support its conclusion that reducing power plant mercury emissions and deposition will reduce local fish methylmercury levels. The TSD omits the Florida data that are inconsistent with that conclusion, however, and presents only the data that support it. Data were collected from 12 Florida locations,[5] but the TSD provides data from only two locations in the Everglades. The data from those two locations appear to support the TSD's conclusions about direct relationships among mercury emissions, mercury deposition, and methylmercury accumulation

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[3] Mason RP, Abbot ML, Bodaly RA, Bullock, OR Jr, Driscoll CT, Evers D, Lindberg SE, Murray M, Swain EB (2005). Monitoring the response to changing mercury deposition. Report on a workshop convened at the 2004 annual meeting of the Society of Environmental Toxicology and Chemistry. Environmental Science and Technology 39:14A-22A

[4] Florida Department of Environmental Protection (2003). *Integrating Atmospheric Mercury Deposition with Aquatic Cycling in South Florida: An approach for conducting a Total Maximum Daily Load analysis for an atmospherically derived pollutant.*

[5] Ibid, page 81

in fish but data from other locations do not.

In the Florida report, regulation of mercury emissions from medical waste incinerators was concluded to have reduced estimated point-source mercury emissions between 1990 and 2000 by 93% (based on unpublished data).[6] Data from the Mercury Deposition Network obtained at one site in the Everglades were used to assert that deposition of mercury via rain at that site declined by 25% between 1994 and 2002.[7] However, Figure 24 in the Florida report shows clearly that between 1994 and 2000, the time period of interest, there was no decline in deposition.[8] The direction of trends in largemouth bass mercury concentrations for an unidentified number of fish caught at 12 Florida locations between 1988 and 2000 was evaluated using a nonparametric test for slope (unpublished data cited in Florida 2003).[9] As can be seen in Exhibit 1, the samples overall were fairly evenly split between declining trend and no or increasing trend. Consistent declining trends across age groups were seen at three of the locations sampled, a consistent lack of trend was seen at four locations, and an increasing trend was seen at one location. The other locations showed some declines and some absence of change depending on the age of the fish. The Florida study has not been peer-reviewed or published in a peer-reviewed scientific journal.

There are a number of additional reasons why it is likely that extrapolating the potential impact of lower incinerator mercury emissions in the Everglades to the potential impact of lower power plant mercury emissions in Illinois is tenuous at best. First, the mercury emitted from incinerators is different from the mercury emitted from power plants. Most incinerator mercury is water-soluble and deposits close to incinerators;[10] most power plant mercury is thought to be

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[6] Ibid, page 76

[7] Ibid, page 78

[8] Ibid, page 81

[9] Ibid, page 82

[10] Ibid page 88

elemental, not water soluble, and ends up becoming part of global atmospheric mercury.[11] Second, the Everglades are a unique, tropical ecosystem that is strikingly different from the decidedly non-tropical ecosystems found in Illinois. They are likely to differ greatly in terms of water chemistry and other factors that determine the extent to which deposited mercury becomes fish methylmercury.[12] And third, there was no contemporaneous determination of whether reduced mercury emissions actually led to reduced local mercury deposition, which would have had to have occurred if there were a connection between local mercury emissions and local freshwater fish methylmercury concentrations. Incinerator controls were initiated in 1987 but deposition measurements were not taken until 1994 and 1995.[13]

The TSD also relies on data from Massachusetts to support its conclusion about a direct relationship between mercury emissions and fish methylmercury concentrations. While the Massachusetts study does suggest a decrease in fish methylmercury concentrations in two species following the elimination of nearby medical waste incinerators and implementation of stringent limits on municipal solid waste incinerators, most of the data supporting that conclusion consist of only two sampling points over time per location; when three data points were available, no statistically significant decline is apparent.[14] Furthermore, the majority of the reported decreases in fish methylmercury did not occur until 36-48 months after the observed decreases in mercury emissions and the magnitude of the decreases in fish methylmercury did not approach the magnitude of the decreases in emissions (25% to 32% versus 87%). Those

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[11] Lohman K, Seigneur C, Edgerton E, Jansen J (2006). Modeling mercury in power plant plumes. Environmental Science & Technology 40:3848-3854; Edgarton ES, Hartsell BE, Jansen JJ (2006). Mercury speciation in coal-fired power plant plumes observed at three surface sites in the southeastern US. Environmental Science & Technology (pre-pub available online, http://pubs.acs.org/cgi-bin/abstract.cgi/esthag/asap/abs/es0515607.html)

[12] US Environmental Protection Agency (2005). *Regulatory Impact Analysis of the Clean Air Mercury Rule. Final Report.* EPA-452/R-05-003. Office of Air Quality Planning and Standards. Research Triangle Park, NC. Page 3-16

[13] Florida report, page 80

[14] Massachusetts Department of Environmental Protection (2006). *Massachusetts Fish Tissue Mercury Studies: Long-Term Monitoring Results, 1999-2004*, Figures 4 and 5

observations support a nonlinear relationship between emissions and fish methylmercury concentrations, suggesting that a 90% reduction in emissions in Illinois is unlikely to lead to a 90% reduction in fish methylmercury concentrations, as implied by the TSD. Also, as with Florida, those results are not likely to be validly extrapolated to coal-based power plants because of the different speciation characteristics of mercury emissions from power plants and the importance of speciation to the extent of local deposition. The Massachusetts study also has not been published in the peer-reviewed scientific literature and appears preliminary in nature due to the small number of samples.

The TSD makes a plausible case for reducing power plant mercury emissions as a general matter. What it does not do is make a case for reducing emissions faster or deeper than would occur if federal regulations were implemented instead. In fact, the TSD omits information that illustrates the effectiveness of federal regulations. For example, Figures 5.1 and 5.2 in the TSD compare US EPA's map of mercury deposition from all sources with its map of mercury deposition if there were no coal-based power plants in the US. Omitted are the US EPA maps that generally accompany those figures showing the impact of federal regulations (see Exhibit 2).[15] In other words, the TSD shows maps illustrating the fact that US power plants contribute to mercury deposition in the US but fails to show how effectively federal regulations would reduce that deposition. However, as discussed above, reducing mercury emissions in Illinois may or may not affect methylmercury levels in Illinois fish. And even if it does, reducing Illinois methylmercury fish tissue concentrations to below the Illinois fish tissue mercury consumption advisory levels will not eliminate fish consumption advisories in Illinois because of the presence in Illinois fish of other substances such as polychlorinated biphenyls.[16]

It seems worth pointing out that in the US overall, according to the National Marine

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[15] US Environmental Protection Agency (2005). *Technical Support Document: Methodology Used to Generate Deposition, Fish Tissue Methylmercury Concentrations, and Exposure for Determining Effectiveness of Utility Emission Controls: Analysis of Mercury from Electricity Generating Units*. Pages 6-11. http://www.epa.gov/ttn/atw/utility/ria_final.pdf

[16] Testimony of Dr. Peter Chapman, Table 3

Fisheries Service, more than 75% of the fish we eat is imported and half of what we eat comes from a can.[17] Based on data from the US Department of Agriculture, of those who eat fish in the US, about 10% of the fish they eat comprises freshwater fish[18] (not all of which would be methylmercury-contaminated). In the State of New York, 98% of sports anglers surveyed reported that they either don't eat what they catch at all or eat it less frequently than once per month.[19] In Wisconsin, of the women of childbearing age who reported eating fish, less than one-third reported eating sport fish and there was no difference between their hair mercury levels and those of women who did not eat sport fish.[20]

There is no information available on the extent to which Illinois anglers consume what they catch. It is not possible to tell from the studies cited in the TSD the extent to which anglers in general eat what they catch or the extent to which the fish that are eaten are contaminated with methylmercury. US data show that fishing is positively correlated with income,[21] so most anglers are unlikely to be subsistence anglers and data based on all anglers in Illinois cannot be used to represent subsistence anglers. It is possible that there are some subsistence anglers in Illinois whose families may be at risk from methylmercury from Illinois fish but the TSD does not identify them or characterize the extent of the problem, so it is not possible to characterize the extent of the potential benefits. Even if reducing power plant mercury emissions in Illinois does turn out to lower methylmercury levels in some local fish, that reduction will benefit only

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[17] US National Marine Fisheries Service (2003). *Per Capita Consumption* http://www.st.nmfs.gov/st1/fus/fus03/08_perita2003.pdf

[18] Annapolis Center (2003). *Mercury in the Environment: The Problems, the Risks, and the Consequences*. http://www.annapoliscenter.org

[19] Li Q, Vena JE, Swanson MK (2005). Reliability of sport fish consumption in the New York State Angler Cohort Study. Environmental Research 97:142-148

[20] Knobeloch L, Anderson HA, Imm P, Peters D, Smith A (2005). Fish consumption, advisory awareness, and hair mercury levels among women of childbearing age. Environmental Research 97:220-227

[21] US Fish & Wildlife Service (2002). *2001 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation*

that small proportion of the people in Illinois who rely on Illinois freshwater predator fish as their primary protein source in the areas where those reductions actually occur. Of course, benefiting "only a small proportion of the people" does not imply that those people don't deserve to be protected, it implies that reducing mercury emissions should not be oversold as a means of improving public health and protecting children in general.

Obtaining specific data on who the women of childbearing age are in Illinois whose children are actually potentially at risk from methylmercury present in Illinois fish would facilitate a more informed discussion of the potential benefits of either CAMR or the proposed rule. In its CAMR reconsideration decision, US EPA has concluded that after CAIR and CAMR are implemented, the only people who would remain potentially at risk from utility-attributable fish methylmercury would be the 99th percentile recreational fishers and mean Native American subsistence fishers who consume solely freshwater fish contaminated at the 99th percentile level.[22] Given that the likelihood of such a scenario is poor, US EPA concludes that utility-attributable mercury emissions remaining after implementation of CAIR and CAMR are not reasonably anticipated to pose hazards to public health.[23]

While it seems logical to assume that reducing power plant or other mercury emissions will lead to reductions in local fish methylmercury levels, available data do not provide much support for that conclusion. The relationship between mercury emissions and fish methylmercury levels appears to be highly site-specific, so it is likely that reducing power plant mercury emissions could lead to lower fish methylmercury levels in some places in Illinois and not in others. Predicting where changes might occur is not possible with currently available data. The people currently at risk from methylmercury in Illinois fish are also unknown. It is therefore

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[22] US EPA also notes that the overwhelming majority of tribal populations live outside areas most impacted by utility-attributable mercury deposition and elevated utility-attributable fish tissue levels.

[23] US Environmental Protection Agency (2006). Revision of December 2000 Clean Air Act Section 112(n) Finding Regarding Electric Utility Steam Generating Units: and Standards of Performance for New and Existing Electric Utility Steam Generating Units: Reconsideration. Final rule. 40 CFR Part 60. EPA-HQ-OAR-2002-0056; FRL-8180-4

not possible to predict whether and to what extent reducing power plant mercury emissions will result in reduced fish methylmercury concentrations in Illinois or the extent to which any such reductions would lead to reduced risk in Illinois. Any claims that Illinois' state-specific proposed rule will protect high consumers of Illinois fish any better than will the federal rule are supported neither by the TSD nor by science.

Methylmercury and developmental toxicity

No one questions Dr. Rice's and the TSD's conclusion that methylmercury can be toxic to the developing brain. The extent to which methylmercury poses a risk at current environmental levels of exposure is debated among scientists and among national and international organizations responsible for protecting public health. Such organizations in the US and worldwide have evaluated methylmercury risks very differently than have either the US EPA or IL EPA. The discussion of methylmercury toxicity in the TSD does not reflect the debate or the different conclusions that have been drawn by different scientists and organizations about what methylmercury exposure level does or does not pose a risk. The TSD does not critically analyze the available data and presents studies in a way that biases the reader, with no discussion of the considerable uncertainties involved. There is no discussion of the weight of scientific evidence. Both the TSD and Dr. Rice's testimony give equal weight to all studies reporting adverse effects and observations, providing no critical analysis of what might be more or less likely, failing to discuss the uncertainties inherent in the studies, and failing to reflect the conclusions of the investigators themselves.

For example, in Dr. Rice's discussion of the 9-year-old followup study in the Seychelles, she states, "An adverse association was found between postnatal exposure and performance on the grooved pegboard using the non-preferred hand, with no other adverse effects." She does not point out that there were more than 60 end points evaluated (only one of which was negatively correlated with methylmercury exposure) nor does she report the authors' conclusion: "These data do not support the hypothesis that there is a neurodevelopmental risk from prenatal [methylmercury] exposure resulting solely from ocean fish consumption."[24] Nor does she note that the average methylmercury concentration in fish in the Seychelles is similar to that in commercial fish consumed in the US (0.3 ppm) but that women in the Seychelles consume an average of 12 fish meals per week,[25] so their exposures greatly exceed most exposures in the US. If methylmercury exposure in the Seychelles greatly exceeds methylmercury exposure in the US and failed to produce adverse effects, then adverse effects in the US are even less likely. Dr. Rice then states that the subsequent study of Huang et al. (2005),[26] evaluating potential nonlinear associations, "suggested adverse effects above 12 ppm in maternal hair on several measures . . .". Again, she omits the authors' conclusion: "We conclude that this reanalysis supports the primary linear analysis, showing little evidence for a prenatal adverse effect."[27]

The TSD also omits from discussion recent studies that conflict with its conclusions about methylmercury's developmental toxicity. For example, the 9-year-old Seychelles followup study discussed above indicated that children exposed to higher levels of methylmercury because their mothers ate more fish when they were pregnant scored higher on some tests of brain development than children who were exposed to lower levels of methylmercury because their mothers ate less fish. As discussed, earlier studies of the same children showed no adverse effects of methylmercury exposure on tests of brain development. A recent study of children in the UK reported that increasing umbilical cord mercury levels were not associated with increased cognitive impairment but that increasing prenatal fish consumption

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[24] Myers GJ, Davidson PW, Cox C, Shamlaye CF, Palumbo D, Cernichiari E, Sloane-Reeves J, Wilding GE, Kost J, Huang LS, Clarkson TW (2003). Prenatal methylmercury exposure from ocean fish consumption in the Seychelles child development study. Lancet 361:1686-1692. Page 1686

[25] Ibid

[26] Huang LS, Cox C, Myers GJ, Davidson PW, Cernichiari E, Shamlaye CF, Sloane-Reeves J, Clarkson TW (2005). Exploring nonlinear association between prenatal methylmercury exposure from fish consumption and child development: evaluation of the Seychelles Child Development Study nine-year data using semiparametric additive models. Environmental Research 97:100-108

[27] Ibid page 100

was associated with improved cognition.[28] A different study of the same group of kids in the UK found that the children of mothers who ate more fish during pregnancy and were exposed to more methylmercury had IQs five points higher than the children of mothers who ate less.[29] A preliminary study in Massachusetts found similar results.[30] In all cases, the cognitive benefits were attributed to the omega-3 fatty acids found in fish. Omega-3 fatty acids are essential for appropriate nervous system development and function. Other micronutrients found in fish are also considered important contributors to successful brain development or are even capable of preventing neurotoxicity.[31] The results of the Seychelles and UK studies do not suggest that methylmercury is good for children, but they do demonstrate that the benefits of fish clearly overcome its potential threats, even in the children of women who derive most of their dietary protein from fish and are exposed to higher levels of methylmercury as a result. They also help explain why effects were seen in the Faroe Islands but not the Seychelles. In the Faroes, the principal source of methylmercury exposure was pilot whale meat while in the Seychelles, the only source was fish. If the benefits of eating fish can outweigh the risks from methylmercury, it is not surprising that where there were fewer benefits from fish, the effects of methylmercury were more likely to be manifested. Neither Dr. Rice nor the TSD include this explanation for the differing results.

Another possible explanation for the different results observed in the Faroe and Seychelle Islands is the presence of high concentrations of polychlorinated biphenyls (PCBs) in pilot whale blubber in the Faroes. Dr. Rice mentions this possibility but then dismisses it, citing the

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[28] Daniels JL, Longnecker MP, Rowland AS, Golding J, ALSPAC study team (2004). Fish intake during pregnancy and early cognitive development of offspring. Epidemiology 15:394-402

[29] Hibbeln (2006) *Nutrition, the brain and mental ill health*. Cleave Lecture. Presented at the conference “Generating Healthy Brains,” 17 January 2006. London

[30] Oken E, Wright RO, Kleinman KP, Bellinger D, Amarasiriwardena CJ, Ju H, Rick-Edwards JW, Gillman MW (2005). Maternal fish consumption, hair mercury, and infant cognition in a U.S. cohort. Environmental Health Perspectives 113:1376

[31] Clarkson TW, Strain JJ (2003). Nutritional factors may modify the toxic action of methyl mercury in fish-eating populations. Journal of Nutrition 133:1539S-1543S

epidemiologic re-evaluations of the study ruling out confounding by prenatal exposure to PCBs and the conclusion of the National Academy of Sciences report on methylmercury.[32] What she fails to mention is that the neither the re-evaluations nor the NAS committee considered the possibility of post-natal developmental effects from PCBs exposure via breast milk. This omission is particularly surprising given that Dr. Rice's own research has demonstrated developmental neurotoxicity in infant monkeys fed PCBs postnatally in formula at a dose equivalent to about half that experienced by the children in the Faroes.[33] Dr. Rice has even co-authored a review concluding that prenatal PCB exposure was associated with poorer performance on the Boston Naming Test in the Faroes (the endpoint upon which the NAS and US EPA methylmercury risk assessments were based).[34] And, according to the Faroes study investigators themselves, when the effects of prenatal exposure to PCBs were properly controlled for, the correlation between methylmercury exposure and poorer performance on the Boston Naming Test was no longer statistically significant.[35] As Exhibit 3 shows, the level of PCBs to which the children were exposed in the Faroe Islands was almost double the level demonstrated to produce neurologic effects in infant monkeys and almost 1,000 times higher than US EPA's reference dose for PCBs. It is my opinion and that of many other scientists that the results of the Faroe Islands study at best should be attributed to combined exposure to methylmercury and PCBs.

Methylmercury exposure limits

The US Centers for Disease Control (CDC) reports that children and women of

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[32] National Academy of Sciences/National Research Council (2000). *Toxicological Effects of Methylmercury*. National Academy Press. Washington, DC

[33] See, for example, Rice DC (1998). Effects of postnatal exposure of monkeys to a PCB mixture on spatial discrimination reversal and DRL performance. Neurotoxicology and Teratology 20:391-400

[34] Schantz SL, Widholm JJ, Rice D (2003). Effects of PCB exposure on neuropsychological function in children. Environmental Health Perspectives 111:357-376

[35] Grandjean P, Weihe P, White RF, Debes F, Araki S, Yokoyama K, Murata K, Sørensen N, Dahl R, Jørgensen, PJ (1997). Cognitive deficit in 7-year-old children with prenatal exposure to methylmercury. Neurotoxicology and Teratology 19:417-428

childbearing age in the US have methylmercury levels in their blood well below those that have been reported to produce adverse effects.[36] Exhibit 4 illustrates the relationships among the methylmercury levels reported to produce adverse effects, US EPA's reference dose, or recommended exposure limit, and actual environmental exposure. According to the National Academy of Sciences report, an umbilical cord blood mercury level of 85 micrograms per liter was associated with a 5% likelihood of poorer performance on the Boston Naming Test, a test of memory, among children in the Faroe Islands, where people rely primarily on seafood as their source of dietary protein.[37] That value is referred to as a benchmark dose or BMD.[38] US EPA used a blood mercury level of 58 micrograms per liter—a conservative, health-protective lower limit on 85 micrograms per liter (BMDL)[39]—as the basis for calculating a methylmercury reference dose. A reference dose is defined by US EPA as "an estimate of an exposure . . . that is likely to be without an appreciable risk of adverse effects over a lifetime." The reference dose for methylmercury, 5.8 micrograms per liter, was obtained by dividing 58 micrograms per liter by an uncertainty factor of 10, in order to protect any unusually sensitive individuals. The average mercury blood level in women of childbearing age reported by the CDC was 0.83 micrograms per liter, with 5.7% of the women tested having blood mercury levels above 5.8 micrograms per liter[40] (i.e., exceeding US EPA's reference dose) (see inset in Exhibit 4). None of this representative cross-section of women who have been tested in the US had blood mercury levels approaching 85 micrograms per liter, the value calculated in the National Academy of Sciences report as being associated with a 5% change in performance on the memory test.

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[36] US Centers for Disease Control and Prevention (2005). *Third National Report on Human Exposure to Environmental Chemicals*. http://www.cdc.gov/exposurereport/

[37] National Academy of Sciences (2000). *Toxicological Effects of Methylmercury*. National Academy Press. Washington, DC

[38] US EPA defines benchmark dose or BMD as "a dose that produces a predetermined change in response rate of an adverse effect compared to background."

[39] US EPA defines BMDL as "a statistical lower confidence limit on the dose at the BMD."

[40] US Centers for Disease Control and Prevention (2005). Third National Report on Human Exposure to Environmental Chemicals. http://www.cdc.gov/exposurereport/3rd/pdf/results_01.pdf

Exhibit 5 shows another way to compare exposures. In addition to blood levels, mercury exposure can be reflected in hair. Exhibit 5 shows (1) measurements of mercury levels in the hair of the women in the Faroe Islands who ate methylmercury and PCB-contaminated pilot whales and whose children tended to perform more poorly on the Boston Naming Test as their mothers' exposure to mercury increased;[41] (2) US EPA's reference dose, or recommended limit on methylmercury exposure;[42] (3) the average mercury level found in the hair of US women of childbearing age tested by the CDC;[43] (4) the upper 90th percentile mercury level in US women of childbearing age; and (5) the mercury level reported for a sample of mothers in Japan.[44] Both Exhibits 4 and 5 show that the mercury level associated with neurodevelopmental deficits in the Faroe Islands is much higher than the levels of mercury exposure in US women. The Japanese data provide an interesting contrast and were used by the Japanese investigators to calculate that more than 90% of Japanese women have mercury levels that exceed US EPA's reference dose for methylmercury.[45] As far as I know, there is no epidemic of poor neurodevelopmental performance in Japan.

Other regulatory agencies and scientific organizations in the US and Europe have identified quantitative exposure levels for methylmercury—based partly on science but mostly on policy—that are considered to be limits on safety. Such limits are goals that, if exceeded,

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[41] Grandjean P, Weihe P, Burse VW, Needham LL, Storr-Hansen E, Heinzow B, Debes F, Murata K, Simonsen H, Ellefsen P, Budtz-Jørgensen E, Keiding N, White RF (2001). Neurobehavioral deficits associated with PCB in 7-year-old children prenatally exposed to seafood neurotoxicants. Neurotoxicology and Teratology 23:305-317

[42] US Environmental Protection Agency (2001). *Water Quality Criterion for the Protection of Human Health: Methylmercury*. Office of Water. Washington, DC http://www.epa.gov/waterscience/criteria/methylmercury/document.html

[43] US Centers for Disease Control (2001). Blood and hair mercury levels in young children and women of childbearing age—United States, 1999. Morbidity and Mortality Weekly Report 50:140-143

[44] Iwasaki Y, Sakamoto M, Nakai K, Oka T, Dakeishi M, Iwata T, Satoh H, Murata K (2003). Estimation of daily mercury intake from seafood in Japanese women: Akita cross-sectional study. Tohuku Journal of Experimental Medicine 200:67-73

[45] Ibid page 67

may warrant actions to reduce exposure, although exceeding a limit does not imply lack of safety. Most exposure limits for methylmercury are advisory levels and not regulatory requirements. Exhibit 6 shows the exposure levels considered protective by different organizations. All of the protective exposure levels identified in Exhibit 6 are based on methylmercury's ability to produce developmental neurotoxicity. Most were based on the data from the Seychelles study mentioned above although some also considered the Faroe Island and New Zealand data. Some derived a benchmark dose from the dose-response relationship for methylmercury exposure and developmental neurotoxicity. In other cases, a no-observed-adverse-effect level (NOAEL) was identified, that is, the median maternal hair concentration from the highest exposure group in the Seychelle Islands study (which, as noted above, found no significant positive association between exposure and abnormality). The benchmark dose or NOAEL, expressed as concentrations of mercury in blood or hair, was then converted to the dose of methylmercury from fish that would produce that blood or hair concentration. Finally, that dose was divided by an "uncertainty factor" to obtain a dose considered to be without deleterious effects by accounting for the possibility that some people might be more sensitive to methylmercury toxicity than others. The resulting dose is considered the amount of methylmercury that can be consumed daily without producing developmental neurotoxicity even in the most sensitive children. US EPA calls such limits reference doses (RfDs), the Agency for Toxic Substances and Disease Registry calls them chronic minimal risk levels (MRLs), and others refer to them as tolerable daily intakes (TDIs).

As Exhibit 6 indicates, the methylmercury exposure limits derived by different organizations vary by an order of magnitude. The different limits result from different decisions about which study was the most representative or valid, the approach taken to evaluate the relationship between dose and response, and the choice of uncertainty factor. None of those choices are necessarily "right" or "wrong" scientifically, although some may reflect the weight of the scientific evidence better than others. They represent different policy choices made by equally competent scientists looking at the same data, making different decisions for different reasons, leading to different conclusions. As such, they illustrate the important role that policy choices make in decisions about limiting chemical exposures and the limited role that science often ends up playing.

The US EPA is the only agency that did not include the Seychelles study in its reference dose calculation, thereby excluding the study in which methylmercury exposure occurred solely through fish, as it does in the US, and that could not have been confounded by PCBs in breast milk or pilot whale blubber. Excluding the Seychelles study produces a more stringent reference dose than would be possible otherwise. A more stringent reference dose produces a lower acceptable fish methylmercury concentration than would be obtained based on other organizations' values. A lower acceptable fish methylmercury concentration suggests that more fish exceed the limit and more people could be at risk than would result otherwise. More fish exceeding the limit and more people potentially at risk drives public concern about mercury in fish and, ultimately, about power plant emissions. Thus the policy—not scientific—decision to exclude the Seychelles data from consideration (despite the fact that the rest of the world appears to rely primarily on the Seychelles data) has contributed to greater public concern in the US about methylmercury and its potential sources than would be likely to occur otherwise.

The impact of different policy choices on acceptable fish methylmercury concentrations is illustrated in Exhibit 7. The first column of Exhibit 7 shows the parameter values chosen by US EPA as the basis for developing its methylmercury fish tissue residue criterion for freshwater and estuarine fish.[46] The following columns show how varying one parameter value, by choosing a value used by one of the other organizations shown and substituting it for US EPA's value, produces a completely different fish tissue residue criterion. Using a different value for the reference dose or a different value for the assumption about fish consumption produces residue criteria that vary by an order of magnitude, providing further illustration that different policy choices lead to different conclusions about risk.

Of particular note in Exhibit 7 is the difference among assumptions about average daily fish consumption. US EPA recommends a default fish intake rate of 17.5 grams/day to

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[46] Environmental Protection Agency (EPA) (2001). *Water Quality Criterion for the Protection of Human Health: Methylmercury*. EPA-823-R-01-001. Office of Water. Washington, DC

adequately protect the general population of fish consumers,[47] based on the 1994 to 1996 data from the USDA's CSFII Survey.[48] US EPA also recommends default fish intake rates for recreational and subsistence fishers of 17.5 grams/day and 142.4 grams/day, respectively.[49] IL EPA has chosen the latter estimate as the basis for its fish tissue methylmercury criterion,[50] so the IL criterion applies to subsistence fishers, not the general population or even most sports anglers. US EPA subtracts the contribution to methylmercury exposure attributable to marine seafood from the daily intake rate, although IL EPA does not. The IL criterion is thus intended to protect the most-exposed, worst-case women of childbearing age who are subsistence fishers relying almost solely on the most contaminated freshwater predator fish in Illinois as their source of protein. As noted above, the TSD has not identified or characterized the locations and numbers of those people potentially at risk, making an evaluation of any potential benefits provided by the state's proposed rule impossible and any claims regarding its superior benefits compared to CAMR wholly untenable.

The derivation of a reference dose or other criterion is thus based on many policy choices in order to serve regulatory purposes and has little scientific basis. Despite numerous assertions to the contrary (including Dr. Rice's), women whose exposures exceed US EPA's methylmercury reference dose are *not* "at risk" of having developmentally impaired children. US EPA is careful to point out that, while exposure at or below a reference dose indicates that a health risk is unlikely, people who are exposed to a substance above its reference dose should not be considered at risk: ". . . exceeding the [reference dose] is not a statement of risk."[51] US

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[47] US Environmental Protection Agency (2000). Methodology for deriving ambient water quality criteria for the protection of human health. EPA-822-B-00-004. Office of Science and Technology, Office of Water. Washington, DC. http://www.epa.gov/ostwater/humanhealth/method/complete.pdf. Page 4-24

[48] US Department of Agriculture (1998). 1994–1996 Continuing Survey of Food Intakes by Individuals and 1994–1996 Diet and Health Knowledge Survey. Agricultural Research Service. Washington, DC

[49] US Environmental Protection Agency (2000). Methodology for deriving ambient water quality criteria for the protection of human health. EPA-822-B-00-004. Office of Science and Technology, Office of Water. Washington, DC. http://www.epa.gov/ostwater/humanhealth/method/complete.pdf. Page 4-24

[50] Based on Table 4.3 in the TSD

[51] US Environmental Protection Agency (2004). *Exposure and Human Health Reassessment of 2,3,7,8-Tetrachlorodibenzo-p-Dioxin (TCDD) and Related Compounds National Academy Sciences*

EPA's Regulatory Impact Assessment for the Clean Air Mercury Rule states, "It is also important to note that the [reference dose] does not define a bright line, above which individuals are at risk of adverse effect."[52] In other words, while exposures at or below a reference dose are unlikely to pose a risk, the converse—that exposures exceeding a reference dose are likely to pose a risk—is not the case. The number of children "at risk" is determined by the dose-response relationship, not by the number of people whose doses or blood mercury levels exceed the reference dose at a single point in time.

Methylmercury and cardiovascular toxicity

There is a large body of evidence demonstrating the cardiovascular benefits of fish consumption in adults.[53] While most of the studies reporting an inverse association between fish consumption and cardiovascular effects did not specifically evaluate mercury exposure, it is reasonable to assume that people who eat more fish are exposed to more mercury. The American Heart Association recommends that individuals consume two servings of a variety of fish weekly, both for the benefits of omega-3 fatty acids and because fish tends to be low in saturated fats, which contribute to elevated cholesterol levels.[54]

A study of Finnish men has been pointed to recently as evidence that mercury exposure is associated with cardiovascular disease. That study found an association among the highest third of hair mercury content and an approximately 60% greater prevalence of coronary heart and cardiovascular diseases compared to men with the lower two-thirds of hair mercury content.[55]

(NAS) Review Draft. National Center for Environmental Assessment. Office of Research and Development. Washington, DC. Page 14

[52] US Environmental Protection Agency (2005). *Regulatory Impact Analysis of the Clean Air Mercury Rule*. EPA-452/R-05-003. Office of Air Quality Planning and Standards. Research Triangle Park, NC. Page 9-2

[53] See review by Kris-Etherton PM, Harris WS, Appel LJ for the Nutrition Committee of the American Heart Association (2002). Fish consumption, fish oil, omega-3 fatty acids, and cardiovascular disease. Circulation 106:2747-2757

[54] American Heart Association Dietary Guidelines for Healthy Adults, http://www.americanheart.org/presenter.jhtml?identifier=4561

[55] Virtanen JK, Voutilainen S, Rissanen TH, Mursu J, Tuomainen TP, Korhonen MJ, Valkonen VP, Seppanen K, Laukkanen JA, Salonen JT (2005). Mercury, fish oils, and risk of acute coronary

The men least likely to experience heart problems were those who had both low levels of hair mercury and high blood levels of fatty acids found in fish that are known to reduce the risk of heart disease. Attempts to correlate hair mercury content with fish consumption were tenuous, with only one third of the men in the highest hair mercury group reporting higher fish consumption than the other study participants. No information was provided on whether high- or low-mercury-containing types of fish were consumed. Contrary to the large body of epidemiologic evidence showing a negative correlation between fish consumption and heart disease, the population of Eastern Finland has a high rate of heart disease in spite of high fish consumption,[56] suggesting that factors other than methylmercury are responsible for elevated risk.[57] The Finnish results were considered preliminary by the American Heart Association, which has concluded that when consumed according to established FDA/US EPA guidelines, the cardiovascular benefits of eating fish far outweigh the risks for middle-aged and older men and women after menopause.[58]

Conclusion

I do not dispute Dr. Rice's and the IL EPA's consideration of methylmercury as a developmental neurotoxicant about which we should be concerned. I do not dispute that methylmercury exposure should be limited to the extent possible during pregnancy while maintaining the many healthy benefits of fish consumption, which includes nutrients essential to the development of healthy brains. I think that a more balanced discussion of methylmercury toxicity that reflects ongoing scientific and policy debates is desirable so as to avoid conveying an inappropriate level of certainty about methylmercury's dose-response characteristics and to

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events and cardiovascular disease, coronary heart disease, and all-cause mortality in men in Eastern Finland. Arteriosclerosis, Thrombosis, and Vascular Biology Arteriosclerosis, Thrombosis, and Vascular Biology 25:222-227

[56] Salonen JT, Seppänen K, Nyyssönen K, Korpela H, Kauhanen J, Kantola M, Tuomilehto J, Esterbauer H, Tatzber E, Salonen R (1995). Intake of mercury from fish, lipid peroxidation, and the risk of myocardial infarction and coronary, cardiovascular, and any death in Eastern Finnish men. Circulation 91:645-655

[57] Smith KM, Sahyoun NR (2005). Fish consumption: recommendations versus advisories, can they be reconciled? Nutrition Reviews 63:39-46

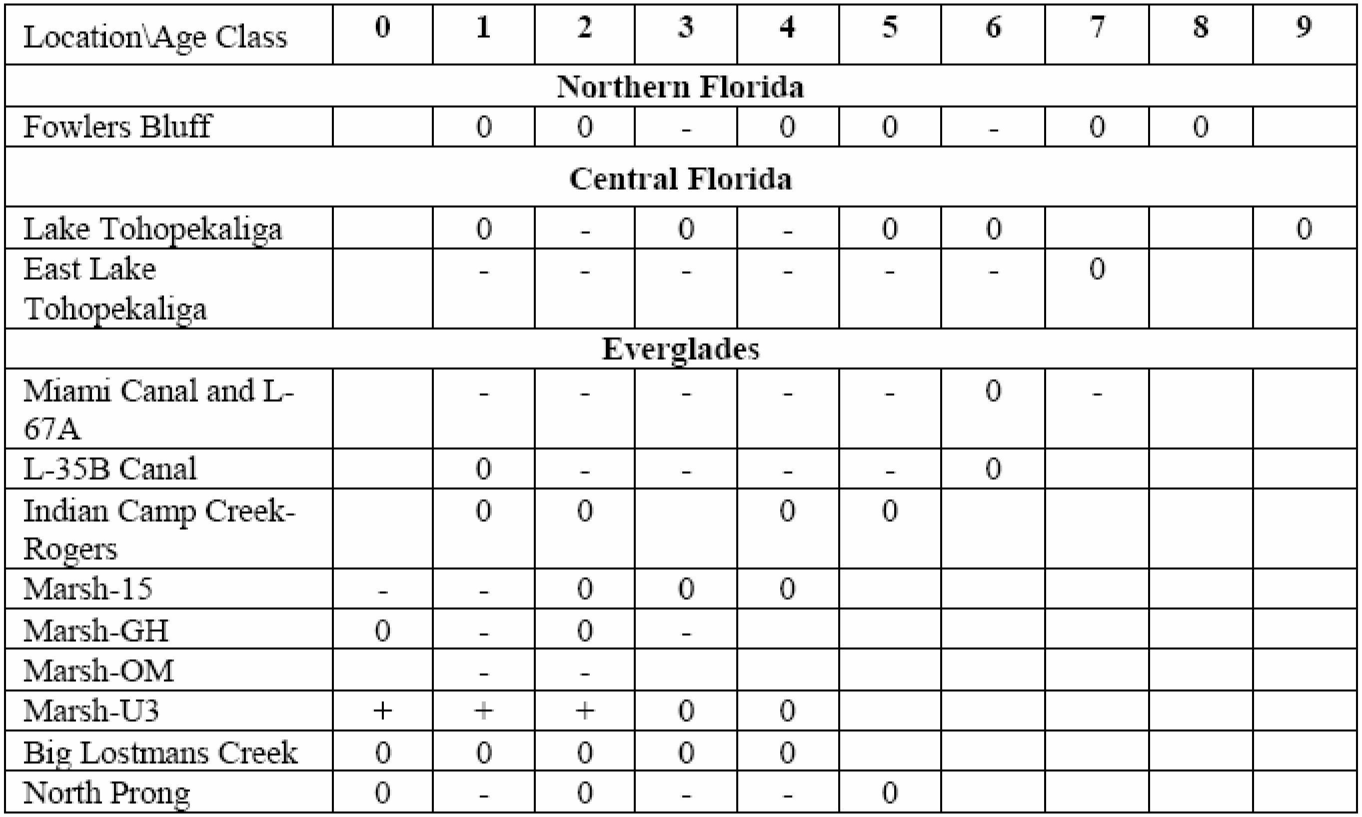
[58] American Heart Association (AHA) (2005). Fish, Levels of Mercury and Omega-3 Fatty Acids. http://www.americanheart.org/presenter.jhtml?identifier=3013797

better illustrate the extent to which its reference dose reflects more policy than science. The fact that other public health organizations have evaluated methylmercury's risks differently than did US EPA itself illustrates the widespread differences of opinion that are possible in terms of scientific interpretation and policy choices.

I do not dispute the desirability of limiting mercury emissions from coal-based power plants as a means of limiting its contribution to fish methylmercury levels in places where it may be significant. I do dispute the simplistic notion that limiting power plant mercury emissions in Illinois is going to have a direct and noticeable impact on Illinois fish methylmercury levels, on Illinois methylmercury exposures, or on public health in Illinois. A tremendous amount of uncertainty remains regarding the relationship between power plant mercury emissions and fish methylmercury levels and toxicity, but the weight of the scientific evidence does not suggest that they are simply and directly related. The public health benefits of limiting Illinois mercury emissions are being oversold and the benefits of limiting mercury emissions deeper and faster than is required by US EPA are political only.

Exhibit 1

Trends in largemouth bass methylmercury concentrations at 12 Florida locations, 1988-2000

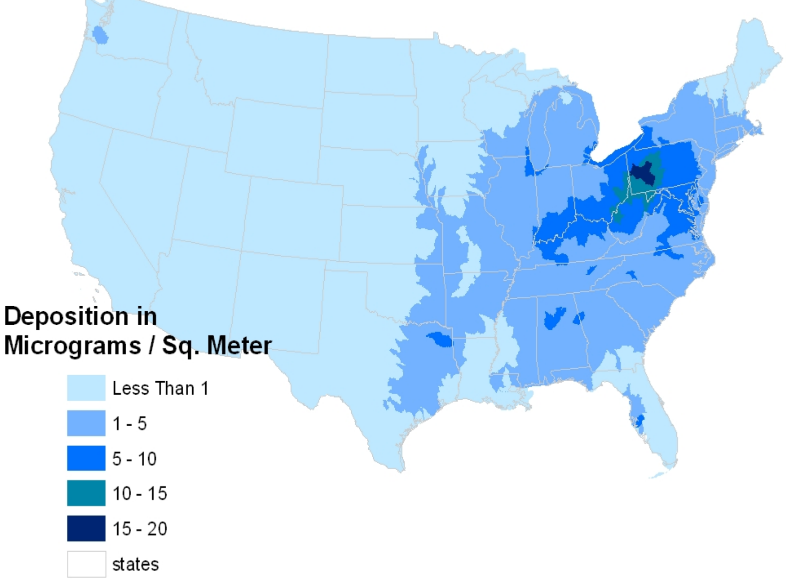


Location\Age Class	0	1	2	3	4	5	6	7	8	9
Northern Florida										
Fowlers Bluff		0	0	-	0	0	-	0	0	
Central Florida										
Lake Tohopekaliga		0	-	0	-	0	0			0
East Lake Tohopekaliga		-	-	-	-	-	-	0		
Everglades										
Miami Canal and L-67A		-	-	-	-	-	0	-		
L-35B Canal		0	-	-	-	-	0			
Indian Camp Creek-Rogers		0	0		0	0				
Marsh-15	-	-	0	0	0					
Marsh-GH	0	-	0	-						
Marsh-OM		-	-							
Marsh-U3	+	+	+	0	0					
Big Lostmans Creek	0	0	0	0	0					
North Prong	0	-	0	-	-	0				

Source: Florida (2003)

Exhibit 2
Effectiveness of federal mercury rules

Deposition From US Power Plants in 2001



Source: USEPA (2005)

Deposition From US Power Plants After CAIR, CAMR, and Other Clean Air Act Programs in 2020

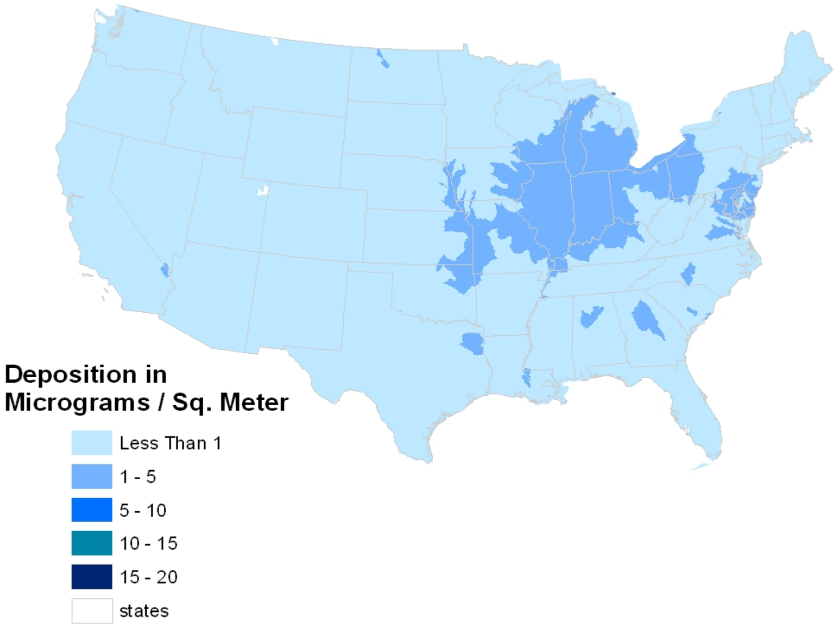
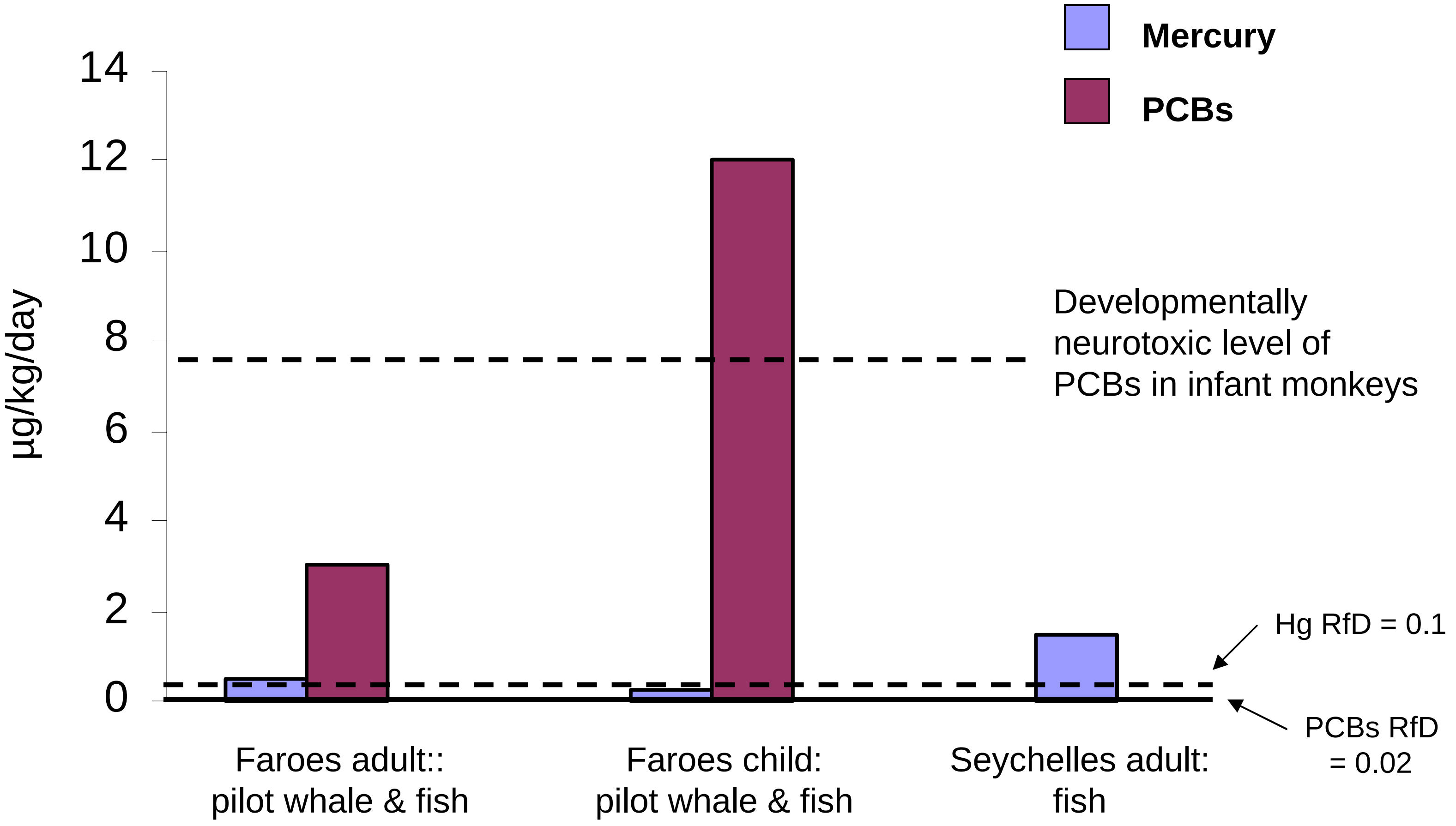
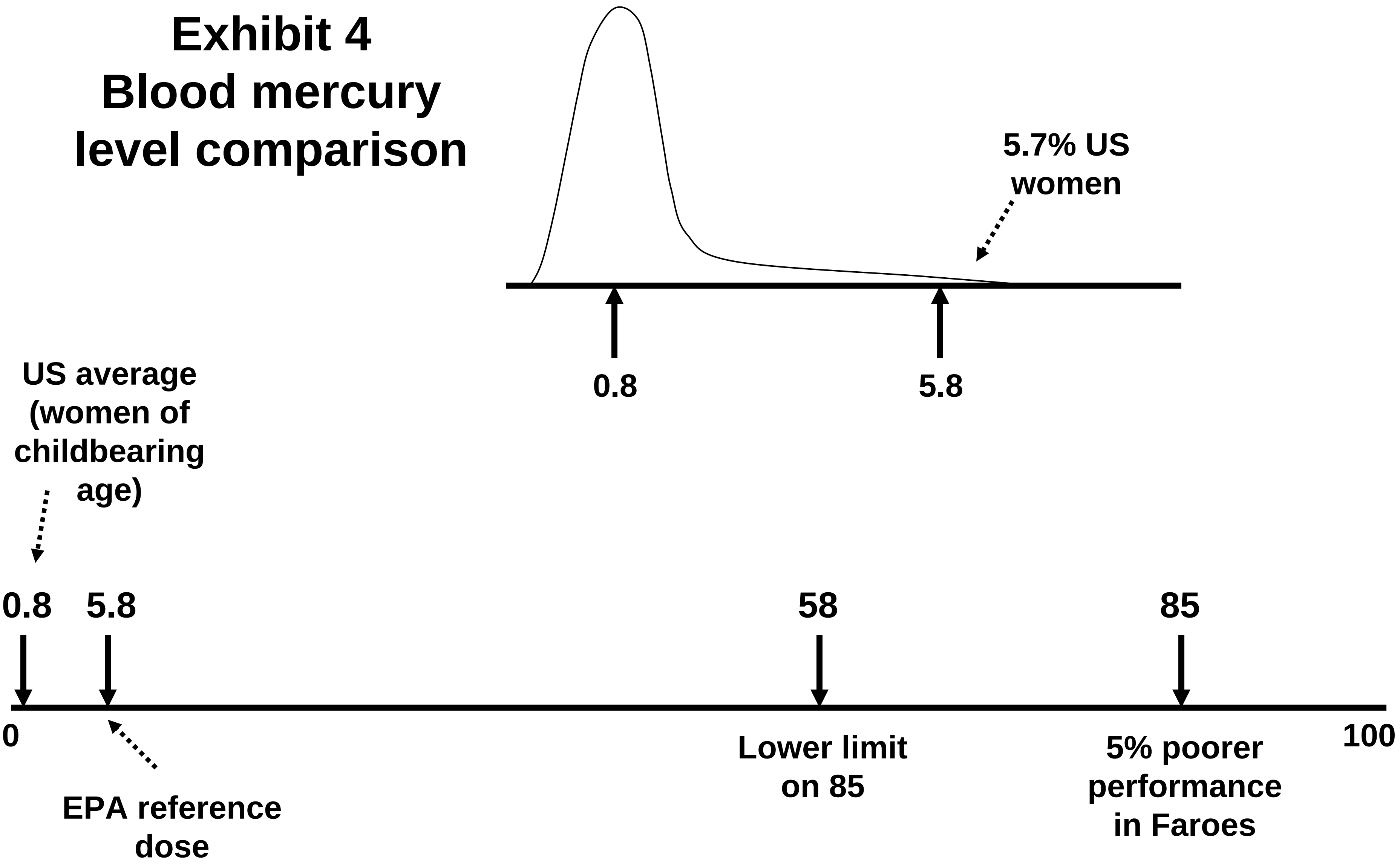


Exhibit 3
Contaminant intakes in the Faroe and Seychelle Islands



Source: Modified from Dourson et al. (2001)

Exhibit 4
Blood mercury level comparison



5.7% US women

0.8

5.8

US average (women of childbearing age)

0.8

5.8

58

85

0

100

EPA reference dose

Lower limit on 85

5% poorer performance in Faroes

Blood mercury concentration (µg per liter)

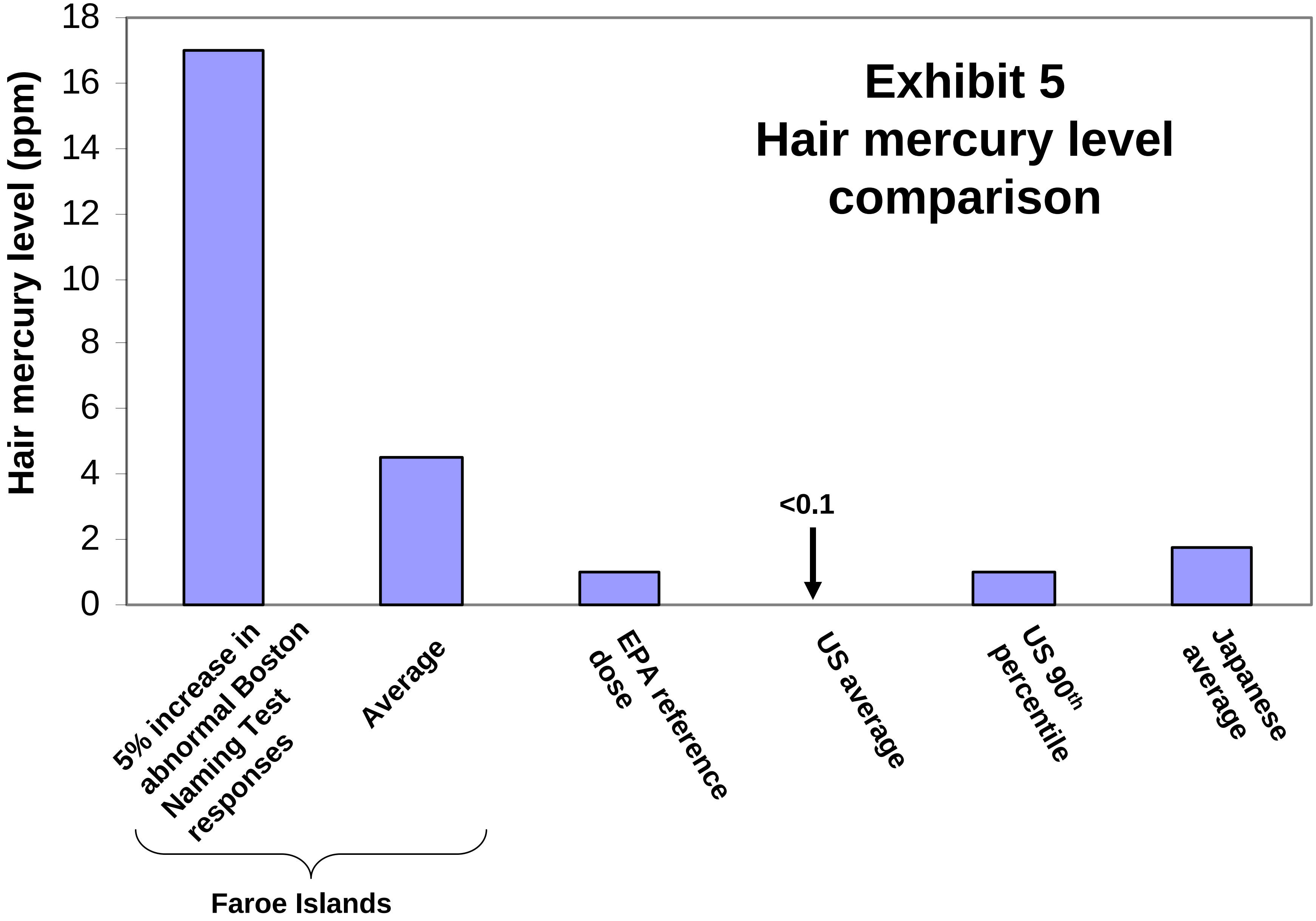


Exhibit 5
Hair mercury level comparison

Exhibit 6
Exposure Limits for Methylmercury

	Organization[a]				
	ATSDR	**EPA**	**RIVM**	**WHO**	**ICF/TERA**
Exposure Limit[b]	0.3 chronic MRL	0.1 RfD	0.1 TDI	0.23 TDI	0.3 to 1 RfD
Study	Seychelles	Faroes	Seychelles	Seychelles, Faroes	Seychelles
Study Dose[b]	1.3	0.9 to 1.5	1.3	1.5	0.9 to 3
Uncertainty Factor[d]	4.5	10	10	3.2	3
Year	1999	2001	2000	2003	1998

[a] Abbreviations for organizations: ATSDR, Agency for Toxic Substances and Disease Registry; EPA, Environmental Protection Agency; RIVM, National Institute for Public Health and the Environment, The Netherlands; WHO, World Health Organization; ICF, ICF Inc.; TERA, Toxicology Excellence for Risk Assessment

[b] Exposures expressed in units of micrograms methylmercury per kilogram body weight per day

[c] Abbreviations for exposure limits: MRL, minimal risk level; RfD, reference dose; TDI, tolerable daily intake

[d] Uncertainty factors are used to lower the acceptable exposure level to the extent considered protective of nearly all people.

Source: Based in part on Toxicology Excellence in Risk Assessment's International Toxicity Estimates for Risk Database (ITER) (2006). http://www.tera.org/iter/

Exhibit 7
Impact of Changing Assumptions on EPA's Permissible Mercury Fish Tissue Concentration

		Change assumption as per				
Parameter	**US EPA,[a,c]**	**IL EPA[b,d]**	**WHO[e]**	**US ATSDR[e]**	**IL PIRG[b,f]**	**ICF/ TERA[e]**
Exposure limit (µg/kg/day)	0.1		0.23	0.3		0.3 to 1
Relative source contribution[g]	0.027					
Body weight (kg)	70					
Daily fish intake (kg)	0.0175	0.14			0.049	
Resulting fish tissue concentration limit (mg/kg or ppm)	0.3	0.04	0.7	0.9	0.1	0.9 to 2.9

[a] For organization abbreviations, see Exhibit 6.

[b] IL EPA, Illinois Environmental Protection Agency; PIRG, Illinois Public Interest Research Group

[c] This column shows the assumptions used by USEPA to calculate its limit on permissible methylmercury concentrations in freshwater and estuarine fish using the following equation:[1]

$$\mathrm{TRC} = \frac{\mathrm{BW} \times (\mathrm{RfD} - \mathrm{RSC})}{\mathrm{FI}}$$

Where:

TRC =	Fish tissue residue criterion (mg methylmercury/kg fish) for freshwater and estuarine fish (i.e., limit on acceptable fish methylmercury concentration)
RfD =	Reference dose = 0.0001 (mg methylmercury/kg body weight/day)
RSC =	Relative source contribution (subtracted from the RfD to account for marine fish consumption) estimated to be 2.7×10^{-5} mg methylmercury/kg body weight/day
BW =	Human body weight default value of 70 kg (for adults)
FI =	Fish intake; total default intake is 0.0175 kg fish/day for general adult population

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[1] Environmental Protection Agency (EPA) (2001). *Water Quality Criterion for the Protection of Human Health: Methylmercury*. EPA-823-R-01-001. Office of Water. Washington, DC. Page 7-1

[d] IL EPA assumes an average fish consumption rate of 0.14 kg/day, ten times higher than US EPA, leading to a fish tissue concentration limit ten times more stringent than US EPA's.

[e] These organizations recommend methylmercury exposure limits that are two to ten times higher than US EPA's, leading to fish tissue concentration limits two to ten times less stringent than US EPA's.

[f] IL PIRG assumes an average fish consumption rate of 0.045 kg/day, about three times higher than US EPA and three times lower than IL EPA, differences reflected in its resulting fish tissue methylmercury concentration limit.

[g] Only US EPA accounts for marine fish consumption as a contributor to average daily methylmercury intake by subtracting its contribution from that of freshwater and estuarine fish. IL EPA and IL PIRG use their fish tissue methylmercury limits as though all methylmercury exposure results from Illinois freshwater fish.

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	**)**	
	)	
PROPOSED NEW 35 ILL.ADM.CODE PART 225	**)**	**PCB R06-25**
CONTROL OF EMISSIONS FROM	**)**	**Rulemaking - Air**
LARGE COMBUSTION SOURCES	**)**	

Testimony of J.E. Cichanowicz
To the
Illinois Pollution Control Board

A REVIEW OF
THE STATUS OF MERCURY CONTROL TECHNOLOGY

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July 28, 2006

EXECUTIVE SUMMARY

My name is J. Edward Cichanowicz. I have provided independent consulting services since 1993 to the utility sector in evaluating environmental control technology, and defining compliance strategies. Prior to that time, I was employed by the Electric Power Research Institute for 15 years, focusing on developing control technologies for NOx, as well as SO_2 and particulate matter. Preceding my employment at EPRI, I worked as a research engineer for the Energy & Environmental Research Corporation (since acquired by GE Power Systems), concerned with developing low NOx burners for coal.

I received a BS in Mechanical Engineering at Clarkson University, and a MS in Mechanical Engineering at the University of California at Berkeley, where I also completed the bulk of coursework for the doctoral degree.

The attached document entitled “A Review of the Status of Mercury Control Technology” summarizes my evaluation of the readiness of mercury (Hg) control technology for use in complying with the proposed Illinois Environmental Protection Agency (IEPA) Rule AQPSTR 06-02. The document consists of a discussion of technical feasibility, an Appendix A that contains the assumptions used to project Hg control performance and cost that was applied to economic modeling, and an Appendix B that contains assumptions defining performance and cost of controls for NOx, SO2, and particulate matter that was applied to modeling CAIR compliance.

The response of the U.S. utility industry to support the development of Hg control technology has been unprecedented – since 2001, over 25 commercial-scale demonstrations have been either completed or are in progress. The large number of demonstrations is warranted by the myriad of plant designs, coal types, and existing environmental control systems to which Hg control technology could be applied. This comprehensive approach is essential – the population of power plants is as varied and diverse as people, with no two alike. Thus, it is important to consider a wide array of plants, operating in a demonstration mode for extended periods, to generalize evolving knowledge.

Despite extensive background work by IEPA staff and consultants, there are several major shortcomings in the rule that complicate, if not prevent, compliance. First, the targeted outlet content of Hg - in many cases less than 1 microgram/m^3 - is too low to be accurately monitored for compliance. The testimony of Mr. R. McRanie will address the specific reasons why. In this testimony, I will accept – without verification or other validation - that such measurements can be made to within a reasonable degree of accuracy, precision, and bias. Section 2.4.2 and 2.4.3 describe why I believe the cumulative effect of measurement uncertainty, variability in coal composition, and variability in process operation require a design Hg removal target of at least 93-95% to consistently deliver 90%.

Second, despite impressive results at selected demonstrations, the control technology that is the focal point of interest - activated carbon injection (ACI) - is not yet sufficiently developed to consistently deliver high Hg removal under the varied conditions in Illinois. For ACI within an existing ESP, several demonstrations recorded 90% or better Hg removal. However, these results reflect short-term tests and 30 day trials, thus the degree these controls can provide satisfactory 24/7/365 service is uncertain.

There are two reasons this uncertainty persists. First, as noted in Section 3, the history of environmental control evolution has taught us long-term experience - on the order of one year - is required before commercialization. Operating trials of a 30-day duration, although an impressive and a necessary first step, are inadequate. In coal-fired applications, environmental controls are exposed to extremely dilute concentrations of trace constituents of coal, which can accumulate on surfaces, and within reaction vessels, to threshold levels where they assert an impact. The case study of the hot-side ESP – addressed in Section 3.4 – chronicles what can happen when a control option is adopted prematurely. The failure of the hot-side ESP to provide the reliable particulate matter control as originally envisioned exemplifies the risks. An example of successful technology evolution is that of flue gas desulfurization, as described in Section 3.1. However, several decades of operating experience, and abandoning unit-specific SO_2 limits for tradable emission “allowances” was required to effect this development. The use of ACI with existing ESPs could endure the same fate as hot-side ESPs - the accumulation of carbon could assert detrimental effects on particulate matter removal or reliability, similar to the way the year-long accumulation of sodium on emitting electrodes compromised the hot-side ESP. That carbon will accumulate is certain - Section 8.4.5.4 of the Technical Support Document cites such accumulation of carbon as a factor why 30 day tests exhibit higher Hg removal than short-term tests. IEPA should recognize that carbon accumulation could assert negative as well as positive impacts.

Also of concern for ACI within an ESP is the possibility of efforts to meet Hg limits triggering New Source Review (NSR). As described in Section 5.6.5, with the Pollution Control Project provisions of NSR vacated by the U.S. Court of Appeals on June 24, 2005, collateral increases in emissions – regardless of the reason – can require NSR. Illinois generators could face the prospect of a state-mandated regulation imposing federal control requirements.

The alternative means to deploy ACI - in a fabric filter environment (e.g. TOXECON I) – provides a much higher opportunity for success, although at a steep price. Even for this approach, 90% Hg removal is not commercially proven – results from the one-year trial completed in 2004 at Gaston did not document 90% removal, but suggest such outcome may be possible. Although 90% Hg removal is the target for the 270 MW Presque Isle demonstration, these results are only now being generated, and on a short-term basis. Early operation at Presque Isle has been stymied by equipment problems that, although perhaps not representing fatal flaws, reflect problems amenable only to long-term testing. Notwithstanding the belief by the Presque Isle project team that 90% Hg removal is certain, to date there is no data defining such results for more than brief test periods.

These uncertainties are important in Illinois. The use of ACI in existing ESPs should recognize the relatively small size of ESPs, as measured by the specific collecting area (SCA). Figure 5.1

in Section 5.3 compares the population distribution of ESPs in Illinois to the national population, and to the demonstration units. Figure 5-1 shows Illinois ESPs to be extremely small when compared to the demonstration units. Further, Table 5-1 in Section 5.6 summarizes the significant ESP modifications – in some cases complete ESP replacements - implemented to six of the most frequently cited demonstration sites. I do not believe that achieving 90 and 93% Hg removal on units such as St. Clair and Meramac – featuring ESPs of 720 and 400 SCA, respectively – portends the same result on the small ESPs at stations such as Will County and Hennepin.

IPEA argued that ESP size is not relevant, but comparing Hg removal data from key demonstrations suggests such a relationship exists. Figure 5-2 in Section 5.6.2. compares Hg removal (either maximum measured or at 3-10 lbs/MACF) for various demonstrations, and suggests there is some factor either directly or indirectly related to ESP SCA that impacts Hg removal. Figure 5-2 is not intended to reflect any fundamental theorem of carbon Hg absorption, or ESP residence time, but rather projects an anecdotal relationship. Figure 5-2 shows the highest Hg removals have been attained on large, state-of-art ESPs that have in many cases replaced the original equipment. Further, as described in Section 5.6.4, I believe the detrimental impact of ACI on small ESPs is well-represented by the experience of Yates 1. Section 5.6.4. also summarizes discussions with staff at Progress Energy Lee Unit 1, which emphasizes the need to consider Exhibit 73 data as preliminary, as suggested by Mr. Nelson in his testimony.

There is a confluence of events under which the IEPA regulation could be attained – the goals of the Presque Isle Demonstration would have to be realized quickly and without further equipment complications; ACI within small ESPs in Illinois would have to be able to sustain carbon injection and provide Hg removal on a long-term basis at or near the best performance measured with short-term tests; and engineering and construction staff and process equipment would have to be available to support rapid application of fabric filter-based (e.g. TOXECON I) technology to more than 60% of the units. The details of equipment selection, inventory, and cost will be addressed in the testimony of Mr. J. Marchetti.

In summary, I conclude there is insufficient data to demonstrate that Hg control technology is available today to assure compliance with the Agency's proposed Hg rule. The data available from short-term tests of conventional or halogenated carbon injection before ESPs is clearly insufficient to project such compliance. Moreover, there is even less short-term data describing the performance of these sorbents within a fabric filter environment, to assure a reasonable certainty of compliance. Nevertheless, in order to project possible costs to achieve compliance and its impact on mercury deposition, I prepared the relationships described in Appendix A that allows compliance decisions to be mimicked, without conceding the available data allows these decisions. Based on these assumptions, I conclude that the capital cost of meeting the mercury rule would exceed 1.77 billion dollars.

A REVIEW OF THE STATUS OF MERCURY CONTROL TECHNOLOGY

SECTION 1

INTRODUCTION

This document concerns the proposed Rule AQPSTR 06-02 by the Illinois Environmental Protection Agency, addressing control of mercury (Hg) emissions from coal-fired power plants. Specifically, this document addresses the technical feasibility and cost of Hg control technology, without the benefit of additional demonstration projects to be completed prior to 2012.

Generating companies throughout the U.S. are evaluating and preparing to implement control technology to meet the Federal Clean Air Mercury Rule (CAMR). The commitment by the utility industry in this endeavor cannot be questioned. Since 2001, the utility industry has hosted, or is presently hosting, over 25 commercial-scale demonstrations and performance tests, and numerous slip-stream or pilot plant tests, to explore various Hg-reduction strategies. Regardless, as recently stated by the U.S. Department of Energy (DOE), the need to continue demonstration and commercialization activities still exists, to support reliable and cost-effective deployment of Hg controls. Consequently, additional demonstration projects will continue through at least 2012 (Feeley, 2005b). The commitment by the utility industry for fast-track development, generalization, and commercialization of Hg controls in the U.S. is unprecedented.

In parallel with this effort, the U.S. utility industry has addressed two other air quality-related mandates – completing the installation of selective catalytic reduction (SCR) for NOx control (to meet the one-hour ozone standard), and compliance steps for the Clean Air Interstate Rule (CAIR). By May of 2006, approximately 120 GW of generating capacity in the U.S. will have been retrofitted with SCR NOx control. Regarding the CAIR, Phase I requires compliance for either NOx or SO2 in 2009 and 2010, respectively, with Phase II compliance by 2015. By 2010, a total of 90 GW of generating capacity is anticipated to be retrofit with both SCR NOx control and flue gas desulfurization (FGD).

The implications of compliance actions prompted by CAIR for Hg control are significant, and should not be underestimated. Deploying advanced environmental controls for NOx, SO2, and improving particulate matter control equipment provides a reliable platform from which to optimize and implement Hg controls. The ability to leverage CAIR-prompted control technology for Hg control will be to the financial and environmental benefit of the CAIR-affected regions. Accelerating the Hg control mandate through proposed state-specific rules will lead to higher compliance costs in the long-term, and interfere with adopting the most effective CAIR strategy in the near term.

SECTION 2

ILLINOIS PROPOSED RULE: WHAT DOES IT REALLY ASK?

2.1. INTRODUCTION

The proposed Illinois Environmental Protection Agency (IEPA) Hg rule is interpreted to require 90% Hg removal, or meet a system-wide Hg emission average of 0.008 lbs/GWh. The proposed rule also includes a provision to allow a shortfall of performance to as low as 75%, as long as either the system average of 90% or the outlet rate of 0.008 lbs/TBtu is attained. This structure – requiring 90% but accommodating units that cannot achieve targeted performance – is proposed to provide for flexibility to address the variable needs of utility systems.

First, the premise that conventional coal cleaning provides 47% Hg removal for Illinois basin coals, and that the average content of Illinois basin coal fired can be considered to be 5.43 lbs/TBtu appears optimistic, compared to alternative sources. Consequently, the conclusion that 87% Hg removal will suffice for compliance – allegedly within the capability of most units with SCR and FGD – is unfounded.

The proposed IEPA Hg rule requires Hg removal significantly beyond 90%, and offers little flexibility. To achieve the rule as proposed, actual design targets will probably need to target 93-95%, when accounting for (a) uncertainty in measurement of mercury in coal and in flue gas, (b) variability in mercury content of coal, (c) variability in process operations. Further, the flexibility to allow a “compromise” of mercury removal to 75% for some units requires an increase in mercury removal to beyond 90% on other units, to attain system compliance.

2.2. ROLE OF COAL CLEANING AND BASELINE HG CONTENT

The Illinois EPA Technical Support Document (TSD) presents on pages 101-103 an analysis stating that (a) median Illinois Hg content is 10.24 lbs/TBtu, and (b) conventional coal cleaning provides an average of 47% Hg removal, lowering the average Hg content of Illinois coal as-fired to 5.43 lbs/TBtu. The basis for this statement appears to be a presentation by M. Rostam-Abadi of the Illinois State Geologic Survey (ISGS) to a November, 2005 meeting of the Illinois Clean Coal Institute (ICCI).

The basis for the 47% Hg reduction appears to be a bar chart on Slide #4, for which supporting data is not presented. This value appears high compared to data published recently by Akers (2006). It is possible that 47% Hg reduction from a limited number of coal samples could have been witnessed, which may not be representative of coal-fired. Further, the reduction in Hg or any other constituent by coal cleaning depends on the “energy recovery”, or the amount of coal discharged with the removed byproducts. This important variable is not defined.

Akers (2006) reports the removal effectiveness of conventional coal cleaning for arsenic, chromium, Hg, and selenium for 24 commercial-scale tests. For these eastern bituminous and Appalachian coals, an average of 37% Hg removal was noted; only four Illinois coals were tested but the 35% Hg reduction for these samples mirrors that for all coals.

The consequences of the ISGS value of 47% - too high in my opinion – is to underestimate by several percentage points the Hg reduction to meet the proposed fixed Hg emission rate. Using the 37% value determined by Akers (2006), and following the logic of the TSD, the average Hg content of Illinois coal as-fired is estimated to be 6.45 lbs/TBtu (compared to the 5.43 lbs/TBtu reported in the TSD). This value implies an approximate 89% Hg removal, not 87%, to meet the presumptive fixed limit of 0.008 lbs/GWh.

As will be shown in subsequent sections, the consideration of Hg variability in coal, and the uncertainty in measurement and operations, further elevates the targeted Hg design rate to significantly exceed 90 and approach 95%.

2.4. VARIABILITY AND UNCERTAINTY IN PLANT HG EMISSIONS

Selecting a fixed emission rate as the basis for a standard historically considers not the average fuel and operating conditions, but reasonable boundaries for each. These conditions should not be “worst-case”, but approximate challenging combinations of fuel composition and operation that are likely to be encountered. Regulatory agencies, including the U.S. EPA, have used statistical concepts to describe these conditions for a number of recent rulemakings. Specifically, the EPA when utilizing data describing the performance of controls that are considered BACT will employ not the average performance, but that which can be attained with a high degree of confidence, such as 90, 95, or 99%. Most recently, in setting fixed limits for CAMR, EPA statistically accounted for variability in (a) Hg content of coal, (b) inaccuracy of measuring Hg, and (c) variability in operating a power generating system or environmental control processes (Wayland, 2005).

Even where a fixed percent Hg removal is required instead of a fixed outlet emissions rate, variability not only in measurement and also process operations must be accounted for (Cole, 2002).

The methodology used to derive target Hg emission rates in state proceedings does not consider variability in coal Hg content, measurement, or process operations. State agencies may believe variability is irrelevant as a 12 month rolling average will eliminate the impact of variations. Consequently, a 90% Hg removal rate contemplated by many states actually mandates design targets such as 93-95%. The reasons for this are discussed in this section, and also considered in more detail in the testimony of Richard McRanie to the Illinois Pollution Control Board (PCB).

2.4.1. The Variability in Coal Hg Content

Coals fired in Illinois consist of subbituminous Powder River Basin (PRB) and eastern bituminous sources. The variability in Hg content has been characterized extensively through the 1999 ICR program (Part II), and supplemented in the past several years by others who have studied fuel composition as part of strategic planning for CAMR. It is instructive to examine coal Hg content in terms of both mean values and the variability.

Figures 2-2 to 2-4 depict coal Hg content for PRB coals obtained from Campbell County, Wyoming, and the Illinois Basin. These data have been obtained from the 1999 ICR Part II program. Figure 2-2 presents the cumulative distribution of Hg content, the latter expressed as lbs/TBtu. Figures 2-3 and 2-4 present the same data expressed in terms of the number of shipments that contain Hg within a given range.

Figure 2-2. Distribution of Hg in Campbell County PRB, Illinois Basin Coals (lbs/TBtu)

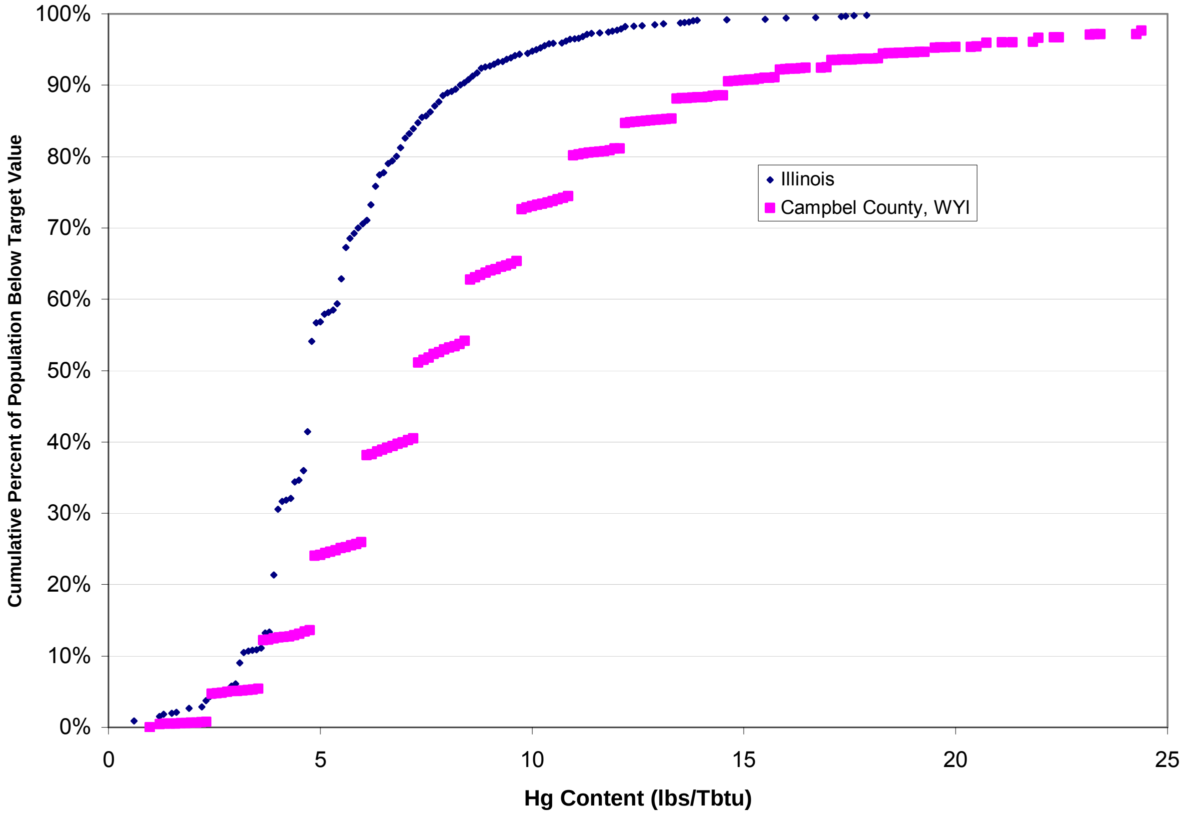


Figure 2-3. Distribution of Hg by Shipment, Campbell County PRB (lbs/TBtu)

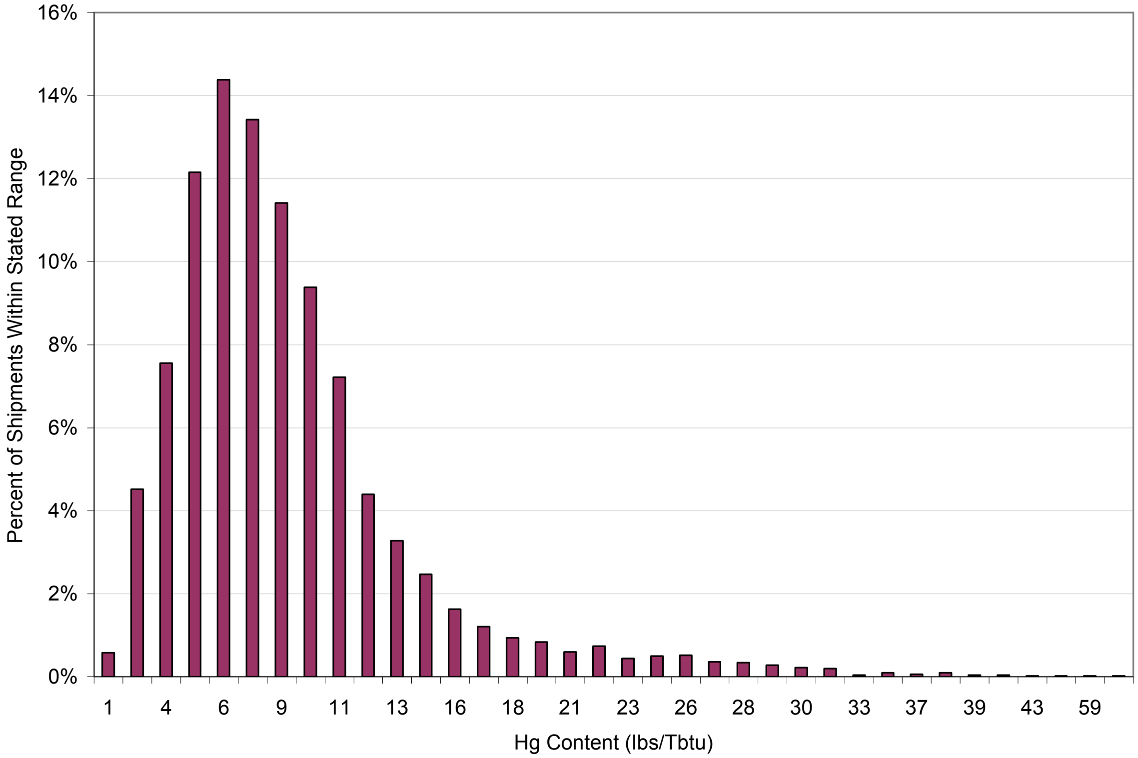
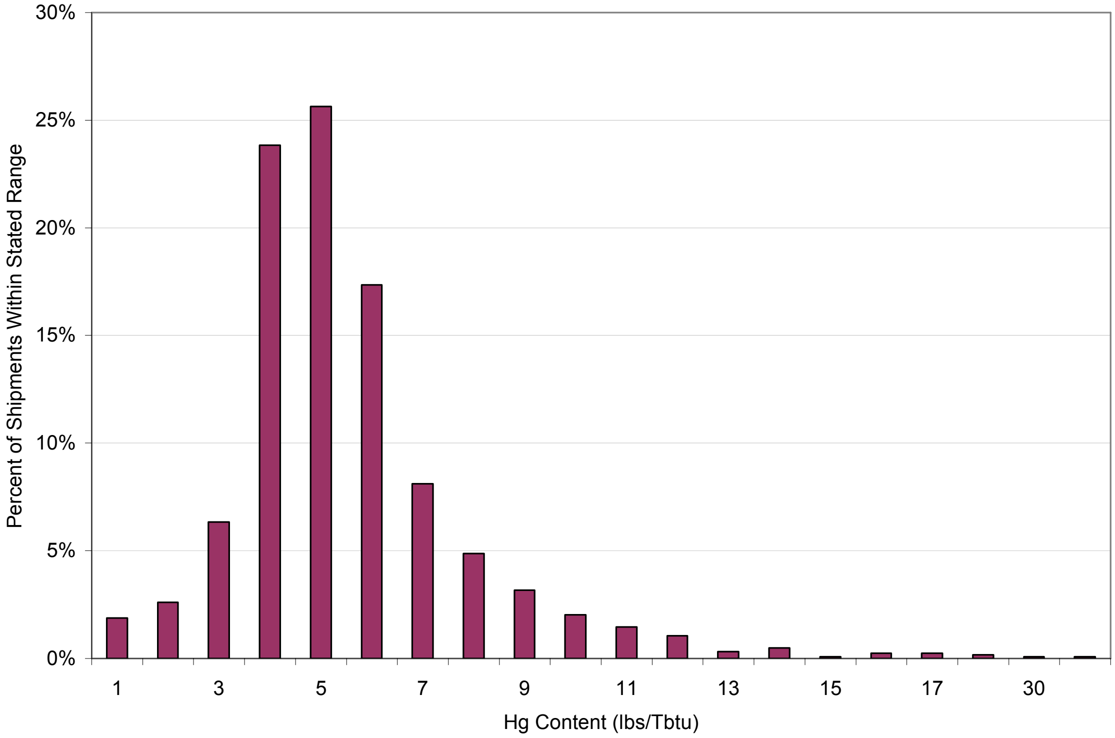


Figure 2-4. Distribution of Hg by Shipment, Illinois Basis coal (lbs/TBtu)



The variability in coal from the Illinois basis has been reported in the TSD to feature a mean value of 10.54 lbs/TBtu. Data is not presented for the mean and standard deviation of Hg in coal from PRB sources. Whereas the TSD assigned a washed coal Hg content of 5.43 lbs/TBtu (considering a 47% credit for coal washing), the Campbell County PRB data shows the median Hg content to be 7.0 lbs/TBtu.

The analysis on page 102 of the TSD does not consider the mean Hg content of coal presently fired in Illinois, or the variability in Hg content. Specifically, the analysis concludes an output rate of 0.008 lbs/GWh is appropriate, assuming coal washing at 47% delivers coal with an average of 5.43 lbs/TBtu to Illinois power stations. Notably, the presentation by Rostam-Abadi delivered to the ICCI Mercury Meeting reports the Hg content of Illinois coals that are "marketed" is 6.6 lbs/TBtu, exceeding the calculated 5.43 lbs/TBtu baseline.

The percentage Hg removal required to meet a given Hg outlet rate depends on the whether the *mean value* or the more statistically meaningful *mean value plus one standard deviation* is used in calculating the target removal. For example, the PRB coal depicted in Figure 2-3 exhibits a mean Hg content of 6.06 lbs/MBtu, with the mean value plus one standard deviation equal to 9.65 lbs/TBtu. An output rate of 0.61 lbs/TBtu, while requiring 90% removal from a mean value, would require 93.7% from the mean plus one standard deviation.

A 12 month rolling average will to some extent reduce the variability of coal Hg content. However, with long-term coal purchase contracts extending multiple years, and some PRB coals exhibiting significantly greater Hg than other PRB coals, there is no certainty coal Hg content will be uniform over this period.

2.4.2. Measurement Uncertainty

The IEPA proposes that long-term Hg measurements be conducted using the monitoring practices adopted for the CAMR, under EPA 40 CFR Part 75, Subpart I, Hg Mass Emission Provisions; and also 40 CFR Part 75, Appendix K, Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems. Further, the analysis of coal Hg content is proposed to be conducted by ASTM D3684-01. The relative accuracy of these measurements must be considered in targeting Hg removal rates. Although the 12 month averaging period reduces the importance of week-by-week or even month-by-month variations in the accuracy of measurements, the role of systematic errors must be accounted for.

The DOE acknowledged the uncertainty in Hg measurements by continuous Hg monitors, and noted this uncertainty within a recently issued cost report (DOE, 2006):

"The vapor phase mercury measurements taken by CEM have a degree of uncertainty due to the presence of extremely low mercury concentrations in the flue gas, which makes the quality assurance and quality control (QA/QC) practices of field contractors extremely important".

Hg CEMS (Continuous Emissions Monitoring Systems)

Several studies have addressed the relative accuracy of Hg CEMS instrumentation. The premise of the RATA analysis is that relative accuracy must be within 20% to be accepted as a valid, certified measurement. Given the evolutionary nature of Hg CEMS, there is no documented reason to believe that the sum of all errors - either over-reporting or under-reporting Hg content - over a 12 month period will equally compensate. Accordingly, based on this concern, and the testimony of Mr. Richard McRanie regarding the accuracy of Hg CEMS measurements, a measurement uncertainty of between 10 and 20% will be assumed.

Coal Hg Content

The accuracy of measuring Hg in coal is important for contemplated regulations that specify an Hg percentage reduction from input values. Errors and bias associated with the measurement of Hg content in coal – either over or under the actual Hg value – can affect whether the unit will be compliant with this form of regulation.

The uncertainties in Hg measurement were addressed in an early study by EPRI that was conducted in concert with the ICR coal measurement program. The results showed that for the most widely used ASTM D3684 method, employing the oxygen-bomb approach, both a high and low bias of reported Hg content was witnessed among participating laboratories. Specifically, a high bias to actual Hg content was noted for low ash coals, while a low bias to actual Hg content was noted for high ash coals (Goodman, 2006). Another widely used method – EPA 7476 – exhibited a low bias. Most of the bias was restricted to less than 20%, but 10 and 15% variations from accepted values were frequently noted.

This uncertainty in measurements of Hg in coal was quantified by correlating the relationship between Hg in coal and that measured in fly ash (Wilson, 2006). This analysis compared the results of Hg measurements in coal from two labs which tested six different coal samples. The comparison of Hg measurements obtained by the two laboratories for the six samples exhibited variability from +60% to -57%, with an average variability of 13% for all samples. Accordingly, an operator receiving coal analysis that under-reports the coal Hg content may not be credited with a 90% Hg reduction. A 12 month rolling average does not necessarily compensate for these variations. Consequently, Hg control technology design must account for this uncertainty.

Finally, a key quality assurance index of Hg measurement both in coal and flue gas is the closure of an Hg balance at a power station where both measurements have been conducted. In evaluating the Hg closure measurements conducted recently for TXU Corporation in commercial-scale equipment, researchers at the University of North Dakota EERC cited that “obtaining mercury mass balances of +/-20% is considered excellent” (Laudal, 2004). A measurement accuracy of +/- 20% will compromise determining if 90% Hg removal is attained, and a 12 month rolling average will not necessarily compensate for these variations. Consequently, Hg control technology design must account for this uncertainty by targeting to perhaps 93 and 95% Hg removal.

2.4.3. Operational Variability

Operational variability addresses the change in the production and removal of Hg due to changes in boiler operation, flue gas temperature, and sorbent distribution and injection rate.

The fate of Hg present in the coal entering the boiler – to be oxidized, remain in an elemental state, or react and transform into particulate matter – will depend on the combustion environment within the boiler, and the nature of deposits on tubes in the convective pass and other heat exchangers. For activated carbon injection (ACI) into an Electro Static Precipitator (ESP), the variability in Hg removal will be due to the distribution and mass rate of sorbent injected, and the amount of carbon accumulated and removed from collecting plate surfaces, due to plate rapping and entrainment. For ACI into a fabric filter, Hg removal variability will depend on the distribution of sorbent into the particulate collector, and how the mechanism of filter bag cleaning influences the exposure of sorbent collected on the bags to flue gas.

Several 30 day tests of ACI into an ESP and a one year-long trial with ACI into a fabric filter all exhibit variations in Hg outlet. Specifically, data from 30 day trials at Holcomb, Meramac, and St. Clair suggests that, depending on the unit, Hg removal varied between approximately 85% and 97+%. The average Hg removal reported for these trials - 91% for St. Clair and 93% for Holcomb and Meramac – suggest these variations are not of consequence. Perhaps more significant is the variability in Hg control at Yates 1, where the injection of 4 lbs/MACF of conventional activated carbon into a small ESP produced total Hg removal of 60-85% - the result of inherent variations in boiler operation, sorbent injection rate, and inherent Hg removal.

The design target for Hg controls should consider such variability. Similar to addressing measurement uncertainty, is reasonable to assess a 3-5% design premium upon a performance target of 90% Hg removal.

2.5. THE IMPACT OF VARIABILITY AND UNCERTAINTY

The significance of the preceding discussion on variability of Hg content, measurement, and operations is that a rational design strategy will incorporate a design margin.

The collective impact of these variations can significantly impact the target design removal to achieve a fixed Hg outlet value. For example, consider the required Hg removal efficiency to meet a proposed limit of 0.008 lbs/GWh, as a function of mean coal Hg content (expressed as lbs/TBtu). For this coal, the value of one standard deviation is 20% of the mean value. Figure 2-5 quantifies the impact of Hg content and measurement uncertainty on the required removal rate to meet an Hg emission rate of 0.008 lbs/GWh. Four scenarios are presented which are defined as follows:

(a) Scenario A. *Mean value Hg content, no margin for measurement or operations*. The mandate to meet 0.008 lbs/GWh requires 90% Hg removal when the average Hg content is 7.3 lbs/TBtu.

(b) Scenario B. *Mean value + one standard deviation Hg content, no margin for measurement or operations*. The mandate to meet 0.008 lbs/GWH requires 91.6% Hg removal for the same mean Hg value of 7.3 lbs/TBtu.

(c) Scenario C. *Mean value Hg content, 20% margin "overcontrol"*. An increase in Hg removal to 92% is required for the 7.3 lbs/TBtu coals, from the 90% value if no margin is considered.

(d) Scenario D. *Mean value + one standard deviation Hg content, 20% margin "overcontrol"*. An increase in Hg removal to 93.3% is required for the 7.3 lb/TBtu coal, compared to 90% if the mean value and no margin are considered.

Consequently, the ability to meet 0.008 lbs/GWh will require a premium beyond a 90% reduction. Even considering the benefits of a 12 month rolling average, uncertainty in Hg measurement and operations will likely require targeting for at least 93-95% to insure compliance with a 90% control requirement.

Figure 2-5. Comparison of Four Design Scenarios on Hg Removal Required for 0.008 lbs/GWh

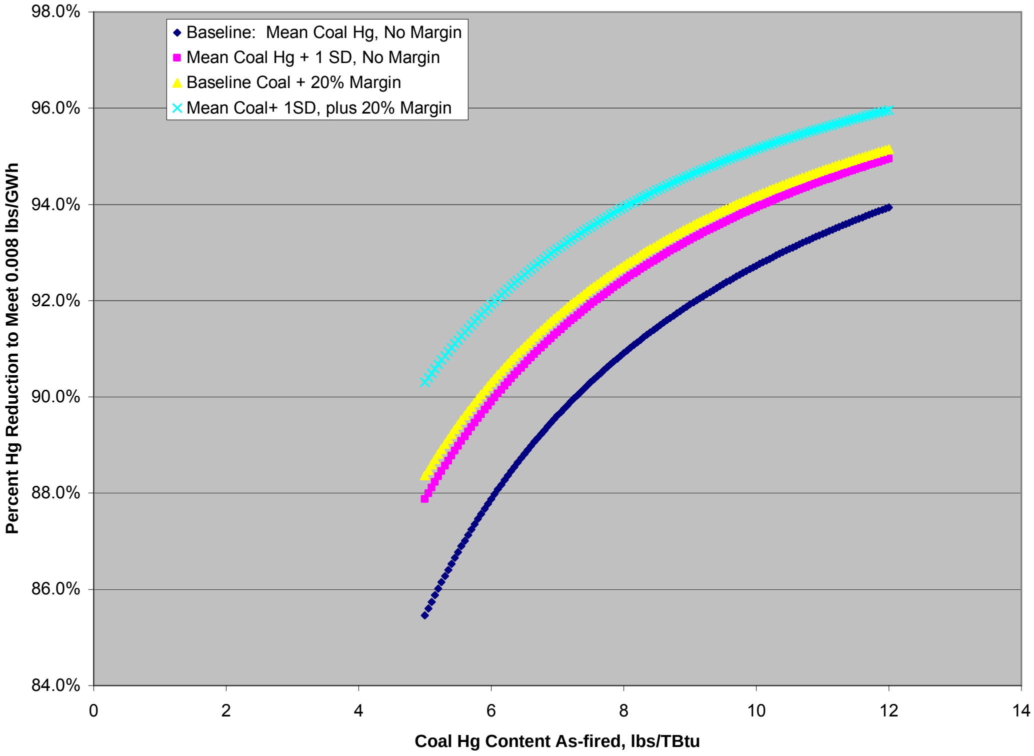
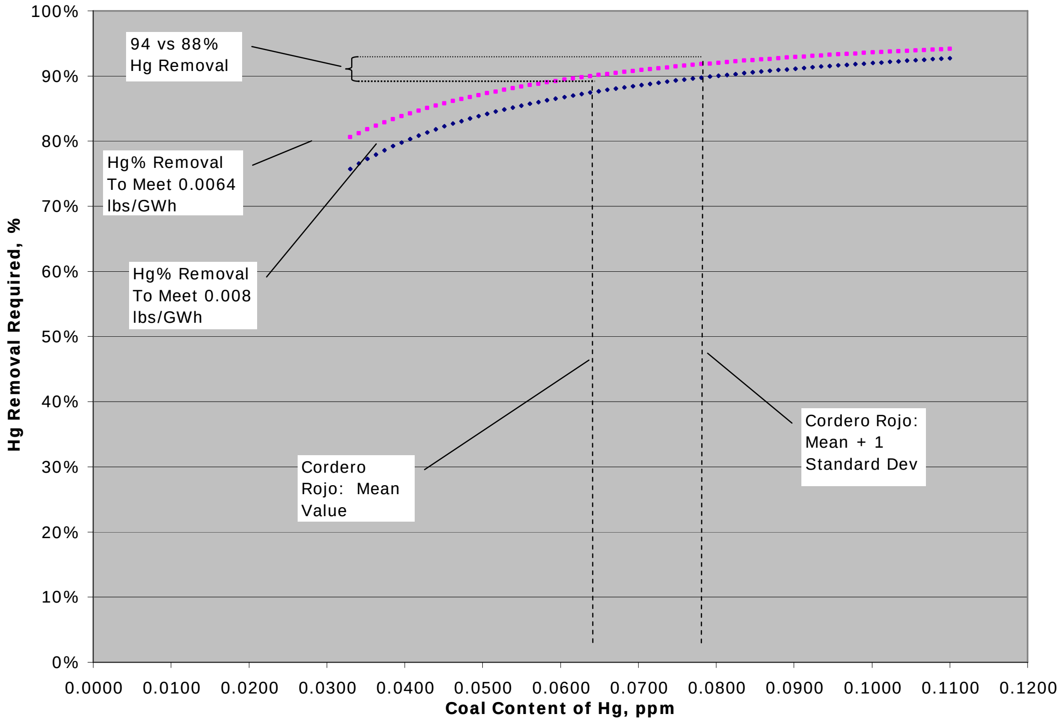


Figure 2-6 presents an alternative graphic describing how design targets for coal Hg content and operating variability influence the required Hg removal. As an example, the Hg content and variability for Cordero Rojo PRB coal is employed. Figure 2-6 depicts Hg removal required, as a function of coal Hg content (ppm basis), to meet an Hg emission target of 0.008 lbs/GWh. Also shown is the Hg removal required to meet an Hg emission target of 0.0064 lbs/GWh, the latter representing a 20% margin that may be required for compliance. The Hg content is noted for Cordero Rojo PRB coal, for both the mean value and the mean + one standard deviation.

Figure 2-6 shows for the mean Cordero Rojo value of 0.065 ppm, Hg removal of 87% and 90% is required to provide an outlet Hg rate of 0.008 and 0.0064 lbs/GWH, respectively. However, for the coal Hg content defined by mean plus one standard deviation, an increase in Hg removal to 90% and 94% is required to meet the same respective values.

Figures 2-5 and 2-6 demonstrate how basing a regulation on mean Hg content, without considering design or operating margins, implies a lower Hg removal rate than may be required. In particular, Figure 2-6 shows how mean Hg values and eliminating margin suggests 88% Hg removal adequate, while accounting for one standard deviation and a 20% design margin implies 93% Hg removal is required. This difference is considered significant.

Figure 2-6. Role of Coal Variability, Measurement Uncertainty on Design Target for 0.008 lbs/GWh



2.6. SYSTEM AVERAGING

A provision of the IEPA proposal is the ability for an owner to elect an Hg control target to as low as 75%, provided the generating system of units can still deliver 90% Hg overall from a base cap. In reality, given the unproven nature of Hg controls and the challenge of meeting even the 90% Hg removal target, this provision adds little flexibility as there is little or no margin by which to "overcontrol" and compensate for an under-performing unit.

The discussion in Section 2.3 noted that 30 day trials at Holcomb, Meramac, and St. Clair showed Hg instantaneous, hourly-based Hg removals as high as 95 and 97% were measured (including the small but important inherent Hg removed); but these are required to offset periods of operation where Hg removal is 85%. The ability to record Hg removal at 95+% for short periods of time is required to attempt to maintain 90%, and simply not be available to compensate for performance shortfalls.

A simple example demonstrates the challenge. Consider as an example a system consisting of two units, equal in all features - generating capacity, heat rate, and coal Hg content – but one unit cannot achieve the targeted Hg removal of 90%. Even if technically possible – one unit operating at 95% Hg removal could only offset an Hg removal compromise to 85%; lower Hg removal cannot be offset by this equivalent one unit. Rather, multiple units or a significantly larger unit would be required to provide the offset for a malperforming unit at 75%. Specifically, and for identical operating conditions, a 600 MW unit operating at 95% Hg removal would be required to offset the emissions from a 200 Mw unit that was limited to 75% Hg removal.

Given the challenge to maintain even 90% Hg removal over a 12 month basis due to variations in coal content, measurement uncertainty, and operations, the provision to allow units within a system to compensate for compromised Hg removal is of little value. Most Illinois units will need to design for 93-95% to meet a 12 month rolling average of 90%.

SECTION 3

EVOLUTION AND COST OF ENVIRONMENTAL CONTROL TECHNOLOGY

3.1. INTRODUCTION

The evolution of environmental controls for coal-fired power plants has historically required an extended period for process development, testing, and full-scale commercialization. The distinguishing feature of capital-intensive process equipment is that product lifetime is measured in decades, and not months or years as with consumer products. Further, the penalties for malperformance or failure of an environmental control system are not limited to a shortfall in environmental control capability or higher operating cost, but actually challenge the reliability of the plant. Given the limitations of suppliers' guarantees, a development schedule that systematically addresses the uncertainties in performance and reliability is prudent. This section will show by historical example the importance of providing adequate time for technology evolution.

It is important to convey the magnitude of the penalty Owners will incur due to process failure or malperformance. The consequence is not simply a matter of implementing minor equipment modifications, or increasing reagent injection to meet Hg removal targets, or to construct an averaging plan with other units in the system. Such issues, although problematic, should not prevent early deployment. Rather, premature technology application can force maintenance outages or load limits, which translate into significant cost penalties, or encourage widespread application of a technology before optimization is complete.

There is much history to invoke in demonstrating the challenges of commercializing environmental controls. The experience with wet flue gas desulfurization, selective catalytic reduction (SCR) NOx control, and hot-side electrostatic precipitators for particulate removal is reviewed as examples.

3.2. WET FLUE GAS DESULFURIZATION

3.2.1. Technology Evolution

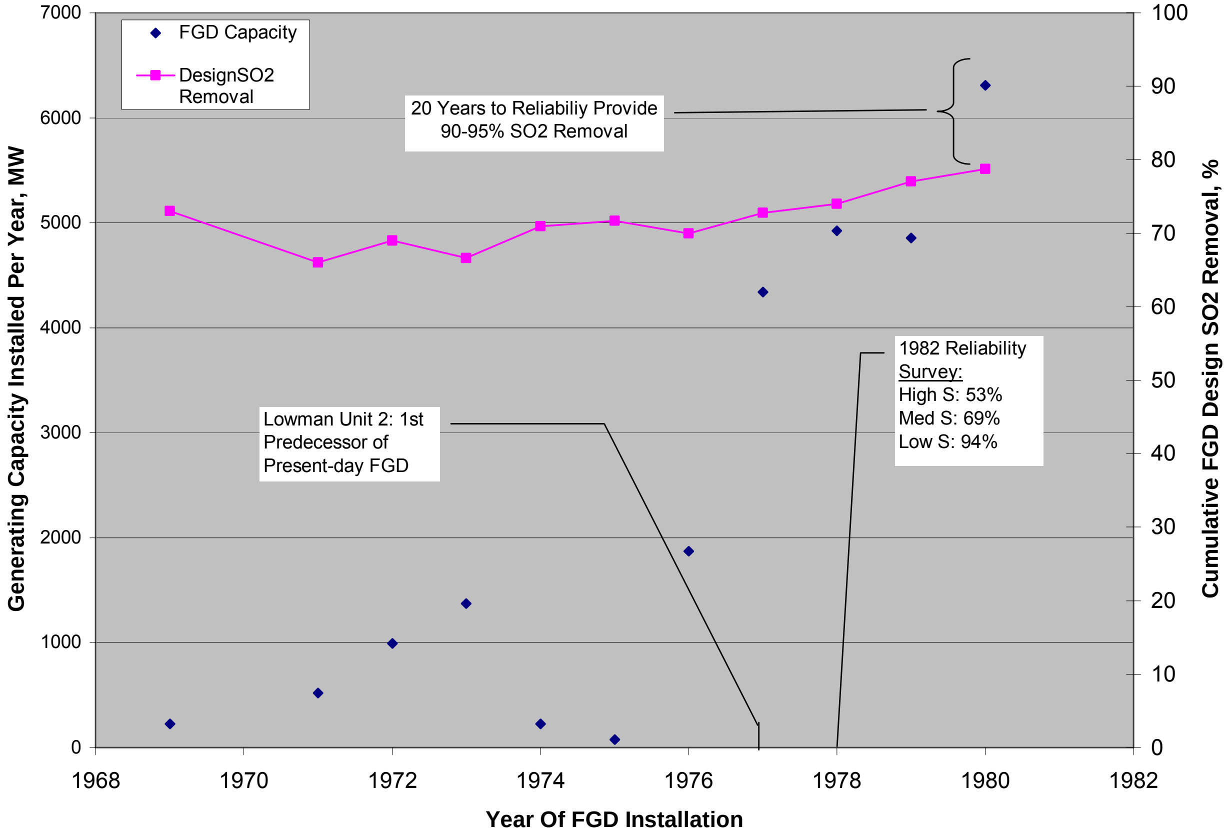
Control options for wet FGD have evolved to where at present SO2 removal of 95% is considered state-of-art, and for many coals 98% removal is attainable.

As summarized by Dalton (1985) and Boward (2003), early FGD applications were characterized by SO2 removal shortfalls, but most significantly reliability problems. The latter were due to excursions in process chemistry that promoted deposition and scaling, that limited load or forced early outages. Specifically, Boward (2003) states that:

”These first systems were often prototypes. A plethora of problems resulted from the application of this technology to the larger sizes and constraints of utility systems. To a certain extent, many of these systems were pre-commercial in nature, since technology was often commercially implemented before being demonstrated at sufficient scale”.

Consequently, both SO2 removal targets and more importantly reliability were often compromised. Early surveys of FGD equipment operation showed the reliability of first-generation FGD equipment was poor due to a lack of understanding of basic process chemistry, which in turn, promoted scaling and deposition within absorber vessels and reaction tanks. Specifically, Laeske (1983) reported that in 1978, FGD reliability for FGD process equipment was 53%, 69%, and 94% respectively for high, medium, and low sulfur coals. Figure 3-1 presents, for the first decade of FGD evolution, the annual capacity of FGD addition and the cumulative design SO2 removal efficiency. It was not until almost 10,000 MW of generating capacity had been equipped with FGD that the first installation of the design commonplace today – the lime or limestone–based open spray tower – was installed. The equipment used in most of these first-generation installations has since either been modified or replaced, or represents a design concept no longer favored.

Figure 3-1. The First Decade of Flue Gas Desulfurization (FGD) Evolution



As noted by Boward (2003), it was not until the 1980s and the genesis of “forced oxidation” FGD designs that meaningful improvements in FGD reliability were achieved. Given that the first lime and limestone-based equipment was commercially sold in the early-mid 1970s, and that several units were converted to or adopted forced oxidation in 1985, it took approximately 10 years of evolution and development with lime or limestone-based FGD to achieve a reliable design.

Thirty years later, after over 100,000 MW of experience world-wide, the following FGD attributes are state-of-art: 93% to 98% SO2 removal; the use of a single absorber tower; the production of high quality gypsum byproduct for sale or management as landfill; and relatively low power demand. This observation suggests that adequate experience is required to deliver reliable, high performance environmental control technology.

3.2.2. Cost Evolution

Low and unacceptable reliability – particularly for FGD equipment designed for medium and high sulfur coals – was partially responsible for the initial high capital cost of FGD equipment. Specifically, Boward (2003) describes the decrease in conventional FGD capital cost from $400/kW in the 1970s to $200/kW in the early 1990s, and notes that both improvements in process chemistry and eliminating spare absorbers modules (through the provisions of the 1990 Clean Air act Amendments) as key contributing factors. Significantly, the large FGD cost decrease was due to both structural changes in the regulations that allowed for emissions allowance exchange, and resulting simplification of design, as well as 20 years to solve process chemistry problems.

At present, FGD costs have escalated due to higher performance demands, retrofit to more difficult units, and the general escalation in construction materials and trade labor (experienced by all major construction projects). On almost a weekly basis, generators announce plans for advanced FGD processes that exceed $300/kW. The most recent – issued on July 20, 2006 by Allegheny Energy – cites the 1,710 MW Hatfield's Ferry station will retrofit a 95% SO2 capital FGD system, for approximately $320/kW.

3.3. SELECTIVE CATALYTIC REDUCTION (SCR) NOx CONTROL

3.3.1. Technology Evolution

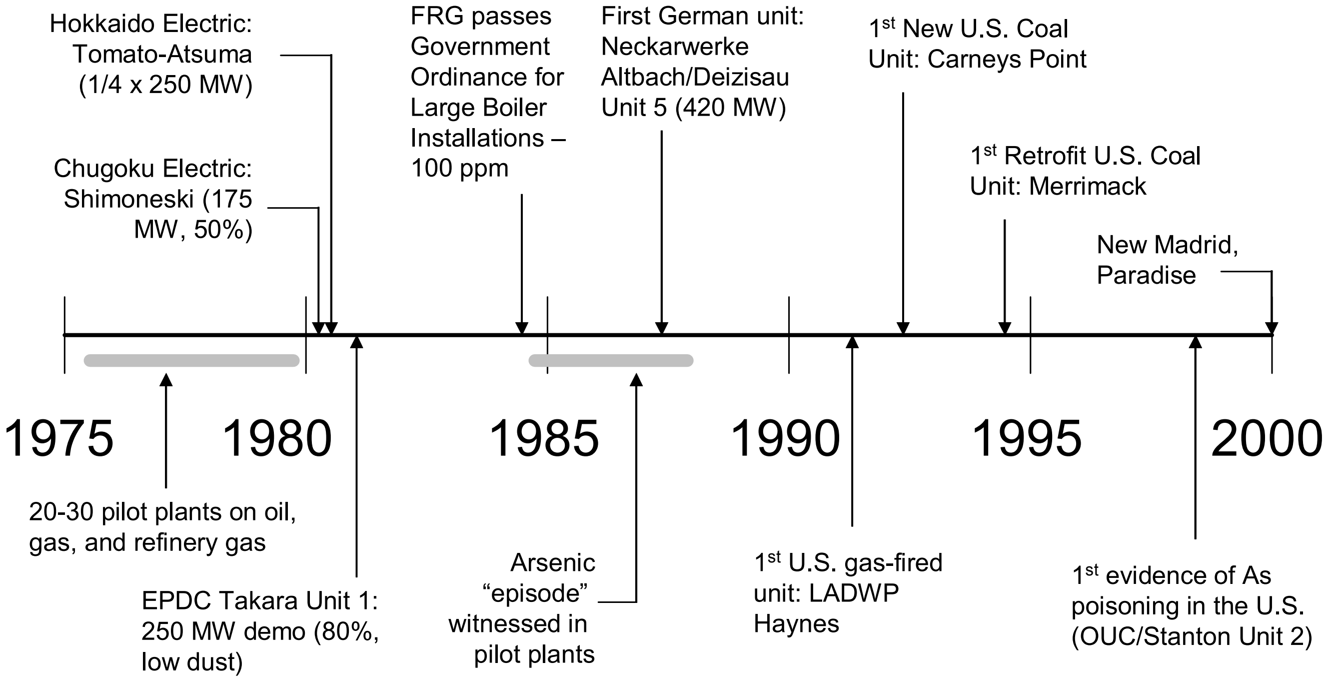
The evolution of SCR NOx control spans three decades, with much of the important experience generated in Europe and Japan prior to application to U.S. coal-fired power plants.

Figure 3-2 presents a timeline of SCR technology evolution (Cichanowicz, 2001). As shown in Figure 3-2, and as detailed in the referenced paper, the first commercial SCR installations occurred in Japan in the early-mid 1980s, on coals with sulfur content generally less than 0.70%, and thus well below those fired in Europe and the U.S. These early applications required only modest (50-80%) NOx reduction.

Based on about 3,000 MW of coal-fired experience in Japan that were operating by 1982, the then Federal Republic of Germany instituted strict NOx regulations that required retrofit of SCR to approximately 5,000 MW of capacity in the time frame of 1987 to 1989. One of these units

(Franken) was reportedly the first commercial unit to consistently achieve 90% NOx reduction. Prior to these first commercial German applications, at least 25 pilot plant tests were initiated in 1984 and run for approximately one year. The experience with SCR technology in Japan did not identify two key problems witnessed in early German applications: poisoning of catalyst, and contamination of ash with excess ammonia. Regarding catalyst poisoning, pilot plant tests identified the rapid deactivation of SCR catalyst by arsenic, a phenomena not recognized by the Japanese experience. Results from these pilot plants and the early commercial units in Germany that encountered early catalyst deactivation lead to the first generation of arsenic–tolerant catalysts.

Figure 3-2. Timeline of SCR Key Events



Further, experience in Japan that 5 ppm of residual NH3 in flue gas would be acceptable proved to be false with German and European coals. Due to differences in ash composition, the 5 ppm rule-of-thumb residual NH3 limit that was successful in Japan was revised to 2 ppm, to avoid ash contamination and loss of fly ash sales.

Several of the first coal-fired SCR applications in the U.S. encountered problems after one year of operation. Most significantly, the SCR process at the Logan Generating Station experienced limited NOx removal and excess residual NH3. Accelerated poisoning of catalyst was witnessed at the Orlando Utilities Commission (OUC) Stanton Unit 3, and ultimately related to shortcomings in the fuel purchase specification. The first retrofit of SCR to an existing coal-fired boiler in the U.S. – at the PSNH Merrimack Station – encountered air heater plugging problems from excess residual NH3. The Merrimack elevated NH3 problem was not due to catalyst deactivation but to flue gas ductwork design. None of these problems were fatal flaws, and all proved amenable to remedial actions. This experience demonstrates that even with 15 years of operating experience in Japan and Europe, the initial, broad deployment of SCR to the U.S. encountered problems.

By some accounts, the most significant problem with SCR was not encountered until 2001, when a high sulfur coal-fired unit generated excess SO3 emissions which increased stack plume opacity. For many applications, controlling plume opacity appears manageable but the cost is not negligible. A recent evaluation of reagent-based SO3 mitigation strategies shows the annual operating cost can approach that for reagent supply (Dombrowski, 2004). Accordingly, SO3 mitigation represents an additional operating cost not quantified or acknowledged by the SCR process developers.

A second unforeseen problem with U.S. SCR installations has been blockage of the catalyst openings with large particle ash (LPA). Georgia Power's first SCR, at Plant Bowen Unit 1, was only able to operate for 69 days before the catalyst was completed plugged with LPA. These ash particles are 5-7 mm diameter agglomerates of low density that can be swept past the economizer hoppers and into the SCR reactors. LPA was noted only occasionally in German experience, considered an anomaly, and thus completely unforeseen as an issue in the U.S. Although no formal survey of LPA-related issues has been conduced, it is believed that 1 in every 4 or 5 units incurs some degree of LPA plugging that compromises SCR performance.

To summarize, broad Japanese and German experience with SCR did not prevent several notable problems in U.S. applications that, if not fatal to operation, compromised reliability and increased cost compared to developer's projections.

3.3.2. Cost Evolution

Perhaps more relevant to Hg control cost is the case of SCR NOx control in terms of capital cost and balance-of-plant impacts.

The U.S. EPA and equipment suppliers significantly underestimated the capital cost of SCR. Early cost studies by EPA projected SCR capital cost to be approximately $60/kW for a 400 MW unit, decreasing to less than $40/kW for units of 600 MW and greater (EPA, 1995). Three SCR cost surveys conducted since 2003 show SCR capital exceeds EPA's projections by a factor of 2 to 3. A trend in which SCR capital cost increased for the first several commercial units installed since the mid-late 1990s was noted (Cichanowicz, 2004). The reasons for escalation in cost from the early applications are unclear, but likely because the first SCR equipment was installed on units atypical of the fleet ultimately retrofit. Specifically, the early SCR installations may have required less complex process equipment, and imposed less site interference and thus installation cost. In contrast to these mid-1990s estimates by EPA and the Institute of Clean Air Companies (ICAC), the average of all units in the cited 2004 survey is $120/kW, with the units installed in 2004 approximating $140/kW. SCR costs of this magnitude were reaffirmed by other surveys (Hoskins, 2003, and Marano, 2006), with the most recent also confirming a spike in capital costs after 2003.

Despite the overwhelming evidence of high SCR cost in these recent surveys, the U.S. EPA as recently as 2004 was still utilizing SCR capital cost estimates of $80/kW in projecting the cost to comply with the CAIR (EPA, 2006a, and Khan, 2004).

Significantly, early SCR cost estimates did not account for balance-of-plant impacts that were only recognized after full-scale application. Specifically, the production of SO3 as a byproduct of SCR was ignored by process suppliers until full-scale evidence from an SO3-induced plume at AEP's Gavin station validated concerns. This issue – widely recognized as problematic for medium-high sulfur coal-fired units – has required reagent injection on 15 plants to date, a number which is anticipated to increase. Based on estimates of reagent injection costs developed by EPRI (Dombrowski, 2004), the annual operating cost can approach $0.5-1 M per year, rivaling that for ammonia reagent.

It should be noted the expansion in SCR installations to a projected 120,000 MW of capacity by 2010 has created a market for catalyst that has significantly reduced catalyst unit price. Catalyst unit price has decreased from over $15,000/m^3 in 1979 to below $4,000/m^3 in 2006, due to competition between numerous suppliers world-wide, and the advent of catalyst regeneration. This price decrease, which required at least 15 years to evolve, has been more than offset by other factors.

3.4. HOT-SIDE ELECTROSTATIC PRECIPITATORS

Perhaps the most relevant example of the consequences of accelerating evolving technology is the case of the hot-side electrostatic precipitator (ESP). In the mid-1970s, the particulate matter (PM) removal efficiency of state-of-art ESPs stagnated, due to limits on the ability to deliver adequate power for particle charging caused by the electrical resistivity of the collected ash. The use of low sulfur western coals exacerbated this problem, as the ash residing on the collecting plate presented a high electrical resistivity that limited delivered power and ESP performance. Subsequently, it was theorized that relocating the ESP from the "cold-side" of the air heater (processing flue gas at temperatures of 300-400 F) to the "hot-side" of the air heater (processing flue gas at 600-700F) would significantly reduce the electrical resistance imposed by the collected fly ash layer. Several pilot plants evaluations were completed and results with first-generation designs suggested this approach would be successful.

The early experience prompted application of hot-side ESPs on several new units, which after about one year operation incurred operating problems. Most significantly, Gulf Power's Lansing Smith station incurred persistent PM removal problems, incurring relatively high opacity beyond predicted levels. Subsequent diagnostic tests determined that the micro-layer of fly ash directly adjacent to the collecting plate was characterized by depleted sodium; an element necessary to provide electrical mobility, and control resistivity.

These diagnostic tests – and further follow-up with pilot plant studies – showed that the use of conditioning agents to deliver sodium into the ESP could restore performance. Even under these conditions PM removal was not ideal and many owners elected to convert hot-side units to the traditional cold-side approach. Interestingly, a key unit in the chronology of demonstration testing for activated carbon injection (ACI) – the WE Energies Pleasant Prairie Station – was initially designed to utilize a hot-side ESP. The performance limitations of this design were recognized prior to construction, prompting the owner to change the ductwork enabling the same ESP to operate as a cold-side unit. The initial decision for Pleasant Prairie to utilize a hot-side ESP resonates today in terms of prompting the large SCA, and ability to accommodate ACI.

Approximately five years of diagnostic tests at commercial scale were required to resolve the hot-side ESP issues. Incurring such a problem today would require less time - the electrical properties of the ESP are monitored better, and numerous pilot plants are available for diagnostic work. However, 2-3 years of additional testing and development of commercial equipment would likely be required.

3.5 SUMMARY

This section has related the significant time and experience required to commercially prove the feasibility of an evolving environmental control technology, particularly where a chemical process is required to achieve 90% removal of a given chemical species.

- For conventional wet flue gas desulfurization, 7-10 years of experience and development was required for process equipment to deliver SO2 removal to near 80%, although reliability for medium and high sulfur applications was limited to 54 and 69%, respectively. The cost for FGD has decreased significantly since the first years of deployment, but required several decades and a change in the form of the regulation to allow compliance on a system and not a unit-specific basis.

- For SCR NOx reduction, approximately 5-10 years of development and experience was required to generalize the technology for German power plants; however this experience did not avoid problems of excess residual NH3 and arsenic-induced poisoning. The cost of SCR has significantly exceeded early projections by EPA and the supplier community.

- Hot-side ESPs never received broad commercialization, and this concept has for the most part been abandoned as a candidate for new units. Existing hot-side ESPs operate usually with some type of additive for sodium replenishment, or use higher sodium coals. The WE Pleasant Prairie station – initially conceived as a hot-side ESP but adopted to cold-side before construction – is a testament to the challenges of accelerated commercialization.

SECTION 4

INHERENT MERCURY REMOVAL FROM ENVIRONMENTAL CONTROLS

4.1. INTRODUCTION

Existing environmental control technologies for coal-fired power stations will remove Hg from flue gas, in amounts that vary widely, depending on equipment configuration and coal composition. As first demonstrated by the ICR, Part III data (EPRI, 2000) and numerous site-specific Hg control demonstrations, inherent Hg capture by existing environmental controls can range from essentially zero to nearly 90%. Specifically, negligible Hg removal is noted for PRB and lignite coal-fired units, while Hg removal of nearly 90% and possibly beyond for some eastern bituminous coal-fired units is measured with SCR and wet FGD. Up to 95% Hg removal is noted for similar coal units equipped with dry FGD and a fabric filter.

Significantly, equipment installed in response to CAIR-required reductions in SO2 and NOx will provide a platform for effective and reliable Hg control. As will be described in this section, these expenditures will provide the essential ingredients for any environmental control process: good mixing of reagent or sorbent with dilute flue gas constituents; adequate residence time for contacting and reaction; and control of process conditions (temperature, gas composition, etc.) to prompt reactions. These very same process conditions will maximize Hg removal. More important than cost is reliability – the strategies and equipment retrofit for CAIR will provide a basis for Hg control.

The most probable equipment configurations to be installed consist of either (a) dry FGD and a fabric filter for SO2/PM control, (b) a wet FGD for SO2 control, preceded by the existing ESP or fabric filter for PM control, and (c) SCR for NOx control, in combination with either option (a) or (b). These configurations do not exhaust the list of options as other technologies are available: selective non-catalytic reduction (SNCR) for NOx; combustion controls for NOx that can assist Hg removal through increasing ash carbon content; and other multi-pollutant controls. However, given the timeframe specified by CAIR and degree of SO2 and NOx control required, most owners are anticipated to deploy options (a), (b), or (c) above.

Prior to addressing the CAIR compliance options, Hg removed as particulate within an ESP or fabric filter will be addressed.

4.2. HG REMOVED AS PARTICULATE (VIA ESP OR FABRIC FILTER)

The removal of particulate-bound Hg is a starting point for determining inherent Hg reductions at existing coal-fired plants. Particulate Hg can be captured by either an ESP or a fabric filter, or other process control equipment. Further, Hg that is not in particulate form can be subsequently captured by the carbon retained in fly ash, depending on the carbon content and its physical features. Test results from field demonstrations in recent years have shown that many factors – in particular competition between Hg and SO_3 for access to absorption sites – affect the amount of Hg removed by carbon.

4.2.1. Hg Removal Correlation: ESPs

In their 2000 analysis of the ICR data, EPRI attempted to capture the relationship between Hg removal, equipment configuration, and coal composition (EPRI, 2000). EPRI developed a correlation describing Hg removal across process equipment, such as a cold-side ESPs, as a function of coal chloride content. Specifically, for the case of calculating inherent Hg removal from a cold-side ESP, EPRI proposed the correlation:

$$\text{Hg Removal} = 0.1233*[\ln(\text{coal Cl content, as ppm})] + [-0.3885]$$

EPRI further noted that the measured Hg removal could range from zero to 55% for the units tested. This correlation also recognizes the role of coal chloride content on inherent Hg removal, not only for ESPs, but for a variety of process equipment.

4.2.2. Role of ESP Size

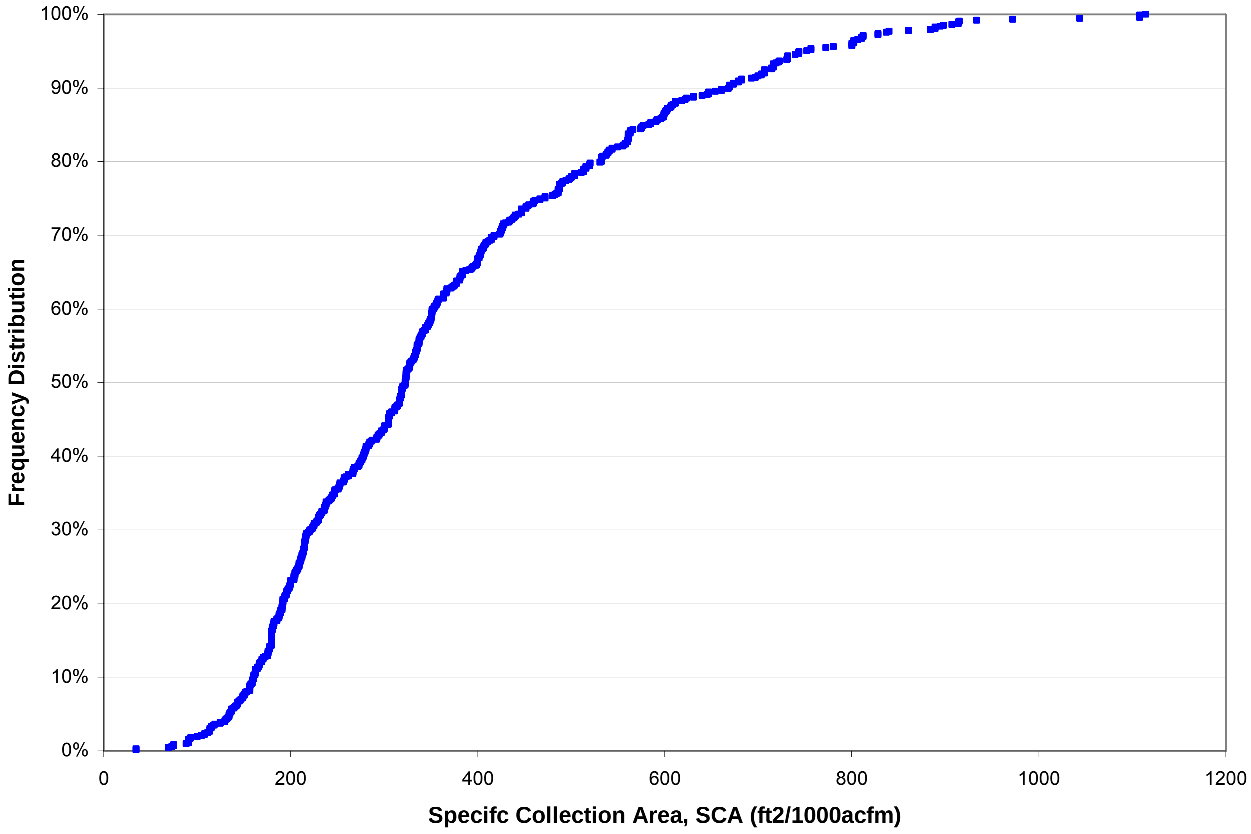
The ESP design characteristic known as specific collecting area (SCA) – defined as the collecting plate surface area normalized by the gas flow rate – is fundamental to ESP performance. A higher SCA implies more surface area available for collection of charged ash particles, and depending on the equipment layout, greater residence time for Hg absorption.

Figure 4-1 presents the cumulative distribution of SCA values for the national ESP population, including the host demonstration sites for most sorbent injection demonstrations. It is possible that high SCA enables high Hg removal within the ESP – both inherent and induced by activated carbon injection - simply due to the residence time and exposure of carbon in the ash to flue gas Hg. Data from commercial-scale tests that suggests Hg removal is influenced by SCA, which may be consistent with fundamental analysis that suggests mass transfer between particles and flue gas is favorably affected by large SCA (Clack, 2006).

A further contributing factor to variable inherent Hg control within an ESP is boiler operation. The key factors may relate to (a) operating load, (b) flue gas flow rate, (c) temperature of the ESP, (d) combustion conditions, and (e) the physical characteristics of carbon produced and retained in the fly ash. Each of these factors can influence inherent Hg removal, and to be discussed subsequently, the performance of ACI.

In summary, the inherent Hg removal within an ESP is highly variable, depends on fly ash carbon content, coal composition including chlorides, and possibly the physical size (e.g. SCA value) of the ESP, as well as boiler operation.

Figure 4-1. Distribution of SCA Value: National ESP Population



4.3. DRY FLUE GAS DESULFURIZATION (FGD) AND FABRIC FILTER

The use of lime-based dry FGD coupled with a fabric filter is anticipated to provide a common compliance tool for CAIR, particularly for owners that anticipate continued use of PRB coal. This FGD process is referred to as “dry” in that water injected with the lime reagent into flue gas at nominally 300-350 F is completely evaporated, lowering flue gas temperature, but not to the moisture saturation temperature where water will condense. A second particulate control device, specifically a fabric filter, is required to collect the dry products of sulfation. Specifically, predominantly $CaSO_4$ is produced from SO_2 and the Ca introduced as lime – which generates particles that must be captured.

Historically, a dry FGD followed by a fabric filter has been used on coals with less than 2% sulfur content. One factor limiting sulfur content is a restriction on the quantity of water that can be injected without reducing the flue gas temperature to near moisture saturation, where water would condense. Despite development programs using 5-10 MW pilot scale facilities in the mid-1980s to generalize dry FGD to higher sulfur coal, most applications today are with 2% sulfur or less coals.

The ability to leverage the investment for dry FGD with Hg removal is inviting, given that a considerable component of the cost is the large reaction vessel that could improve dispersing reagent within flue gas. Specifically, the dry FGD vessel (also referred to as a spray dryer) will offer 6-8 seconds of residence time for gas contacting, with mixing of lime promoted by the use of a high speed atomization head spinning at 100,000 rpm. Consequently, the combination of residence time and turbulence within the vessel promotes contacting of sorbent with flue gas. The well-mixed sorbent ultimately is collected on the fabric filter, where it accumulates and is exposed top flue gas. The extended contact time between sorbent accumulated on the filter and flue gas Hg provides potential to remove significant Hg. A key advantage of coupling Hg removal with dry FGD is the relatively low operating temperature of the fabric filter, a result of injecting water through the high speed atomizers.

The disadvantage of the dry FGD process is that the alkaline environment necessary to react with SO2 also removes chlorides and other halogen species that promote Hg oxidation. As a consequence, early ICR data and subsequent testing funded by the DOE-NETL showed that PRB-fired units equipped with dry FGD derived only 25% Hg removal (Sjostrom, 2006a, Slide #3). The low inherent Hg removal of 25-30% was corroborated through baseline testing at Sunflower Electric’s Holcomb Station (Sjostrom, 2006a, Slide #9). As will be discussed in Section 4, the halogens critical to high Hg removal can be introduced with sorbent injected for Hg removal. Consequently, the dry FGD with fabric filter presents a reliable platform from which additional Hg removal can be obtained.

It is possible that PRB and eastern bituminous coal could be blended to establish higher sulfur, higher chloride content coal that may improve Hg removal. There has been success with blending PRB with 15% western bituminous coal where Hg capture increased from near 0 to near 80% (Sjostrom, 2006a, Slide 20). However, at Basin Electric’s Laramie River station – employing an ESP for the second particulate collector in lieu of a fabric filter – coal blending did not provide encouraging Hg removal. Specifically, blending from 16 to 20% western bituminous coal with PRB elevated Hg removal from 0 to 10% (Sjostrom, 2006a, Slide 21). Accordingly, the blending of higher chloride coal to improve Hg removal is an interesting but uncertain option with regard to Hg removal.

4.4. WET FLUE GAS DESULFURIZATION (FGD)

The use of wet FGD following particulate matter removal by either a fabric filter or ESP will also remove Hg, by amounts that vary depending on coal composition and FGD chemistry. It is generally believed that oxidized Hg, which is water soluble, will be removed in a wet FGD process, with the actual fraction of Hg removed depending on process chemistry (Blythe, 2004). Specifically, it is believed within the FGD “slurry”, oxidizing conditions and prevalence of sulfate over sulfite promote the capture and retention of Hg. Accordingly, any action that promotes the oxidation of elemental Hg - such as forced oxidation or the use of SCR NOx control - appears to increase Hg removal. The Hg removal potential for FGD will be described both with and without SCR.

Hg Removal Wet FGD without SCR

Figure 4-2 (extracted from Chu, 2006) compares FGD Hg removal for units equipped with both SCR and FGD. The measured Hg removal attributable to only wet FGD (e.g. data without SCR) for the nine sites ranged between 45 and 70%. The physical and chemical mechanism by which Hg is removed – and does not either evade capture or is captured but re-emitted – is presently the subject of research (Blythe, 2005).

FGD with SCR

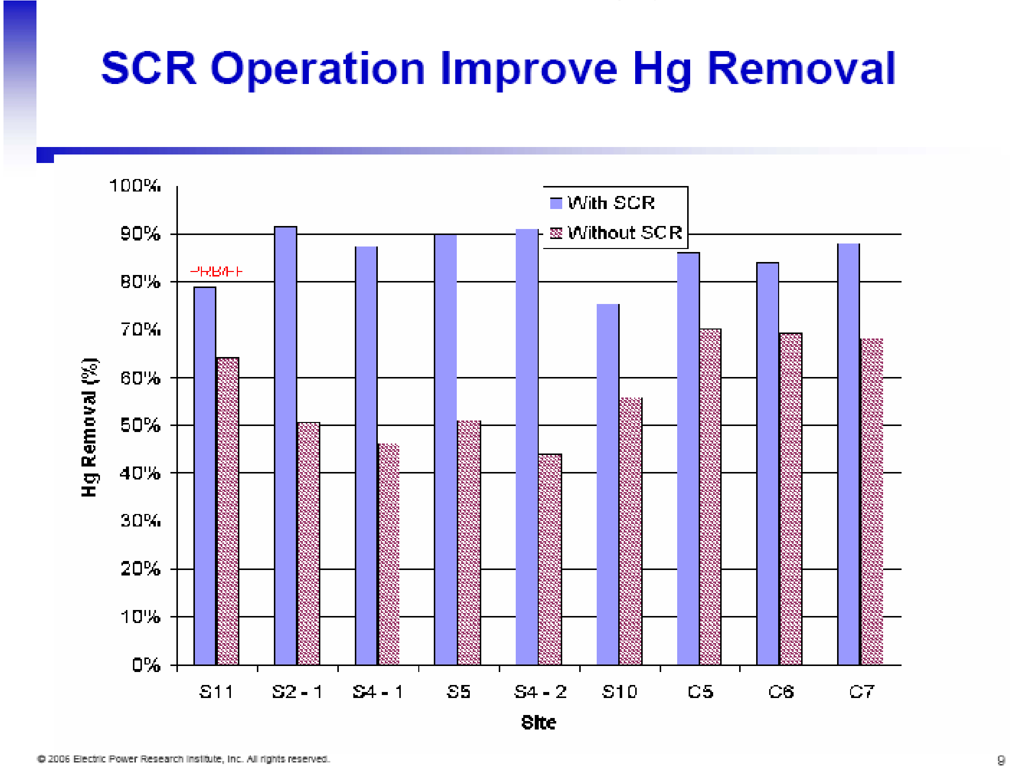
Figure 4-2 data describing Hg removal with both SCR and FGD shows that for six systems Hg removal ranged from 72% to more than 92%. These data are based on short-term tests without long-term confirmation of reproducibility or longevity. Three of the power plant systems exhibited short-term test results equal to or exceeding 90% Hg removal.

Both Chu (2006) and Senior (2006) have published an insightful depiction of the role of SCR on Hg oxidation. Figure 4-3, also extracted from Chu (2006), depicts the amount of oxidized Hg that leaves the SCR reactor as a function of coal chloride content. The amount of Hg oxidized – determinate to the Hg removed - is highly variable, and while generally related to coal chloride, exhibits significant variability for coals with similar chloride value.

The data in both Figures 4-2 and 4-3 suggests 90% Hg removal may be a reasonable target, but at present cannot be presumed for wet FGD, even with SCR. Figures 4-2 and 4-3 suggest that 90% Hg removal is the exception and not an expected outcome.

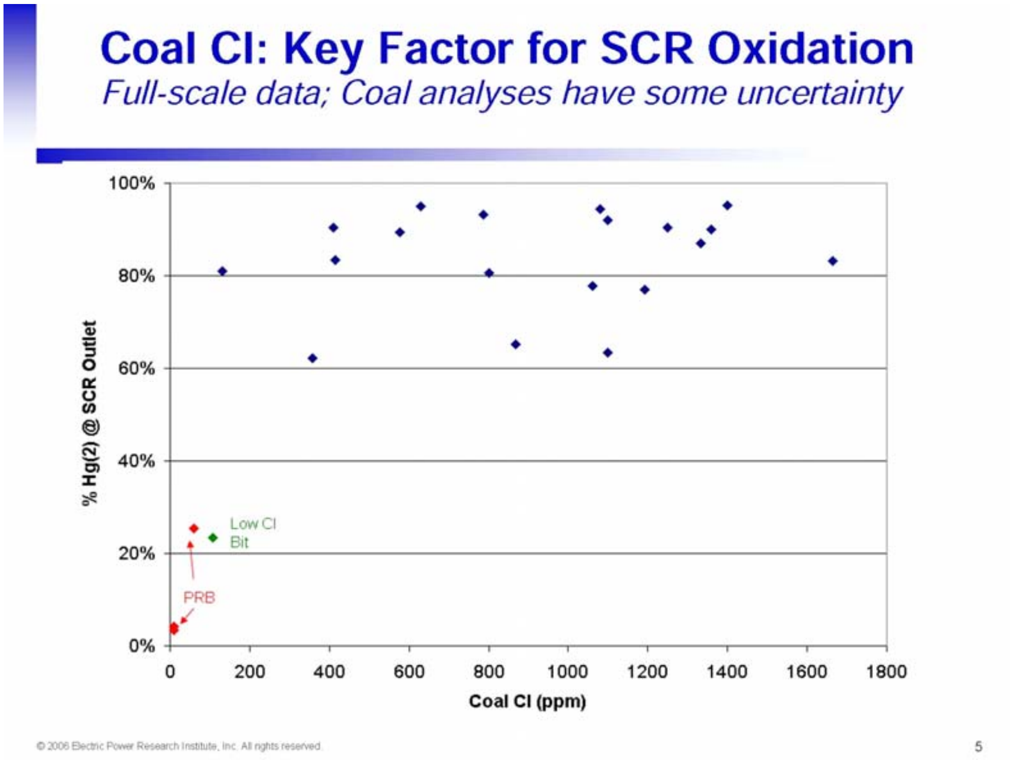
Finally, the question of the fate of Hg removed by FGD must be addressed to insure that byproducts incorporating power plant-derived gypsum, such as wallboard, do not release significant captured Hg. Several studies are in progress, involving a major wallboard supplier (U.S. Gypsum). Initial results from this analysis have been posted on the DOE-NETL web site. Pending confirmation that Hg removed in the FGD and reporting to gypsum is not problematic, a wet FGD process appears to offer a robust and reliable platform to remove Hg.

Figure 4-2. The Role of SCR on Removal of Hg by FGD (after Chu, 2006)



SCR Operation Improve Hg Removal

Figure 4-3. The Role of SCR on Removal of Hg by FGD (after Chu, 2006)



Coal Cl: Key Factor for SCR Oxidation

Full-scale data; Coal analyses have some uncertainty

SECTION 5

MERCURY SPECIFIC CONTROL TECHNOLOGIES

5.1. INTRODUCTION

A large number of Hg control concepts have been identified and evaluated at scales ranging from laboratory test apparatus to commercial-scale equipment. The objective of this section is not to provide a thorough review of these options – Feely (2005b) and Srivastava (2006) have provided such a review. Rather, this section will highlight key near-term concepts and emphasize the uncertainties that remain. The research scheduled to further define the feasibility of these concepts will be identified.

5.2. EXPLOITING FGD CO-BENEFITS

Perhaps the most effective means of increasing Hg removal is by exploiting the existing co-benefits exhibited by particulate, SO2, and NOx controls to improve Hg removal. These are described as follows.

5.2.1. Hg Removal by Wet FGD

<u>FGD Additives.</u> As described in Section 4, the ability of a conventional wet FGD process to remove and retain Hg from flue gas is highly variable, and appears to depend on the degree of oxidation exhibited by FGD chemistry – perhaps the ratio of sulfite to sulfate. Under DOE funding, the Babcock & Wilcox (B&W) Company has evaluated using sodium hydrosulfide as a wet FGD additive to increase Hg removal at units operated by Michigan South Central Power Agency, Cinergy, and Dominion Resources.

Results to date, summarized in Table 5-1, are mixed but generally encouraging. Specifically, at Michigan South Central Power Agency’s Endicott plant, the use of B&W’s additive increased Hg removal from a baseline of approximately 70% to 79% (Farthing, 2003). At Cinergy’s Zimmer plant, B&W’s additive provided Hg removal by wet FGD of 51% (Farthing, 2003). Additional testing at Dominion Resources Mt. Storm Station showed modest improvement in FGD Hg capture, albeit from relatively high levels of 90% (Renninger, 2004).

Table 5-1. Summary of Testing Additives to Enhance Hg Removal by FGD

Utility/Station	**Capacity (MW)**	**FGD Type/SO2 Inlet**	**Baseline Hg Removal vs. with Additive**	**Hg Removal Test Duration**
Michigan South Central Power/Endicott	55	Limestone reagent, in-situ oxidation, 3600 ppm SO2 inlet	70 % baseline vs. 79% with additive	4 months
Cinergy/Zimmer	1300	Thiosorbic lime, ex-situ oxidation, 3600 ppm	48% baseline vs. 51% with additive	14 days
Dominion	545	Limestone, in-situ forced oxidation, 1400 ppm	Without SCR: 71 vs. 78% Hg removal	7 days
			With SCR: >90% vs. >90% (e.g. no material affect of additive).	7 days

Further work is being conducted with additives, such as Degussa's TMT-15, but investigators state additional work is necessary to explore the reaction mechanisms in the presence of high chlorides and other confounding species (DeBerry, 2005). Bench-scale and pilot plant tests exploring fundamental chemistry will continue through 2007. Additional commercial demonstrations of additives to promote FGD removal and sequestration by gypsum will be sought.

Oxidation Catalysts. Special-purpose catalysts tailored to oxidize Hg to maximize removal by FGD are being tested for application at the outlet of the particulate collector (either an ESP or a fabric filter). Early results show that several catalysts provide Hg oxidation near or exceeding 90% for an initial operating period, but incur deactivation as particulate matter accumulates on the horizontal gas flow surfaces. Additional testing is exploring how to keep the catalyst clean and generalize the concept to commercial-scale equipment. Also of note is that for at least one coal, near-complete removal of oxidized Hg was not attained as Hg "re-emission" limited total removal to less than 80%. Further work will identify this barrier to Hg removal (Blythe, 2005). Additional tests evaluating the longevity of the catalyst are planned for 2006 and 2007, as well as the parallel work (described previously) to insure Hg capture and safe sequestration.

5.2.2. Hg Removal by Dry FGD

Section 4.2 described how dry FGD process conditions prevent high inherent Hg removal. The use of either conventional or halogenated ACI provides significant improvement. For PRB and PRB blends, the use of fuel additives to increase the performance of conventional ACI has been evaluated as a mean to promote generally modest Hg removal (Sjostrom, 2006, Slide #9). Data to date – again over a short-term (periods of hours) basis – suggests Hg removal at or near 90% is feasible. Most significantly, 30 day tests at Sunflower Electric' Holcomb Station exhibited

93% Hg removal (Sjostrom, 2006, Slide #10). Although the sustainability of these data is not proven, these 30 day tests suggest high Hg removal is possible.

An alternative method of delivering halogens into flue gas to promote Hg removal by ACI is using fuel additives. The use of such a fuel additive (KNX) with conventional ACI at the Missouri Basin Power Project Laramie River Unit 3, equipped with a dry FGD and ESP, was evaluated. Based on short-term (e.g. several hours) tests, greater than 90% Hg capture was noted. Extended tests are necessary (~ approximately one year) to verify that this level of Hg capture can be sustained considering boiler and equipment reliability.

For lignite, completed trials of 30 days at the Antelope Valley Station, which fires Freedom lignite, using conventional carbon sorbent and special-purpose additives developed by UNDEERC suggest 70 to 90% Hg removal within a dry FGD followed by a fabric filter (Brandt, 2006, and Holmes, 2005, Slide #20 and 21). It is not known if the generous sizing of the fabric filter – featuring an air/cloth ratio of 2/1 – is required to sustain this level of Hg removal. A “multi-month” test is in progress and will be completed in 2006. Long-term testing must be completed before commercial readiness is proven. Also for lignite coal, data showing approximately 90% Hg removal was obtained at the Leland Olds Station (Holmes, 2005, Slide #12) and Great River Energy’s (GRE) Stanton Unit 10 (Holmes, 2005, Slide #10). Leland Olds data reflected a 30 day test run, while GRE Unit 10 was based on short-term data of several hours.

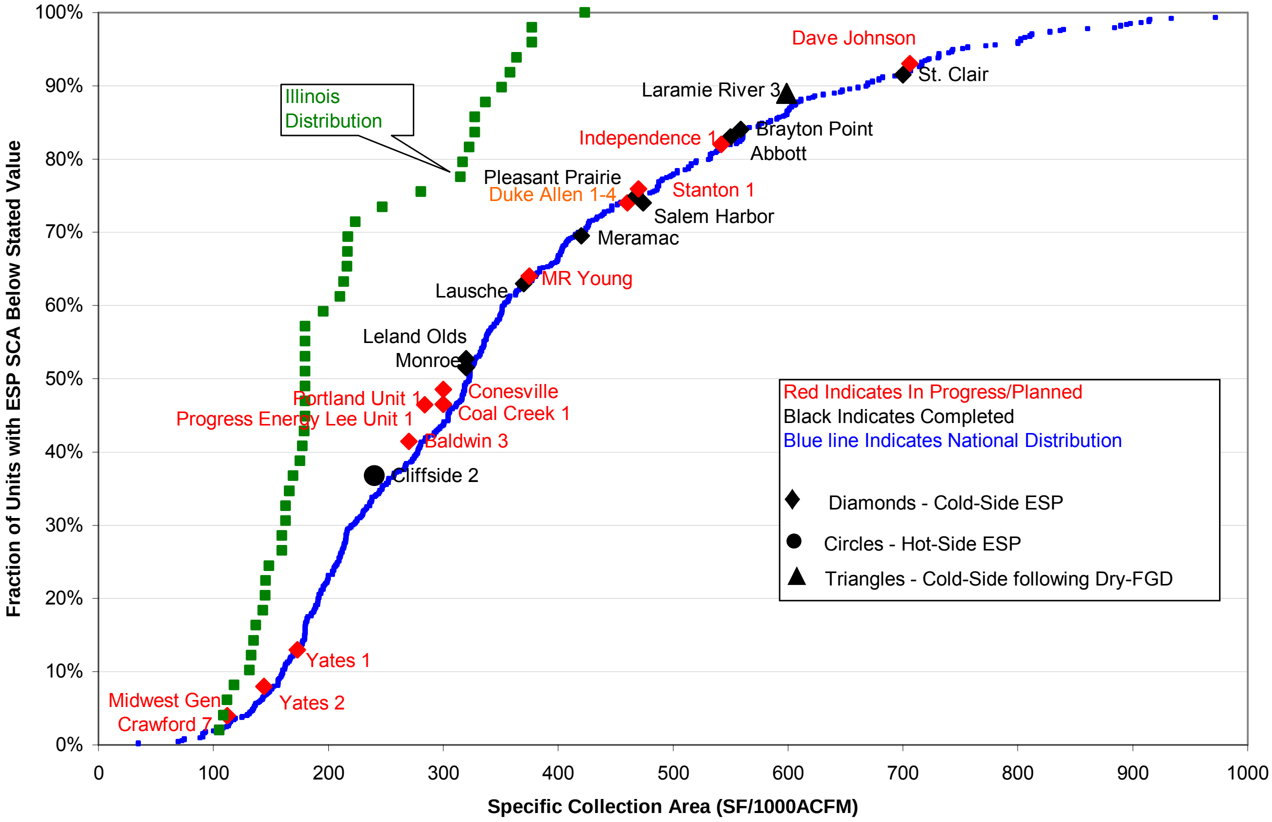
5.3. SORBENT INJECTION WITHIN ESPs

A significant number of demonstrations have been conducted with sorbent injection, exploring various sorbent types, particulate control equipment into which the sorbent is injected, and consequences for ash resale and management. A thorough review of these options has been provided by DOE (Feely, 2005a and 2005b); this document will highlight key demonstration results that are relevant to technology feasibility in the next 2-3 years.

Sorbent can be injected into either an existing ESP or a fabric filter. Of the almost 20 commercial-scale demonstrations or short-term tests conducted to date, most have employed an ESP. Historically, for any environmental control, maximizing residence time for contacting with reagent and absorption/reaction promotes efficient removal. It is anticipated a large ESP with extended lengths of inlet ductwork, and generous collecting plate surface area, will promote Hg removal while smaller ESPs with limited surface area and inlet ductwork residence time offer limited Hg removal.

Figure 4-2 presented the distribution of specific collecting area (SCA) values for the national ESP population. Figure 5-1 presents the same data, but includes ESP SCA values for units located in Illinois, and for most of the sorbent injection demonstration sites. Figure 5-1 shows that many demonstrations of ACI – including the frequently cited St. Clair and Meramac Station - have been conducted at large SCA ESPs.

Figure 5-1. ESP SCA of Sorbent Injection Test Sites Compared to U.S. ESP Population



5.3.1. Conventional Activated Carbon

Conventional ACI is a viable means to control Hg and can play an important role in Hg compliance strategies, due to high availability and a broad array of suppliers. As described in an independent study by UNDEERC, significant world-wide capacity exists for AC. The key limitation to employing conventional ACI is the potential to compromise to ESP performance

The performance of conventional activated carbon is summarized by coal type as follows:

<u>PRB, Lignite.</u> The performance of conventional (e.g. non-treated) activated carbon, the reference sorbent tested in all demonstrations conducted in 2000 and 2001, has been surpassed for many (but not all) applications by treated halogenated sorbents. Conventional sorbents provided limited Hg removal particularly for PRB and lignite or western fuels (Sjostrom, 2006, Slide #16), where a lack of halogens and their oxidizing power limited performance.

Short-term tests at Detroit Edison's PRB-fired St. Clair station – depicted in Figure 5-1 as featuring the largest ESP of any demonstration site - showed that conventional AC provided 60% Hg removal for 100% PRB, increasing to 70% for PRB blended with 15% eastern bituminous (Nelson, 2005b). A similar finding was reported for the WE Energies Pleasant Prairie Station –

the fourth largest ESP of the demonstration sites - with Hg removal also limited to approximately 60% on this PRB-fired unit. Further, testing at Ameren's PRB-fired Meramac Station - representing approximately the median ESP SCA value of 320 ft^2/kacfm - showed Hg removal with conventional ACI was limited to 60-70%, even at extremely high ACI rates (Sjostrom, 2005b, Slide #24).

Medium, High Sulfur Coals. Researchers have speculated as to the impact sulfur trioxide might have on the performance of ACI at units fired with medium to high sulfur in fuel content. Limited data suggests SO3 may compete with Hg for active absorption sites, compromising performance. This issue would become significant either for medium or high sulfur coal-fired units, or those that employ SO3-based flue gas conditioning to improve ESP performance.

5.3.2. Halogenated Sorbent and Additives

The limitations in conventional AC prompted developing additives to improve the ability to capture elemental Hg. The concept of halogenated AC - pioneered by Sorbent Technologies and Darco/ADA-ES - appears to provide improved Hg removal within process environments that are deficient in halogens such as chlorine and bromine.

PRB, Western Fuels. At Detroit Edison's St. Claire station, where the use of conventional AC provided 60-70% Hg removal, brominated AC provided greater than 90% capture during a series of short-term tests (Nelson, 2005b). Significantly, an average of 94% Hg removal was achieved (92% attributable to brominated AC) during a 30 day test (Nelson, 2005a, Slide #11). At Ameren's Meramac station, a halogenated AC from Norit increased short-term Hg removal from 60-70% with conventional AC to approximately 95% (Sjostrom, 2005b, Slide #25). Longer term, 30 day tests at the same facility reported 93% Hg removal (Sjostrom, 2005b, Slide # 28).

Eastern Bituminous. At Duke Energy's Allen Unit 1, several halogenated sorbents were characterized during short-term testing. Results showed that at the highest injection rates of 7 lbs/MACF, between 80 and 85% Hg removal was measured (Nelson, 2006, Slide #26). At Detroit Edison's Monroe Plant, Hg removal with halogenated AC was less than that measured with conventional, with highest removal being approximately 83% (Sjostrom, 2006, Slide #24). Data obtained in 2003 during commercial-scale tests at the small Lausche plant showed that for one sorbent (Sorbent Technologies B-PAC) 70% Hg removal was achieved (Nelson, 2006, Slide #30).

The price of halogenated sorbents - usually reported as $0.85-0.90 per lb at the manufacturing site - may escalate due to a shortage of bromine. Published literature suggests the halogenated AC price has increased since 2003. Public pronouncements by suppliers of bromine that 100% price increases in bromine are possible further suggest that prices may not be stable. It should be noted there is only one source of bromine in the U.S. – saline aquifers in Arkansas – so transportation and supply conditions could be constrained.

5.4. SORBENT INECTION WITHIN FABRIC FILTERS

The performance of sorbent injection within a fabric filter is discussed according to coal type.

5.4.1. Eastern Bituminous Coal

The results of testing at Alabama Power's Gaston station – fired by a low sulfur eastern bituminous coal - have been well publicized. The one year long-term term operation showed that on average, 86% Hg removal was achieved with conventional sorbents; higher Hg removal was limited by the ability to maintain the filters clean and sustain a low flue gas pressure drop within the fabric filter. Short-term tests at lower air/cloth ratio suggest 90% Hg removal can be attained, in concert with a different design fabric filter and perhaps bag cleaning strategy.

5.4.2. PRB, Lignite, and Blends

Month long-tests at TXU's Big Brown station, which fires Texas lignite and PRB in a 70/30 blend, will evaluate the combination of conventional activated carbon and special-purpose flue gas and coal additives in a 30 day test to take place in early 2006. Pilot-scale tests at UNDEERC showed Hg removal was limited to 60-70%, but only at extremely high sorbent injection rates, with 55% believed to be a practical target (Almlie, 2006). The 30 day tests will address the prospects of Hg removal with this coal.

A similar exercise was conducted at the PRB-fired Hawthorn station. With test durations of several hours, research showed 80+% Hg capture (Laumb, 2006, Slide #12). Extended tests are necessary to confirm that the use of ACI under this configuration and coal type is commercially achievable.

The focal point for this control technology option is the recently initiated demonstration of sorbent injection within a fabric filter at the WE Energies Presque Isle station; the configuration known as EPRI's TOXECON. The demonstration target for this project is 90% Hg removal, and defining any uncertainties in long-term sustainable operation. For example, initial start-up tests revealed issues such as ignition of AC in several fly ash hoppers, and flue gas water condensation, which must be thoroughly evaluated to rule out design flaws. This experience demonstrates why long-term tests under a variety of conditions are required to assess the technology feasibility.

5.5. COAL BLENDING WITH SORBENT INJECTION

The use of blended coals to provide halogens that are necessary for sorbent performance can be considered a viable strategy for Hg compliance. The feasibility of coal blending goes beyond evaluating the process conditions of the environmental control system. The boiler and coal handling equipment must be evaluated to determine if the new fuel can be blended; whether blending will cause a change in plant generating capacity; and whether there is any differential in power production cost other than fuel price.

The role of coal blending on Hg removal performance of ACI with an ESP can be inferred by comparing data from Ameren's Meramac and Detroit Edison's Monroe Station. Both of the tested units featured ESPs of similar SCA, but fired different fuels - Meramac exclusively fires PRB, while Monroe fires PRB with a 40% blend of bituminous coal. Conventional ACI provided up to 70% Hg removal for both units (Sjostrom, 2005, Figure 2). Further increases in ACI rate increase Hg removal for the PRB/bituminous coal blend at Monroe, reaching about 80% Hg removal at 7 lbs/MACF. For the exclusive PRB-fired Meramac, such increases did not yield significant additional Hg removal. It should be noted that at Monroe use of halogenated sorbents provided lower Hg removal than conventional; it is possible that halogens introduced by the blended east bit coal exceeded those with reagent and dominated the results (Sjostrom, 2005b, Figure 5).

5.6. LIMITS OF DEMONSTRATION DATA IN ILLINOIS

The experience with ACI in ESPs, although providing high Hg removal in large ESPs, does not necessarily demonstrate such performance can be attained on Illinois units without significant upgrade.

5.6.1. ACI Demonstration Site Characteristics

A significant observation from ACI demonstration tests with an ESP is that the highest Hg removals and least operating problems have been achieved on units with extremely large SCA. Specifically, Hg removal exceeding 90% on a 30 day basis was measured at St. Clair, representing the largest ESP in the demonstration population. Hg removal exceeding 90% was also obtained at the Ameren Meramac station, which also featured high SCA.

Table 5-2 summarizes several key features of the earliest sites where demonstration tests for ACI within an ESP were conducted. Specifically, for each site, the test date, source for the initial and presently-used coals, initial and final design SCA, and comments on the design and any changes to the ESP are summarized. As shown in Table 5-2, the ESPs featured in the early demonstration projects have – either intentionally or by co-incidence – been all rebuilt and do not represent the original equipment. The first demonstration sites tested in 2001 and 2002 at Brayton Point and Salem Harbor, both of which generated near 90% Hg removal, were upgraded with either a second, supplementary ESP (Brayton Point) or with extra fields (Salem Harbor). The case of Pleasant Prairie – featuring a 472 SCA ft^2/kacfm ESP as a consequence of the conversion from hot-side – has been already discussed. Most significantly, a complete new ESP, inlet ductwork, and flue gas handling modifications were installed at St. Clair and Meramac.

Table 5-2. ESP Modifications and Upgrades: Key Demonstration Units

Utility/Station/Unit	**Test Date**	**Design Coal**	**Present Coal**	**Initial/Final ESP SCA (ft^2/kacfm)**	**Description of ESP Upgrade**
WE Energies Pleasant Prairie Unit 2	4Q 2001	Low-Med S E. Bit	PRB	574/574	Before construction, design changed from hot-side to cold-side, by re-routing ductwork
PG&E/NEP/Brayton Point/Unit 1	3Q 2002	Low-Med S E. Bit	Low S E. Bit	~156/403	Second ESP added to increase SCA to 559 ft^2/kacfm
PG&E/NEP Salem Harbor Unit 1	4Q 2002	Low-Med S E. Bit	Low S E. Bit	~150/474	Original ESP replaced with an enlarged unit with an SCA of 474 ft^2/kacfm
DEC St. Claire Unit 1	2003	Med-High S E. Bit	PRB Blend	~150/700	Replace original ESP with new unit of 720 SCA ft^2/kacfm; convert to balanced draft (1985)
Ameren Meramac Unit 2	2004	Med-High S E. Bit	PRB	~150/400	Replace original ESP with new unit of 320 ft^2/kacfm, include new ID fan (1980)
Duke Power Allen Unit 1	2004	Low-Med S E. Bit	Low S E. Bit	~150/400	Removal of initial ESP and replacement with 400 SCA ft^2/kacfm unit (1988-1989)
Georgia Power Yates Unit 1-4	2005	Low S E. Bit	Low S E. bit	~173/173	Replaced initial Buell design with rigid frame by BHA; upgraded microprocessor controls (1995-1997)

Additional discussion regarding the site-specific features several demonstration sites in Table 5-2 are summarized as follows:

<ins>DEC St. Claire Unit 1</ins>. All units at this station received a major overhaul of the ESP and flue gas handling equipment in the mid-1980s, to support the transition from firing eastern bituminous to subbituminous coal for SO2 control. The original ESPs featured an SCA of approximately 150 ft^2/kacfm, and thus significantly undersized for subbituminous coal.

<ins>Ameren Meramac Unit 2</ins>. Similar to St. Claire, all four Meramac units were equipped with new ESPs with an SCA of 320 ft^2/kacfm, with the original units abandoned in place. The location of the new ESPs behind the stack required extended ductwork for access, which provides for additional residence time for sorbent prior to the ESP inlet.

<ins>Duke Power Allen Unit 1</ins>. Both Allen Units 1 and 2 in 1988 and 1989 removed the original ESP with an SCA of 150 SCA ft^2/kacfm, and installed 400 ft^2/kacfm units.

The SCA values of early demonstration units at WE Energies Pleasant Prairie Unit 2, PG&E NEP Brayton Point Unit 1, and Salem Harbor Unit 1 have been well-documented in DOE final reports (ADA-ES 2003, ADA-ES 2004, ADA-ES, 2005).

5.6.2. ESP SCA and Hg Removal

IEPA submits that Hg removal by ACI will be independent of the size of the ESP, as indicated by the SCA. The basis for this statement is not referenced – but may be related to measurements of Hg removal at Brayton Point, which suggested most Hg removal by sorbent was attained in-flight, prior to the second, add-on ESP (Starns, 2003). The ability to generalize this observation is unknown – the Brayton Point site featured two ESPs in series, and a high fraction of Hg as particulate content. Similar tests at Salem Harbor also suggested significant in-flight removal, but again within ductwork preceding a second, add-on ESP located (ADA-ES, 2004).

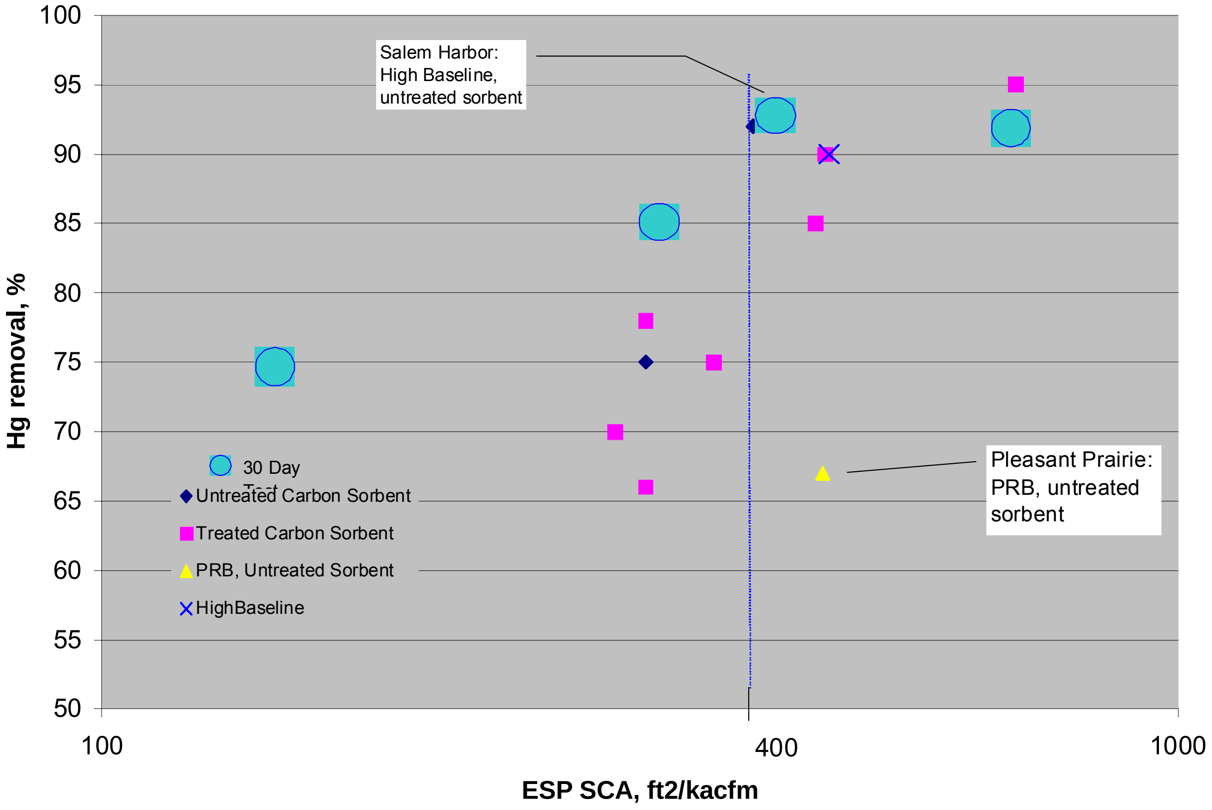
An alternative method of examining a relationship between Hg removal and ESP SCA is simply to compare observed Hg removal with the SCA of the demonstration unit. Figure 5-2 depicts the observed Hg removal by sorbent injection in ESPs, as a function of the ESP SCA value, for 13 well-publicized demonstration sites. Any trend implied from Figure 5-2 must be considered approximate - the results mix both conventional and treated sorbent, and compare either the maximum Hg removal or that measured at sorbent injection rates between 5 and 10 lbs/MACF. The ESP SCA value is plotted on the horizontal axis, in a logarithmic manner. Hg removal data based on a 30 day tests is identified as separate from short-term test results.

Two data points from early commercial demonstrations should be noted. The Pleasant Prairie Unit 2 data exhibiting 65% Hg removal represents the use of conventional AC on PRB coal, which at present is recognized as providing limited Hg removal unless halogens are introduced by either additives to the coal or flue gas. The use of halogenated sorbents would likely increase Hg removal beyond this value. Also, Salem Harbor Hg removals are confounded by a high baseline Hg removal of 90%, likely due to extremely high carbon content in fly ash.

The sparse data from the small ESPs such as Yates 1/2 suggests limited Hg removal, perhaps induced by the presence of ACI. The testing of COHPAC II at Coal Creek effectively reduced the SCA of the unit to 300 ft^2/kacfm, where ESP operating problems were noted.

In summary, although Figure 5-2 mixes several variables on one chart - sorbent type, duration of test, mass injection rate, and ESP design – the resultant trend suggests that major ESP upgrades are required to derive 90% Hg removal. These upgrades may have affected not only the SCA, but other variable that could influence the ability of activated carbon to penetrate the ESP. These include the plate height, aspect ratio (e.g .width versus depth), length and treatment, number of sections in the direction of gas flow, and hopper design.

Figure 5-2. Hg Removal and ESP SCA Value from 14 Demonstrations



5.6.3. Issues with Carbon in ESPs

The concern for the carbon impacting the performance of an ESP is due to the influence on electrical characteristics of the particles to be collected. The concept of introducing carbon into an ESP is not new – early installations of low NOx burners at times generated elevated carbon in fly ash, which could compromise ESP performance. The problems stems from carbon imparting the following effects:

- <u>Retained Electrical Charge On Collected Particles</u>. Ash particles, after being charged, migrate to the collecting plate, and are retained by residual electrical charge. The ash particles once collected must adhere to the plate for up to 5-15 minutes, when they are removed by the mechanical plate rappers. Ash particles laden with carbon can lose the electrical charge and adhesive forces, and be re-entrained into the flue gas. These re-entrained particles are either re-acquired or penetrate the ESP. The loss of electrical charge can cause ash particles – as they are separated from the collecting plate by the action of the mechanical rappers - to re-entrain and enter the flow field. This phenomena is speculated to have contributed to a doubling in outlet PM emissions witnessed during testing of the TOXECON II concept at Coal Creek Station (Starns, 2004). Remedial actions such as changing the plate rapping sequence may be feasible, but require additional testing.

- Long-Term Carbon Accumulation. Carbon – like any other solid – can accumulate within the ductwork or internal surfaces of the ESP, and influence the electrical properties. Specifically, erratic electrical behavior was witnessed at Yates due to shorting of current over insulators; and deposits on insulators at Coal Creek may have contributed to T/R set failure. This problem, which perhaps contributed to a compromise in ESP performance at both sites, may not be a fatal flaw, but additional tests to evaluate new insulator or cleaning equipment is required.

The long-term accumulation or depletion of material within process equipment is not new, or unique to Hg control. The depletion of sodium in hot-side ESPs was recognized after approximately one year of operation; SCR catalyst does not experience measurable deactivation until at least 8,000 and up to 16,000 operating hours; sulfate scaling in early-generation wet FGD systems frequently required at least several months of operation, while more than 6 months was required to accumulate chlorides in the reaction tanks to assess corrosion. The extended time required for testing is simply a consequence of the need for low concentrations of trace species or compounds to accumulate to threshold levels where they can assert an impact. The TSD acknowledges that carbon accumulates within the ESP and may impact Hg removal performance. Given the relative accuracy of Hg monitors, measurement error could be at least partially responsible for this behavior.

As a consequence, there is a practical limit as to the quantity of carbon that can be introduced into an ESP without compromising performance.

5.6.4. Comments on IEPA Testimony

During the June 13 presentation to the PCB by IEPA, staff and testifying experts argued that (a) DOE ACI tests at Yates do not show carbon injection compromised performance, and (b) preliminary data suggest Sorbent Technologies B-Pac both removes Hg and improves ESP opacity. These statements are considered in the following sections.

Yates Units 1 (Georgia Power)

The ESP at Yates Unit 1 was described – and I paraphrase here - as having problems before and after the ACI test, and to be a poor performing ESP. The Yates ESPs are not experiencing problems and are not poorly performing. Three items are instructive on this topic.

First, the PM emissions standards for Yates are well below the Georgia limit 0.2 lbs/MBtu; the owner frequently operates these units at less than 0.10 lbs/MBtu, which typifies PM limits in other regions in their system. (For example, Alabama requires a PM limit of 0.10 lbs/MBtu). Data presented in the quarterly report to the DOE summarizing these results (Richardson, 2005) shows baseline PM emissions less than 0.10 lbs/MBtu. This should be no surprise - Yates Units 1-4 were rebuilt in 1997-1999. Unlike other ACI demonstration units, space did not allow adding an extra field, or expanding the width of the collecting zones, so the relatively high flue gas velocity (approximately 4 ft/s) could not be reduced. The original ESP, provided by Buell, was replaced by a rigid discharge electrode design by BHA. A new microprocessor-based power supply and control system was installed, as well as a state-of-art data management system. In short, Yates Unit 1 (as well as Units 2-4) are state-of-art, if perhaps small and site-constrained, ESPs.

Second, the units are well maintained. Relatively high levels of carbon in ash as indicated by LOI are noted, but these are attributed to the low NOx burners and the required mode of operation to meet the station NOx limit. Regarding the failed insulators, the quarterly progress report is clear: "The stand-off insulators at the bottom of the high voltage frame were found damaged or broken. It is unclear when this damage occurred (i.e. whether the damage is related to activated carbon injection". This statement reflects the investigators opinion that carbon deposited onto the insulators could have contributed to the failure of this component.

Third, carbon breakthrough was clearly noted with ACI. It is only under the conditions of ACI that the Yates ESPs exceed a limit of 0.20 lbs/MBtu; the owner only avoided a PM violation as the flue gas desulfurization (FGD) equipment removed the additional breakthrough of PM. The quarterly report notes "Evidence of carbon breakthrough from the ESP was evident in Method 17 filter samples and the JBR scrubber solids".

It is true that ESP electrical operating characteristics were clearly not typical of a unit operating conventionally. ESPs that experience arcing are not delivering the maximum level of power to the emitting electrodes and collecting plates – arcing essentially diverts the power from the charging electrode, where it can do useful work, if only for a brief interval. Regardless, the result is reduced usable power for PM removal. Yates 1 tests suggest, but do not prove conclusively, that injecting carbon increases the arc rate.

Compounding the relationship between ACI and ESP performance is data from Yates 6, which features an ESP with an SCA of 328 ft^2/kacfm (refurbished in 1997). ACI tests on Yates 6 were conducted as a follow-on to the Yates 1 evidence that ACI increases PM emissions. These tests showed that for an ESP of 328 ft^2/kacfm, Baseline Method 17 data report PM emissions with up to 15-18 lbs/MACF of carbon as approximately 0.06 lbs/MBtu, lower than baseline data of approximately 0.08 lbs/MBtu. This is attributed to the rebuilt ESP, which presents a favorable geometry to avoid carbon breakthrough. Specifically, the rebuilt ESP was able to exploit additional space to both add a new field; increase width to lower velocities to 2.5 aft/s; and further to increase the "sectionalization" that improves carbon retention. In short, the rebuild of Yates Unit 6 presented advantageous - in fact almost ideal - conditions for carbon capture.

Lee Unit 1 (Progress Energy)

Mr. S. Nelson of Sorbent Technologies released preliminary data – denoted as Exhibit #73 - that showed a Sorbent Technologies B-Pac sorbent could both remove Hg and improve ESP opacity, eliminating the need for SO3 conditioning.

Exhibit 73 was offered as evidence. This conclusion – that B-Pac sorbent could be substituted for SO3 conditioning – was not corroborated by the host utility (Progress Energy) project manager for this test. Specifically, Mr. Peter Hoeflich stated that although B-Pac did to some degree mitigate the opacity problems caused by eliminating SO3 injection, the effect is not adequate to provide long-term remediation (Hoeflich, 2006). Mr. Hoeflich cited results from a perhaps imprecise but insightful test in which the role of SO3 conditioning and B-Pac on ESP opacity was inferred. Specifically, after completion of the 30 day trial with B-Pac (showing 83% Hg removal), Unit 1 opacity was noted to be 28%. Upon terminating B-Pac injection, opacity increased to 32%. Restoring conventional SO3 conditioning reduced the opacity to 3%. In summary, these tests suggest that B-Pac can marginally improve opacity, but not to the extent claimed by Exhibit 73. Progress Energy was not made aware of the data in Exhibit 73 until July 17, and is presently reviewing how the data selected for the exhibit represents actual Unit 1 ESP operation.

The Yates and Lee units are not the only data points describing low SCA ESPs. Field tests at Coal Creek identified ACI as inducing both accelerated sparking and high particulate matter emissions.

Due to this concern, it is likely that small units – those with an ESP of 250 SCA or smaller – will require adding an extra field to maintain PM removal performance, and compensate for reduced power delivered to the electrical field. It should be noted that adding an extra field – conceptually as described by Gaikwad (1997) for a 250 MW unit – may not always be feasible at each unit. One complication preventing installing an extra field is a lack of space at the ESP exit, due to the location of the inducted draft fan. Similarly, increasing the ESP SCA by adding a field at the ESP inlet may be prevented by equipment and ductwork, or the need to maintain a uniform flue gas flow profile.

5.6.5. INCREASED PM EMISSIONS AND NSR

On June 24, 2005, the U.S. Court of Appeals vacated the Pollution Control Project provisions of the New Source Review (NSR) rule, which provided that pollution control projects were exempt from NSR. The implications for ACI in ESPs could be significant – any collateral increases of particulate matter (PM) emissions could trigger NSR. If injecting ACI into an ESP increases annual total PM emissions by 25 tons per year, or annual PM10 emissions by 15 tons per year, the project would be subject to NSR. Consequently, the host unit to which ACI is adopted may be required to implement Lowest Achievable Emissions Rate (LAER) or Best Available Control Technology (BACT) for PM. The stipulated annual thresholds PM and PM10 - 25 and 15 tons, respectively – comprise strict requirements that become more onerous as the boiler size increases.

Table 5-3 presents estimates of annual PM emission increases for different-sized utility plants firing eastern bituminous coal, thus producing 5.8 lbs/MBtu of fly ash entering the ESP, and achieving a total PM collection efficiency of 98.3%, thus emitting 0.10 lbs/MBtu of total PM. Injecting ACI at a level of 5 lbs/MACF increases the ESP inlet loading to the equivalent to 0.11 lbs/MBtu, and for the same PM capture efficiency increases PM exit emissions by 0.0019 lbs/MBtu. This degree of PM control is probably optimistic - as discussed previously, the electrical nature of carbon particles and their significantly lower density makes them harder to capture than fly ash. If the efficiency of carbon particle capture is assumed to be only 95%, the incremental carbon emissions would increase from 0.0019 to 0.0055 lbs/MBtu. This analysis ignores the potential degradation of the coal-derived fly ash capture by the ESP due to operating problems such as insulator shorts or electrical arcing caused by carbon. PM emissions could increase even further for these conditions.

Table 5-3 shows annual emissions for increasing plant size, for both the 98.3% and 95% carbon capture assumptions. Generating plants larger than about 100 MW could exceed the 25 ton annual PM emissions increase, and trigger either LAER or BACT. If carbon does interfere with fly ash capture by coating high-voltage insulators or some other method, then the ability to inject carbon on even the smallest utility plants may trigger NSR.

The implications of the revisions to the NSR rule is that ACI with existing ESPs may only be applicable to small plants, or those with the large ESPs. Of course, it may be possible to develop an ESP upgrade technology that would reduce any increased PM emissions below the 15 or 25 ton per year threshold, but such options are not known to be commercially proven for carbon-laden ash.

Table 5-3. Estimated Carbon Particulate Emissions from ACI

Plant Size, MW	**AC Injected (tons/year)**	**ACI-Induced PM Emissions (tons/year at 98.3% efficiency)**	**ACI-Induced PM Emissions (tons/year at 95% efficiency)**
25	94	2	5
50	188	3	9
100	376	6	19
250	941	16	47
500	1882	32	94
750	2832	48	141

Assumed: bituminous coal with 12,000 Btu/lb heating value; ash content of 10%; fly ash/bottom ash ratio of 70%/30%; capacity factor of 80%; and ACI rate of 5 lbs/MACF.

SECTION 6

PROCESS GUARANTEES

6.1. INTRODUCTION

Technology developers have offered performance guarantees for various Hg control technologies, such as sorbent injection, the oxidation of Hg by SCR catalyst, and the removal of oxidized Hg by an FGD process. The availability of such guarantees has been cited as evidence of the maturing of Hg control technology, and proof that Hg limits can be adopted without concern by Owners for failure. The willingness of developers to offer such guarantees is a sign of their confidence in success. However, the terms and conditions of the guarantees are limited. This section will describe how, despite attempts by suppliers to mitigate risk, the uncertainties incurred by early adopters of control technology are significant risk in terms of uncompensated costs and revenue loss.

6.2. MODES PROCESS FAILURE

Recognizing how a process fails – and the implications for operating cost and lost revenue – is important.

For example, a performance guarantee may specify a given removal of Hg (or some other species) be attained, at a fixed consumption rate of chemicals, auxiliary power, and impact to plant thermal efficiency. For a technology like SCR NOx control, the guarantee will also specify the operating time before catalyst must be replaced – which requires capital infusion and an outage that can be lengthy and not planned. There are several scenarios of malperformance or failure that can be experienced, described as follows:

Performance Delivered But Not At Guaranteed Conditions. If the guaranteed emission control is achieved, but at higher consumption of chemicals or auxiliary power than specified, the Owner's risk is limited to additional operating cost. Similarly, a process may meet the guaranteed performance, but impose a greater penalty on plant thermal efficiency than specified. These shortcomings induce higher operating cost but do not disturb or prevent power generation.

Performance Not Delivered. If the guaranteed emission control cannot be attained, the Owner is subject to fines or penalties for non-compliance, or forced to purchase "allowances" from a tradable market (if one exists). This shortcoming does not limit power generation and revenue loss.

Performance Delivered But With Collateral Damages. The guaranteed emission control is delivered, but the process imposes significant collateral damage to the Owner. An example of this is the early experience with FGD equipment, where the inability to control process chemistry induced scaling of ductwork and reaction vessels, compromising reliability.

<u>Performance Not Delivered But With Collateral Damages</u>. The worst scenario is not meeting environmental performance requirements while incurring collateral damages, which can be costly. As noted by Laeske (1983), the reliability of the first-generation of FGD process equipment was limited to 54% and 69%, respectively, for high and medium sulfur coals. This poor reliability imposed revenue penalties on the host units. The SCR process at the Logan Generating station delivered the required NOx reduction, but only by generating excess residual NH3 which limited plant full load operation. Also, the installation of a fabric filter to replace an existing ESP and improve particulate control at PPL's Brunner Island station resulted in flue gas pressure drop exceeding the guaranteed value of 6 in w.g., which limited load.

6.3. GUARANTEE: A DEVELOPERS PERSPECTIVE

Process developers offer compensation that, with limited exception, addresses only direct operating requirements and not collateral damages. These guarantees are only adequate if damages are limited to a shortfall in performance, or higher operating cost for reagent.

Process malperformance per Scenario (a) can be compensated for by a guarantee that covers higher costs over a reasonable future timeframe. For example, the FGD process for the Limestone Generating station, installed by Reliant Power (Texas) and operable by 1994, did not initially meet SO2 removal requirements at the guaranteed consumption of reagent and auxiliary power. The process supplier compensated the Owner with a one-time payment equal to the value of an extended supply (~10 years) of a performance-enhancing additive that eliminated the shortfall.

This guarantee structure is similar to that offered by suppliers of ACI. Generally, if Hg removal is not attained with the guaranteed injection rate of activated carbon, the supplier provides reagent above and beyond the guaranteed rate to attain such values. Most of the ACI guarantees limit the value of the compensation to the value of the contract, written to reflect the one-time capital charge and not necessarily the operating cost. Thus, if compensation offered in the guarantee is limited to the contract value (typically $1-2 M for ACI process equipment), additional reagent is provided by the supplier up to this value. The owner must then purchase additional sorbent at their own cost.

6.4. GUARANTEE: AN OWNERS PERSPECTIVE

An example of an Owners perspective is the case for SCR NOx control – and the ability to meet the guaranteed NOx control at the end-of-life period (usually 16,000 to 24,000 operating hours), while limiting residual NH3 and SO3 byproduct emissions. Consider the case where the NOx emission target is not meet, or is attained only in exchange for higher residual NH3 by over-injecting ammonia reagent. This method of forcing NOx control can produce deposits on downstream equipment that could require a forced outage for cleaning or maintenance. The compensation generally offered by the catalyst supplier – to provide replacement or additional catalyst (on a prorated use basis) - is of little value compared to (a) penalties for not meeting the

NOx target, or (b) the lost opportunity to generate power if the unit must be removed from service for cleaning or additional maintenance.

Significantly, these guarantees do not cover collateral damages to ancillary or downstream equipment. The use of ACI in certain demonstration tests, most notably on units that utilize an ESP for particulate control that is not large compared to the average, can possibly compromise particulate matter removal. At Georgia Power's Yates Units 1 and 2, ACI may have induced higher stack opacity (e.g. reduced particulate matter removal). Anecdotal observations at Detroit Edison's Monroe station suggested the same. The upgrade of ESPs to tolerate ACI could be required to retain particulate matter control.

For an Owner to be fully compensated for failure of an environmental control process, the following guarantee criteria would have to be provided:

Penalty for Accelerated or Additional Outages. The additional downtime imposed on a unit due to equipment failure, or an accelerated major outage to repair or replace components, is significant. As an example, an additional 17 day outage required for equipment repair for a 500 MW unit can cost between \$0.44 - \$1.6M, per each outage.

Higher Reagent Cost. The increased demand for chemical or reagent to operate a process, beyond that specified by the supplier, represents an increased operating cost. The value of reagent beyond that projected in the guarantee should be provided for an extended operating period. Otherwise, the owner must pay for 10–20 years for the shortcomings of the supplier.

Additional Process Requirements. Perhaps the best example of the "law of unintended consequences" is the additional SO2 oxidation provided by SCR process equipment, mandating SO3 mitigating technology. In this case, several owners of SCR-equipped units were required to install SO3 mitigation systems due to additional SO3 generated by the SCR process. The cost for operating these mitigation systems can rival that of SCR process operation, elevating this cost from negligible to a major decision factor.

Consider an example where an owner elects to use halogenated sorbent to achieve 90% Hg removal, on a large ESP such as the 145 MW St. Clair unit. For this unit, the capital cost for a sorbent receiving, delivery and injection system has been estimated by DOE to \$8.8/kW, requiring an installed process capital charge of \$1.27 M. The demonstration data suggests that in excess of 90% Hg removal can be achieved with 3 lbs sorbent /MACF.

If meeting the targeted Hg removal requires 5 lbs/MACF instead of 3 lbs/MACF, the additional cost for reagent (at 80% capacity factor) is \$1.342 M per year (at a delivered sorbent price of \$0.85/lb). The supplier will provide this additional sorbent at no cost, but limited to the contract value of \$1.27 M. Thus, after 25 months of providing additional reagent, the owner must bear all costs, while future revenue to the supplier increases by 66%. Consequently, the supplier has little to lose and significant up-side market potential with this guarantee.

Guarantees in environmental control technology provide only partial compensation for shortcomings, and are not significant factors in the decision to adopt any particular technology.

SECTION 7

SCHEDULE AND DEMONSTRATION PLANS

7.1. INTRODUCTION

Given the present schedule of Hg control technology demonstrations and early commercial applications, it is prudent for states to select an implementation schedule that derives maximum benefit from the federal and privately funded research, as well as from equipment installed for CAIR.

7.2. PLANNED DEMONSTRATIONS

As stated in Section 1, the involvement and support by the electric utility industry in conducting Hg control technology demonstrations is unprecedented, as measured in terms of both the number of participating utilities, the specific demonstration or pilot-plant tests hosted, and funds committed.

Since 1998, and through 2004, the U.S. Department of Energy through NETL has invested approximately \$52.5 M in R&D funding for Hg control. Together with utility industry cost-sharing of 25%, almost \$65M worth of R&D has been expended (Feely, 2004).

Similarly, from 2005 and through 2009, the DOE plans to expend approximately \$60 M (Feeley, 2006a) in the same endeavor of demonstration and testing of Hg controls – which with a 25% utility industry cost-share, approximates \$75M. These totals apply through 2009, and DOE has targeted undisclosed additional funds for demonstration and long-term testing beyond those dates.

7.3. ADDITIONAL INFORMATION REQUIRED

This document has presented evidence that two categories of information or experience are lacking that may thwart deploying Hg controls. These activities are:

<u>Operating Experience Beyond 30 Days and Of Nominally One Year</u>. Extended operating experience is required to define all balance-of plant impacts. All field tests and demonstrations presently funded contain a task to operate Hg control technology for 30 continuous days, providing invaluable experience. However, tests extending to one year – to avoid an outcome analogous to the hot-side ESP episode as described in Section 3 – are required to prove the technology. The DOE demonstrations planned and contemplated in the future will sponsor one-year operation for several process candidates. Within this category of technology demonstrations, perhaps most important are those that allow injected sorbent to accumulate on surfaces to where a steady–state deposit is reached. This accumulation – speculated to enhance

Hg control – may induce operating problems, as witnessed with dry sorbent injection for SO2 in the 1980s.

Byproduct Impacts and Long-term Disposal Issues. To date, essentially every test that has addressed the potential for Hg-laden byproducts has shown the ultimate form of byproduct or solid effluent does not leach or re-emit the Hg into the environment. These results are perhaps the most significant of any testing and analysis conducted to date. Despite encouraging early results, prudent actions mandate completion of this work, to include long-term leaching or re-emission studies. These activities are presently funded and planned, and additional work as suggested by the research community should be completed.

Perhaps the most significant validation of the need to consider these results in finalizing Hg limits and control technology is the recognition by the U.S. EPA of the lack of operating experience, and the importance of considering the results of this planned future demonstration work in establishing Hg control limits. Specifically, as noted by EPA in the preamble to the CAMR issued on May 18, 2005:

"With the exception of one test that last for approximately one year, no Utility Unit has operated a Hg-specific control technology full scale for longer than approximately one month."

Further, the EPA Preamble stated:

… the DOE and EPA have underway broad and aggressive research program, which will yield experience and data in the next few years. Accordingly, EPA continues to believe that ACI and enhanced multi-pollutant controls have been demonstrated to effectively remove Hg and will be available after 2010 for commercial application on most or all key combinations of coal rank and control technology to provide Hg removal levels between 60 and 90 percent on individual Utility Units.

Finally, to reiterate comments in April of 2006 by DOE by Feely (2006b) in clarifying a discussion of Hg control readiness for application in Pennsylvania:

"…there remain a number of critical technical and cost issues that need to be resolved through additional research before these technologies can be considered commercially available for all U.S. coals and the different coal-fired power plant configurations in operation in the United States".

These statements recognize the need for additional data, and that 90% Hg control remains at the edge of research targets. Significant investment in further research is already committed; the selection of Hg limits and the compliance schedule based on these results is prudent for the industry and ratepayers.

SECTION 8

CONCLUSIONS

Technology developers have provided innovative, potentially effective means to control mercury emissions. Results to date are encouraging – but as the utility industry has learned from experience with wet FGD, SCR NOx control, and hot-side ESPs, successfully deploying environmental controls requires approximately 5-7 years of testing and demonstration with commercial-scale equipment. Operating this equipment for extended periods – preferably at least one year – is required to assure process reliability. With both wet FGD and SCR, much of the product development was conducted on the first 5-10 commercial installations that were considered "commercially available" but were not "commercially proven".

Significant key uncertainties remain regarding evolving mercury controls, but demonstrations in the pipeline will provide the necessary information.

Most significantly, building an Hg compliance strategy upon the process equipment slated for CAIR implementation provides the most cost-effective, reliable approach. The equipment to be deployed for CAIR- be it dry or wet FGD, and possibly the retrofit of a fabric filter – provides the residence time, mixing environment, and process chemistry to transform elemental and oxidized Hg into solid effluents that may be proven to be benign to the environment. Coupling Hg compliance to SO2 and NOx reduction – in terms of both equipment and schedule – provides the most cost-effective and reliable compliance path.

Implementing CAIR-driven equipment is underway now. Building upon this process equipment to increase Hg control beyond inherent capabilities is the most prudent means for reliable Hg removal.

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APPENDIX A

SUMMARY OF ASSUMPTIONS DEFINING HG CONTROL TECHNOLOGY PERFORMANCE AND COST FOR USE IN EVALUATING PROPOSED STATE HG RULES

SECTION A-1

INTRODUCTION

This document describes the series of assumptions defining the technical feasibility and cost of mercury control (Hg) options from coal-fired power plants, to be used in evaluating the impacts of the proposed State of Illinois Hg control legislation.

The assumptions presented in this document reflect the feasibility and cost for commercial scale operation, for continuous 24x7 duty, and over extended operating periods. As stated in the main body of the testimony, the data from which these assumptions are derived are short-term results (e.g. several hours or days), with some tests extending up to but not beyond 30 days.

For some applications, these Hg control assumptions directly adopt the results of commercial-scale demonstrations, without necessarily agreeing with the conclusions or methodology. For other applications, either the cost or performance is adjusted to reflect site-specific conditions for the unit, or the realities of continuous operation. As previously stated, perhaps the most significant shortcoming is the preponderance of short-term data (e.g. measured in hours or 1-2 days) and operations, in contrast to extended operation of 6 months and more. Results of the sole demonstration that extended one year or the several that generated 30 days of operation are adopted in their entirety, for the site-specific conditions they reflect. Again, this done without validating the studies, including the uncertainty of Hg measurements

These assumptions describe (a) inherent Hg removal, as observed with existing plant equipment (Section A-2), (b) the performance and cost of conventional and halogenated activated carbon injection in ESPs (Section A-3), fabric filters (Section A-4), and dry flue gas desulfurization (FGD) process equipment (Section A-5). The calculation of “Hg cobenefits” from SCR and conventional wet FGD process equipment is addressed in Section A-6.

SECTION A-2

INHERENT REMOVAL AND BASELINE HG EMISSIONS

The first step in evaluating Hg control feasibility and cost is determining the inherent Hg removal provided by the exiting control technology arrangements.

Initial results from the ICR analysis conducted in 1999 have been evaluated by EPRI to establish a correlation between coal properties, environmental control equipment, and the removal and speciation of Hg in boiler flue gases (EPRI, 2000). Since these correlations were published, additional data has been derived and these relationships have been updated, not as a closed-form correlation but through "emissions modification factor" (EMFs) derived for a specific control device or combination of control devices. These "EMF" factors, shown in Table A.2-1, are identical to the recommendations forwarded by UARG to the EPA on January 3 in response to the NODA solicitation, for final comments on mercury controls.

Table A.2-1. EMF Recommendations

Control Configuration	**Bituminous Coal**	**Sub-bituminous**	**Lignite**
CS-ESP	0.64	0.97	1.0
CS-ESP/wet FGD	0.40	0.82	0.56
CS-ESP/dry FGD	0.60	0.80	1.0
SCR/CS-ESP/wet FGD	Per Section 6	Per Section 6	Per Section 6
SCR/CS-ESP/dry FGD	0.25	0.80	1.0
FF	0.25	0.35	1.0
FF/wet FGD	0.10	0.25	1.0
FF/dryFGD	0.10	0.85	0.56
SCR/FF-wetFGD	Per Section 6	Per Section 6	Per Section 6
SCR/FF-dryFGD	0.10	0.85	1.0
HS-ESP	1.0	1.0	1.0
HS-ESP/wetFGD	0.50	0.80	0.80
SCR/HS-ESP/wetFGD	0.15	0.80	0.80

Note: EMF = (1-Control Efficiency)

As noted in Table A2-1, the Hg removal provided by SCR NOx control in conjunction with wet, conventional FGD will be determined by the methodology described in Section B-5. This approach is adopted in lieu of an EMF as significant recent research has focused on improving the ability to predict Hg removal, based on coal chloride content (Chu, 2006).

The EPRI published correlations will be used to determine (a) Hg emissions from fluid bed units equipped with fabric filter particulate controls, and (b) the speciation of Hg between the oxidized and elemental forms. The correlations relating fluid bed Hg emissions are of the same form used in most ICR correlations:

Hg Removal (or percent elemental) = Multiplier * ln (coal Cl, ppm) + Constant

Table B.2-2 summarizes the multiplier and constant for the fluid bed boiler technology.

Table A.2-2. Summary of Factors in the FBC Correlation

Control Component	Multiplier	Constant
FBC FF	0.1394	0.1127

There are several special exceptions to the use of these correlations, based on field tests conducted by Illinois generators. Most significantly, a series of field tests dedicated to PRB-fired cyclone boilers showed that most units averaged an inherent Hg removal of 50%, with the exception of Dynegy Baldwin, which featured an inherent Hg removal of 80%. Accordingly, these values were used as inputs to the analysis.

SECTION A-3

ACTIVATED CARBON INJECTION (ACI) IN PM CONTROLS

The removal of Hg by injecting conventional and specially-treated (e.g. halogenated) activated carbon into particulate matter (PM) controls is addressed in this section.

A.3.1 Conventional ACI/ESPs

The assumptions defining Hg removal performance of activated carbon injection (ACI) into ESPs located on the both cold-side (ESPc) and hot-side (ESPh) ESPs depend on the concentration of flue gas SO3, the ESP SCA, and to a lesser extent, unit generating capacity. Table A.3-1 presents the assumed relationship (**in bold print**), and the specific reference of demonstration test data from which the assumption is derived (*in 10 pitch italic print)*. Table A.3-1 summarizes the relationship between ACI and ESP, depending on coal type (e.g. PRB or eastern bituminous coal), for two ranges of ESP specific collecting area (SCA) and various generating capacities. Reference data is shown for PRB coals and one eastern bituminous application.

The results are described as follows, according to the projected impact of coal type, the size of the generating unit, and the ESP size (specific collecting area, or SCA):

Coal Type

<u>PRB</u>. Data for exclusive use of PRB is presented, and relevant references identified. The ability of conventional ACI to remove Hg is believed to be limited by a lack of halogens (Cl, Br).

<u>PRB/Eastern Bituminous Blend</u>. Data for the use of a PRB blend and eastern bituminous coal, with PRB the predominant constituent, may provide for improved Hg control. Eastern bituminous coal may introduce adequate chlorides to promote Hg oxidation, while the predominance of PRB and extremely alkaline ash minimizes the production of SO3 (which can interfere with carbon absorption). These assumptions assign a 10-15% improvement in Hg removal due to the use of an approximate 75/25 blend of PRB and eastern bituminous coal.

Exclusive Eastern Bituminous Coal. In the content of these assumptions, eastern bituminous coal is defined as such with at least 1% sulfur content. This level of sulfur is assumed necessary to generate the 4-6 ppm of SO3 that may be the threshold for impairing Hg removal. Bituminous coals from sources with less than 1% are assumed to behave more like a PRB/eastern bit blend.

For higher sulfur coal, it is believed that flue gas SO3 will compete with Hg for active sites on the carbon surface, and degrade performance. Limited data exists defining the Hg removal with conventional activated carbon. Tests at Plant Daniel (Bustard, 2006), Lausche (Nelson, 2003), and Yates (Dombrowski, 2005) are cited. These sources suggest Hg removal varies widely.

With the exception of the small units as reflected by Yates, a 60% Hg removal is adopted, assuming higher ACI rates and modest sorbent improvements are possible.

Consistent with the observation the flue gas SO3 will compete with Hg for absorption sites, a separate set of Hg removal assumptions will be adopted for units that employ SO3 conditioning. Based on commercial–scale testing conducted for an Illinois generator, Hg removal was limited for both conventional and halogenated sorbent. Table B.3-1 and B.3-2 will specify the details of these assumptions.

Generator Size, ESP SCA

In addition to coal type and blend, and the presence of flue gas SO3 conditioning, Hg removal results are assumed to depend on both ESP SCA, and generator size.

ESP SCA. Given that 70% of all ESPs in the U.S. feature an SCA less than 300 ft^2/kacfm (Slide #4 of Dombrowski, 2005), the predominance of large ESPs in the numerous demonstration units presents an optimistic case for the ability to inject activated carbon without inducing ESP opacity problems. It is notable that the sole small ESP tested (Yates at 170 SCA) did incur opacity problems; and even at the large SCA Monroe station anecdotal evidence of opacity problems were noted. Accordingly, the assumptions proposed for this study assign a limit on ACI performance for units <250 SCA, and further require such units to be upgraded by the addition of one field to achieve the projected Hg control requirement.

Generating Capacity. The ability to uniformly disperse sorbent throughout the entirely of a flue gas cross-section, necessary for high Hg removal, is assumed to increase with the size of the flue gas duct. This view is consistent with a global review of the various ACI demonstrations - among the highest Hg removal was noted at the smallest generating sites (e.g. St. Claire, Meramac) and among the lowest at the largest generating sites (Pleasant Prairie, Monroe). Although coal composition and SCA likely also play a role, given the information available to date it is not possible to exclude generating size. This concern is bolstered by release of results from CFD modeling of reagent injection systems that report the distribution of residence time in real systems can be only half that calculated for “plug flow” conditions. Although these specific results for Brayton Point did not compromise performance, they do not allay concerns that sorbent mixing and distribution problems are independent of generating size

These assumptions presume that all units equipped with low SCA ESPs – specifically those with an SCA less than 250 ft^2/kacfm - will an extra field to sustain the same level of carbon injection as larger ESPs. The capital cost will be defined by the analysis of Boward (1997), escalated to a 2006 dollar basis and including adjustments as defined by utility-specific studies for these modifications. Accordingly, the capital cost for this ESP upgrade will be $35/kW for a 250 MW unit. The upgrade of a unit to an SCA of 250 ft^2/kacfm will be required to derive the cited Hg removal. The capital cost of $35/kW, as determined for a 250 MW unit, will be generalized to other generating capacities by a power-law relationship, using a 0.35-power scaling factor, described as follows;

$$\text{ESP Upgrade Cost (@ Capacity)} = 35 * (250/\text{Capacity})^{-0.35}$$

Table A.3-1 also presents results for the special case of units utilizing ESPs with SO3-based flue gas conditioning. As suggested during tests with simulated SO3 flue gas content (Durham, 2006) and specifically for units with flue gas SO3 conditioning (Ameren, 2006a), the introduction of 3-5 ppm SO3 or more will limit Hg removal to a long-term value of 35% with conventional sorbent. Tests conducted by ADA-ES for Ameren suggest that the use of halogenated sorbents may increase the Hg removal to approximately 50%.

A.3.2. Specially-Treated (Halogenated) ACI in ESP

Several field tests evaluating the feasibility of halogenated activated carbon injection (HACI) into both ESPs and fabric filters have been completed through July of 2005. The extent of this work – still lacking the desired long-term experience of 12 and 18 months believed necessary – is inadequate to fully characterize the use of halogenated sorbents. More significantly, all full-scale tests with HACI are on PRB or lignite coals, with no eastern bit coals planned for testing until the AEP Conesville station in 2006. Thus, Hg removal data is presented for PRB, with an adjustment implemented for the Plant Daniel tests showing the role of SO3 as reported by Durham (2005). The data of Durham (2005) suggest a compromise in Hg removal by 20-40% is incurred for only 6 ppm SO3; accordingly a 20% compromise is assumed contingent upon a 50% increase in AC injection rate**.**

Table A.3-2 summarizes the performance assumptions selected to reflect present technology status. The Hg removal rates and associated HACI rates are derived from three prominent demonstrations of HACI performance. Significantly, data from the 600 MW Monroe unit shows that 75-80% Hg removal was achieved, approximately the same as the value attained with conventional ACI. Results from the 80 MW demonstration segment of the 160 MW St. Clair unit suggest 90% Hg removal is feasible. More significantly, 30 day continuous tests at St. Clair showed that 93% Hg removal was achieved, at 3 lbs/MBtu of B-PAC (Slide 5 of Landreuth, 2004). Data from the high sulfur coal –fired extremely small (18 MW) Lausche unit shows 70% Hg, and the authors cite this as evidence that excessive SO3 provides “challenging” process conditions for Hg removal, even for HACI, corroborating the data of Durham (2005).

For halogenated ACI, Hg removal assumptions are presented for PRB, and adjusted for east bituminous coal.

Table A.3-2 also presents results for the special case of units utilizing ESPs with SO3-based flue gas conditioning. As suggested during tests with simulated SO3 flue gas content (Durham, 2005) and specifically for units with flue gas SO3 conditioning (Ameren, 2006a), the introduction of 3-5 ppm SO3 or more will limit Hg removal to a long-term value of 50% with halogenated sorbent.

Table A.3-1. Summary of ACI/ESP Assumptions: Conventional Sorbent

Capital Cost ($/kW)	Capacity (Reference unit)	ESP SCA (ft^2/kacfm)	Hg Removal, %	ACI Rate (lbs/MACF)	Comment
Note 1	**>500**	**>250**	**PRB: 75**	**7**	Total, include inherent Hg removal as calculated per EPRI (2000)
			PRB/E. Bit: 75	**6**	
			East Bit: 60	**12**	
			All coals w/FGC: 35%	**5**	
<u>*Reference:*</u>	*Pleasant Prairie (600)*	*485*	*PRB: 60*	*10*	*PRB: Durham, 2003*
<u>*Reference:*</u>	*Monroe 785 (196)*	*285*	*75*	*6*	*PRB/E. Bit blend: Slide 29 of Sjostrom 2005 (AQV)*
<u>*Reference*</u>	*Labadie, 630*	*279/ FGC*	*PRB: 35*	*5*	*ADA-ES Report for Ameren*
Note 1	**250-500**	**>250**	**PRB: 80**	**6**	*East Bit: defined by Slide #28 of Durham (2006)*
			PRB/E. Bit: 80	**6**	
			East Bit: 65	**8**	
			All Coals w/FGC: 35%	**5**	
Note 1	**25-249**	**>250**	**PRB: 85**	**6**	
			PRB/E. Bit: 85	**6**	
			East Bit: 70	**8**	
			All coals w/FGC: 35%	**5**	
	Meramec 140 (70)	*320*	*75*	*5*	*PRB. Slide 26 of Sjostrom 2005 (AQV)*
	St. Clair 160	*470*	*70*	*6*	*PRB/E. bit.*
	Lausche (18 MW); Daniel (500 MW)	*370*	*25*	*5*	*High S East Bit w/20 ppm SO3. Nelson, 2003, Figure 15. Also Slide 29, Durham (2005)*
	Labadie, 630	*279/ FGC*	*PRB: 35*	*5*	*ADA-ES Report for Ameren*
Note 2	**>500**	**<250**	**PRB: 70**	**7**	Small capacity, SCR assumed to compensate for PRB. Hg removed for East Bit capped at 60%.
			PRB/E. Bit. : 70	**8**	
			E. Bit: 60	**8**	
			All coals w/FGC: 35%	**5**	
	250-500	**<250**	**PRB: 75**	7	
			PRB/E. Bit. : 75	8	
			E. Bit: 70	8	
			All coals w/FGC: 35%	5	
	<25-249	**<250**	**PRB: 80**	7	
			PRB/E. Bit: 80	8	
			East. Bit: 75	8	
			All coals w/FGC: 35%	5	
<u>*Reference:*</u>	*Yates (100 MW)*	173	75	4	E. Bit: Dombrowski (2006), Slide #21.

1. Curve from Slide 28 of Durham, 2005
2. Note 1 data and cost for 1 additional ESP field, per Gaikwad (1997) (Note: add $25/kW for capital, scaled from 250 MW).

Table A.3-2. **Summary of ACI/ESP Assumptions: Treated Sorbent**

Capital Cost ($/kW)	Capacity (Reference unit)	ESP SCA (ft^2/kacfm)	Hg Removal	ACI Rate (lbs/MACF)	Comment
Note 1	**>500**	**>250**	**PRB: 80** **PRB/E. Bit: 80** **East Bit: 60** **All coals w/FGC: 50%**	**4** **6** **6** **5**	1. Presumes short-term Monroe test results apply. 2. Assumes east bit coal derives 20% less Hg removal at 50% more AC, per Durham (2005)
	Monroe 785 (196)	*285*	*PRB: 80-82 East bit correction from Plant Daniel data*		*80/20 PRB/E. Bit Blend: No increase in Hg removal. Sjostrom 2005a, Slide 28; East bit correction from Slide 28 of Durham 2005.*
<u>Reference</u>	*Labadie, 630*	*279/ FGC*	*PRB: 35*	*5*	*ADA-ES Report for Ameren*
Note 1	**250-500**	**>250**	**PRB: 85** **PRB/E. Bit: 85** **East Bit: 65** **All coals w/FGC: 50%**	**4** **6** **6** **5**	Same as >500 MW
Note 1	**25-249**	**>250**	**PRB: 90** **PRB/E. Bit: 90** **East Bit: 70** **All coals w/FGC: 50%**	**4** **6** **6** **5**	Smaller unit size, mixing distance improve performance
	Meramec (140/70)	*320*	*95*	*4*	*100% PRB: Darco LH. Short-term tests, PRB coal*
	DEC St. Claire (80)	*ESPc: 470*	*90%, at 3 lbs/MACF*	*3*	*80/20 PRB/E. bit Blend: Sorbent Technologies, 2005a* *330 F ESP*
	Laushe (18)	*ESPc: 370*	*70*	*4*	*Nelson, 2003, high S East Bit. States high SO3 complicates removal*
Note 2	**>500**	**<250**	**PRB: 75** **PRB/E. Bit: 75** **East Bit: 60** **All coals w/FGC: 50%**	**4** **6** **6** **5**	Assumes east bit coal derives 20% less Hg removal at 50% more AC, per Durham (2005)
“	**250-500**	**<250**	**PRB: 80** **PRB/E. Bit: 80** **Eat Bit: 65** **All coals w/FGC: 50%**	**4** **6** **6** **5**	Same
“	**25-249**	**<250**	**PRB: 85** **PRB/E. Bit: 85** **East Bit: 70** **All coals w/FGC: 50%**	**4** **6** **6** **5**	Same

Note 1. Curve from Slide 30 of Durham, 2005

Note 2. Include Slide 30 (Durham, 2006) and cost for 1 additional ESP field, per Gaikwad (1997) (add $25/kW for capital, scaled from 250 MW).

Based on the results in Table A.1-4, and similar to the case for conventional ACI, the performance of HACI is assumed to depend on both generating capacity and ESP SCA.

These assumptions acknowledge, and are consistent with, two 30–day tests of HACI showing Hg removal exceeding 90%. Specifically, in 30 day tests, both the St. Claire and Meramac units achieved in excess of 90% Hg removal for 3-4 lbs/MACF. The assumptions acknowledge and reflect this data for small capacity, high ESP SCA units.

The delivered cost for HACI is selected based on the following observations:

- In 2003, Sorbent Technologies presented data for their "Type A" sorbent, later revealed to be B-Pac. In 2003 Sorbent Technologies cited this reagent would be "conservatively" estimated as available for $0.60/lb.

- In 2004-2006, Sorbent Technologies states this same reagent will be available for $0.75/lb.

- In 2006, ADA-ES representatives state Darco LH is available for $0.85/lb at the manufacturing site, without delivery charge. This anticipated charge for delivery to Illinois may be $0.10-0.15/lb, increasing the total delivered cost to $0.95-1.00 $/lb.

This gradual escalation in prices has been witnessed prior to demand of the sorbent, which could be expected with broad deployment of HACI. Consequently, the average sorbent cost assumed for an Illinois adoption of strict Hg controls is $1.15/lb.

A.3.3. The Special Case of Hot-Side ESPs

The special case of reducing Hg emissions from units equipped with hot-side ESPs is been the subject of demonstrations of HACI by several suppliers. The hot-side ESP, due to higher operating temperature, can impair the performance of both conventional and halogenated sorbents.

Table A.3-3 summarizes the assumptions defining HACI performance for hot-side units, based on results from Duke Power's Cliffside and Buck station. The proposed Hg performance levels are assumed invariant with generating size and ESP SCA, as there is no data over which to generalize performance to larger capacities of smaller ESPs. For all generating capacities, Hg removal of 50% at 3 lbs/MBtu will be assumed.

Table A.3-3. HACI: Hot-Side ESPs

Capital Cost ($/kW)	Unit Capacity (Reference unit)	ESP SCA (ft^2/kacfm)	Hg Removal	ACI Rate (lbs/MACF)	Comment
Note 1	**all**	**all**	**50**	**3**	Conclusion of Sorbent Technologies, Slide #29 of Nelson (2005)
Duke Cliffside	*40 MW ESP*	*ESPh: 240*	*60-75%*	*5*	*Short-term results: Slide 23 of Nelson (2005)*
Duke Buck	*140 (70)*	*ESPh: 240*	*64%*	*7*	*E. Bit Low S coal: Nelson (2005) Slide 25*

Of course, units equipped with hot-side ESPs can be retrofit with a fabric filter to provide a TOXECON process environment, as will be described in a subsequent section.

A.3-3. Fly Ash Revenue Loss

One additional element of the calculation is to account for the potential loss of fly ash sale due to higher carbon content. It is assumed that 40% of the ash generated is presently sold, and all of this will not be marketable, and further a combined charge of $25/ton will be assessed for additional disposal and loss of ash revenue.

SECTION A-4

ACI/FABRIC FILTER

Either conventional or halogenated activated carbon can be injected into a fabric filter, arranged either to augment PM removal in a COHPAC application, or as the sole particulate control device.

A.4.1. COHPAC: Conventional Activated Carbon

The assumptions defining Hg removal by conventional ACI on fabric filters for particulate control has been explored in most depth on Alabama Power's Gaston station, which is the sole reference for performance used in this study.

The ACI/FF demonstration at Gaston is the most advanced commercial application of ACI. A Phase II long-term test program has been completed, with up to four months of continuous data. These results showed that the long-term average of Hg removal was 86%, at an ACI rate of 1.5 lbs/MBtu. Special diagnostic tests at the end of the program suggested that greater than 90% Hg removal was possible, at a lower air/cloth ratio. However, these results were obtained from test periods that averaged several hours each. Given the variation in coal composition and uncertainties in process measurements, we adopted the 86% level demonstrated at Gaston.

Table A.4-1. Hg Performance Achieved by ACI/FF

Capital Cost ($/kW)	Unit Capacity (Reference unit)	FF Design, per air/cloth ratio	Hg Removal	ACI Rate (lbs/MACF)	Comment
Note 3	all	all	86	1.5	Based on Phase II, long-term testing from Gaston
	Gaston, 170 MW		80-90	1.5	Gaston is considered the most significant reference point.

Note 3. FF capital cost scaled from data available from the Presque Isle 3x90 MW DOE Demonstration

High Hg removal was not assumed as Gaston tests noted load limits were imposed by flue gas pressure drop at the design air/cloth ratio. However, lower flue gas flow rate to decrease air/cloth ratio allowed 90% Hg removal. These were short tem tests and although encouraging provide inadequate basis for certifying 90% Hg removal long-term.

It should be noted that Hg removal measured in a fabric filter following a dry FGD process is not considered representative of application for solely particulate removal. The most significant difference is the temperature of FF operation, and (depending on where the AC is injected) the dispersal of AC within the flue gas. AC injected prior to the dry scrubber vessel will derive the benefit of the high energy mixing and dispersal environment of the dry scrubber vessel, in which 4-6 second residence time is provided for contacting. The injection of ACI into a FF – either following a hot-side or cold-side ESP – will not offer the same degree of contacting, and thus process conditions may not be comparable.

Capital costs for retrofit of a fabric filter to an ESP are based on the recent design study conducted for the WE Energies TOXECON retrofit to Presque Isle Power Station (Johnson, 2005). The design study conducted to support this project shows the capital cost for three 90 MW units will be $34 M, equivalent to $120/kW. The capital cost can be scaled with a 0.333 power-law, with values "capped" by those for units beyond 600 MW. Further details of the fabric filter or COHPAC capital cost is presented in the companion document for CAIR compliance.

Regarding solid byproduct management, the COHPAC application collects injected activated carbon after fly ash has been removed, so only the Hg-laden carbon must be disposed of. This material is assumed to require lined landfill and to incur a disposal cost of $1,200/ton.

A.4.2. COHPAC: Halogenated Activated Carbon

As of February 2006, there is no data describing Hg removal from halogenated AC within a FF operated solely for particulate removal (and thus not following a dry FGD). However, it is anticipated that based on Gaston results, up to 1.5 lbs/MACF can be injected into a COHPAC-type environment without incurring significant operating problems. For the purpose of this analysis, this level of carbon injection is assumed adequate to deliver 90% Hg removal.

Significantly, the 3x90 MW demonstration of FF following an ESP (Toxecon) funded by DOE is intended to demonstration that "at least 90% Hg removal" is available.

Table A.4-2. Halogenated AC with FF

Capital Cost ($/kW)	Capacity (Reference unit)	FF Design, per air/cloth ratio	Hg Removal	ACI Rate	Comment
Note 3	all	all	90	1.0	Based on Phase II, long-term testing from Gaston, with reduced ACI rate to reflect HAC reactivity.
	Presque Isle		TBD per DOE demo	TBD	Presque Isle will be considered the most significant reference point.

1. Curve from Slide 28 of Durham, 2005

It should be noted that data from several SDA/FF-equipped units shows HACI derives greater than 90% Hg removal. However, these process conditions reflect (a) lower FF temperature, due to humidification by the SDA vessel, and (b) a high degree of dispersion of reagent.

The lack of commercial confidence by equipment and process suppliers is evidenced by the fact that DOE has directed $24 M into the Presque Isle Toxecon II Demonstration project, for the explicit objective to “demonstrate at least 90% Hg reduction” (Michaud, 2005). The complete commercial availability of HACI within a FF at 90% Hg would not require DOE cofunding for risk mitigation, testing, and evaluation of process impacts.

A.4.3. Fabric Filter as Sole PM Removal

Some units are equipped with a fabric filter in lieu of the ESP as the sole source of PM removal. Either conventional or halogenated activated carbon can be injected for Hg removal.

As there is no experience directly addressing this application, Hg removal data from the Gaston COHPAC demonstration is assumed valid. Accordingly, for conventional ACI, 86% Hg removal is assumed achievable at 1.5 lbs/MACF, and for halogenated ACI 90% Hg is assumed achievable at 1.0 lbs/MACF.

The significant difference in calculating the incurred cost is that unlike for COHPAC, where fly ash is captured separately and not contaminated by carbon, the fly ash collected with this application is contaminated by carbon. Thus, solid byproduct managements cost are identical to that incurred for ACI within an ESP, as described in Section A.3.3.

SECTION A-5

CARBON INJECTION: SPRAY DRYER ABSORBER (SDA)/FF

This section addresses the injection of both conventional and halogenated AC into a SDA/FF, designed for combined SO2 and particulate removal, for Hg removal. Conventional and halogenated AC are treated separately

A.5.1. Conventional AC/I w SDA/FF

The use of conventional AC into a SDA/FF can derive Hg removal, well above the baseline inherent Hg removal levels.

Table A.5-1. Hg Removal in Spray Dryer Absorber/PM, with Conventional ACI

Capital Cost ($/kW)	Capacity (Reference unit)	PM Collector, Design	Hg Removal (%)	ACI Rate	Comment
Note 1	**all**	**FF**	**75%**	**5**	Lower level selected to account for variability
Reference:	*Sunflower/ Holcomb*		*80*	*3*	*PRB: Sjostrom, (2005a) Slide #21*
	Great River Energy/ Stanton U10		*75*	*7*	*Stanton U10 (Sjostrom, 2005a, Slide 21*
Note 1	**all**	**ESP**	**45**	**6**	
Reference:	*Basin Electric/ Laramie River*	*599 SCA*	*45*	*6*	*Laramie River (Sjostrom (2005a) Slide #23*

1. Curve from Slide 28 of Durham, 2005

The results of a recent full-scale trial at Sunflower Electric's Holcomb Station (Sjostrom, 2005a) suggest the use of both conventional activated carbon, in this case Norit DARCO Hg when injected preceding the dry scrubber, can effect significant Hg removal. Short-term tests (2-3 hours) showed Hg removal higher than 90% was achievable at 6 lbs/MACF (See Slide 21 of Sjostrom, 2005a). Previously, Sjostrom (2003) reported that ACI with the dry FGD at Great River Electric's Stanton unit produced Hg removal of 65%, at an ACI of 5 lbs/MACF. None of these units are commercially operating, thus an average is used to assign Hg removal and ACI rate. Specifically, we propose to specify 70 % Hg removal from a dry FGD process on either lignite or subbituminous coal is attainable, with an ACI rate of 6 lbs/MACF. This assumption provides for some degree of additional Hg control beyond the inherent calculated level, but recognizes the unproven nature of the data.

A.5.2. Halogenated ACI with SDA/FF

The use of halogenated sorbent has been explored on these and similar units. As reported by Sjostrom (2005a, 2005b) both Darco Hg and B-Pac specially-treated, halogenated sorbents were evaluated in a spray dryer absorber following by a fabric filter or ESP. Results from short-term tests showed 90% Hg removal at 1.5 lbs/MACF, and for B-Pac exceeding 90% at 2 lbs/MACF. More significantly, 30 days tests at Holcomb (Sjostrom, 2005a (Slide 21) and Sjostrom, 2005b (Slide 23) reported greater than 90% Hg removal at 1.3 lbs/MBtu.

Table A.5-2. Hg Removal in SDA/PM, with Halogenated Sorbents

Capital Cost ($/kW)	Host Unit/Test Capacity (MW)	PM Collect or, Design	Sorbent	Hg Removal	ACI Rate	Comment
Note 1	**all**	**FF**	**HACI**	**90%**	**1.5**	Per commercial-scale tests
Reference:	*Sunflower/ Holcomb:*		*Darco Hg*	*90*	*1.5*	*Holcomb (Sjostrom, 2005a) (NETL, Slide 21)*
	Great River Energy/ Stanton U10		*Darco Hg*	*90*	*1.5*	*Stanton U10 (Sjostrom, 2005a, Slide 21*
			B-Pac	*90*	*1.5*	*Stanton U10 (Sjostrom, 2005a, Slide 21*
Note 1	**all**	**ESP**	**HACI**	**90%**	**6.5**	
	Basin Electric/ Laramie River (540/140)	*ESP, 599 SCA*	*Darco Hg*	*94*	*6.5*	*Laramie River (Sjostrom, 2005a) Slide 26*

1. Curve from Slide 28 of Durham, 2005

Unlike the case for ACI into an ESP or FF, there is no solid waste impact of using either conventional or halogenated AC.

A.5.3. Retrofit Application of SDA/FF

The application of a SDA/FF to an existing until will entail retrofit following an existing ESP. In order to preserve fly ash markets, it is likely the existing ESP will not be de-energized, and operation retained. This unit will be expected to continue to deliver the inherent Hg removal as projected by the EMFs in Section A-1. Accordingly, the SDA/FF Hg removal cited in this section will provide the stated Hg removal in addition to inherent values calculated for the ESP.

SECTION A-6

SCR AND FGD HG REMOVAL

The presence of FGD will remove almost all Hg oxidized into the oxidized state, and SCR can increase the oxidation thus improving the net removal. The assumptions describing the Hg removal are summarized in this section.

A.6.1. The Role of FGD

Conventional wet FGD is assumed to remove 90% of the oxidized Hg entering the process, based on results from field tests with highly oxidized FGD slurry (EPA, 2005) This magnitude accounts for the small amount of Hg re-emission.

Evaluation of compliance strategies will calculate the speciation of Hg into Hg++, and assume 90% is removed in a conventional wet FGD limestone, forced oxidation system. The use of an FGD other than forced oxidation limestone based, such as a lime or magnesium lime system, will be assigned a 70% Hg removal.

A.6.2. The Role of SCR

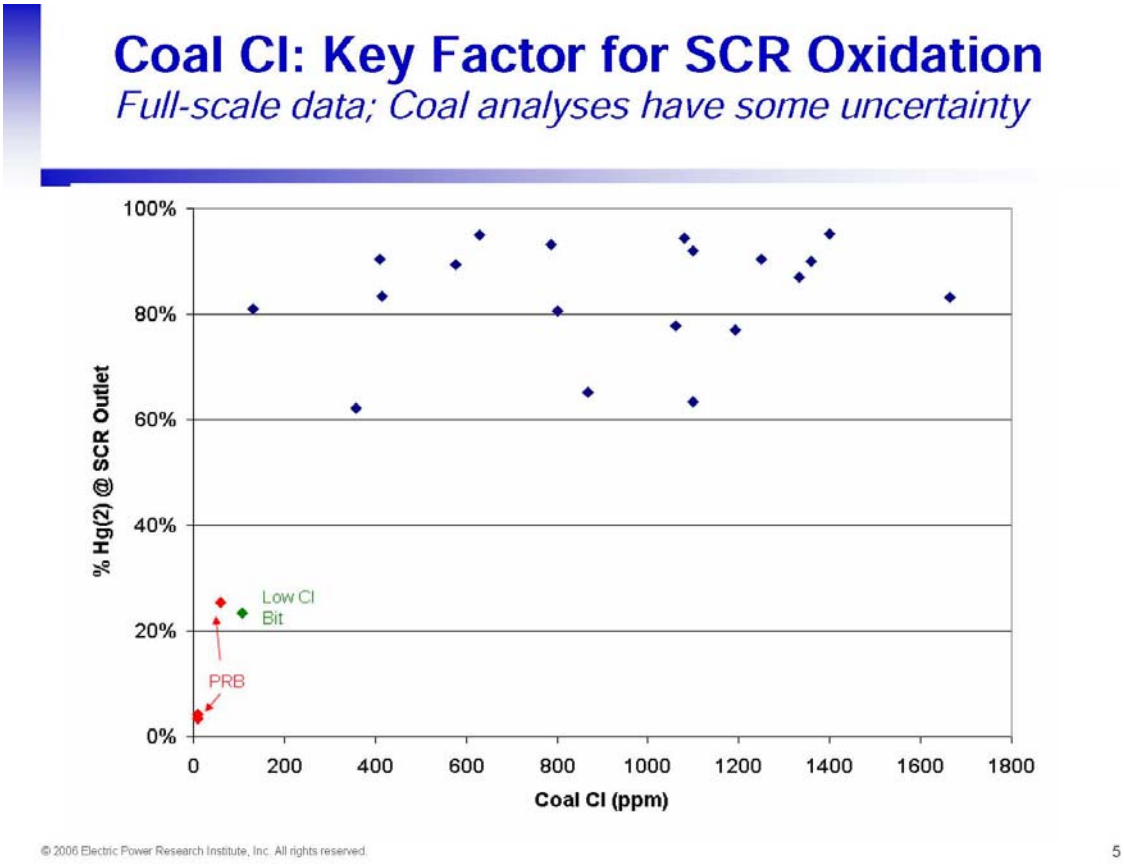
SCR NOx control is observed to increase the level of oxidation of Hg; the recent data of Chu (2006) and shown in Figure A.6-1 summarizes a relationship between the average increase in Hg oxidation for various SCR installations as a function of coal chloride content.

The approach for calculating the Hg removed by SCR, for the case of either an ESP or fabric filter used for PM control, and followed by wet FGD is described as follows:

Estimate Hg Oxidation Due to SCR. If SCR is present, the Hg oxidation rate will be increased to the value determined by a curve fit of the relationship between Hg oxidation and coal chloride content, per Chu (2006).

Oxidized Hg Removed. It will be assumed ninety percent of the Hg in the oxidized state is removed by the FGD process. If SCR is not employed, the oxidized Hg will be determined from the ICR correlations as published by EPRI (2000).

Figure A.6-1. Relationship Between Hg Oxidation and Coal Chloride Content (Chu, 2006)



Coal Cl: Key Factor for SCR Oxidation

Full-scale data; Coal analyses have some uncertainty

SECTION A-7

FLUID BED UNITS: ACI/FABRIC FILTER (COHPAC/TOXECON)

An aggressive mercury control option could be applied to FBC units to meet extreme mercury caps. This control option allows for an effective removal between 70 and 87 percent for FBC units using a retrofit FF/ACI. Capital costs are assigned to be $175 kW for these relatively small units (<100 MW), as derived from the $125/kW capital estimate from the Presque Isle 270 MW demonstration. The activated carbon injection rate is 2 lbs/MACF. Disposal cost of the reagent is the same as COHPAC on steam units at $1,200/ton. Fixed O&M costs are also the same at 1% of total capital.

APPENDIX A REFERENCES

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Sorbent Technologies, 2006	Update on Sorbent-Based Mercury Control in Hot-Side Environments", downloaded from Sorbent Technologies website, January, 2006.

APPENDIX B

ASSUMPTIONS DEFINING THE PERFORMANCE AND COST OF SO2, NOx, AND PARTICULATE MATTER FOR CAIR COMPLIANCE

SECTION B-1
INTRODUCTION

BACKGROUND

Appendix B presents details regarding the assumptions defining the feasibility and cost of control technology for SO2, NOx, and particulate matter that are used to calculate Hg control costs, through providing “co-benefits”.

It is well known that many choices exist from which to select flue gas desulphurization and NOx control technology. However, for the purpose of this analysis, the two key flue gas desulfurization options – wet conventional limestone-based and lime-base dry FGD – were evaluated. Also, SCR NOx control was assigned for selected units based on a CAIR decision-making simulation.

Hg control assumptions are addressed in Appendix A; however the cost of particulate matter control equipment or upgrades that may be required for Hg processes is addressed in this section. Two particulate matter control options are considered – one an upgrade of the existing ESP, and the second a stand-alone pulse-jet fabric filter. For an existing ESP, it is assumed a minimum SCA of 250 ft^2/1000 ACFM is required to sustain activated carbon injection without operating problems, thus one additional collecting field is added for small units to meet this criteria. Also, a fabric filter can be retrofit following an ESP - the concept referred to by EPRI as COHPAC. Finally, a fabric filter can be installed in place of an ESP.

DATA SOURCES

The source of cost information depends on the control technology. The cost analysis includes capital, fixed operating and maintenance (O&M), and variable O&M costs for various control technologies.

For FGD and fabric filters, a mix of both (a) actual costs incurred and reported for completed projects, and (b) detailed estimates by major architectural/engineering (A/E) firms have been used. For SCR, the cost basis is actual costs incurred for completed projects, based on a survey of costs reported in 2004. The results of this survey were corroborated in a more recent survey, and thus are considered valid.

The cost evaluation employs those values determined for individual units, adjusted as necessary into a 2006 dollar basis. Units for which specific cost estimates have not been developed are assigned costs from a generic relationship of capital versus generating capacity, based on cost data submitted by participating Owners. Cost data from other sources is used, but only when credible and referenced.

SCOPE OF ANALYSIS

The scope of the cost estimates include (a) process equipment, (b) installation and construction, (c) allowance for funds used during construction, (d) engineering charges, (e) owners costs and incurred charges, and (f) 10-15% project contingency. Some cost estimates also include a nominal charge for the engineering/procure/construct (EPC) contractor. This fee, usually 8%, is incurred by the EPC contractor to provide turnkey final design, installation, and startup. It is reported that Owners electing to not utilize an EPC approach and instead employ an A/E firm to supervise procurement will avoid the EPC fee but incur A/E fees approximately the same. Given the range of engineering charges used – 10 to 15% - the EPC fee although not small will not affect the outcome.

COST BASIS

The costs reported are expressed on a 1Q2006 dollar basis. Operating costs are also reported on this basis and not levelized over the projected 20 or 30 year period to account for escalation, and other factors.

SECTION B-2

FLUE GAS DESULFURIZATION CONTROL TECHNOLOGY

Both conventional wet limestone and dry lime-based FGD are considered.

B.2.1Wet FGD

The reference wet, limestone-based FGD process is based on the conceptual design as described by an analysis conducted for the National Lime Association by Sargent & Lundy Engineers (Sargent & Lundy, 2003). Wet FGD technology will be assigned to units according to unit size, number of units at a station, and coal type. Stations with multiple, smaller units will utilize one absorber vessel for several units. The following rules will be applied:

- Units of 100 MW capacity or less will not receive any FGD
- Units from 100-300 MW will consolidate flue gas flow into one absorber; however, the common absorber should not exceed a flue gas treatment capacity greater than 500 MW.

The SO_2 removal efficiency was assumed to depend on the coal sulfur content. Table A-1 presents the SO2 removal capability assumed for both PRB and a medium-high sulfur coal. The lower SO2 limit for PRB is consistent with basic FGD design, and as well as experience with at least one FGD-equipped unit firing predominantly PRB (ref). Table B-1 also reports the energy penalty due to wet FGD, in terms of (a) auxiliary power consumption, and the power generated that cannot be sold into the market, and (b) the maximum capacity penalty, or the fraction of maximum generating capacity lost.

The main source of cost information for conventional limestone-based FGD is an analysis prepared for a number of utilities in Illinois and Pennsylvania, as well as reported, incurred costs. The capital cost estimates are shown in Figure B-1.

Regarding operating costs, Fixed O&M are presented in Figure B-2, and are based on detailed engineering analysis of various units. Variable O&M costs were selected from Table B-2, also based on engineering studies.

Table B-1 - Wet FGD Design and Operating Variables

Coal Type	SO2 Removal: Baseline Design	Capacity Penalty (% of capacity)	Energy Penalty (% of capacity)
PRB	93	2.0	1.5
Medium Sulfur	98	2.0	1.5
High Sulfur	98	2.0	1.5

Figure B-1 – Conventional Wet FGD Capital Cost Estimates

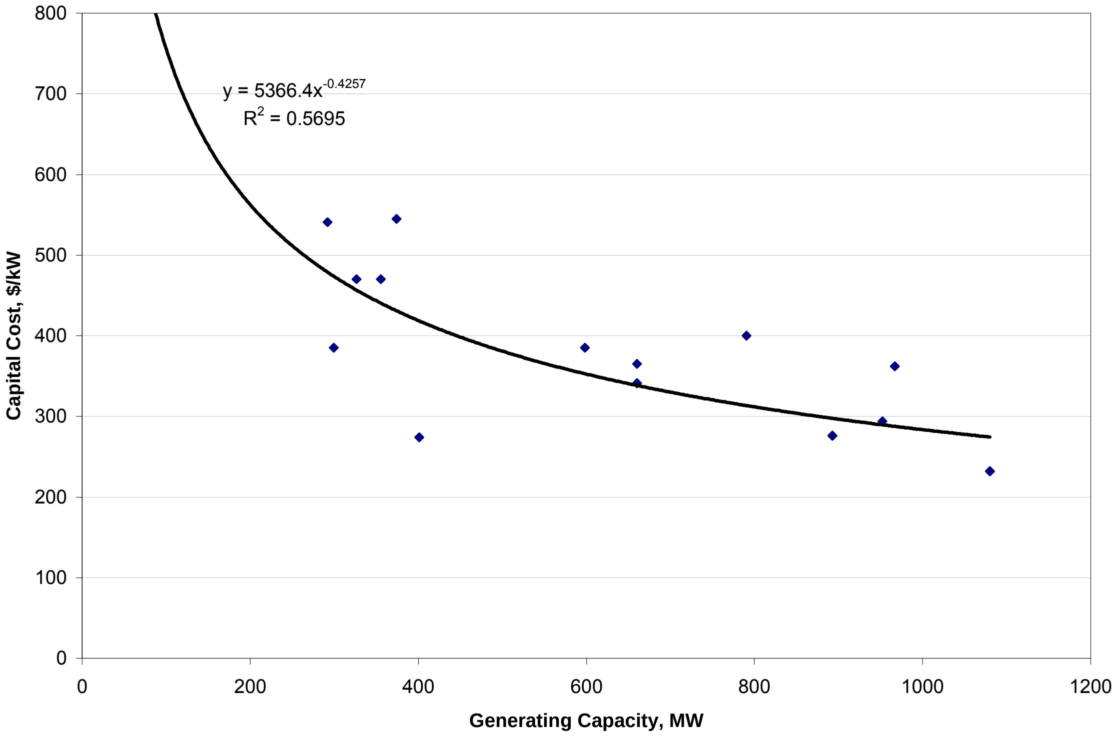
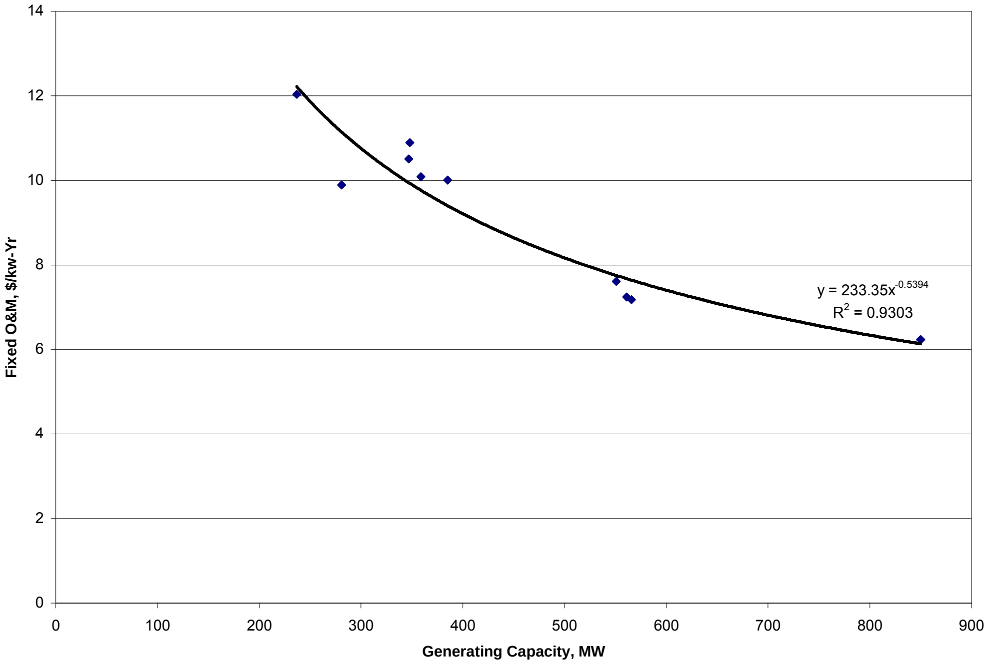


Figure B-2 – Fixed O&M Costs: Conventional Wet and Dry FGD



The variable O&M is summarized as follows:

Table B-2. Summary of Conventional Wet FGD Variable Operating Costs

Coal Sulfur Designation	SO2, lbs/MBtu	Cost Basis (mills/kWh)
High Sulfur	5.5. lbs/MBtu	3.2
Medium/High	4.5-5.5 lbs/MBtu	2.7
Medium	2.25-<4.5	2.2
Low	<2.25	1.5

B.2.2. Dry FGD

The reference dry, lime-based FGD is based on the conceptual design as described by an analysis conducted for the National Lime Association by Sargent & Lundy Engineers (2002).

Capital costs for dry FGD equipment including a fabric filter for particulate matter removal were presented in Figure B-3. Notably, in all cases dry FGD with a fabric filter requires less capital cost than wet FGD.

Fixed O&M costs depicted in Figure B-4 are also notably less than for wet FGD, mostly due to lower manpower requirement for less complex equipment.

Figure B-3. Dry FGD Capital Cost

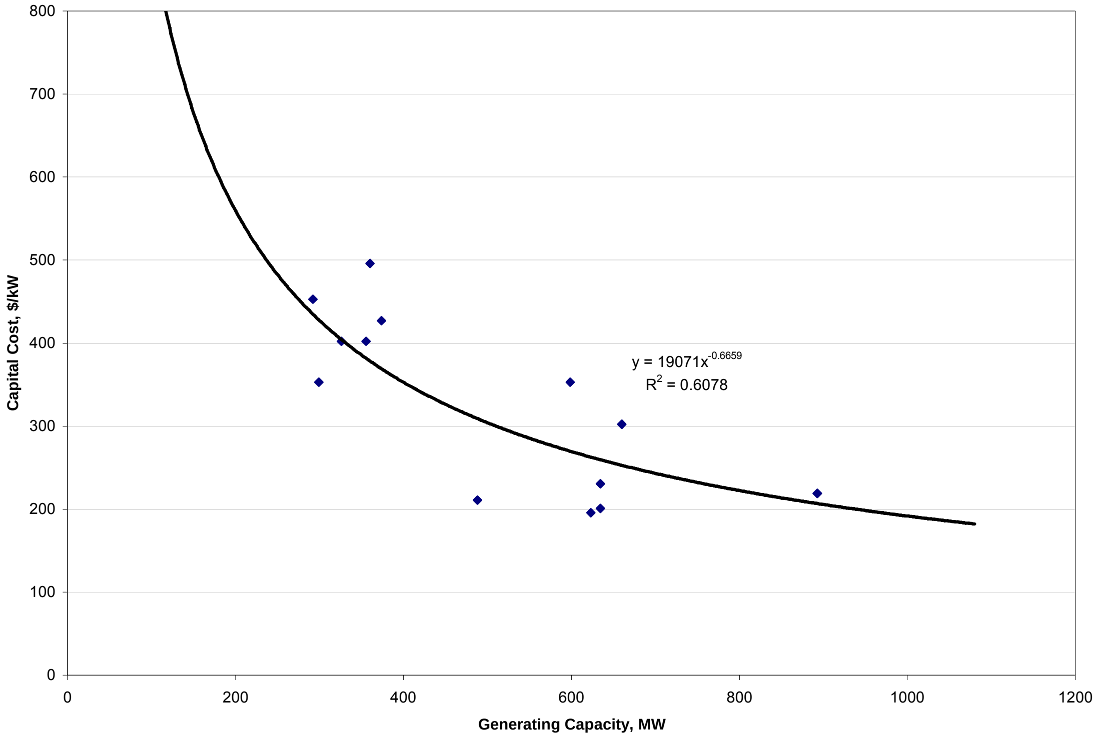
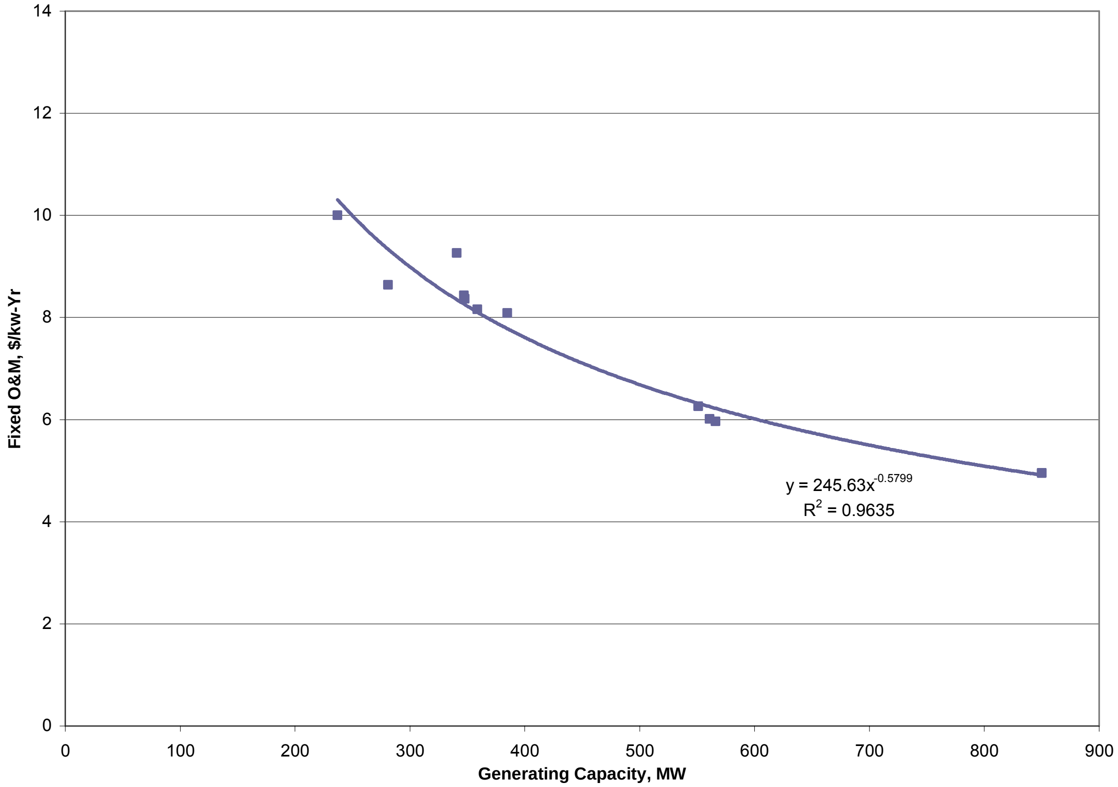


Figure B-4. Dry FGD Fixed Operating Costs



Variable operating costs for dry FGD processes have been projected for PRB coal – the prime fuel to which dry FGD equipment is considered. Variable operating costs are anticipated to be approximately 1.05 mills/kWh. This cost includes reagent, auxiliary power cost for FGD equipment, for the fabric filter module both replacement filter media and auxiliary power.

SECTION B-3

NITROGEN OXIDES (NOx) CONTROL TECHNOLOGY

SCR capital and operating cost are presented in Tables B-3 and Figure B-5. Table B-3 presents fixed and variable operating cost, as a function of boiler type, and initial NOx rate. Figure B-5 presents the derived relationship between SCR capital cost and generating capacity. Basic process design factors such as boiler NOx rate entering the SCR process and the design NOx removal efficiency are well-known to influence the catalyst volume and replacement rate. However, the cost impact of these factors can be superceded by site – specific factors that affect the amount of labor required for retrofit; according only generating capacity is used to express capital cost in this relationship.

Figure B-5 was derived based on a survey of actual SCR costs incurred by domestic U.S. power producers (Cichanowicz, 2004). As Figure B-5 represents actually incurred costs, and has been corroborated by a second, more recent survey (Marano, 2006), these values are used in the economic evaluation of SCR on units for which a site-specific estimate does not exists.

The SCR long-term continuous NOx removal efficiency was assumed to be 90 percent; however, NOx emission rate floors were established based upon coal rank. These floors, which determine the minimum SCR outlet controlled level, are shown in Table B-4. For example, these floors are 0.06 lbs/MBtu for low (<1.2%) sulfur sub-bituminous coal, and 0.045 lbs/MBtu for PRB. It is important to note these NOx targets are for annual averaging periods; shorter averaging periods will likely be characterized by higher SO2 emission rates. For example, a 30 day NOx emissions average for high sulfur bituminous coal could be 0.08 lbs/MBtu.

Figure B-5. SCR Capital Cost

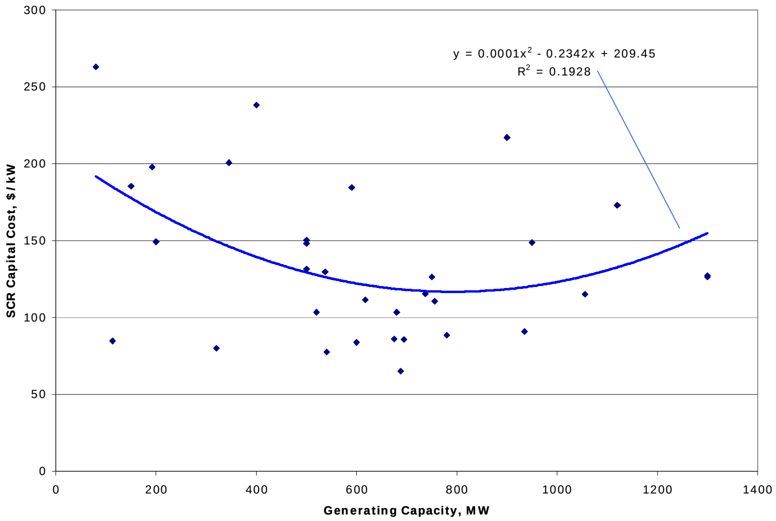


Table B-3. SCR Fixed, Variable Operating Costs

Capacity (MW)	**Burner Firing Type** t-tangential; f- front-fired; o - opposed fired	**Initial Boiler NOx** (lbs/MBtu)	**SCR O&M** ($/MWh)	**SCR Fixed O&M** (% of Capital /yr)
>500	t-f-o	0.20-0.30	0.52	0.75
	t-f-o	0.31-0.40	0.62	
	t-f-o	0.40-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.97	
	"	>0.65	1.02	
	cyclone/wet-bottom	<0.86	1.15	
	"	>0.86	1.2	
400-500	t-f-o	0.20-0.30	0.52	0.75
	t-f-o	0.31-0.40	0.62	
	t-f-o	0.40-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.97	
	"	>0.65	1.02	
	cyclone/wet-bottom	<0.86	1.15	
		>0.86	1.2	
300-400	t-f-o	0.20-0.30	0.52	0.75
	t-f-o	0.31-0.40	0.62	
	t-f-o	0.40-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.97	
	"	>0.65	1.02	
	cyclone/wet-bottom	<0.86	1.15	
	"	>0.86	1.2	
200-300	t-f-o	0.30-0.40	0.62	0.75
	t-f-o	0.41-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.62	
	"	>0.65	0.75	
	cyclone/wet-bottom	<0.86	1.15	
	"	>0.86	1.2	
126-200	t-f-o	<0.40	0.62	0.65
	t-f-o	0.40-0.50	0.75	
	t-f-o	>0.50	0.85	
	cell	<0.65	0.62	
	"	>0.65	0.75	
	cyclone/wet-bottom	<0.86	1.15	
	"	>0.86	1.2	
75-125	t-f-o	<0.40	0.7	0.5
	t-f-o	0.40-0.50	0.8	
100	t-f-o	>0.50	0.9	
	cell	all	1.2	
	cyclone/wet-bottom	all	1.2	

Table B-4. Minimum SCR-Equipped NOx Outlet Emissions Per Coal type

Coal Source	Minimum NOx Outlet Rate (lbs/MBtu)
PRB	0.045
<1.2%	0.05
1.2-2.5%	0.06
>2.5%	0.07

SECTION B-4

PARTICULATE MATTER CONTROL TECHNOLOGY

B.4.1. Fabric Filter: COHPAC–Type Application

Control technology equipment for particulate matter is relevant in the context of Hg control. Assumptions defining the capital and operating cost of equipment that may be necessary for retrofit to support Hg controls are discussed in this section.

Figure B-6 presents the capital cost of a fabric filter for particulate matter control as a function of generating capacity. These data describe the installed cost for units including additional ductwork, flue gas fans, and other ancillary operating equipment. These capital cost estimates, derived from units both designed as stand-alone particulate matter collectors and as second particulate collectors for dry FGD, reflect a range of air/cloth ratio of between 4/1 and 6/1. Figure B-7 presents the fixed O&M costs for the fabric filter particulate matter collectors as a function of generating capacity.

Figure B-6. Fabric Filter Capital Cost As a Function of Generating Capacity

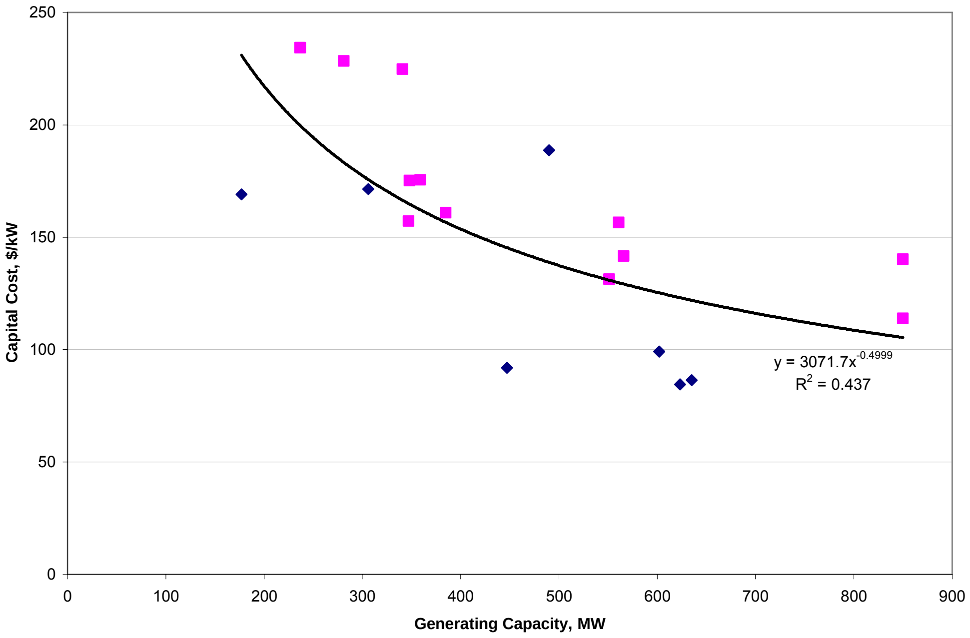
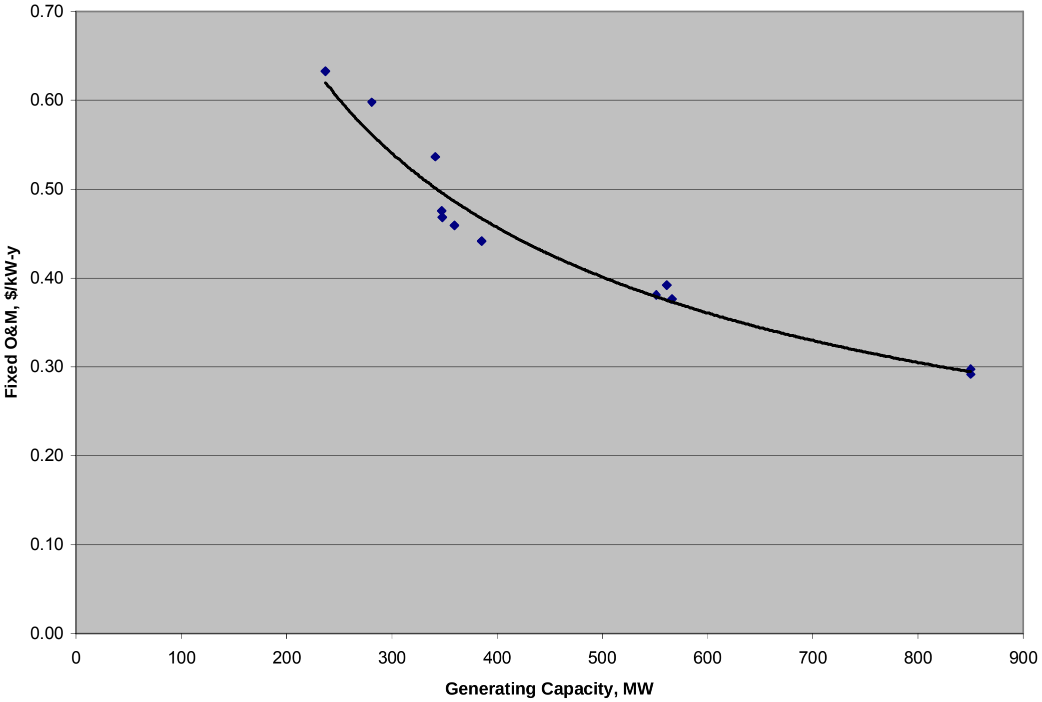


Figure B-7. Fixed Operating & Maintenance Costs for Fabric Filter Particulate Collectors



Variable operating costs for the fabric filter for PM control alone is presumed to solely consist of auxiliary power consumption, due to an assumed 6 in w.g. H2O pressure drop. The auxiliary power required by the fan will be calculated using the following relationship:

Power = 0.000181 * Q * deltaP * Time

Where:

- Power is the required power consumption, in kWh/y
- Q is the system flowrate processed, in terms of actual cubic feet per minute,
- deltaP is the pressure drop incurred across the filter, in terms of inches H2O
- Time is the operating time in hours per year

The resulting power tem will be multiplied by the assumed cost value of auxiliary power, presumed to be $30/MWh.

B.4.2. Electrostatic Precipitator (ESP)

Units considering activated carbon injection will be assumed to require an increase in specific collecting area, SCA, if the value reported is less than 250 ft^2/KAFM.

This capital cost is defined by the analysis of Boward (1997), escalated to a 2006 dollar basis and including adjustments as defined by utility-specific studies for these modifications. Accordingly, the capital cost for this ESP upgrade will be $35/kW for a 250 MW unit. The upgrade of a unit to 250

SCA will be required to derive the cited Hg removal. The capital cost of \$35/kW, as determined for a 250 MW unit, will be generalized to other generating capacities by a power-law relationship, using a 0.35-power scaling factor, described as follows;

$$\text{ESP Upgrade Cost (@ Capacity)} = 35 *(250/\text{Capacity})^{-0.35}$$

SECTION B-5

ACTIVATED CARBON INJECTION HARDWARE

The capital cost for activated carbon injection was determined by a number of studies conducted for Illinois utilities, by Sargent & Lundy. Figure B-8 and B-9 present the capital and fixed operating cost, as a function of generating capacity.

Figure B-8. Activated Carbon Injection Capital Cost As a Function of Generating Capacity

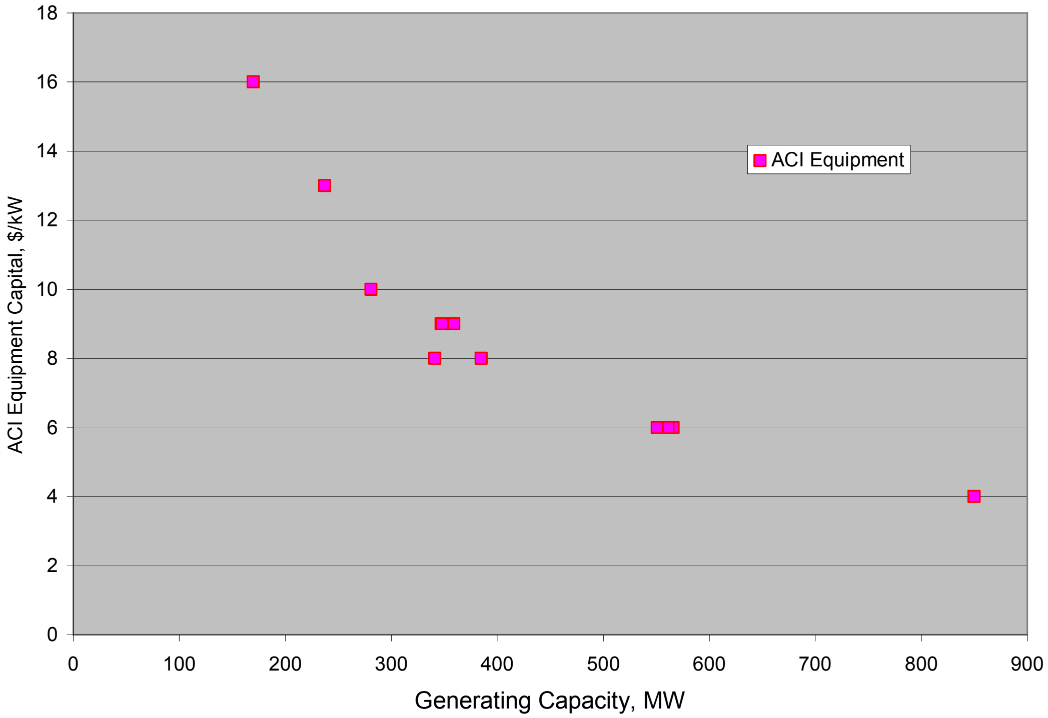
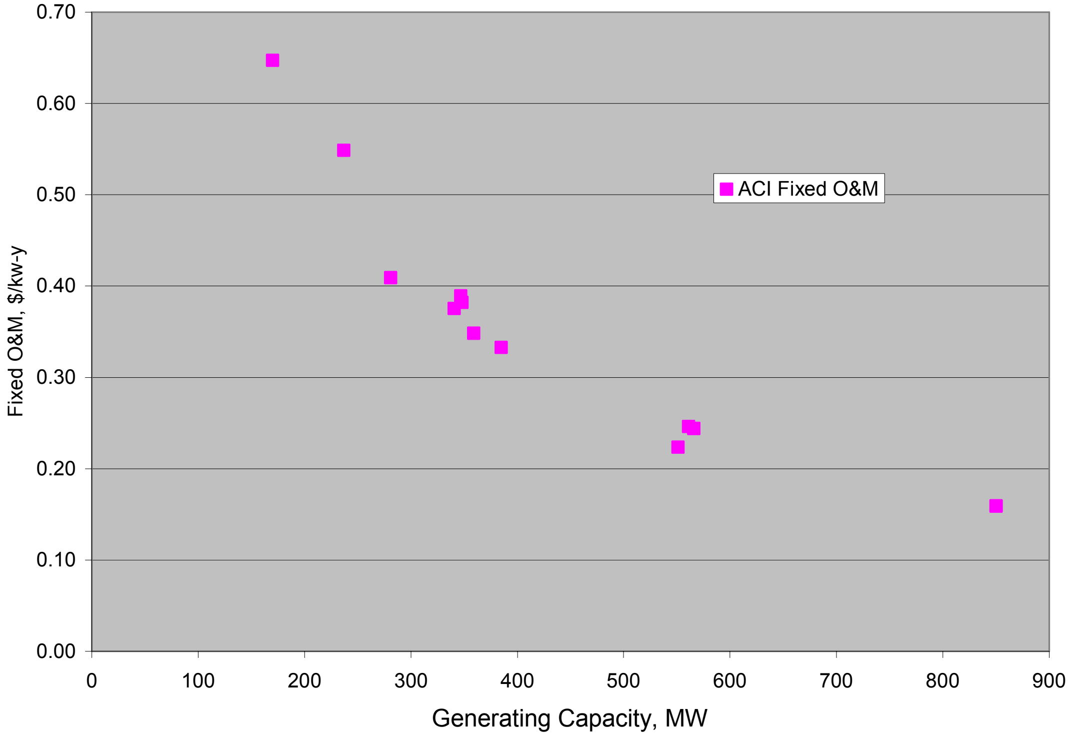


Figure B-9. Activated Carbon Injection Fixed Operating & Maintenance Costs



SECTION B-6

ACI/FABRIC FILTER (COHPAC/TOXECON) for FLUIDIZIED BED UNITS

Deploying ACI with a fabric filter is an option for fluidized bed combustion (FBC) units to meet extremely low mercury caps. This control option allows for a 70% effective removal for FBC units using a retrofit FF/ACI. Capital costs are assigned at $175 KW. The activated carbon injection rate is 2 lbs/MACF. Disposal cost of the reagent is the same as COHPAC on steam units at $1,200/ton. Fixed O&M costs are also the same at 1% of total capital.

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ELECTRONIC FILING, RECEIVED, CLERK'S OFFICE JULY 28, 2006

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
PROPOSED NEW 35 ILL.ADM.CODE PART 225	)	**PCB R06-25**
CONTROL OF EMISSIONS FROM	)	
LARGE COMBUSTION SOURCES	)	

TESTIMONY OF MR. WILLIAM DEPRIEST

I. INTRODUCTION

Sargent & Lundy, L.L.C. (S&L) has been retained to provide testimony regarding the technical aspects, capital costs, and implementation schedules required to engineer, fabricate, install, and bring into service mercury control processes at the Illinois coal-fired generating units. S&L is a Chicago-based architect-engineering firm that has provided engineering services exclusively to the power industry for 115 years. S&L has provided engineering services to nearly all of the Illinois coal-fired generating units.

Mr. William DePriest is a Senior Vice President at S&L, and Director of S&L's Environmental Services program. In this capacity, Mr. DePriest is responsible for ensuring that all fossil-related projects are fully supported with the appropriate environmental related expertise for successful execution of the project. He is also responsible for maintaining S&L's expertise in environmental technologies for fossil-fired power facilities. He has over 30 years of experience in the application of emission control technology in the utility industry, focused on control of emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate, and air toxins including mercury. He has directed the application of both combustion-based and post-combustion-based environmental control technologies on a wide variety of coal-fired and gas-fired utility plants representing over 50,000 MW of capacity. Mr. DePriest's resume is attached to this testimony as Attachment A.

The S&L air quality control group, under Mr. DePriest's direction, has assisted, in varying capacities, over 75 power generating companies with environmental compliance planning and environmental technology application over the past 20 years. Recently, this work has included compliance planning studies to meet the federal Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) for many of the Illinois coal-fired units. These compliance planning studies typically include conceptual designs, cost estimates, and schedules for a variety of environmental control (SO_2, NOx, mercury, particulate) technology retrofits at each unit.

In addition to these compliance planning activities, S&L is currently providing engineering services for the implementation of over 60 air quality control projects across the country, and has been continuously involved in the design and project management of clean air projects for fossil fired utilities since the 1970s. This experience has provided S&L with a robust database of current information regarding realistic costs, schedules, and retrofit issues related to environmental compliance projects, obtained from direct involvement in these projects.

This testimony is organized in the following fashion to address the issues noted below:

II. The design decision impacts of the proposed Illinois mercury rule on the synergies inherent in the federal CAIR and CAMR regulations;

III. Retrofit difficulties that will affect the cost of mercury control on the Illinois coal-fired power plants;

IV. Current market factors that will affect the cost and schedule of compliance with the proposed Illinois mercury rule;

V. Expected project implementation schedules for measures required to comply with the proposed rule; and

VI. Installed cost projections for retrofits expected to be required to comply with the proposed rule.

II. DESIGN DECISION IMPACTS OF THE PROPOSED ILLINOIS MERCURY RULE ON THE SYNGERGIES INHERENT IN THE FEDERAL CAIR AND CAMR REGULATIONS

The Illinois mercury rule, as proposed, would require existing coal-fired electric generating units (EGUs) to reduce mercury (Hg) emissions by 90%, or achieve a controlled Hg emission rate of 0.0080 lb/GWh-gross electrical output by July 1, 2009. The rule includes provisions, effective through 2013, allowing owners/operators of an affected EGU to demonstrate compliance with the emission limits by averaging mercury emissions from other EGUs (generally units with a common owner), provided all individual sources achieve a minimum 75% mercury reduction or a controlled mercury emission rate of 0.020 lb/GWh-gross electrical output. Although the proposed rule includes averaging provisions, it is likely that due to the high level of reduction required by the proposed Illinois rule, most coal-fired power generating units in Illinois would be required to install unit-specific mercury control technologies by 2009 to meet the proposed emission limits.

In contrast, the Clean Air Mercury Rule (CAMR) creates a market-based cap-and-trade program that will reduce nationwide power plant mercury emissions in two distinct phases. CAMR caps mercury emissions from all coal-fired power plants at 38 tons in 2010, which represents a reduction of approximately 20% nationwide from the estimated existing power plant mercury emissions of 48 tons. The second phase cap, which takes effect in 2018, reduces nationwide mercury emissions from coal-fired power plants to 15 tpy – an overall reduction of approximately 70% from the current day estimated emission of 48 tons per year of mercury.

During the same timeframe, power plants will be working to comply with emission reduction requirements in the Clean Air Interstate Rule (CAIR). CAIR will permanently cap SO_2 and NOx emissions from fossil fuel-fired power plants in 28 eastern and midwestern states, including Illinois. CAIR caps SO_2 and NOx emissions in two phases. The first emission reductions are required in 2009 for NO_X and 2010 for SO_2. The second phase of emission reductions for both pollutants are required in 2015. When fully implemented, CAIR will reduce emissions from 2003 levels by approximately 60% for NO_X and 73% for SO_2.

EPA developed the phased CAIR/CAMR emission reduction requirements to simultaneously address mercury, SO_2, and NOx emissions from coal-fired power plants. EPA modeling showed that compliance with the CAIR emission reduction requirements would significantly reduce the mercury emissions from coal-fired power plants. In fact, the first phase CAMR mercury cap (38 tons) was established to take advantage of "co-benefit" reductions - that is, mercury reductions achieved by reducing SO_2 and NOx emissions under CAIR. Coal-fired power plants are currently developing emission reduction strategies to meet the CAIR/CAMR requirements, and, to the extent possible, take advantage of mercury reductions achieved as a co-benefit of emission control technologies installed to control SO_2 and NOx emissions.

The proposed Illinois mercury rule could jeopardize the intended synergies between CAIR and CAMR. Potential impacts to the compliance planning and technology implementation associated with eliminating the CAIR/CAMR synergies are discussed below:

1. **CAIR and CAMR emission reduction timelines were drafted to allow owners/operators of affected units to take advantage of mercury reductions achieved as a co-benefit of emission control technologies installed to meet the CAIR SO_2 and NOx requirements. Imposing stringent mercury-only control requirements by 2009 would eliminate the owners/operators' ability to evaluate, and potentially enhance, the mercury control benefits associated with flue gas desulfurization (FGD) and NOx control systems required under the CAIR program.**

   Illinois coal unit owners/operators are currently in the process of strategic planning and technology implementation for compliance with CAIR and CAMR. We expect that approximately 25-50% of the currently "unscrubbed" units will install either "wet" or "dry" FGD systems to achieve compliance with the SO_2 reductions mandated by CAIR. At the basis of this prediction is that the cost of an SO_2 allowance used in the CAIR program will rise to the marginal cost to reduce a ton of SO_2 emitted from the plants using FGD technology. This will result in the necessity to deploy FGD on plants burning low sulfur coals as the requirement to reduce SO_2 in the CAIR region falls to levels below that currently achieved with the low sulfur coals in the U. S. Some of these same units will install selective catalytic reduction (SCR) control systems, or begin operating their existing SCR systems year-round, to achieve compliance with the NOx reductions mandated by CAIR. Testing performed in the utility industry indicates that these control technologies (SCR and FGD), installed to achieve compliance with CAIR, will also reduce mercury emissions.

Specifically, testing has shown that FGD control systems will capture a large percentage of the oxidized forms of mercury in the flue gas. For example, units that elect to install a dry FGD system, which is generally the most economical SO_2 removal system for units that burn low-sulfur coals, will also install a fabric filter (or “baghouse”) downstream of the spray dryer absorber as part of the dry FGD process. This dry FGD/baghouse control system will effectively capture oxidized and particulate mercury in the flue gas stream. Similarly, units that install a wet FGD system to control SO_2 emissions will effectively capture oxidized mercury in the wet FGD absorber. To assist in this effort, the SCR system will oxidize a portion of the mercury in the flue gas, and in that way, facilitate its capture in the FGD system.

The current understanding of the mechanisms that enhance mercury oxidation in the combustion process should result in the FGD control system providing some level of mercury control. However, it is likely that enhanced mercury control will be needed to achieve overall control efficiencies in the range of 90%. At the present time the most commercially developed mercury control technology is activated carbon (various forms are available including plain activated carbon and halogenated activated carbon) injection into the flue gas and subsequent capture in a particulate control device.

One option for activated carbon injection is upstream of the existing electrostatic precipitator (ESP). This scenario should provide some mercury reduction, but it will be limited by the capability of the existing ESP to capture the activated carbon without exceeding the plant's particulate emission limit or opacity limit. The adsorption of mercury by activated carbon will also be limited in this ESP related configuration by the presence of sulfur trioxide (SO_3) in the flue gas. Many of the coal-fired plants in Illinois were originally designed to burn Illinois Basin coals. Combustion of these coals results in a portion of the sulfur in the coal being converted into SO_3 which, in turn, assisted in the capture of particulate matter in the ESP. However, due to both environmental and economic issues, many of these plants have been converted to low sulfur coals which has necessitated the injection of "artificial" SO_3 into the flue gas to maintain the performance of the ESP. Testing has shown that this SO_3 will inhibit the ability of the activated carbon to adsorb mercury. This inhibition will necessitate a higher activated carbon injection rate which will increase particulate emissions and possibly increase opacity.

In the dry FGD control scenario, activated carbon would be injected upstream of the FGD reaction vessel and the baghouse. Injection of the activated carbon prior to the FGD is necessary to take advantage of any halides (particularly chlorides) in the flue gas as they enhance the ability of the carbon to capture mercury. Most halides are effectively captured in an FGD system and, therefore, the AC injection needs to be prior to the FGD system. Mercury adsorbed onto the carbon would be captured in the baghouse and removed with the fly ash. In the wet FGD control scenario, an activated carbon injection system with an associated baghouse could be used to supplement the inherent mercury capture capabilities of the wet FGD absorber and would need to be located upstream of the wet FGD vessel. Mercury adsorbed on to the activated carbon would be removed from the flue gas stream in the baghouse prior to the wet FGD.

Although activated carbon injection is the most commercially developed mercury control system, pollution control companies are actively working on other techniques to enhance mercury capture in FGD control systems. For example, research is underway to evaluate existing SCR catalysts and develop new catalysts that oxidize elemental mercury in the flue gas stream. Oxidized forms of mercury are effectively captured in FGD control systems. Similarly, strategies to modify the flue gas composition are being studied to increase mercury capture in FGD control systems. Flue gas modification strategies include introducing halogens, primarily chlorine or bromine, into the combustion process to enhance mercury oxidation and facilitate its capture in the FGD control system.

The synergies created between CAIR and CAMR were designed to provide incremental mercury reduction as a co-benefit of NOx and SO_2 control, and allow the development of enhanced mercury control strategies. It is possible that advances in SCR catalysts, halogen additives, and FGD scrubber enhancements may make the ACI/baghouse systems unnecessary by 2018.

If the Illinois mercury rule mandates 90% mercury control prior to CAIR, units that would otherwise plan to achieve mercury removal using the co-benefits of the combined NOx control systems (SCR), SO_2 control systems (FGD), and particulate control systems required for CAIR would be forced to employ other means to achieve the 90% mercury reductions and not fully leverage their ongoing investment in the CAIR program.

- For units where a dry FGD/ fabric filter system is planned for CAIR compliance, the unit owners would likely need to install the fabric filter portion of the system in 2009 (for mercury control), with temporary ductwork in place that would later be demolished when the full dry FGD system is installed. The extra cost to install and then demolish this temporary ductwork will vary depending on the unit arrangement, but has been estimated by S&L to range from $2 to $6 million for the units we investigated. In addition to this cost, the owners of these units would incur additional financing costs associated with installation of the ductwork and fabric filter portion of the dry FGD/fabric filter project by up to six years earlier than is necessary for the CAIR/CAMR programs. Depending on the size and retrofit difficulty of the unit, the portion of the dry FGD/fabric filter installation that would be installed by up to six years earlier than necessary for CAIR/CAMR could range from $20 million to $120 million. The financing costs for this capital for up to 6 years could be a significant cost that would not be incurred if the project was implemented using the schedule of the CAIR/CAMR program. These costs reflect the possible need to install the full amount of ductwork, fan, and electrical upgrades, that would ultimately be required for the dry FGD system, at the time that the fabric filter is installed, plus additional "spacer" ductwork to save space for the future spray drier absorber.

- Installation of the dry FGD/fabric filter system in two phases instead of one will also result in additional costs for two unit outages instead of one. Typically, dry FGD/fabric filter retrofits are built in one step, with most construction occurring outside of the operating flue gas train, to allow most construction to proceed while the unit is operating and minimize tie-in outage time. By requiring the fabric filter to be operational before the dry FGD, a second outage will be required for the FGD installation.This will result in an additional cost to the owner due to loss of generating revenue during the second outage.

- For units that plan to install a wet FGD system in the future for CAIR compliance, a smaller “polishing” fabric filter could be needed in 2009 to meet the proposed Illinois mercury rule. This polishing fabric filter is considerably smaller than the fabric filter used in conjunction with a dry FGD system. The quantity of particulate matter collected after a dry FGD system is significantly greater than that associated with an activated carbon injection system and this results in the polishing fabric filter being approximately 50% smaller than a typical fabric filter. Because this baghouse will be installed upstream of the wet FGD absorber, added costs similar to those described above for temporary ductwork, additional outage time, and the cost of financing portions of the ultimate environmental project up to six years earlier are expected to be incurred for the wet FGD case.

2. **If the phased mercury control approach of CAMR is eliminated, most Illinois generating plants will not have the opportunity to assess the mercury removal performance of activated carbon injection alone before proceeding to a fabric filter, because they may feel the need to immediately implement fabric filter retrofit projects to minimize the risk of non-compliance.**

> The owners of the Illinois coal-fired units have reached the conclusion that they will not be able to meet the requirements of the proposed Illinois mercury rule with activated carbon injection alone at most units, based on lack of precipitator margin. In addition, suppliers of the activated carbon technology are currently not willing to guarantee 90% mercury removal with activated carbon injection alone. Furthermore, the schedule for compliance with the Illinois mercury rule cannot accommodate a test program for demonstrating activated carbon injection upstream of the existing ESPs that would allow for a thorough evaluation of the performance followed by installation of fabric filters where compliance cannot be achieved, all by July 1, 2009. Without the availability of an Hg emission trading system to provide a level of compliance security (i.e., the opportunity to purchase Hg allowances if the selected control system does not reach the 90% goal… a significant risk with injection into an existing ESP). , the owners of many units could be expected to immediately commit to fabric filter installation in order to minimize the risks of not achieving the 90% compliance requirement.

III. RETROFIT DIFFICULTIES THAT AFFECT THE COSTS OF MERCURY CONTROL ON THE ILLINOIS COAL-FIRED POWER PLANTS

The cost and schedule to retrofit an environmental control technology to an existing fossil station can vary greatly, depending on the design and configuration of the existing facilities. Some of the key factors that affect both cost and schedule are: the capabilities of the existing infrastructure to accommodate the requirements of the new environmental control equipment, the difficulty of fitting the new equipment into the appropriate location in the existing plant, the impact of new environmental control systems on plant operations, and the sequence in which the technologies are implemented if more than one technology is required. Most of the coal-fired units in the U.S., and in particular those in Illinois (because of the age of the facilities), would be considered to be in the moderate to difficult retrofit range. The higher the retrofit difficulty, the higher the cost and the longer the schedule.

S&L's extensive work at the Illinois coal-fired plants, and our past studies of environmental compliance costs for the Illinois units have shown that estimated costs for environmental retrofits such as fabric filters significantly exceed typical $/kW costs that may be quoted by industry fabric filter suppliers for new units, or even for existing units. Our experience has shown that retrofit factors alone could as much as double the cost of a fabric filter installation on an existing coal-fired plant. In addition to the cost to install the fabric filter alone, most Illinois coal-fired units will require long lengths of ductwork to a remote location due to tight plant arrangements, induced draft fan upgrades because existing fans have no remaining margin, significant electrical upgrades to power the new equipment, and possible upgrades and reinforcement to other existing systems. Costs for demolition and relocation of equipment and structures that currently stand in the way of a fabric filter arrangement are also a reality at some units. Specific issues that are expected to add to the cost of fabric filter installation at the Illinois units are outlined below in more detail:

1. Capabilities of the Existing Electrostatic Precipitator (ESP) to Capture Mercury-Specific Sorbents Without Exceeding the Particulate Emission Limitations of the Plant

The existing fleet of ESPs installed on the Illinois coal-fired electric generating fleet were typically designed to capture fly ash generated from the combustion of Illinois Basin coal. In many cases, this ESP performance capability has been compromised by the conversion of the plants to burn lower sulfur coals. To counter this performance degradation, physical modifications and operational changes (e.g. $S0_3$ addition) have been made to many of the state's ESPs. Consequently, very little, if any, margin typically exists beyond this design criteria to accommodate the addition and capture of mercury-specific sorbents. The capabilities of these existing ESPs to capture these sorbents without exceeding particulate/opacity limitations will vary significantly across the coal-fired units in Illinois. Retrofitting additional collecting areas (ESP fields) to accommodate the sorbent will be extremely difficult considering the current configuration of the existing ESPs with the remaining plant infrastructure (i.e. ID fans, chimney, air heaters, etc.). Considering the negative impacts of SO_3 on activated carbon performance (discussed earlier in my testimony), many of the ESPs on the Illinois EGUs will be hard pressed to achieve their permitted particulate and opacity limits while simultaneously meeting a 90% mercury reduction with activated carbon injection.

2. Fan Upgrades Required Due to Existing Fan Limitations

Retrofit of carbon injection with a fabric filter adds between 6 and 12 inches of pressure drop to the flue gas train. The precise amount of additional pressure loss depends upon the type of fabric filter, the ash loading in the flue gas, and the complexity of the ductwork arrangement required to transport the flue gas to and from the fabric filter device. Most operating utilities do not have this amount of margin in the existing ID fan. Therefore, either new booster fans or retrofit of larger impellers to the existing ID fans is necessary. Either of these scenarios also imparts a much larger power draw for the system. New larger motors for the redesigned ID fans or new large motors for the booster fans are also required. Fan and motor upgrade costs will vary, but can easily be in the range of $1 to $5 million dollars per unit.

3. Electrical Distribution Upgrades Due to Existing Infrastructure Limitations

The coal-fired power stations in Illinois are primarily 1970s vintage or earlier. The electrical distributions systems have been burdened with additional loads over the years, and have little spare capacity. In most instances, the additional power load required to support the new fan requirements discussed above, in addition to the electrical loads (albeit much smaller) from the activated carbon injection system, cannot be accommodated by the existing electrical systems. Additional auxiliary power transformers with redundant buses may be required to accommodate the new loads. These electrical upgrades, if required, can cost between $1 and $5 million per unit to support a fabric filter and sorbent injection system.

4. Infrastructure Limitations

Potentially the most costly of the possible infrastructure limitations that the utilities may encounter when planning for mercury control is adherence to the National Fire Protection Association (NFPA) Guideline No. 85. The NFPA guideline requires that the flue gas train be designed for the maximum pressure capability of the draft system. Considering the addition of a fabric filter with its attendant booster fan, the design criteria for all plant components in the flue gas stream would need to be revised to the maximum positive and negative pressure potential of the new system, including the booster fan. Reinforcement of the boiler, flue gas ducts and vessels may be required to mitigate the possibility of implosion. The utility insurance carriers will require analysis of the draft system to validate the capabilities of the existing hardware and controls to mitigate the risk of implosion, or design the system for the appropriate reinforcement.

Other infrastructure limitations that may require upgrades to accommodate a fabric filter and sorbent injection system include: compressed air systems, cooling water systems, relocation of underground facilities, expansion and modification of distributed control system, ash collection and transport systems, lighting, communication, and fire protection and detection.

5. Physical Limitations of Existing ESPs, Existing Ductwork Configurations, and Existing Plant Layouts

To optimize the effectiveness of activated carbon injection, especially when employed with an ESP for carbon collection, straight duct runs for multiple duct diameter lengths are required to maximize flue gas contact with the sorbent. Existing units were designed without this consideration, and typically do not have adequate straight duct between the injection point and the precipitator inlet to ensure adequate residence time to reach the same goals as an ideally designed configuration.

The overall existing plant layout may also add to the cost of a mercury control retrofit. The location of existing equipment and structures may preclude optimal ductwork arrangement, ideal fabric filter location, or potentially lower-cost solutions such as precipitator upgrades to meet the mercury removal criteria.

6. Outage Limitations

Operations optimization and the onset of predictive/preventive maintenance at coal-fired plants have decreased required planned outage frequencies and durations to meet unit reliability requirements. Where two outages per year were previously the standard, many units now plan for major outages only every two to three years. Owners of coal units have been planning outage schedules based on a combination of maintenance needs and implementation plans for CAIR and CAMR compliance. The accelerated schedule of the proposed Illinois mercury rule may require many coal-fired plants to add previously unplanned outage time to achieve mercury compliance by July 2009. Outage duration requirements will vary greatly depending on the technology required to meet the mercury reduction goal. Simple injection of sorbent upstream of the existing ESP requires a relatively short outage, while modifications to the ESP or addition of a fabric filter could require more lengthy outages. These outages will most likely need to occur in Fall 2008 or Spring 2009 to meet the compliance deadlines.. However, based on the schedule requirements discussed later in this testimony (Section V), it may not be possible to achieve equipment and material delivery and construction completion in time for a Fall 2008 or Spring 2009 outage if a fabric filter is required.

7. Waste Disposal Limitations

Depending on the level of activated carbon injection, the marketability of the fly ash for various industrial uses may be hampered or curtailed due to carbon contamination of the ash. This will almost certainly be the case if 90% mercury capture is required. However, if a polishing fabric filter is used downstream of the existing ESP for sorbent injection and capture, the existing ESP may be able to continue in operation to collect uncontaminated ash before carbon injection. However, if the existing ESP is used to collect the mercury sorbent, the operator will need to make the necessary provisions for landfill of the unmarketable fly ash, with the attendant costs and secondary environmental risks. I understand that these issues are addressed in more detail by another witness.

IV. CURRENT MARKET FACTORS THAT AFFECT THE COST AND SCHEDULE OF COMPLIANCE WITH THE PROPOSED ILLINOIS MERCURY RULE

The power industry market is very active at this time, particularly in the environmental area. The projected peak in implementing environmental control projects for Phase I of the CAIR is expected to be in the 2008 to 2009 timeframe to coincide with the Phase I NOx compliance date of 2009 and the Phase I SO_2 compliance date of 2010. Current projections for flue gas desulfurization projects required to meet the SO_2 requirements of Phase I of CAIR will require the installation of over 150 new FGD systems representing over 60,000 MWs of coal-fired capacity in the U.S. These new FGD systems will go into service between 2006 and 2010 and represent a market that is more than 7 times the size of that which was achieved in all of the 1990's. This environmental market, in conjunction with the ongoing SCR program for NOx and the accelerating construction of new coal plants across the country, is straining the capabilities of industry resources to keep up with both the quality and quantity demands of the utility industry. Under the proposed Illinois mercury rule compliance deadlines, implementation of mercury control technology would fall within this same period of peak market demand and already historic levels of strain on the resources supporting this market.

The following are expected impacts if mercury compliance is accelerated from the current CAMR timetable to July 2009:

1. **Design and Manufacturing Capabilities**

   The design and manufacturing capabilities of many environmental control-related equipment manufacturers are currently strained for the 2009 delivery time frame. Limited supplier engineering staffs are showing signs of not being able to produce design information and drawings in a timely manner. To maintain schedules, manufacturing may be started before the design is complete, which may adversely affect quality control and efficiency of design.

   Schedules and costs to obtain raw materials for fabrication have increased significantly. Lead times for fabricated steel products have nearly doubled from two years ago. These supply-side pressures are straining fabrication shops which could result in overflow work going to fabricators who do not routinely perform heavy industrial work.

   A recent survey of the major fabric filter manufacturers indicates that the projected span from contract award to delivery is currently five months longer than two years ago. A fabric filter purchased today would require a minimum of 30 months to complete from the date of purchase. The large fan manufacturers and motor manufacturers are similarly extending their lead times for delivery to 13 months after drawing approval. They do not expect to see any reduction in these manufacturing spans over the next two years.

2. Labor Market

The power industry has acknowledged an industry-wide shortage of experienced craft labor. The shortage trend is expected to continue as the workforce is aging, and as numbers of individuals entering the craft labor market have difficulty matching the attrition rate.

As reported by the Department of Labor, aging industrial and power facilities in the country are expected to undergo large construction refurbishment in the next ten-year window to maintain their operations. This coupled with new generation plans and environment control projects for the coal-fired stations establish an increased demand for a decreasing labor pool.

To compensate for the labor shortages, large construction projects are being priced based on a minimum 50-hour workweek to ensure attraction and retention of craft labor. For smaller projects, additional pay incentives may be required. Premiums to attract and retain labor may increase the construction labor costs of a typical project by 10% to 25%.

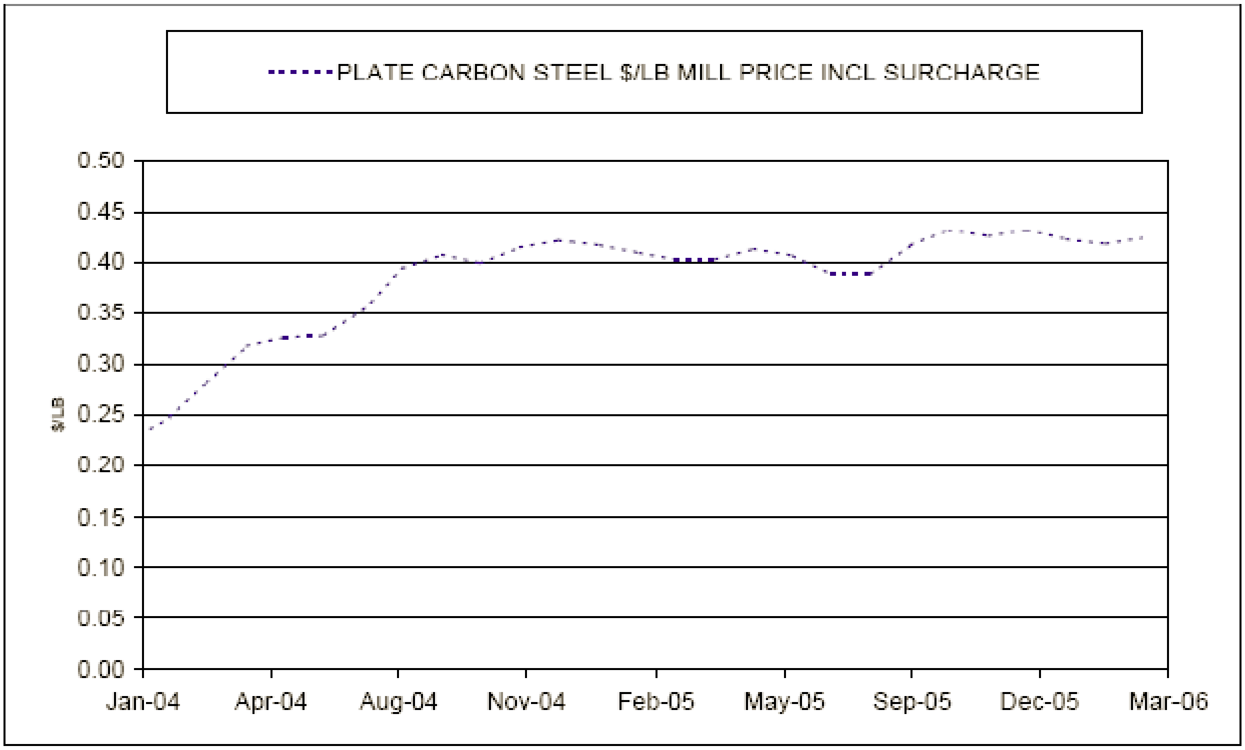
A source of information on construction labor resources that we use in our work is the Construction Industry Institute (CII). An article of particular interest when planning for construction programs in the 2006-2010 time frame is titled “Shortages of craft workers continue to plague the construction industry” and can be found on the CII website http://www.construction-institute.org

3. Seller’s Market

The purchaser of materials and labor is at a disadvantage in the current market. Because there are more projects than resources, many manufacturers have become selective in choosing which opportunities to pursue. Many are directing their resources to projects that are either large, low risk, or negotiated rather than bid. Addition of mercury compliance measures to the peak demand time frame for environmental projects may limit the number of suppliers willing to bid, and place unit owners in a weak commercial position.

4. Steel and Alloy Market Volatility

The high market demand for steel worldwide has increased the cost of materials required to implement environmental control projects by over 40% in the past two years. Exhibit 3 illustrates the market trends for carbon steel plate, a major component of ducts, structural steel, fabric filter housings and components, etc. through March of 2006.



This inflated pricing has been maintained for over two quarters. Market analysts do not expect prices to return to more normal levels within the next few economic cycles. Therefore industry historical pricing, as recent as last year, underestimates the actual installed cost of power and process systems.

5. Outage Costs and Impacts

Based on information collected and maintained by the Department of Energy, 49% of the power generated in the state of Illinois in 2004 was produced by coal fired boilers. Based on the Technical Support Document AQPSTR 06-02 presented by the IEPA, the trend is expected to continue through 2018. If half of the Illinois fossil fleet takes an outage in the spring of 2009 to accommodate the proposed Illinois mercury rule, nearly 25% of the state power generation would be unavailable at some time during these few months. This quantity of power offline begins to approach the capacity margin of 39% for the MAIN region.

6. Owner Resources and Contracting Approaches

Limited owner resources, as discussed above, and the compressed schedule necessary to meet a mid-2009 compliance date, may lead some unit owners to outsource to an independent contractor for engineering, project management, material supply, and construction for their environmental retrofit projects. This approach, in which an outside contractor assumes the management responsibilities and many of the risks for the project, typically adds a 15% premium to the cost of a project such as an environmental retrofit installation. A compliance schedule that was integrated more synergistically with the ongoing CAIR and CAMR programs would allow utilities to “levelize” their management, engineering, procurement and construction resources resulting in lower cost designs that offer greater flexibility in meeting specific plant needs.

V. EXPECTED PROJECT IMPLEMENTATION SCHEDULES FOR MEASURES REQUIRED TO COMPLY WITH THE PROPOSED ILLINOIS MERCURY RULE

The owners/operators of the EGUs in the state cannot obtain the necessary financing for pollution control projects prior to the adoption of the requirements to be addressed by the project being financed. Therefore, while the owners/operators may engage in a limited level of planning now, they cannot complete that planning and make commitments with vendors until after the rule is adopted. The Illinois mercury rule, if finalized in November 2006, will allow 31 months to study, plan, permit, design, furnish, and install mercury reduction technology. This timeline will not be sufficient for all of the fabric filter and/or precipitator upgrades that are expected to be required by the rule. A typical milestone schedule for a fabric filter/sorbent injection project is included as Exhibit V-1. Although a fabric filter scenario does not represent the only technology choice for 90% mercury control, it represents a reasonable approach, (while keeping in mind the risks associated with any emerging technology,) for many of the fossil units in the state due to the limitations of most of the industry's ESPs as discussed earlier in this testimony.

The estimated typical schedule for a fabric filter retrofit from conceptual design to operation is a minimum of 36 months. Units with high retrofit difficulty may require more time. This schedule projection, takes into account reports from suppliers indicating that fabrication and delivery durations for fabric filters have increased by a minimum of 2 months and as much as 9 months depending on project specifics, .

VI. INSTALLED COST PROJECTIONS FOR RETROFITS EXPECTED TO BE REQUIRED TO COMPLY WITH THE PROPOSED ILLINOIS MERCURY RULE

The cost of retrofitting environmental control technology including mercury control technology to a coal-fired boiler is very site specific. As discussed earlier in this testimony, the technology selection(s), implementation sequence, retrofit conditions, market conditions, and the implementation schedule all play a role in the capital cost.

1. Cost Ranges for Sorbent Injection Alone

The use of sorbent injection such as activated carbon for mercury control, with no additional particulate collection optimization, is the lowest capital cost alternative. The owners of the Illinois generating units anticipate that a minority of the units in the state would be credible candidates for selection of this technology alone under the proposed Illinois mercury rule. The estimated installed cost of this technology ranges between $1.5 to $3.0 million per unit. If an EPC approach is required because of utility resource limitations and market factors, the installed cost could be as high as $3.5 million. The capital cost does not vary much with unit size because the unloading, bulk storage and distribution systems are typically standardized. The frequency of carbon delivery will typically vary based upon the unit size, performance needs and needs of the supplier’s delivery system. The range of yearly operating cost for this technology will be $1 to $6 million per year per unit depending primarily on the size (150-600MW assumed here) of the unit and some basic assumptions regarding the cost of the sorbent (assumed at $1/lb) and typical sorbent injection rates. (3-5 lbs/MACFM). Note that these operating costs make no projections on the Hg removal rate as this will be dependent on the form of mercury in the flue gas and the ability to optimize (% removal, sorbent injection rate, residence time, etc.) the technology in each specific retrofit application. Nor does this operating cost include the potential liability of landfill cost if marketable quality flyash needs to be landfilled due to contamination with the Hg sorbent.

2. Cost Ranges for Polishing Fabric Filter Plus Sorbent Injection

The combined cost of activated carbon injection followed by a polishing fabric filter is more sensitive to retrofit and market factors than activated carbon injection alone. Based on S&L's recent and ongoing projects, the range of estimated costs for implementation of this technology within the next four years using a multiple contracting approach can be characterized as follows:

Activated Carbon Injection with a Polishing Fabric Filter (yr 2006 $/kw)

Unit Size	**Retrofit Complexity Moderate**	**Retrofit Complexity Difficult**	**Retrofit Complexity Severe**
200 MW	120-140	140-160	160-240
400 MW	105-125	120-150	150-230
600 MW	95-115	105-130	130-150

The following is an example of how the above $/kW cost ranges translate into budgets for a 400 MW unit:

- Moderate complexity for a 400 MW unit: $42-50 million
- Difficult complexity for a 400 MW unit: $48-60 million
- Severe complexity for a 400 MW unit: $60-92 million

Current market price estimates account for the following examples of recent material pricing increases that we have seen on other retrofit projects in the industry:

- 36% increase in fabricated steel cost within the past 9 months *(under review)*
- 40% increase in copper within the last 6 months*(under review)*
- 12% increase in ductwork within the past 9 months*(under review)*

- 20% increase in labor cost (premium time to attract and retain labor and loss of productivity due to longer work days and weeks) *(under review)*

As discussed earlier in this testimony, if the owner's resources are constrained to the point of necessitating an outside contractor to engineer, procure and construct the entire retrofit, an additional cost premium of 15% would be expected to cover the contractors risk, fee, markups, etc.

As an example of a difficult retrofit case, Exhibit VI-1 depicts a conceptual design layout prepared for the Will County Station, Units 3&4. This layout shows the installation of a dry FGD and associated fabric filter, but a similar duct and equipment arrangement would be required for a polishing baghouse alone. Because this unit is located immediately adjacent to the canal, installation of a baghouse at either Unit 3 or Unit 4 would require several hundred feet of ductwork to route flue gas south of the power block to where a baghouse and new booster fans could be located, and then back to the existing stack. Duct lengths for Unit 3 would need to be particularly long to leave room to clear a Unit 4 baghouse located closer to the power block buildings. In addition to the extensive ductwork, demolition and relocation of miscellaneous existing components that interfere with the new equipment would be required.

All of these issues will add significant cost to the project at the Will County 3 & 4 site making the total cost much greater than a retrofit on an open site. In 2005, S&L estimated the cost to install a baghouse and activated carbon injection system for Will County Unit 3 to be $67 million, based on the site-specific arrangement shown in Exhibit VI-1.

The example of Will County Unit 3 is particularly pertinent because the testimony of the Illinois EPA's technical expert states that two of the Illinois units with hot-side precipitators, including Will County Unit 3, would require installation of a TOXECON system to comply with the proposed Illinois mercury rule. The cost estimate for this system prepared by S&L, which was based on a site-specific arrangement and walkdowns, is significantly higher than the $17.94 million estimate for a TOXECON system for this unit presented in the Illinois EPA's Technical Support Document (TSD). We understand that the TSD cost estimates were not based on site walkdowns or site-specific conceptual designs.

Another baghouse retrofit example is the Dynegy Vermilion baghouse project. S&L has prepared the detailed design for this retrofit, and the project is currently under construction. The retrofit includes approximately 200 feet of ductwork to route the flue gas to and from an area where the baghouse could be located, and also includes new booster ID fans, because the existing ID fans were not sufficient to accommodate the additional pressure loss in the baghouse. The cost to complete the Vermilion project is currently forecast at approximately $32 million, or approximately $160/kW.

Another hot-side precipitator example is the Dynegy Havana 6 unit. We understand that Dynegy's current Consent Decree deadline is December 31, 2012 for installation of an FGD and fabric filter system. Compliance with the proposed Illinois mercury rule would require that the fabric filter installation schedule be accelerated to July 1, 2009. We understand, based on reports from Dynegy, that a single outage was planned for installation of the FGD and fabric filter, and that Dynegy would likely need to accelerate the installation of the FGD and fabric filter to the year 2009 in order to avoid multiple protracted outages for the unit.

The range of yearly operating cost for this technology is $1 to $4 million per unit for units in the size range of 150-600MW.

3. Cost Ranges For Full Pulse Jet Fabric Filter to be Used in Conjunction with Dry FGD and Sorbent Injection

Implementation of dry FGD with a pulse jet fabric filter for CAIR SO_2 compliance, in conjunction with sorbent injection, would achieve mercury control compliance with CAMR and should achieve compliance with the proposed Illinois mercury rule. Some of the coal-fired units in Illinois will be considering the addition of dry FGD to their units to comply with the of the federal CAIR in 2010. Because of the timing of the proposed Illinois mercury rule, the fabric filter and sorbent injection system portions of the planned CAIR/CAMR compliance strategy would require installation in 2009 before the dry FGD component and including the temporary ductwork to be used as a spacer for the future spray drier absorber.

The capital investment required for either of these choices is significantly higher than would be required if the sorbent injection/dry FGD/fabric filter were installed in one step. Either a costly second outage would be required, or the design would need to include additional ductwork to orient the fabric filter in a manner that will allow reasonable construction access for the addition of the future FGD system.

Based on S&L's experience with these types of technologies in various retrofit applications, the range of costs for implementation of this technology within the next four years can be characterized as follows:

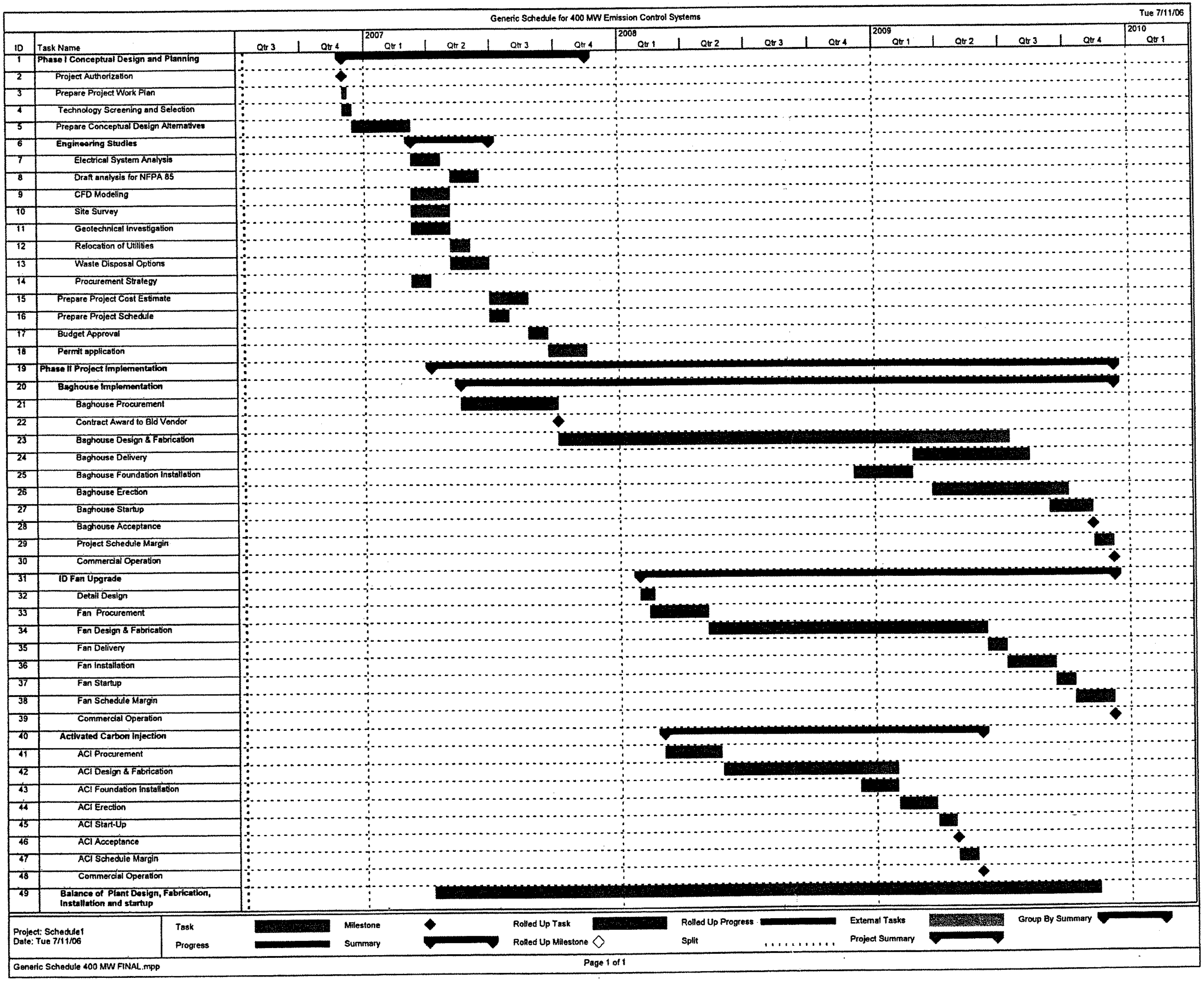
Two Stage Compliance ($/kw)
Phase 1: Activated Carbon and Pulse Jet Fabric Filter
Phase 2: Addition for Dry FGD

Unit Size	Retrofit Complexity Moderate	Retrofit Complexity Difficult	Retrofit Complexity Severe
200 MW	300-320	330-350	400-500
400 MW	220-240	240-270	270-320
600 MW	190-210	210-230	230-260

Again, an EPC contracting approach potentially necessitated by the market conditions will raise the implementation costs another 15%.

- END OF TESTIMONY -

EXHIBIT V-1



Generic Schedule for 400 MW Emission Control Systems

Tue 7/11/06

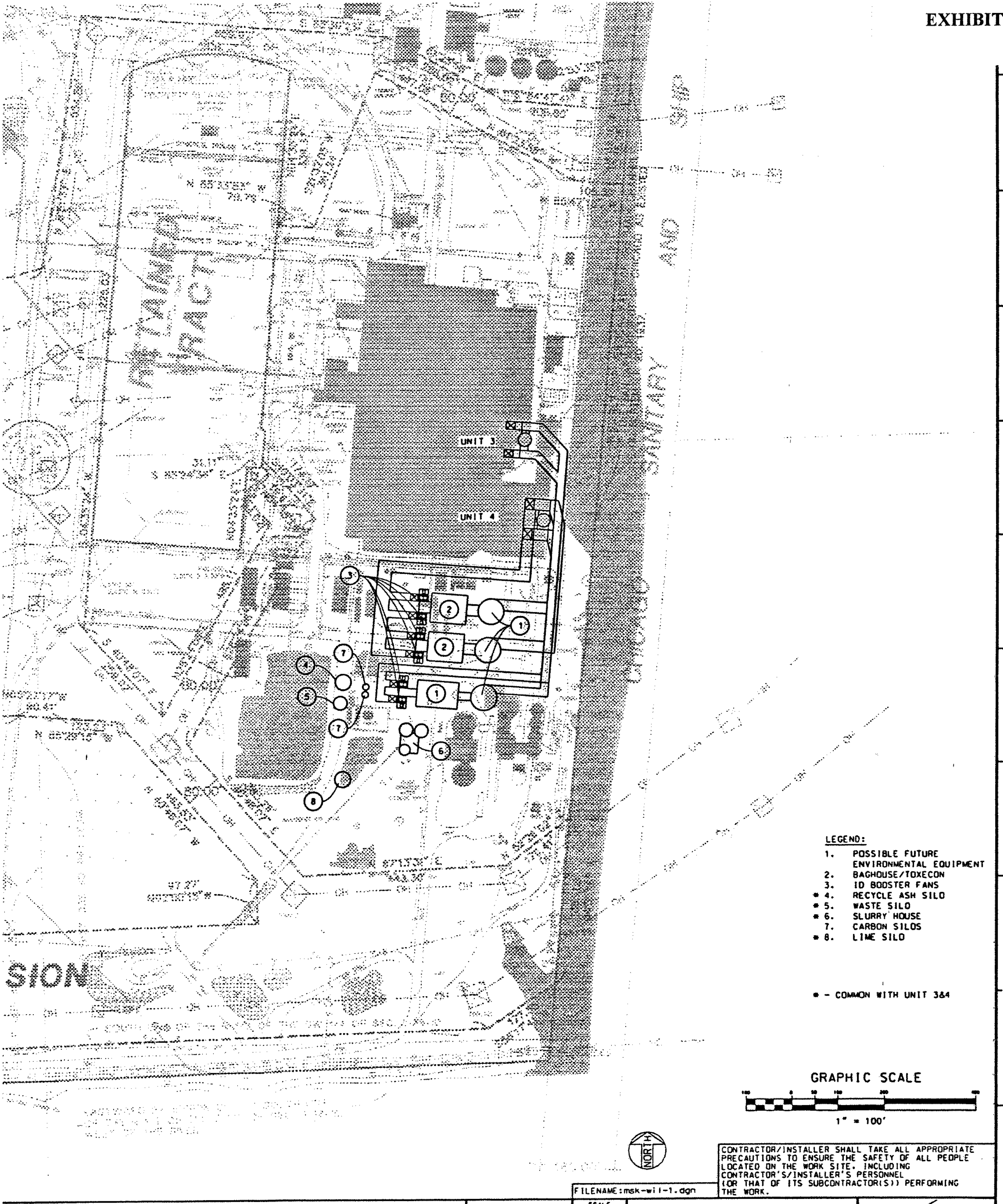
ID	Task Name
1	**Phase I Conceptual Design and Planning**
2	Project Authorization
3	Prepare Project Work Plan
4	Technology Screening and Selection
5	Prepare Conceptual Design Alternatives
6	**Engineering Studies**
7	Electrical System Analysis
8	Draft analysis for NFPA 85
9	CFD Modeling
10	Site Survey
11	Geotechnical Investigation
12	Relocation of Utilities
13	Waste Disposal Options
14	Procurement Strategy
15	Prepare Project Cost Estimate
16	Prepare Project Schedule
17	Budget Approval
18	Permit application
19	**Phase II Project Implementation**
20	**Baghouse Implementation**
21	Baghouse Procurement
22	Contract Award to Bid Vendor
23	Baghouse Design & Fabrication
24	Baghouse Delivery
25	Baghouse Foundation Installation
26	Baghouse Erection
27	Baghouse Startup
28	Baghouse Acceptance
29	Project Schedule Margin
30	Commercial Operation
31	**ID Fan Upgrade**
32	Detail Design
33	Fan Procurement
34	Fan Design & Fabrication
35	Fan Delivery
36	Fan Installation
37	Fan Startup
38	Fan Schedule Margin
39	Commercial Operation
40	**Activated Carbon Injection**
41	ACI Procurement
42	ACI Design & Fabrication
43	ACI Foundation Installation
44	ACI Erection
45	ACI Start-Up
46	ACI Acceptance
47	ACI Schedule Margin
48	Commercial Operation
49	**Balance of Plant Design, Fabrication, Installation and startup**

Project: Schedule1
Date: Tue 7/11/06

Page 1 of 1

Generic Schedule 400 MW FINAL.mpp

EXHIBIT VI-1



LEGEND:

1. POSSIBLE FUTURE ENVIRONMENTAL EQUIPMENT
2. BAGHOUSE/TOXECON
3. ID BOOSTER FANS
* 4. RECYCLE ASH SILO
* 5. WASTE SILO
* 6. SLURRY HOUSE
7. CARBON SILOS
* 8. LIME SILO

* - COMMON WITH UNIT 3&4

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE. INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUBCONTRACTOR(S)) PERFORMING THE WORK.

FILENAME:msk-wil-1.dgn

DRAWING RELEASE RECORD		
EVIEWED	APPROVED	PURPOSE

SCALE
1"=100'
PROJECT NUMBER
10683-900

GENERAL ARRANGEMENT
ENVIRONMENTAL RETROFIT
OPTIONS
STATION 8 - UNIT 3&4
WILL COUNTY STATION
MIDWEST GENERATION
CHICAGO, ILLINOIS

Sargent & Lundy

DRAWING NO. MSK-WIL-7
REV.
SHEET OF

ATTACHMENT A

Sargent & Lundy LLC

WILLIAM DEPRIEST
Senior Vice President and Director
Environmental Services
Fossil Power Technologies

EDUCATION

Michigan Technological University - B. S. Chemical Engineering - 1972

REGISTRATIONS

Professional Engineer - Wisconsin

EXPERTISE

Air toxic control technologies

Combined NO_X and SO_2 control technologies

Coal gasification and its integration with combustion turbines and combined cycles (IGCC)

Condition assessment of emission control systems and equipment

Combustion and post-combustion NO_X control technologies (LNB, OFA, SNCR, SCR, etc.)

ESP and FF particulate control technologies

Emission control byproduct development (gypsum, fertilizer, etc.)

Emission control technologies

Flue gas desulfurization (FGD)

Repowering with advanced combustion technologies

RESPONSIBILITIES

As Senior Vice President and Director of Environmental Services, Mr. DePriest is responsible for ensuring that all fossil-related projects are fully supported with the appropriate environmental related expertise for successful execution of the project. He is also responsible for maintaining current expertise in environmental technologies for fossil fired power facilities including PC, CFB, and IGCC plants.

EXPERIENCE

Mr. DePriest has more than 30 years of experience dedicated to the application of emission control technology in the utility industry. This expertise primarily focuses on the areas of NO_X, SO_2, and particulate control with expanding expertise in air toxin and CO_2 control.

As Sr. Vice President and Director of Environmental Services, Mr. DePriest has directed the application of both combustion-based and post-combustion-based NO_X control technologies on a variety of coal and gas fired utility plants representing well over 30,000 MW of capacity. These NO_X control technologies covered the spectrum of commercially available technologies including low NO_X burners (LNB), over-fire air (OFA) systems, neural networks, selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), reburning, and combinations of these.

In addition, Mr. DePriest has directed, or is currently directing, the application of flue gas desulfurization (FGD) technology on 20 recent retrofit FGD projects representing over 12,000 MW of coal-fired generating capacity.

Mr. DePriest has also directed S&L's IGCC Program through work with utility clients, EPRI, and permitting agencies.

ATTACHMENT A

Mr. DePriest is a recognized expert in the industry on environmental control technology and he has written and published extensively on the subject.

Before joining Sargent & Lundy, he was the environmental product manager for a major equipment supplier to the utility industry. He had responsibility for the company's environmental product lines, including, NO_X reduction systems, FGD systems (wet and dry), precipitators and baghouses. In this capacity he managed the functional engineering on more than 10 wet and dry FGD systems. This functional engineering involved equipment sizing, specifications, material of construction, and overall process design from the air heater outlet to the stack. Also included was similar design work on auxiliaries, such as reagent preparation systems and waste dewatering and disposal systems. Two of these systems produce gypsum as a byproduct, which is currently being used by leading wallboard manufacturers.

Mr. DePriest managed a field process-engineering group in conjunction with this design work, which started up and serviced utility emission control systems. He also supervised the operation of two emission control pilot projects operated at coal-fired utility sites. One used magnesium-promoted lime as the reagent and the other used waste soda liquor. Information generated from these pilots was then used in the process design of full-scale FGD systems.

His specific experience over his 20 years with Sargent & Lundy includes:

COAL GASIFICATION EXPERIENCE (IGCC)

- Minnesota Power
  - Advanced integrated gasification/pressurized fluid bed combustion.

    Project Manager. Development of an advanced integrated gasification/pressurized fluid bed combustion conceptual design with a major boiler manufacturer. Project included hot/pressurized particulate and sulfur clean-up processes as well as advanced combustion turbine technology. (1992 to 1994)
- Electric Power Research Institute
  - PRENFLO-based integrated-gasification combined cycle (IGCC) study.

    Project Manager. Study investigating the advantages and disadvantages of integration of the air separation plant with the combustion turbine on a PRENFLO-based IGCC power plant. Study also included the use of advanced high-temperature particulate control of the raw syngas prior to desulfurization and combustion. (1989 to 1993)
  - Advanced IGCC concepts study.

    Project Engineer. Study of advanced concepts of IGCC power facilities. Study quantified the heat rate improvements expected from employing advanced cycle designs and the related costs for a nominal 400-MW plant. (1987 to 1989)
- IGCC Site Selection
  - Under Mr. DePriest's direction, S&L has assisted utilities with the selection of sites for IGCC deployment in Indiana, Virginia, Oklahoma, Kentucky, Louisiana, Arkansas, Ohio, Tennessee, West Virginia, Virginia and Indiana.

- IGCC Permit Application and Support
  - Under Mr. DePriest's direction, S&L has written permit applications and/or performed BACT analysis for IGCC deployment in IL, MT, NT, ND, WY, and MI.

RECENT EMISSION CONTROL PROJECT EXPERIENCE

- SO_2 Control Projects

  20 FGD projects representing over 12,000 MW of coal-fired capacity. Included in this experience are the following example of utility FGD programs:

  - Cinergy
  - Kentucky Utilities (LGE)
  - American Electric Power
  - Santee Cooper

- Strategic Planning Projects

  Strategic Compliance (NO_X, SO_X, particulate and Hg) Plan Development for 36 different utility systems representing over 40,000 MW of capacity. Included in this experience are the following examples of utility system-wide emission compliance plans:

  - Ameren UE/Ameren CIPS
  - Associated Electric
  - Cinergy
  - MidAmerican
  - Reliant Energy
  - TXU

- NO_X Control Projects

  Over 30 low NO_X burner (LNB) projects representing over 6,000 MW of capacity, 30 selective catalytic reduction (SCR) retrofit design projects for coal fired units representing 16,000 MW of capacity, and 13 gas fired units representing over 8000 MWs of capacity. Some recent examples are:

  - Dynegy (LNB, OFA, SCR, ESP)
  - Reliant Energy (LNB, OFA, SCR)
  - Santee Cooper (SCR, FGD)
  - Cinergy (LNB, SCR, FGD)

- Electric Power Research Institute
  - Development of advanced retrofit FGD concepts for compliance with the 1990 Clean Air Act Amendments. (1991 to 1992)
  - Development of the Clean Air Technology (CAT) computer workstation to identify least-cost SO_2 and NO_X compliance strategies. (1991 to 1992)
  - Project Manager: Study involves the screening of over 60 advanced combined NO_X/SO_2 processes, selecting the eight most promising for utility application, performing conceptual design and cost estimates, and identifying research and development requirements to bring to commercial viability. (1988 to 1992)
  - Project Manager. Study of FGD systems in cycling service that investigated the effect that various types of unit cycling will have on six different generic types of FGD processes. Guidelines for design and operation resulted from the study. (1988 to 1991)
  - Project Consultant. Retrofit FGD design improvement study to identify and investigate design improvements to reduce the cost of retrofitting FGD to utility power plants. (1988 to 1990)

Some specific examples of Mr. DePriest's work with the control of SO_2 while with Sargent & Lundy follow:

As Manager of Environmental Services, Mr. DePriest has managed the process design on all of S&L's 20 FGD projects since 1990. The following five FGD retrofit projects are examples of these projects:

- Kentucky Utilities: Ghent 1, coal, 550 MW
- Owensboro Municipal Utilities: Elmer Smith 1 and 2, coal, 416 MW total
- TXU: Monticello 3, coal, 750 MW and Martin Lake 1-3, coal, 720 MW each
- Cinergy: Gibson 4, coal, 650 MW
- Santee Cooper Winyah 1 and 2, coal, 320 MW each

The following are other examples of Mr. DePriest's experience with SO_2 control on coal-fired power plants:

- Owensboro Municipal Utilities
  - Elmer Smith 1 and 2, coal, 416 MW total

    Emission Control Consultant. Acid rain legislation compliance study. (1989 to 1990)
- Ameren
  - Systemwide coal-fired units.

    Project Manager. System Strategic NO_X and SO_2 compliance planning study. (1989 to 1990)

- Northern Indiana Public Service Company
    - Bailly 7 and 8, coal, 616 MW total

      Provided expert advice on the retrofit of a Mitsubishi wet FGD system (Pure Air) to the combined flue gases from these two units. (1988 to 1989)
- Central Louisiana Electric Company, Inc.
    - Dolet Hills 1, lignite, 719 MW

      Provided expert advice on performance test methodologies, interpretations of testing results, and comparison of results with contract guarantees. Systems tested included the electrostatic precipitator and FGD systems. (1987 to 1989)
- TXU
    - Sandow 4, lignite, 591 MW

      Designed process to recover di-basic acid from the spent slurry leaving a limestone-based FGD system. This facilitated recycling the di-basic acid for reduced plant operating expense. (1986 to 1987)
- Southwestern Electric Power Company
    - Pirkey 1, lignite, 720 MW

      Developed a performance test specification and methodologies for contract guarantee testing of the air heaters, precipitators, and FGD system. Interpreted test results and system suppliers' compliance with guarantees. Provided general process expertise for solving performance problems that were causing load reductions to maintain compliance with emission regulations. (1985 to 1986)

OTHER FLUE GAS DESULFURIZATION PROJECT EXPERIENCE PRIOR TO JOINING SARGENT & LUNDY

- Pacific Power & Light Company/Idaho Power Company
    - Jim Bridger 2, coal, 508 MW

      Managed the process design and functional engineering of the backfitted sodium-based FGD system. Managed the one-year/$1,000,000 pilot project at the station, the results of which were used in the full-scale equipment design. (1983 to 1985)
- Lakeland Department of Electric & Water Utilities
    - McIntosh 3; coal, oil, and municipal refuse; 350 MW

      Managed the process design and functional engineering of the FGD system on this multi-fueled power plant. Plant typically operates on high-sulfur augmented with refuse. (1978 to 1982)

- San Miguel Electric Cooperative
  - San Miguel 1, lignite, 400 MW

    (1976 to 1982)
- Sikeston, Board of Municipal Utilities
  - Sikeston 1, coal, 235 MW

    (1978 to 1981)
- South Carolina Public Service Authority/Santee Cooper
  - Winyah 2 and 3, coal, 270 MW each

    (1975 to 1980)
- Southern Illinois Power Cooperative
  - Marion 4, coal, 173 MW

    Process Design Engineer and Supervisor. Control and instrumentation systems design and supervisor of field process engineering and startup services for limestone-based FGD systems. (1976 to 1978)
- Allegheny Power System/Monongahela Power Company
  - Pleasants 1 and 2, coal, 626 MW each

    Process Design Engineer and Supervisor. Control and instrumentation systems design as well as supervisor of field process engineering and startup services for limestone-based FGD system. Designed a 5,000 cfm pilot to simulate the full-size unit and develop data for use in its ultimate design. (1977 to 1980)
- Kansas City Power & Light Company/Kansas Gas and Electric Company
  - LaCygne 1, coal, 848 MW

    Field Service Engineer. Pioneering (5% to 7%) limestone-based FGD system. (1973 to 1975)
- Commonwealth Edison Company
  - Will County 1, coal, 188 MW

    Field Service Engineer. Company's first FGD system, which was also a retrofit application. (1972 to 1973)

NO$_X$ CONTROL EXPERIENCE:

Mr. DePriest has been the Environmental Services Director for both combustion-based and post-combustion-based NO$_X$ control projects.

Following are example utilities where Mr. DePriest has experience with the retrofit of the lowNO$_X$ burners (LNB) and overfire air (OVA) systems:

- Reliant Energy (Texas Genco)
- Owensboro Municiple Utilities
- Mid American

Following are example utilities where Mr. DePriest has experience with the design of post combustion SCR projects:

- Dynegy
- Reliant Energy (Texas Genco)
- Santee Cooper

EMISSION CONTROL BYPRODUCT DEVELOPMENT

- Owensboro Municipal Utilities
  - Elmer Smith 1 and 2, coal, 450 MW

    Conversion of forced oxidation system to commercial grade gypsum production for wallboard use. (1994)

Houston Lighting & Power Company

  - Limestone 1 and 2, lignite, 809 MW each

    Performed a detailed technical and economic study for the conversion of the existing FGD system to forced oxidation and the production of a marketable gypsum byproduct. (1986)

- Applied Energy Services
  - Deepwater 1, petroleum coke, 135 MW

    Manager. Process design and functional engineering for the FGD, wet electrostatic precipitator, and pressurized forced oxidation system. Wet precipitator removed sulfuric acid mist resulting from firing a high vanadium petroleum coke. The pressurized oxidation system produced a high-quality wallboard gypsum. Managed field startup service activities. (1983 to 1985)

- Grand Haven Board of Light & Power
  - J. B. Sims 3, coal, 65 MW

    Managed the process design and functional engineering of lime-based FGD system. Design included a unique concept for force oxidizing the sulfite-rich slurry to produce a marketed gypsum product (for wallboard) while enhancing the SO_2 removal capabilities of the system. Managed the field startup and field process engineering activities. (1980 to 1984)

CONDITION ASSESSMENT

- Louisville Gas & Electric Company
  - Cane Run 4-6, coal, 645 MW total.

    Project Engineer for condition assessment of FGD equipment. (1991)
- Duquesne Light Company
  - Elrama 1-4, coal, 425 MW

    Project engineer on the FGD portion of the plant condition assessment study to assess operation to the year 2007. (1987 to 1988)

MEMBERSHIPS

American Society of Mechanical Engineers

Committee PTC-40, Performance Test Code on Flue Gas Desulfurization

Environmental Control Division FGD Subcommittee (chairman)

Environmental Control Division Economic Evaluation Committee

Air & Waste Management Association

PUBLICATIONS

"Technologies and Emission Allowances", Emission Management Association 8th Annual Spring Meeting, New Orleans, May 2004

"Condensable Particulate Matter Emission Sources and Control in Coal-Fired Power Plants", EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollution Control Mega Symposium, Washington, DC, August 2004

"Economics of Lime and Limestone for Control of Sulfur Dioxide", EPRI-DOE-EPA-AWMA Combined Power Plant Air Pollution Control Mega Symposium, Washington, DC, May 2003

"Prospects for Lime in Future FGD Markets", National Lime Association Meeting, Santa Monica, CA, February 2003

"Mercury Speciation and Impact of Current Controls: An Interpretation of the ICR Database", CoalGen Conference, July 2001

"Reliant Energy's NO_X Reduction Program for their Houston Area Generating Facilities", Technology Selection and Design Challenges" EPA-DOE-EPRI Power Plant Air Pollution Control Symposium, Chicago, August 2001

"Development and Maturing of Environmental Control Technologies in the Power Industry", Emissions Trading: Environmental Policy's New Approach, Copyright 2000 University of Illinois at Chicago

"Optimizing SCR Reactor Design for Future Operating Flexibility" ICAC FORUM 2000 on "Cutting NO_X Emissions", March 2000

"Control Technology Selection and Application to Meet NO_X Compliance", Plant Design and Operating Committee Meeting, Galveston, TX, 2000

"Short-Term NO_X Emission Reductions with Combustion Modifications on Low to Medium Sulfur Coal-fired Cyclone Boilers", EPRI-DOE-EPA Combined Utility Air Pollutant Control Symposium, Washington, D.C., 1997

"Revisiting Your NO_X Compliance Strategy: The Impact of Title IV - Phase II, Title I-OTAG, and Proposed New NAAQS", 59th American Power Conference, 1997, Chicago, Illinois

"Impacts of Title III and IV of the Clean Air Act and the Revised NAAQS on Particulate Control Strategies for Year 2000 and Beyond", International Joint Power Generation Conference, Denver, 1997

"Cost Effective Deployment of Technology to Meet Air Emission Compliance in Developing Regulatory Environment" PowerGen Asia Conference, New Delhi, India, 1996

"Options for Repowering the Utility Industry" PowerGen Conference, Anaheim, California 1995

"Compliance and Competition: Obstacle or Opportunity," 1995 Sargent& Lundy Fossil Engineering Conference, Chicago, Illinois, 1995

"Key Issues for Low Cost FGD Installation," Energy and Environment: Transitions in East Central Europe, Prague, 1994

"Cost-Effective Retrofits for Emission Controls," Energy and Environment: Transitions in East Central Europe, Prague, 1994

"CO_2 and Air Toxins: Planning for Future Regulatory Uncertainty," 1994 International Joint Power Generation Conference, Phoenix, Arizona, 1994 (et al.)

"Clean Air Technology (CAT) Workstation: Case Study" 1993 SO_2 Symposium, Boston, Massachusetts, 1993

"Flue Gas Desulfurization Cycling Guidelines" 1993 SO_2 Symposium, Boston, Massachusetts, 1993

"Novel Integration Concepts for GCC Power Plants," Fifth International Power Generation Conference, Orlando, Florida, 1992

"Clean Air Technology Workstation," 1991 SO_2 Control Conference, Washington, D.C., 1991

"Comparison of Coal Gasification Combined-Cycle Integration Concepts," EPRI 10th Annual Conference on Coal Gasification Power Plants, San Francisco, California, 1991

"Engineering Evaluation of Combined NO_x/SO_2 Controls for Utility Application," 1991 SO_2 Control Conference, Washington, D.C., 1991"Acid Rain Compliance Analysis Evaluating Technology Options Within a Market-Based Regulatory Scheme," IJPGC, Boston, Massachusetts, 1990

"Combining SO_2 and NO_x Control Technologies as a Strategy for Environmental Compliance," Clean Power from Coal Conference, Brussels, Belgium, 1990

"Design and Operation of FGD Systems for Cycling Service," EPA/EPRI 1990 SO_2 Control Symposium, New Orleans, Louisiana, 1990

"Engineering Evaluation of Combined NO_x/SO_2 Removal Processes: 2nd Interim Report," EPA/EPRI 1990 SO_2 Control Symposium, New Orleans, Louisiana, 1990

"Integrated Coal Gasification Combined Cycle: Is It Competitive With a Pulverized Coal-Fired Boiler for Power Generation?" Sargent & Lundy Engineering Conference, Chicago, Dallas, and Houston, Texas, 1990

"A Second Look at Cogeneration in a Coke Oven Plant," Annual Association of Iron and Steel Engineers Convention, Pittsburgh, Pennsylvania, 1989

"Conceptual Design and Economic Evaluation of a Coal Dechlorination Plant," EPRI First International Conference on Chlorine in Coal, Chicago, Illinois, 1989

"Engineering Evaluation of Combined NO_x/SO_2 Removal Processes: Interim Report" Joint Symposium on Stationary Combustion NO_x Control, San Francisco, California, 1989

"Review of Potential Cycle Improvements for an IGCC Plant" 8th EPRI Coal Gasification Conference, Palo Alto, California, 1988

"Flue Gas Desulfurization: Growing Pains/Proven Remedies," Sargent& Lundy Engineering Conference, Dallas, Texas, 1987

"Gypsum - An FGD Byproduct," Coal Technology '85, Pittsburgh, Pennsylvania, 1985

"Wet Lime FGD System Design and Early Operating Experience at the City of Grand Haven, Michigan, Board of Light and Power's J. B. Sims Unit 3," National Lime Association, Denver, Colorado, 1983

"Dry SO_2 System Design and Early Operation Experience at Basin Electric's Laramie River Station," 32nd Canadian Chemical Engineering Conference, Vancouver, British Columbia, Canada, and the Joint Power Conference, Denver, Colorado, 1982

"Wet SO_2 Removal Operating Experience at Cincinnati Gas & Electric Company's East Bend Station," American Power Conference, Chicago, Illinois, 1982

"Three Years of SO_2 Control Experience at Winyah Station, South Carolina Public Service Authority," American Power Conference, Chicago, Illinois, 1981

"Lime and Limestone Wet Scrubber Performance," Third International Coal Utilization Exhibition and Conference, Houston, Texas, 1980

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	**)**	
	)	
PROPOSED NEW 35 ILL.ADM.CODE PART 225	**)**	**PCB R06-25**
CONTROL OF EMISSIONS FROM	**)**	**Rulemaking - Air**
LARGE COMBUSTION SOURCES	**)**	

Testimony of James Marchetti

I. QUALIFICATIONS

My name is James Marchetti and I am president of James Marchetti Inc. I have over 25 years of experience in performing various kinds of economic and policy analyses for both the electric utilities and the coal industry. I have completed numerous strategic analyses related to determining the economic and compliance implications to electric generators of complying with specific federal or state regulatory proposals. These regulatory proposals have included: (i) Clear Skies Act and Clean Air Planning Act; (ii) U.S. Environmental Protection Agency's Clean Air Interstate Rule and Clean Air Mercury Rule; (iii) regional and state proposals such as the Ozone Transport Commission's CAIR-Plus proposal and the Pennsylvania Department of Environmental Protection's Mercury Reduction Proposal. The Illinois Environmental Protection Agency's (IL EPA) report entitled *Fossil Fuel-Fired Power Plants* (Section 9.10 Report), included modeling results which I prepared. In conjunction with Edward Cichanowicz and Michael Hein, we (MCH) co-developed the *Emission-Economic Modeling System (EEMS)*, which has been used by both electric generators and coal interests to evaluate both the economic and technological implications of environmental policies. Recent clients have included Utility Air Regulatory Group, Center for Energy and Economic Development, National Rural Electric Co-operative Association, Edison Electric Institute, Midwest Ozone Group, Illinois Energy Association, and individual electric generators.

I have a Masters Degree in City and Regional Planning from the Bloustein School of Planning and Public Policy at Rutgers University, as well as a Masters Degree in Urban Affairs from Boston University. I received a Bachelor of Arts from St. Anselm College. In addition, I did graduate work in economics at New York University.

My testimony addresses the potential compliance costs and implications to IL generators in meeting IL EPA's proposed rule to reduce mercury emissions form IL coal-fired generating units.

II. INTRODUCTION

On March 14, 2006, the Illinois Environmental Protection Agency (IL EPA) filed a proposed rule with the Illinois Pollution Control Board that would require coal-fired electric generating units (EGU) to reduce their mercury emissions sooner and more substantially than the U.S. Environmental Protection Agency's (EPA) Clean Air Mercury Rule (CAMR).

The purpose of the analysis presented in my testimony is to evaluate the compliance costs to IL generators of meeting the reduction requirements proposed in the IL Rule and to isolate the incremental compliance costs between CAMR and the IL Mercury Rule. To better understand mercury emissions attributed to IL generators, this analysis also included an evaluation the EPA's Clean Air Interstate Rule (CAIR) for IL generators. By modeling EPA's CAIR, one can better quantify and understand the level of co-benefits/mercury reductions that are attributed to CAIR compliance for IL generators. In addition, by modeling CAIR, we can better understand the level of SO2 and NOx technology that has to be deployed, as well as the compliance costs and issues related to this technology deployment. Therefore, this analysis included two modeling simulations: (i) IL generator compliance related to meeting CAIR/CAMR; and, (ii) IL generator compliance costs related to meeting CAIR/IL Mercury Rule. In addition, this analysis also discusses the major compliance implications for IL generators in achieving the targets and timetable of the IL Rule.

A brief discussion of the methodology and input assumptions appears in Appendix A. A detailed discussion of the SO2, NOx and mercury control assumptions that were modeled in this analysis appears in Appendix A and B of J.E. Cichanowicz's testimony.

III. IL MERCURY RULE

Briefly, the proposed IL Rule, would require existing EGUs by July 1, 2009 to achieve either a 90% reduction from input mercury levels (mercury in the fuel prior to entering the unit) or an emission standard of 0.0080 lb/GWh (Proposed § 225.230).[1] .The emission standard is based upon gross output or gross GWh (Proposed § 225.230(a)) and generators are allowed to use facility-wide averaging to achieve either one of these reduction targets (Proposed § 225.230(d)).

However, the rule permits what is called "Averaging Demonstrations for Existing Sources" which allows systems to utilize a system-wide average between July 1, 2009 and December 31, 2013 (Proposed § 225.232(a)). This demonstration requires all facilities to achieve a minimum emission standard of 0.020 lb/GWh or 75% reduction from the input mercury, but requires the system to achieve an overall 90% reduction for the time period (Proposed § 225.232(b)). It allows single-facility systems, such as Electric Energy Inc., City Water, Light & Power of Springfield, Southern Illinois Power Cooperative and Kincaid Generating Station, to form a hypothetical system that would allow for participation in this demonstration (Proposed § 225.232(d)(2)(i)). Beginning January 1, 2014, systems would then have to meet the facility-wide standards of 90% or 0.0080 lbs/GWh.

A new unit, which commences operation on or after January 1, 2009, will be required to meet either the emission standard of 0.0080 lbs/GWh or the 90% reduction from input mercury (Proposed § 225.237(a)). A unit at a new source must meet the above standard or reduction on an individual, unit-by-unit basis; however a new unit at an

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[1] Existing EGU is a coal-fired unit >25 MW that produces electricity for sale and was in commercial operation on or before December 31, 2008 (Proposed § 225.230(a)(1)).

existing source would be allowed average with other units at that source (*Compare* Proposed § 225.237 with Proposed § 225.230(d)).

IV. METHODOLOGY AND CONTROL ASSUMPTIONS

MCH's analysis of the Proposed IL Mercury Rule employed the *Emission-Economic Modeling System (EEMS)*, a computer model designed to undertake emission and economic analyses of environmental polices and regulations. *EEMS* identifies a combination of control options (technology versus allowances) that approximates the least cost solution for a given utility system and regulatory (e.g., trading) regime.

The control assumptions that were modeled are as follows:

SO2 Controls

- Wet FGD (WFGD)
- Dry FGD (DFGD)
- Fuel Switching (FS)[2]

NOx Controls

- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)
- SIP Call SCR operating an additional 7 months – (7SCR)

Mercury Controls

- Activated Carbon Injection (ACI)
- Halogenated Activated Carbon Injection (HACI)
- COHPAC (COHP)
- Halogenated COHPAC (HCOHP)
- Fabric Filter (FF)

An important technology deployment presumption is that units older than 50 years at the time a compliance decision is required *do not* receive any control technology. The rationale for the 50 year old rule on technology deployment is that MCH feels industry is unlikely to make major capital investments on older units, which could result in one trying to recover capital on units that may be in excess of 65 years old at the end of the recovery period. The IL Rule is so stringent that the averaging provisions that are included in the Rule are not sufficient to allow companies to avoid controlling the older

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[2] Fuel Switching takes into account switching from high sulfur to a low sulfur coal, as well as switching from a low or compliance coal to high sulfur when installing a FGD system.

units, and the prohibition of trading precludes their buying allowances if they are not able to comply. Therefore, the companies have no choice but to add controls to the older units, contrary to the economic logic of the technology deployment presumption, and this need to control older units is reflected in this analysis. In contrast, however, the technology deployment presumption can be utilized in CAMR, because trading is allowed and was applied in that portion of this analysis.

The selection of specific compliance technologies by the model is not intended to replicate an individual company's compliance decisions; rather, the model results are based upon the application of a set of control assumptions that are uniformly applied across the entire boiler population within a specific (geographical) jurisdiction based upon unit specific information contained in the model's data base.

Capital and operating costs were developed based upon IL electric generators' experience in retrofitting recent SO2, NOx and mercury control technologies. It should be noted that the above mentioned control assumptions represent realistic assumptions in terms of applicability and performance.

V. COMPARISON OF COMPLIANCE EFFECTS OF MEETING CAIR/CAMR AND CAIR/IL MERCURY RULE FOR IL GENERATORS

The focus of this section is to provide a comparison of the compliance effects to IL generators in meeting CAIR/CAMR and CAIR/IL Rule between 2009 and 2018. As shown in Table 1, coal-fired generation is expected to decrease by about 5 percent from 2009 through 2012. This decrease is precipitated by both changes in the dispatch order and a reduction in exports brought about by the IL Rule. However, beginning in 2013 and continuing through 2018, coal-fired generation in IL is expected to be very close to its CAIR/CAMR generation levels, while oil/gas-fired generation will be slightly higher than they would be under CAIR/CAMR.

TABLE 1
IL COAL- & GAS/OIL-FIRED GENERATION: 2005 - 2018
(GWh)

Rules/Fuel	2005	2009	2010	2013	2015	2018
CAIR/CAMR						
Coal	100,171.0	107,818.5	109,862.3	122,429.7	122,730.5	122,342.6
Gas/Oil	3,657.6	3,965.5	4,284.0	5,393.2	6,472.8	6,128.9
CAIR/IL Rule						
Coal	100,171.0	102,515.7	105,072.5	120,647.2	122,073.2	121,759.5
Gas/Oil	3,657.6	3,677.9	4,201.9	5,411.7	6,794.1	6,239.7

As shown above the implementation of the IL mercury rule will reduce coal-fired generation in IL compared to predictions of generation if CAMR were implemented instead. This reduction in generation under the IL rule is expected to reduce fuel costs to those generators; however, at the same time these same generators would lose sales in the wholesale electricity market resulting in this lost generation. The estimate of the lost electricity sales to IL generators between 2009 and 2018, is $972.9 million, and subtracting the savings of reduced coal burned at IL generating units for the same period ($300.7 million), the proposed rule can result in an estimated net economic loss to IL generating operations of $672.2 million, which does not count any compliance costs related to SO2, NOx and mercury controls.[3]

As shown in Table 2, SO2 and NOx emissions are expected to drop significantly under CAIR, because of the preponderance of low sulfur Powder River Basin (PRB) coal being burned by IL generators, coupled with the operation of 5,234 MW of FGD systems and 5,473 MW of SCR systems operating year-round. This combination of PRB coal and SO2 and NOx control technology will significantly reduce both SO2 and NOx emissions in IL, when coal-fired generation is projected to increase by 22.1 percent between 2005 and 2018. As shown in Table 2, the state's mercury emissions under the IL rule are

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[3] The estimate of the lost electricity sales was determined by multiplying the annual loss generation by projected annual wholesale energy prices generated be CRA International's *North American Electricity and Environment Model*. The estimate of fuel cost due to reduced coal usage was determined by converting the annual lost generation into Btu and multiplying this value by the Energy Information Administration's *Annual Energy Outlook 2006* projected regional delivered coal prices by supply region.

projected to be less than the mercury emissions under CAMR. The state's mercury emissions will be significantly reduced under the IL Rule; however, at what cost?

TABLE 2
SO2, NOx and MERCURY EMISSIONS FROM IL GENERATORS
(SO2 & NOx in tons and Hg in pounds)

Rules/Fuel	2005	2009	2010	2013	2015	2018
CAIR/CAMR						
SO2	346,881	322,047	265,278	242,900	246,680	242,124
NOx	133,493	73,747	74,201	77,578	78,189	77,122
Hg	4,617	4,864	4,224	4,054	4,081	3,885
CAIR/IL Rule						
SO2	346,881	306,320	247,276	241,481	247,256	242,166
NOx	133,493	70,806	72,252	77,785	79,935	78,696
Hg	4,617	869	842	924	937	932

Summary of Compliance Costs

To meet the targets and timetables of CAIR/CAMR, IL generators would have to make a capital investment of $740 million in SO2, NOx and mercury control technologies, as illustrated in Table 3. However, under a CAIR/IL Rule regulatory regime, capital investment in control technologies is expected to reach almost $2.44 billion, of which $1.77 billion or 72.5 percent of this investment would be attributed to actual mercury control technologies as opposed to the CAIR co-benefits. This is more than three times the investment or 230 percent more capital than is required under CAIR/CAMR. Further, a very important financing and technology deployment issue related to these mercury controls is that IL generators may have to begin raising this capital by the beginning of 2007 in order for these technologies to be operating by July 1, 2009.[4]

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[4] This analysis assumes that an activated carbon injection would take 6 months to design and construct and a COHPAC would take between 12 to 18 months to design and construct. However, actual design and construction could be considerably longer. Nevertheless, this analysis assumes this shorter period of time.

TABLE 3
CAPITAL INVESTMENT OF SO2, NOx AND MERCURY CONTROL TECHNOLOGIES: 2009 – 2018
(billions of 2006 $)

Rules	SO2	NOx	Hg	Total
CAIR/CAMR	0.38	0.30	0.06	0.74
CAIR/IL Rule	0.38	0.29	1.77	2.44
Differential Cost	0	-0.01	1.71	1.70

The cumulative annualized compliance costs for IL generators between 2009 and 2018 under CAIR/CAMR are projected to be $3.10 billion, as shown in Table 4.[5] However, under a CAIR/IL Rule regulatory regime, compliance costs are projected to be $5.10 billion for the same 2009 to 2018 time period. Consequently, the proposed IL Rule would increase the cost of operating coal-fired generation facilities in IL by $2.00 billion between 2009 and 2018.

TABLE 4
COMPARISON OF CUMULATIVE ANNUALIZED COMPLIANCE COSTS FOR SO2, NOx AND MERCURY CONTROLS: 2009-2018
(billions of 2006 $)

Rules	SO2	NOx	Hg	Total
CAIR/CAMR	1.91	0.65	0.54	3.10
CAIR/IL Rule	1.85	0.62	2.63	5.10
Differential Cost	-0.06	-0.03	2.09	2.00

This analysis included allowance sales for those generators that had excess or banked allowances under both CAIR/CAMR scenario and the CAIR only portion of the CAIR/IL Rule scenario. These sales were netted out of the total annualized compliance costs to control SO2, NOx and mercury under CAIR/CAMR. Allowance sales for IL generators under CAIR/ CAMR totaled $450 million for the years between 2009 and 2018.

Because of the co-benefits of CAIR reductions to mercury reductions and the impacts of relying on co-benefits to comply with mercury reduction requirements on the

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[5] Annualized compliance costs included an annual capital charge for control technology, annual fixed and variable O&M costs for control technology, changes in annual fuel costs due to compliance and allowance costs.

cost of mercury compliance, this analysis discusses in some detail the control regimes that would be employed for compliance with the CAIR.

CAIR SO2 Compliance

Under a CAIR/CAMR regulatory regime, IL generators are projected to continue to burn Powder River Basin (PRB) coal; therefore, no additional FGD systems are projected in this analysis beyond those systems already announced by generators to meet CAIR. Consequently, the only modeled compliance decision under CAIR was a fuel switch on two units equipped with a WFGD presently burning a medium sulfur Eastern Interior coal switching to a PRB coal. By 2010, PRB coals are projected to be consumed by 94.6 percent of IL's total coal-fired capacity (17,141 MW).

The projected price discrepancy between PRB and Eastern Interior coals negates any economic incentive to switch to a higher sulfur coal when retrofitting a FGD system. Consequently, if IL generators were required to scrub extremely low sulfur PRB coal, they would incur very high removal costs ($/ton basis). Specifically, the cheapest scrubber that was computed for an IL unit was a DFGD with a removal cost of $2,600/ton, while most DFGD removal costs for IL generating units range between $3,000 to $4,200/ ton. Therefore, the cheapest or least cost compliance option for many IL generators to comply with CAIR would be to purchase the amount of SO2 allowances for those SO2 emissions that exceed their system-wide CAIR allowance caps.

The primary factor affecting the decrease in CAIR SO2 compliance costs under a CAIR/IL Rule regulatory regime is a decrease in coal-fired generation during the period from 2009 – 2012, which is displayed in Table 1. This decrease in generation reduces both annual control technology costs and allowance purchases.

CAIR NOx Compliance

Similar to SO2, under a CAIR/CAMR regulatory regime, the burning of PRB coal by IL generators has a significant effect on NOx compliance. The modeling projected two additional units, representing 1,784 MW of coal-fired capacity, to be retrofitted with SCR systems, at initial removal costs of between $1,500 to $1,600/ton. Most of the projected NOx removal costs by SCR for PRB-fired units range between $3,000 to $10,000/ton, because of the very small reductions that can be achieved from relatively low NOx emission levels. Therefore, to comply with CAIR NOx provisions, IL generators are projected to primarily rely on a combination of extending the operation of existing SIP Call SCR equipment year-round, the installation of SNCR technology, and NOx allowance purchases, in addition to the two projected SCRs. The existing SIP Call SCRs (10), which represent 3,689 MW of the state's coal-fired capacity, would provide inexpensive NOx reductions by operating an additional 7 months (7SCR). The incremental removal cost for these existing SCRs ranges between $130 to $280/ton. IL generators are projected to install 7 SNCRs, which can provide modest NOx reductions of 20-35% for costs ranging from $1,300 to $2,000/ton.

The primary cause of the decrease in CAIR NOx compliance costs under the CAIR/IL Rule regime is a result of two SNCRs, which were deployed in the CAIR/CAMR simulation, not being installed in the CAIR/IL Rule simulation. These two deployments were affected by the model's projected decrease in coal-fired generation, which resulted in an increase in their $/ton removal costs and pushed them over the allowance price.

CAMR and *IL Rule Compliance*

The model found under CAMR, by 2018, 4,192 MW of IL's coal-fired capacity would install mercury control technologies at a removal cost of not exceeding $42,000 per pound on units not exceeding 50 years old at the time of compliance. For other coal units (units 50 years old or less), the model computed extremely high removal costs ranging from $51,000 to $545,000 per pound; consequently, CAMR allows IL electric generators the flexibility to make the most rationale, cost-effective and least costly compliance decisions with regard to mercury compliance.

Under the IL Rule, state generators would have to expend almost $2.63 billion between 2009 and 2018 to meet and maintain the reduction requirements spelled out in the rule. These compliance costs are almost $2.1 billion above or four times greater than the compliance costs estimated for CAMR compliance ($540 million) over the same period. The rule would force IL generators to spend an additional $200 million per year to operate their coal-fired facilities in the state.

The IL Rule forces state generators to install mercury control technology on 14,564 MW of coal-fired capacity, which represents 83.6 percent of state's total coal-fired capacity (17,141 MW) in 2010. The IL Rule prohibits federal trading and, as it provides no state mercury allowance trading, IL generators are forced not only to install technology on older units, but to install the more expensive filter technology (COHP, HCOHP and FF) to control mercury. Specifically, almost 73 percent (or 10,737 MW) of the projected mercury control technology will be filter technology; thereby, removal costs will average around $75,000 per pound.

Due to the stringency of both the timing and the reduction targets of the IL Rule, some generators are faced with installing other types of pollution control technology earlier than planned, thereby incurring additional compliance costs, as well as making capital investments much earlier than planned. Specifically, the IL Rule would force Dynegy to accelerate the installation of the fabric filters and DFGDs on the three Baldwin units by one year, one and one-half years, and two and one-half years before their planned deployment These equipment-forcing deployments are required in order for the Baldwin plant to meet the rule's emission standards in 2009. In addition, 20 units representing 3,093 MW of generating capacity would be greater than 50 years old in 2009 and would be required to install mercury controls.

The modeling results revealed that no IL electric generating system would be able to take advantage of the "*Averaging Demonstration for Existing Sources*." In addition, based upon the control assumptions, the modeling predicted that two plants (Vermilion and Newton) representing 1,419 MW of capacity (8.2 % of the operating coal capacity in

2010) would not be able to achieve either a 90% reduction from input mercury levels or the 0.0080 lb/GWh using facility averaging.[6]

The difference in compliance costs between the two rules is significant. Under CAMR the average $/lb removal costs are expected to range between $30,000 to $33,000 per pound during Phase I and increase to almost $42,000 per pound in the beginning of Phase II (2018). CAMR provides IL generators the flexibility to comply at the least possible cost, thereby allowing IL generators to avoid very expensive mercury controls through a market-based approach. Even though the IL Rule, through its command-and-control regulatory regime, will reduce mercury emissions in the state, it will come at a greater cost to in-state generators than to those of other states in the region who will be using a less restrictive, trading regime. As mentioned earlier, the annualized compliance costs for the IL rule are four times greater than CAMR, with the average control costs ($/pound) being more than double those of CAMR. The marginal cost of control for the IL Rule will almost reach about $400,000 per pound in 2009, which indicates equipment being deployed on smaller and less-efficient coal units.

Another potential implication with regard the IL Rule is the uncertainty of whether IL generators would be able to recover the $1.77 billion they would need to invest in the mercury control equipment before July 1, 2009. If generators are unable to recover their investment, it may force them to retire or shutdown some older/ uneconomical units that are required to install mercury control technologies under the IL Rule. A potential casualty could be some or all of the previously mentioned 3,093 MW of capacity that would be greater than 50 years old in 2009 and required to install mercury control technology.

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[6] It should be noted that this simulation of the IL Rule did not evaluate any fuel blending or switching options to control mercury, specifically substituting IL Basin coal for PRB coal. Potential implications of any blending or substitution for IL generators are (i) increased fuel costs; (ii) additional CAIR SO2 compliance costs, such as additional allowance purchases; and, (iii) possible additional investment to the unit to burn a higher sulfur bituminous coal.

VI. SUMMARY OF COMPLIANCE ISSUES

This evaluation illustrates, as regulatory regimes become more stringent, not only do electric generating compliance costs increase significantly, but there are serious implications in meeting very extreme emission targets and timetables. However, there are major policy issues that arise in meeting the targets and timetables of the IL Rule, and they are:

- The IL rule would force IL generators to invest an additional $1.71 billion into their coal-fired generating units to control mercury, which is triple the capital investment required by CAIR/CAMR;
- The IL rule would increase the cost of operating the state’s coal-fired facilities by $200 million per year;
- The inflexibility of the IL Rule requires the deployment of more expensive filter technology to control mercury on older units;
- The IL Rule would force some IL generators to install other pollution control equipment much earlier than planned; and,
- It is uncertain whether IL generators will be able to recover the $1.77 billion in capital investment required to meet the IL Rule.

VII. COMPARISON OF COMPLIANCE COSTS

The focus of this section is to offer a comparison of the compliance costs presented in this analysis (MCH) and those presented in the IL EPA Technical Support Document (TSD) and the ICF analysis entitled *Analysis of the Proposed Mercury Rule* (ICF) and discuss the underlying factors that may contribute to their differences. The table below presents the level of capital investment and annualized cost for the year 2009/2010 from each of the three analyses.

TABLE 5
COMPARISON FOR MERCURY CONTROL COMPLIANCE COSTS
(in 2006 million dollars)

	MCH	**TSD**	**ICF**
Capital Investment			
CAMR (2010)	**29.1**	**35.5**	**NA**
IL Rule (2009)	**1,770.0**	**75.6**	**NA**
Annualized Cost			
CAMR (2010)	**49.7**	**33.5**	**NA**
IL Rule (2010)	**276.4**	**66.1**	**151.3**

Note: 1. The 2009 value for the ICF analysis represents a full year of compliance and their values escalated from 1999 dollars to 2006 dollars.
2. NA indicates information in not available.
3. The ICF value was computed based upon differential production cost between CAIR/CAMR and CAIR/IL Rule (not including the reduced fuel costs) for 2009 from Table 1-3 of their report.

As shown in the above table the TSD estimates more capital investment beginning in 2010 under CAMR, than MCH; however, the MCH analysis allows IL generators purchasing allowances under CAMR trading regime and avoiding installing expensive mercury controls. MCH projects by 2017, IL generators will have invested $55.2 million in mercury control equipment to comply with CAMR. The most significant difference between MCH and the TSD becomes evident in meeting the requirements of the IL Rule. The TSD projects capital investment to be $75.6 million, whereas, MCH projects that $1.77 billion will need to be invested in mercury control equipment by IL generators by 2009, which is 23 times greater than the TSD estimate.

Why such an enormous difference? The primary factor is the control assumptions used in both analyses. Specifically, the MCH takes into account more detailed specific facility/unit characteristics than the TSD, which ultimately affects the unit investment costs ($/kW) and effective removal of the mercury control equipment. For example, in evaluating the deployment of ACI or HACI on a specific unit, MCH took into account the size of the specific collecting area (SCA), and if the SCA was less than 250 ft^2/kacfm, the electrostatic precipitators (ESP) would have to be upgraded by an additional field in order to achieve the projected removal percentage. This upgrade requires an additional amount of capital to be invested beyond the capital required for the mercury control equipment.

Another example of the specificity incorporated into the MCH modeling is whether a unit's flue gas contains SO3, which can inhibit the removal efficiency of a mercury control technology. Specific unit or facility characteristics, which can affect both the cost and operation of mercury control equipment, are not apparent in the TSD analysis.

The table below illustrates, the difference in unit costs for ACI and COHPAC between MCH and the TSD based upon an average $/kW.

TABLE 6
MCH AND TSD COMPARATIVE UNIT TECHNOLOGY COSTS: $/kW
(in 2006 dollars)

Technology	MCH	TSD
ACI	15.18	2.50
COHPAC	163.37	60.00

As can be seen from the above table, the inclusion of more detailed unit/facility characteristics tends to significantly increase the unit costs for ACI and COHPAC. Consequently, the modeling of the MCH control assumptions yielded a significant amount of filter technology to control mercury (10,737 MW) in comparison to the TSD (627 MW). A detailed discussion of the mercury control assumptions used in the MCH modeling can be found in Appendix A of J.E. Cichanowicz's testimony.

In terms of the annualized compliance costs, illustrated in Table 5, the MCH costs are expected to be greater than the TSD, based upon the previously discussed issues. The ICF costs tend to fall between MCH and the TSD; however, the ICF report provides very little information on their assumptions, which makes it difficult to track their findings. The modeling assumes a 90 percent removal of mercury by a mercury control system, as presented in Table 3.2 of Appendix C. ICF estimates that 10,590 MW of IL coal-fired capacity would have to install mercury control systems by 2009. However, ICF does not differentiate the type of control system that has to be installed (e.g., ACI, COHPAC). ICF's projected 10,590 MW of controlled capacity represents about 73 percent of the control capacity in 2009 estimated by MCH.

ICF estimates that about 2,500 MW of FGD capacity would have to be installed in 2015 to meet CAIR and projects about 88 percent of this capacity would be moved up to 2010 to provide additional mercury reductions. ICF also projects, in conjunction with these FGD retrofits, there would a shift from sub-bituminous to bituminous coals. However, future coal price projections make it improbable that IL generators would be switching to bituminous coals between 2009 and 2015, and it is very unlikely that all the 2,200 MW would be able to be installed and operating by the beginning of 2009. Therefore, ICF may have over-estimated the amount of co-benefit removal that could be achieved in 2009, which would then under-estimate the amount of mercury control technology that would have to be operating in 2009.

APPENDIX A

METHODOLOGY AND INPUT ASSUMPTIONS

Model: This study employed the *Emission-Economic Modeling System (EEMS)*, a computer model designed to undertake emission and economic analyses of environmental polices and regulations. *EEMS* identifies a combination of control options (technology versus allowances) that approximates the least cost solution for a given utility system and regulatory (e.g., trading) regime. The order in which individual units are assumed to deploy their initial compliance option is determined by their dispatch order removal costs ($/ton) with the cheapest units assumed to deploy control technology first. Removal cost values are compared to allowance prices, if it is a market based trading regime, to determine if technology is deployed or if allowances are purchased. However, under a command-and-control regulatory regime, which is effectively what the IL Rule is because of the lack of flexibility in the rule, *EEMS* systematically assigns control technology until the reduction target is achieved at the least possible cost.

CAIR SO2 and NOx & CAMR Mercury Allowance Allocations: The SO2, NOx and Mercury unit allowance allocations followed the model cap and trade rules outlined in both CAIR and CAMR.

CAIR – SO2 Allocations

The CAIR unit SO2 allowances were determined by discounting 2010 Title IV allocations by 50% (dividing by 2) for years 2010 through 2014 and 65% (2.86) for the years 2015 and beyond.

CAIR – NOx Allocations

The allocation to units on-line before January 1, 2001 was based upon the average of the highest three years of heat input for the years 2000 – 2004. Fuel adjustment factors (coal – 1.0, oil – 0.6, gas – 0.4) were applied to the average values. For those units that came on-line January 1, 2001 and thereafter, they received a unit allocation from a new source set-aside (NSSA) until they achieved a 5-year baseline. Whereas, an existing unit’s baseline was determined by heat input, new unit baseline was determined by “modified output” format, which involved multiplying a unit’s gross output by a stipulated heat rate (coal - 7,900 Btu/kWh and gas/oil – 6,675 Btu/kWh). Once a 5-year baseline was established, the average of the highest three years would be computed and added into the state’s other existing units average heat input to compute an allocation proportion.

The NSSA for CAIR is 5% for the years 2009 – 2013 and 3% for 2014 and thereafter. The NSSA is allocated to units based upon the previous year’s NOx emissions and in most cases is pro-rated to units because the demand will exceed the availability of NSSA allowances.

The table below illustrates the assumed NOx allowance allocation schedule, which also indicates when new units would move from a NSSA allocation to (full) allocation share as existing units under CAIR.

TABLE A-1
NOx UNIT ALLOCATION SCHEDULE UNDER CAIR

Control Period	Issued	New Units – Full Allocation
2009 - 2014	2006	NA
2015	2009	On-line 2001,2002,2003
2016	2010	On-line 2004
2017	2011	On-line 2005
2018	2012	On-line 2006

CAMR – Mercury Allocations

The allocation to units on-line before January 1, 2001 was based upon the average of the highest three years of heat input for the years 2000 – 2004. Coal adjustment factors (Bit. – 1.0, Sub – 1.25, Lignite – 3.0) were applied to the annual heat input values. For those units that came on-line January 1, 2001 and thereafter, they received a unit allocation from a new source set-aside (NSSA) until they achieved a 5-year baseline. Whereas, an existing unit's baseline was determined by heat input, new unit baseline was determined by the same "modified output" format as applied under the CAIR, which involved multiplying a new coal's unit's gross output by a stipulated heat rate (coal - 7,900 Btu/kWh). There is no differentiation in this stipulated heat rate by coal type. Once a 5-year baseline was established, the average of the highest three years would be computed and added into the state's other existing units average heat input to compute an allocation proportion.

The NSSA for CAMR is 5% for the years 2010 – 2014 and 3% for 2015 and thereafter. The NSSA is allocated to units based upon the previous year's Hg emissions and in most cases is pro-rated to units because the demand will exceed the availability of NSSA allowances.

The table below illustrates the assumed Hg allowance allocation schedule and also indicates when new units would move from a NSSA allocation to (full) allocation share as existing units under CAMR

TABLE A-2
MERCURY UNIT ALLOCATION SCHEDULE UNDER CAMR

Control Period	Issued	New Units – Full Allocation
2010 - 2014	2006	NA
2015	2009	On-line 2001,2002,2003
2016	2010	On-line 2004
2017	2011	On-line 2005
2018	2012	On-line 2006

In terms of allowance trading under CAIR and CAMR, NOx allowances can be traded within the 25-state NOx CAIR region and SO2 and Mercury allowances can be traded nationally, with no restrictions on banking.

An affected unit for the both CAIR and CAMR followed the definitions outlined in both rules, which are fossil (coal for CAMR) generating units greater than 25 MW that sell at least one-third of its power to the grid.

Generation, Fuel and Allowance Forecasts: The unit generation forecasts for IL coal and gas/oil units for the years 2006 to 2018 were provided by CRA International and were derived from their *North American Electricity & Environment Model (NEEM)*. Projected CAIR and CAMR allowance prices (2009 – 2018) were also generated by *NEEM* based upon MCH's SO2, NOx and Mercury control assumptions. The SCR basis for NOx allowance prices was $200/kW and the FGD basis for SO2 allowance prices was $300/kW. The basis for the mercury allowance prices was $120/kW for a COHPAC and $35/kW for ACI and halogenated ACI, which includes upgrades to the ESPs with SCA of 250 or less, which are discussed in Appendices A and B of J.E. Cichanowicz's testimony.

The table below illustrates the projected CAIR (SO2, NOx) and CAMR (mercury) allowance prices in 2006 dollars for selected years.

TABLE A-3
CAIR AND CAMR ALLOWANCE PRICES
(2006 $)

Year	SO2($/ton)	NOx($/ton)	Hg($/lb)
2009	0	1,934	0
2010	745	2,069	31,449
2013	913	1,791	32,767
2015	1,046	2,050	37,514
2018	1,282	2,512	45,958

Note: 1. The CAIR SO2 allowance prices reflect the discounting of Title IV allowances by 50% (2.0) from 2010 – 2014 and 65% (2.86) for 2015 and beyond.

NEEM also provided projected delivered coal and gas prices to IL generators and they were used in conjunction with projected regional fuel prices from Energy

Information Administration’s *Annual Energy Outlook (AEO2006)* and IL coal price forecasts from Energy Venture Analysis’s *FuelCast* model.

Addendum of Anne E. Smith, Ph.D.
to the Testimony of Krish Vijayaraghavan and James Marchetti

As an expert on modeling impacts of emissions control policies on electricity markets and electric sector investment decisions, I prepared, and documented in this Addendum, the projections of elemental and divalent emissions from individual stacks serving coal-fired electric generating units throughout the United States used as inputs to the mercury deposition analysis that Mr. Krish Vijayaragahavan describes in his testimony. This Addendum also documents the assumptions and data provided as inputs to Mr. James Marchetti regarding unit-level generation and coal choices of Illinois coal-fired units and emissions allowance prices.

I. BACKGROUND AND QUALIFICATIONS

I am an economist and decision analyst who has specialized for the past thirty years in environmental risk assessment, cost and economic impact assessment, and integrated assessment to support environmental policy decisions. In my career, I have worked for government and private sector clients on a global basis. From 1977 to 1979, I served as an economist in the Office of Policy Planning and Evaluation of the U.S. Environmental Protection Agency ("U.S. EPA"). From 1979 through 1985, I consulted on risk assessment and risk management for environmental policy to the U.S. EPA, to governments in Europe, and on United Nations expert committees convened in Geneva, Rome, and Thailand. From 1985 through 1998, I was employed by Decision Focus International (later named Talus Solutions, Incorporated), which was a risk analysis consulting firm that had substantial practices supporting electric utility operating and business decisions, and supporting policy assessment for the U.S. EPA. From 1988 to 1990, I advised the Director of the National Acid Precipitation Assessment Program ("NAPAP") on integrated assessment of the costs and benefits of policies to control SO_2 and NO_X. Since 1998, I have been a Vice President of CRA International, a global economics consulting firm with a substantial practice on issues related to energy and the environment.

I have also served as a member of several committees of the National Academy of Sciences focusing on risk assessment and risk-based decision making. I have testified several times before committees of the U.S. Senate on risks from fine particulate matter, on costs and benefits associated with regional haze policies, and on costs of climate change policies.

I have been analyzing multi-pollutant policies for the U.S. utility sector, including mercury, SO_2, NO_X, and other emissions limitations, for the past six years. Under funding from the Edison Electric Institute, and with technical support on data from the Electric Power Institute ("EPRI"), I led a team that developed the leading alternative model to the IPM model that U.S. EPA uses for all of its electric-sector multi-pollutant policy modeling. I supported the utility industry in assessing impacts of alternative mercury MACT controls under Section 112 of the Clean Air Act, and I also prepared an expert report on the costs and effectiveness of the proposed Clean Air Mercury Rule ("CAMR") that was used in comments submitted by EPRI on the proposed CAMR rule, and later also on the Notice of Data Availability ("NODA") regarding the proposed CAMR. My projections of speciated mercury emissions were used as a key input to the mercury deposition modeling that EPRI has also documented in comments on the proposed CAMR rule, in response to the mercury NODA, and in comments on the reconsideration of the CAMR rule. I also developed a cost-effectiveness framework for evaluating mercury control policies that was published as an EPRI report in 2003. The latter study demonstrated how to integrate projections of cost, deposition, exposure, and health risks for alterative mercury control approaches.

I received my Ph.D. (1984) in economics with a Ph.D. minor in engineering-economic systems from Stanford University. My M.A. (1981) in economics was also from Stanford University. I received my B.A. (1977) in economics from Duke University, *summa cum laude*. A copy of my curriculum vitae with my major publications is attached.

II. ANALYSIS OF ELECTRICITY MARKET OPERATIONS

A. Overview

I have performed two simulations of the U.S. electricity market using a model that is described below. The first simulation is one in which the Clean Air Interstate Rule (“CAIR”), the Clean Air Visibility Rule (“CAVR”), and CAMR are applicable throughout the United States, including Illinois. I will call this the “CAIR/CAMR” scenario. The second simulation also includes CAIR, CAVR, and CAMR, but Illinois’ proposed mercury rule replaces the CAMR for units in Illinois. I will call this the “IL Rule.”[7]

The results of my simulations include speciated mercury emissions for each coal-fired plant stack in the continental United States. I have provided these speciated mercury emissions to Mr. Krish Vijayaraghavan of AER, Incorporated. Other results include annual generation and coal choices for Illinois coal-fired generators and allowance prices for SO_2, NO_X and mercury for both the CAIR and CAMR policies. I have provided these results to Mr. James Marchetti.

B. CRA’s North American Electricity and Environment Model

My simulations have been conducted using CRA’s North American Electricity and Environment Model (“NEEM”). NEEM is a linear programming model that simulates a competitive electricity market for the continental United States by minimizing the present value of incremental costs to the electric sector while meeting electricity demand and complying with relevant environmental limits. NEEM was designed specifically to be able to simultaneously model least-cost compliance with all state, regional and national, seasonal and annual emissions caps for SO_2, NO_X and Hg. The least-cost outcome is the expected result in a competitive wholesale electricity market.

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[7] This case starts with the CAIR/CAMR case and removes Illinois coal generators from CAMR. The CAMR cap applied to the remaining states is reduced by the amount of Illinois’ allocations in 2010 and 2018, respectively. Each Illinois coal unit in excess of 25 MW is then required to meet the 0.008 lbs/GWh mercury constraint, or 90% removal constraint starting in 2009. The IL Rule case does not address the proposed TTBS.

NEEM is a process-based model of U.S. electricity markets and portions of the Canadian system. U.S. electricity markets are divided into 24 individual demand regions (based on NERC sub-regions) and interconnected by limited transmission capabilities (also based on NERC data). Coal units in particular are represented in detail as these are most affected by environmental regulation. All coal units greater than 200 MW in size are individually represented in the simulation.[8] All non-coal generating units in the United States are also represented in the model with some level of unit aggregation. Units are dispatched to load duration curves within each region. There are 20 load segments spread over three different seasons.

NEEM produces forecasts of short-term and long-term decisions such as coal choices, investments in pollution control equipment, new capacity additions, unit utilization, unit retirements, and unit emissions. NEEM also produces associated projections of wholesale electricity prices by region, capacity values, and allowance prices for emissions that are subject to a cap.

CRA International has used NEEM extensively to assess electric sector responses to many different types of national, regional and state environmental policies in analyses for EPRI, the Edison Electric Institute, the National Rural Electric Cooperatives Association, and for a number of individual utilities and other companies. NEEM has also been licensed to clients for their in-house modeling purposes.

NEEM is a similar model to the IPM model that is used extensively by the U.S. EPA, and also has been used by the IEPA in this proceeding. Both models are dynamic, linear programming models of the U.S. electricity sector. The models both minimize the present value of incremental costs subject to a set of operational constraints. The primary difference between NEEM and IPM is in the exogenous assumptions used in the

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[8] For this analysis, even the smallest coal units in Illinois were individually represented in NEEM to provide greater accuracy.

respective models, such as cost and effectiveness of control technologies, fuel prices, and future electricity demand levels.

This type of model is particularly well suited to evaluate environmental policies that affect the electric sector, as it has a long-term focus necessary to assess major capital investments like retrofit decisions and a national scope necessary to simulate emissions markets that affect compliance planning. This type of model is usually used to compare between alternative scenarios, thus providing a “controlled experiment” regarding the relative impacts of two possible future policy paths. This comparative format is useful because it mitigates much of the uncertainty that is associated with any single projection. The appropriateness of this type of model is reflected in the fact that it has been used to evaluate every major electricity sector emissions policy in the last twenty years. The extensive use of these models has also made them well understood in the modeling community, and implies that their internal computations have withstood repeated scrutiny and critique. The primary concern when evaluating new simulations from NEEM or IPM should be focused on the quality of their input assumptions.

C. Key Modeling Assumptions

As discussed above, the NEEM model is a national model of the electricity sector. From the model outputs, I have provided national emissions results to Mr. Vijayaraghavan. I have provided unit-specific results for Illinois units to Mr. Marchetti, along with national emissions allowance prices. The results provided to Mr. Vijayaraghavan and Mr. Marchetti are from the same model runs and, therefore, are mutually consistent with each other.

I provided speciated mercury emissions outputs to Mr. Vijayaraghavan for coal-fired units for the entire continental U.S. However, as the focus of the impacts is on Illinois, I summarize my assumptions for the Illinois coal units in detail here.

I began by defining the relevant set of Illinois coal plants and their existing equipment. This starting point determines the need for future controls to comply with the more stringent requirements of the CAIR, CAMR and the Illinois' proposed mercury rule. Table 1 includes the 22 coal plants in Illinois that would be subject to the proposed mercury rule. There are 51 operating coal units at these plants that account for 15 GW of capacity.[9]

Table 1: Coal Plants in Illinois

Plant Name	# of Units	MW	Existing Equipment
Baldwin	3	1,751	SCR (1,2), CSESP (1,2,3)
Coffeen	2	900	SCR (1,2), CSESP (1,2)
Crawford	2	532	CSESP (1,2)
Dallman	3	365	Wet FGD/SCR/CSESP (1,2,3)
Duck Creek	1	366	Wet FGD/SCR/Fabric Filter
E.D. Edwards	3	740	SCR (3), CSESP (1,2,3)
Fisk	1	326	CSESP
Havana	1	428	SCR, HSESP
Hennepin	2	289	CSESP (1,2)
Hutsonville	2	153	CSESP (1,2)
Joliet 29	2	1,036	CSESP (1,2)
Joliet 9	1	314	CSESP
Joppa	6	1,020	CSESP (1-6)
Kincaid	2	1,158	SCR (1,2), CSESP (1,2)
Marion	2	272	Wet FGD/SCR (1), CFB (2)
Meredosia	3	339	CSESP (1,2,3)
Newton	2	1,110	CSESP (1,2)
Powerton	2	1,538	CSESP (1,2)
Vermilion	2	176	CSESP (1,2)
Waukegan	3	789	HSESP (1), CSESP (2,3)
Will County	4	1,060	HSESP (1), CSESP (2,3,4)
Wood River	2	468	CSESP (1,2)

I have relied upon information provided by Mr. Ed Cichanowicz (and included as Appendix C to Mr. Marchetti's testimony) for the costs and characteristics of mercury controls in my analysis. Available mercury-specific controls include activated carbon injection ("ACI"), halogenated activated carbon injection ("HACI"), and ACI plus Fabric Filter. Some mercury is also removed by existing particulate control equipment, and mercury removal can be further enhanced by wet or dry scrubbers ("wet FGD" and "dry

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[9] This table does not include the two CWLP units at Lakeside as these are slated to retire prior to needing to install controls to comply with the proposed mercury rule.

FGD," respectively) and selective catalytic reduction ("SCR"). These reductions, sometimes called "co-benefits" vary by type of plant and coal rank. I have also relied upon Mr. Cichanowicz for the mercury emission modification factors ("EMFs") that reflect these co-benefits.

Mr. Vijayaraghavan's mercury deposition analysis requires that mercury emissions be speciated between elemental mercury and divalent mercury.[10] The speciation of the mercury that is emitted is a function of the rank of coal and the equipment configuration of the coal unit. Table 2 reports the percentage of mercury that I assumed to be emitted as elemental mercury for each equipment configuration and coal rank; the remainder is emitted as divalent mercury. EPRI developed the values in Table 2 based on data from EPA's 1999 Information Collection Request[11] ("ICR"), and adjusted by EPRI researchers based on post-ICR field experience. These values are documented in EPRI's formal written comments to U.S. EPA on the proposed CAMR rule.[12]

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[10] Particulate mercury is considered *de minimis* and is not provided to AER. It is my understanding that Mr. Vijayaraghavan has apportioned a small fraction of the divalent mercury emissions as particulate mercury.

[11] See http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html for details.

[12] Part of Docket No. OAR-2002-0056 and available at http://epa.gov/mercury/pdfs/OAR-2002-0056-2578.pdf.

Table 2: Speciation of Mercury Emissions (% Elemental)

Equipment	**Bituminous**	**Subbituminous**	**Lignite**
FF/Dry FGD	70%	90%	95%
FF/Dry FGD/SCR	30%	90%	95%
FF/Wet FGD	45%	85%	85%
FF/Wet FGD/SCR	40%	85%	85%
FF	5%	30%	30%
FF/SCR	5%	30%	30%
CSESP/Dry FGD	90%	95%	95%
CSESP/Dry FGD/SCR	60%	95%	95%
CSESP/Wet FGD	85%	90%	90%
CSESP/Wet FGD/SCR	60%	90%	90%
CSESP	35%	60%	55%
CSESP/SCR	10%	60%	55%
HSESP/Dry FGD	40%	80%	80%
HSESP/Dry FGD/SCR	40%	80%	80%
HSESP/Wet FGD	80%	98%	95%
HSESP/Wet FGD/SCR	60%	98%	95%
HSESP	40%	70%	70%
HSESP/SCR	10%	70%	70%
New Coal Units	40%	85%	85%
FF = Fabric Filter; FGD = Flue Gas Desulfurization; SCR = Selective Catalytic Reduction; CSESP = Cold-Side ESP; HSESP = Hot-Side ESP			

The characteristics of the coals burned by Illinois generators are another important input to NEEM. The majority of Illinois generators are currently burning Powder River Basin ("PRB") coal, which is subbituminous coal from Wyoming that has relatively low sulfur content. Some Illinois generators burn Illinois Basin coals that are mined in Illinois, Indiana and Kentucky which is a bituminous coal. Table 3 shows the characteristics of these coals assumed in NEEM, which are based on ICR data reported to the U.S. EPA.

Table 3: Characteristics of Coals Burned by Illinois Generators

Coal Description	**Heating Value (Btu/lb)**	**SO_2 Content (lbs/MMBtu)**	**Hg Content (lbs/TBtu)**
Illinois Basin – High Sulfur	11,395	5.20	6.44
Illinois Basin – Medium Sulfur	11,395	2.80	6.44
Illinois Basin – Low Sulfur	11,395	1.70	6.44
PRB – North	8,380	0.89	7.08
PRB – Central	8,562	0.75	5.42
PRB - South	8,854	0.65	5.76

D. Emissions Results Provided to Mr. Vijayaraghavan

I have provided to Mr. Vijayaraghavan speciated mercury for each power plant stack that emits Hg from coal-fired generating units. I provided this information for the CAIR/CAMR case for 2006, 2010 and 2020 and for the IL Rule for 2010. Summary state-level speciated emissions for these scenarios are included in Table 3, Table 4, Table 5 and Table 6, respectively.

Table 3: CAIR/CAMR 2006 Mercury Emissions from Coal-Fired Units (Pounds)

State	Elemental	Divalent	Total
AL	1,899	2,239	4,138
AR	915	591	1,506
AZ	1,184	167	1,351
CA	28	23	51
CO	747	437	1,183
CT	51	94	145
DE	182	318	500
FL	2,124	1,127	3,251
GA	1,810	2,704	4,514
IA	1,238	743	1,980
IL	3,052	2,202	5,254
IN	2,091	2,364	4,455
KS	1,626	402	2,028
KY	1,480	1,407	2,887
LA	807	545	1,353
MA	104	343	447
MD	548	1,482	2,031
MI	1,688	1,622	3,310
MN	1,174	437	1,611
MO	2,528	1,579	4,107
MS	295	316	611
MT	1,026	104	1,130
NC	1,125	3,520	4,644
ND	1,787	524	2,311
NE	699	472	1,170
NH	33	119	151
NJ	135	463	597
NM	669	95	763
NV	144	72	216
NY	599	1,024	1,622
OH	1,892	4,337	6,229
OK	1,307	802	2,109
OR	89	73	161
PA	2,320	4,436	6,757
SC	438	1,208	1,646
SD	70	46	116
TN	1,121	1,031	2,152
TX	5,044	2,469	7,513
UT	597	167	764
VA	748	1,216	1,964
WA	524	58	582
WI	858	543	1,401
WV	1,195	2,952	4,147
WY	2,156	482	2,638
Total	50,144	47,351	97,495

Table 4: CAIR/CAMR 2010 Mercury Emissions from Coal-Fired Units (Pounds)

State	Elemental	Divalent	Total
AL	2,050	1,637	3,686
AR	794	476	1,269
AZ	1,187	167	1,354
CA	28	23	51
CO	742	417	1,159
CT	51	94	145
DE	137	205	342
FL	691	545	1,236
GA	2,351	2,010	4,361
IA	1,167	687	1,853
IL	2,766	1,707	4,472
IN	2,006	1,603	3,609
KS	1,070	340	1,410
KY	1,489	1,091	2,580
LA	894	557	1,451
MA	104	343	447
MD	386	821	1,207
MI	1,811	1,703	3,514
MN	864	229	1,093
MO	1,801	1,015	2,815
MS	295	298	593
MT	848	119	968
NC	1,566	1,212	2,778
ND	1,150	419	1,569
NE	533	360	894
NH	33	119	151
NJ	126	344	470
NM	671	95	766
NV	146	72	217
NY	371	639	1,009
OH	1,606	2,071	3,677
OK	1,121	640	1,761
OR	90	73	162
PA	1,663	2,108	3,771
SC	583	719	1,303
SD	114	75	190
TN	1,283	850	2,133
TX	5,331	1,587	6,918
UT	604	167	771
VA	633	804	1,436
WA	403	45	448
WI	1,105	472	1,577
WV	1,016	1,208	2,223
WY	1,799	375	2,174
Total	45,477	30,537	76,013

Table 5: CAIR/CAMR 2020 Mercury Emissions from Coal-Fired Units (Pounds)

State	Elemental	Divalent	Total
AL	1,011	491	1,502
AR	990	135	1,125
AZ	908	130	1,038
CA	42	28	70
CO	760	353	1,113
CT	29	53	82
DE	98	81	179
FL	632	228	860
GA	852	432	1,284
IA	432	248	680
IL	943	415	1,358
IN	704	469	1,173
KS	338	110	448
KY	778	522	1,301
LA	200	42	242
MA	75	193	268
MD	310	242	552
MI	486	338	824
MN	304	100	405
MO	944	416	1,360
MS	183	31	215
MT	300	93	393
NC	1,256	578	1,834
ND	630	120	749
NE	605	249	854
NH	42	57	99
NJ	117	81	198
NM	436	82	518
NV	84	63	146
NY	163	199	362
OH	792	562	1,355
OK	985	192	1,178
OR	23	18	41
PA	1,073	739	1,811
SC	512	311	823
SD	119	13	132
TN	936	609	1,545
TX	2,391	502	2,893
UT	401	98	499
VA	473	317	790
WA	103	11	114
WI	578	129	707
WV	629	415	1,044
WY	653	240	893
Total	24,321	10,736	35,057

Table 6: IL Rule 2010 Mercury Emissions from Coal-Fired Units (Pounds)

State	Elemental	Divalent	Total
AL	2,050	1,634	3,684
AR	801	478	1,279
AZ	1,187	167	1,354
CA	28	23	51
CO	743	418	1,161
CT	51	94	145
DE	137	205	342
FL	708	527	1,235
GA	2,408	1,984	4,391
IA	1,177	691	1,868
IL	528	327	855
IN	2,008	1,614	3,622
KS	1,062	329	1,391
KY	1,499	1,105	2,604
LA	896	555	1,451
MA	104	343	447
MD	381	1,003	1,384
MI	1,819	1,717	3,536
MN	971	281	1,252
MO	1,938	1,108	3,046
MS	309	310	619
MT	849	120	968
NC	1,573	1,220	2,794
ND	1,150	419	1,569
NE	535	361	896
NH	33	119	151
NJ	126	344	470
NM	671	95	766
NV	146	72	217
NY	371	639	1,009
OH	1,632	2,096	3,728
OK	1,138	643	1,780
OR	90	73	162
PA	1,701	2,110	3,811
SC	710	741	1,451
SD	114	75	190
TN	1,279	850	2,129
TX	5,473	1,681	7,154
UT	604	167	772
VA	635	808	1,443
WA	403	45	448
WI	1,139	496	1,635
WV	1,017	1,210	2,226
WY	1,800	376	2,176
Total	43,992	29,669	73,661

E. Results Provided to Mr. Marchetti

For each scenario, I have provided annual generation levels for Illinois generating units to Mr. Marchetti. I have also provided coal consumption and delivered coal prices, SO_2 and NO_X allowance prices, and delivered natural gas prices. All of these data, with the exception of natural gas prices, are direct outputs from the NEEM simulations of CAIR/CAMR and the IL Rule. Natural gas prices are an input to NEEM based on historical basis differentials, Henry Hub futures prices from the New York Mercantile Exchange ("NYMEX") and the Energy Information Administration's Annual Energy Outlook 2006 wellhead natural gas price projections.

Coal prices are determined based on national demand for coal and coal supply curves that CRA has prepared based on industry data. Because the coal prices are based upon national demand for coal, changes in Illinois demand have little impact and the coal prices in the two scenarios (CAIR/CAMR and the IL Rule) are nearly identical.

Table 9 presents the SO_2 and NO_X allowance prices for each scenario.

Table 7: Summary Generation from Illinois Coal Plants (GWh)

Policy	**2006**	**2008**	**2009**	**2010**	**2013**	**2015**	**2018**
CAIR/CAMR	107,609	107,164	107,819	109,862	122,430	122,730	122,343
IL Rule	107,592	107,169	102,516	105,073	120,647	122,073	121,759

** Generation figures in both policies include approximately 16,000 GWh from new coal-fired generators starting in 2013*

Table 8: Coal Consumption by Illinois Coal Plants (TBtu)

Coal Type	2006	2008	2009	2010	2013	2015	2018
CAIR/CAMR							
Illinois Basin	141	122	130	118	376	259	257
PRB	903	914	916	965	804	968	965
Other	40	42	42	29	40	2	2
TOTAL	1,084	1,078	1,088	1,112	1,220	1,229	1,224
IL Rule							
Illinois Basin	141	122	214	228	385	365	363
PRB	902	913	769	819	780	835	833
Other	41	43	51	16	38	20	20
TOTAL	1,084	1,078	1,034	1,063	1,203	1,220	1,217

Table 9: Allowance Prices Projected in NEEM Scenarios (2003$)

Allowance Type	2006	2008	2009	2010	2013	2015	2018
CAIR/CAMR							
NO_X annual ($/ton)			1833	1962	1,698	1,944	2,381
NO_X SIP Call ($/ton)	500	500					
SO_2($/allowance)	1,308	617	661	353	433	347	425
Mercury ($/lb)				29,815	31,065	35,565	43,570
IL Rule							
NO_X annual ($/ton)			1,823	1,951	1,683	1,926	2,360
NO_X SIP Call ($/ton)	500	500					
SO_2($/allowance)	1,313	611	653	350	428	343	420
Mercury ($/lb)				29,610	31,535	36,105	44,230

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BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:)
) R06-25
PROPOSED NEW 35 ILL. ADM. CODE 225) (Rulemaking – Air)
CONTROL OF EMISSIONS FROM)
LARGE COMBUSTION SOURCES (MERCURY))

TESTIMONY OF RICHARD D. McRANIE

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July 28, 2006

Executive Summary

The State of Illinois Environmental Protection Agency (IEPA) has proposed to add new regulations to 35 Ill Adm. Code Part 225, Control of Emissions from Large Combustion Sources. These regulations would control mercury (Hg) emissions from coal-fired electric generating units (EGUs) located in the state. Fundamentally, the regulations would require that EGUs meet emission limits of either (1) 0.0080 lb Hg/GWh gross electrical output or, (2) 90% reduction of input Hg. In order to demonstrate compliance with the proposed regulation, EGUs in Illinois would be required to show that 90 % of the mercury has been removed from the emissions based on the input fuel Hg content or that an emission limit cap of 0.0080 lb Hg/GWh has been achieved on a rolling 12-month rolling average basis. A new compliance determination is made at the end of each month.

The general thesis associated with this “hard cap” compliance approach is that the multitude of Hg input and output measurements needed to make a compliance determination can be made accurately, precisely, without bias and with no consideration for propagation of error. Unfortunately, recent research evidence is that the necessary Hg measurements are very difficult to make, are not very precise and are not very accurate. In fact, I do not believe that the required measurements can be made with the accuracy and precision demanded for a hard cap emission limit or a percent reduction limit at the 90% level.

The proposed Illinois regulations make frequent reference to US Environmental Protection Agency (EPA) regulations at 40 CFR Part 75. These regulations contain the Hg continuous emissions monitoring system (CEMS) rules and procedures for the federal Hg control and trading program. It must be keep in mind that the Hg CEMS sections of Part 75 were written by EPA to mirror the SO_2 and NO_X monitoring provisions. At the time they were written, EPA had virtually no experience with Hg CEMS or evidence about the performance of Hg CEMS to guide their drafting of the regulations. This contrasts with over 20 years of experience with SO_2 and NO_X CEMS prior to the drafting of the original Acid Rain rules. We have all now learned that monitoring Hg emissions is not as straightforward as monitoring SO_2 and NO_X. Considerable research has been done by both EPA and the utility industry and that research is ongoing and will be discussed more fully in the body of this report.

The stack gas from a coal-fired utility boiler contains Hg in three primary forms – elemental Hg (Hg^0), oxidized Hg (generally $HgCl_2$) and so called “particulate” Hg. “Particulate” Hg is Hg that is physically or chemically attached to particulate matter. “Particulate” Hg comprises a very small portion (1-2%) of the total Hg emissions and is technically impossible to measure with a Hg CEMS. Therefore, only elemental and oxidized Hg emissions are measured. There are four very important things to remember about measuring Hg emissions from a power plant smoke stack. First, the total concentration of Hg is extremely low (around 0.1 ppb volume/volume) on a plant with a SCR and scrubber. Second, elemental Hg will amalgamate with just about any metal so metal tubing and fittings have to be coated to prevent this reaction. Third, oxidized Hg is a physically "sticky" compound and is difficult to transport through sample probes and sample lines, even at elevated temperature. Fourth, any oxidized Hg in the sample must be converted to elemental Hg to be measured by the Hg analyzer/detector.

The primary difficulty of making Hg emission measurements on stacks is getting a sample of the stack gas, containing the mercury to be measured, to the analyzer in a quantitative manner. This has turned out to be an extraordinarily difficult task for both the stack gas as well as the calibration gas. The fundamental fact is that mercury, at a concentration of 0.1 ppb, is very difficult to transport quantitatively from the stack or calibrator to the analyzer.

This level of sample transport difficulty is reflected by the extraordinarily complex design of Hg CEMS and the low level of measurement precision and accuracy. The body of this report contains a rather detailed discussion of these issues.

The proposed Illinois regulations are seriously flawed by the inclusion of missing data substitution. Missing data substitution is a process invented by EPA for the SO_2 and NO_X trading programs. The substitute data are made up using various algorithms that are unrelated to reality and, in many cases, are deliberately biased high. EPA made the decision long ago that missing data substitution is inappropriate for hard cap regulations and data substitution is specifically excluded in 40 CFR Part 60 New Source Performance Standards regulations.

The proposed Illinois Hg control regulations impose hard cap emission limits in terms of 90 percent Hg removal or a limit of 0.0080 lb/GWh. This will result in Hg emissions that are too low to measure to the level of accuracy and precision required for a hard cap limit. In addition, the proposed regulations require the use of missing data substitution, which will add made up, high biased data that do not reflect real emissions. It is my opinion that the results will be a risky regulatory program, certainly for those trying to comply or determine compliance, which will be impossible to implement in any rational fashion.

In summary, I calculate that the proposed Illinois regulations contemplate Hg emission measurements in the range of 0.80 micrograms/m^3 when the monitors may be calibrated to a tolerance of ±1.0 microgram/m^3. This means that compliance with the proposed rule, as further explained in my testimony, cannot be measured to the necessary level of accuracy. For reference purposes, the EPA Hg monitoring regulations in 40 CFR Part 75 allow a Hg CEMS to be certified if the difference between the Reference Method and Hg CEMS measurements is ±1.0 microgram/m^3. In addition, the 40 CFR Part 75 regulations allow for a Hg CEMS to pass the daily calibration error check if the Hg CEMS reading during the calibration check is within ±1.0 microgram/m^3 of the expected value. In other words, the EPA regulations contemplate a Hg emissions accuracy and precision of ±1.0 microgram/m^3 to be adequate and both EPA and industry research programs support that this performance criteria is reasonable. From my reading of the Technical Support Document and the transcript it appears that Illinois has no data to support accurate and precise Hg measurements suitable for a hard cap Hg emissions limit of 0.80

micrograms/m^3. As discussed more fully in this report, this emission limit suggests a measurement precision and accuracy of 0.001 microgram/m^3, or four orders of magnitude better than reality.

Qualifications

My name is Richard D. McRanie. I am a Principal at RMB Consulting & Research, Inc (RMB) in Raleigh, NC. I am a co-founder of RMB, which began business on July 1, 1994. Prior to the formation of RMB, I was the Director of Utility Services for Systems Applications International and Kilkelly Environmental Associates. Before entering the consulting business, I was an employee of the Southern Company for 23 years where my last position was Manager of Power Plant Performance Improvement in the Southern Company Services, Inc. Research and Environmental Affairs Department.

Over the period of my career, I have been involved in virtually every major national rulemaking concerning air emissions from electric utility sources. Much of this involvement relates to the measurement of emissions from utility boilers and combustion turbines. I serve as a primary consultant for the Utility Air Regulatory Group (UARG) Measurement Techniques Committee and the Electric Power Research Institute (EPRI), as well as a consultant for a number of individual utility and industrial companies.

Over the past several years I have worked closely with UARG developing input to and comments on the Clean Air Mercury Rule. I have also been managing an EPRI Tailored Collaboration (TC) project to investigate mercury (Hg) measurement issues in particular as those issues relate to Hg continuous emissions monitoring systems (CEMS) and EPA Reference Test procedures. This project is presently focused on operation of the Trimble County Hg CEMS demonstration project and, in coordination with EPA, development of a Hg instrumental reference method.

I have been the lead consultant on projects to develop industry input into the Acid Rain regulations, particularly Appendix D and E to 40 CFR Part 75 for the measurement of SO_2 and NO_X from gas- and oil-fired generating units. I was the lead consultant on a project for EPRI that discovered the reason for, and developed a solution for, the problem of significant measurement error associated with stack flow monitors. During the course of this project, I was responsible for overall project management, working with a subcontractor to develop a design for a "swirl tunnel," developing the tunnel test program, evaluating the results, developing and managing the field test program and preparation of the final report. The results of this project clearly illustrated the positive bias in Reference Method 2 when there was swirl in the flow field and led EPA to develop and promulgate Reference Methods 2F, 2G and 2H.

I have worked on an EPRI project to better understand the ability to measure very low levels (1-5 ppm) of NO_X and NH_3 emissions from gas turbine combined cycle units equipped with selective catalytic reduction. It is very difficult to make precise measurements in this very low concentration range. The EPRI project coordinated with work done by the California Energy Commission (CEC) and the California Air Resources

Board. The objective of the work was to determine, if possible, how to make these low-level measurements as precisely and accurately as possible.

I have also worked on UARG projects that were involved in rule changes to correct regulatory problems in 40 CFR Part 60 Subparts Da, Db and GG that affect compliance measurements on both simple cycle and combined cycle gas turbines. The various regulations that impact combined cycle units were not consistent and, in many cases (like Subpart Da and GG), were outdated. The result was regulations that contained unnecessary and dangerous performance tests. I interfaced with EPA to draft changes to the regulations that minimized these problems with no impact on compliance determinations. The revised regulations were promulgated.

I have worked with EPRI over the past twenty years managing projects to refine and upgrade the ESPM electrostatic precipitator (ESP) performance model. I was the project manager for the initial model development. Following that initial development, RMB was retained to revise the ESPM ESP performance model to update the model from DOS to the Windows operating system. RMB is the present EPRI developer of record for the ESPM model and has been recently requested to add features to model the effect of carbon injection.

I was also the lead consultant on an EPRI project to develop a Compliance Assurance Monitoring (CAM) Protocol for ESPs. I developed the concept of using an ESP model for CAM purposes, developed the research program to demonstrate the validity of the approach, managed the demonstration field programs and prepared all of the reports.

I have also worked with a number of utilities to assist them with CAM rule implementation projects. A large number of ESPs were evaluated to determine the appropriate CAM Protocol design. The protocol verification testing approach was developed and testing was conducted to verify the CAM plan design. CAM plans were then prepared.

I have published numerous reports and papers on various technical and measurement issues as listed in my resume. (See Attachment 1)

Introduction

On March 15, 2005, the U.S. Environmental Protection Agency (EPA) issued the Clean Air Mercury Rule (CAMR) designed to reduce mercury (Hg) emissions from coal-fired utility boilers. The rule creates a “nationwide” cap-and-trade program that will be implemented in two phases. Phase 1 caps Hg emissions at 38 tons per year (tpy) in 2010 and Phase 2 caps Hg emissions at 15 tpy in 2018. 40 CFR Part 75 serves as the foundation of the CAMR Hg monitoring, recordkeeping and reporting requirements. CAMR requires each affected unit to begin monitoring Hg continuously with a certified system by January 1, 2009.

The CAMR rule offers an alternative for States to adopt Hg control programs that do not include the “nationwide cap and trade” provisions so long as the State Hg emissions budget is met. The State of Illinois has proposed to take such an approach with unit/system specific Hg emission limits or percent Hg removal criteria. Such an approach, however, introduces a number of technical issues concerning the Hg input and Hg emissions measurements that will be necessary to demonstrate compliance with the proposed Illinois Hg control regulations.

Based on the information and data from both EPA and EPRI research studies conducted thus far, I do not believe that the measurements required by the proposed Illinois regulations can be made to the necessary level of precision and accuracy to demonstrate compliance with the proposed regulations as they are presently structured. The structure of the rule as a hard Hg cap or percent Hg reduction dictates very accurate and precise Hg emissions measurements at a very low concentration level be made using Hg continuous emissions monitoring systems (CEMS). The required level of Hg CEMS measurement capability does not exist.

It must always be remembered that if accurate compliance measurements cannot be made, the underlying regulations are essentially useless and impossible to administer. Measurement of noise is just measurement of noise – no more, no less.

Brief Description of the Proposed Illinois Rule

The State of Illinois Environmental Protection Agency (IEPA) has proposed to add new regulations to 35 Ill Adm. Code Part 225, Control of Emissions from Large Combustion Sources. These regulations would control Hg emissions from coal-fired electric generating units (EGUs) located in the state. Fundamentally, the regulations would require that EGU's meet emission limits of either (1) 0.0080 lb Hg/GWh gross electrical output or, (2) 90% reduction of input Hg. There are provisions for common stack sources and multiple units at a source. There are also exemption provisions for units that are to be shutdown.

The above is only a general overview of the proposed regulation since it is not the intention of this report to comment on the regulation provisions beyond the requirements for compliance measurement. The discussion in this report assumes that the compliance provisions are as stated in emission limit options (1) and (2) above. The "so called" flexibility provisions in the proposed rule just push compliance measurement problems from unit to unit and assume that averaging will solve problems. In actuality, these options just compound the propagation of error problem. In short, they are not flexibility, so these options will not be addressed.

Overview Discussion of Hg Measurements Required

In order to demonstrate compliance with the proposed regulation, electric generation units (EGU) in Illinois would be required to show that 90 % of the mercury has been removed from the emissions based on the input fuel Hg content or that an emission limit cap of 0.0080 lb Hg/GWh has been achieved on a rolling 12-month rolling average basis. A new compliance determination is made at the end of each month. To accomplish this will require the measurement of input Hg content in the fuel and outlet (stack) emissions content in terms of pounds (lb). Since neither lb of input Hg or lb of outlet Hg can be measured directly, a number of associated measurements (stack Hg content, stack CO_2 content, coal mercury content, coal Btu, etc) have to be made to perform the final compliance calculations. The general thesis associated with this compliance approach is that all of these measurements can be made precisely, accurately, without bias and with no consideration for propagation of error. In theory, these measurements, like any other measurement, can be done. Unfortunately, we do not make theoretical measurements, we make real measurements in a real world and recent evidence is that the necessary measurements are very difficult to make, are not very precise and are not very accurate. In fact, I do not believe that the required measurements can be made with the accuracy and precision demanded for a hard cap emission limit or a percent reduction limit at the 90% level.

General Discussion of the Probable Monitoring Issues

It appears that the State of Illinois has proposed these new mercury control regulations without seriously considering any of the Hg emissions measurement issues. A search of the Technical Support Document for the words “accuracy,” “precision,” “error” and “errors” produced zero hits. A search for the term CEMS produced one hit and that was contained in a carbon vendor’s guarantee language.

Unfortunately, virtually all regulators assume that emissions measurements can be made at whatever level might be desirable with no accuracy, precision or bias problems. This assumption is just not true – all measurements have accuracy, precision and bias criteria. These criteria vary with the measurement technology and the measurement being attempted.

It is a fundamental precept of making any measurements that the lower or finer the value being measured the more difficult the measurement and the higher the error in the measurement. It is more difficult to measure a nanogram than it is to measure a kilogram. And, it is more difficult to measure a nanosecond than a minute. For the first measurement we need an atomic clock, while a Timex watch will be adequate for the second. While the regulator may believe that writing a regulation will create the “so called” Hg measurement “atomic clock,” that is just not the way it works in real life – especially when Hg is being measured.

I will explore the Hg emission measurement issues in more detail in subsequent sections of this report. Since the proposed Illinois regulations make frequent reference to 40 CFR Part 75, the reader must keep in mind that the Hg continuous monitoring sections of Part 75 were written by EPA to mirror the SO_2 and NO_X monitoring provisions. At the time they were written, EPA had virtually no evidence about the performance of Hg CEMS, other than CEMS vendors allegations that the CEMS were “commercial,” to guide their drafting of the regulations. This contrasts with over 20 years of experience with SO_2 and NO_X CEMS prior to the drafting of the original Acid Rain rules. We have all now learned that monitoring Hg emissions is not as straightforward as monitoring SO_2 and

NO_X. Considerable research has been done by both EPA and the utility industry and that research is ongoing and will be discussed more fully later in this report.

Brief Discussion of Emissions Trading Versus Emission Limit and Percent Removal Compliance Approaches

Emissions trading programs are very different from command and control (hard cap emissions limit or percent removal) programs. It is obvious that trading programs have more flexibility than command and control programs because of the ability of a source to buy and sell allowances, assuming they are available, under trading programs. The other unique aspect of trading programs is that the total program measurement error, in the absence of a true bias, is spread across hundreds of sources and the movement of allowances is the mechanism that transfers both the error and control device problems from source to source. While a trading program can cost a poorly performing source a considerable amount of money, there is little possibility of noncompliance.

On the other hand, a hard emissions limit or percent reduction program can have a number of problems if it is not technology based. By technology based, I mean that the control technology is able to achieve the limit or percent reduction required and that the resulting emissions can be measured accurately and precisely. If either of these factors cannot be achieved, then the command and control approach, especially at the 90% level, has a real problem and is very risky. While I have no comment on Hg control device performance, I do believe that the level of the standard in the proposed Illinois rule approaches or exceeds the ability of present Hg CEMS measurement technology. As discussed in the next section, the proposed Illinois rule requires measurement resolution of less than ***1 part per trillion***.

Significant Figures

Before I move forward to the specifics of Hg measurements, I would like to briefly discuss significant figures relative to emission limits. Regulators have developed the habit of adding significant figures to emission limits in an attempt to tighten the limits. The proposed Illinois Hg emission limit of 0.0080 lb/GWh is an example of this practice. This limit implies that an additional significant figure beyond the last zero can be measured and resolved accurately and precisely.[1] For example, this limit implies that 0.00001 lb/GWh can be measured accurately and this is approximately equal to a stack Hg concentration of 0.001 microgram/m^3 or approximately ***0.12 part per trillion*** v/v.[2] It is our and EPA's[3] position that the probable measurement error can be as high as ±1.0 microgram/m^3 and our experience reinforces this position.[4] Using the same number of

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[1] See ASTM Standard Practice E 380, "Use of the International System of Units," Section 5, Rules for Conversion and Rounding.

[2] For reference purposes, 1 microgram/m^3 is approximately 0.12 parts per billion or 120 parts per trillion v/v. ppb Hg = microgram/m^3 x 24.27 / mw = 1 x 24.47 / 200.6 = 0.12

[3] See the daily calibration error test limits at 40 CFR Part 75, Appendix B, Section 2.1.4. For a Hg CEMS, these limits are 5% of span or ±1.0 microgram/m^3, whichever is higher.

[4] Throughout this paper, I will be discussing Hg concentration in terms of microgram/m^3 because that is the unit of measurement specified in 40 CFR Part 75. If one makes a number of assumptions, it is found

significant figures, the proposed Illinois Hg emission limit of 0.0080 lb/GWh is approximately equal to a stack concentration of 0.80 microgram/m^3. To provide meaning to the last significant figure would suggest that one needs to be able to precisely resolve the difference between 0.804 and 0.805 microgram/m^3 and this is impossible. I do not believe that we can accurately resolve the difference between 0.80 and 0.81 microgram/m^3 much less an order of magnitude better. To suggest this level of Hg measurement capability and precision is, in the most polite terms, technical and regulatory silliness.

Historical Perspective of Hg Emissions Monitoring

The present day Hg CEMS are generally based on ambient air Hg monitoring or incinerator Hg monitoring equipment. Virtually all use either atomic fluorescence or atomic absorption as the method of detection. Atomic fluorescence is the most sensitive technique and, combined with gold trap Hg concentration, is capable of measuring very low levels of Hg in the ambient or in the laboratory. The atomic fluorescence gold trap analyzers require switching valves, an argon and deionized water supply and a number of mass flow meters and flow controllers to control the Hg absorption, desorption and analytical process associated with the gold traps. Tekran and GE/PSA are examples of Hg CEMS that use atomic fluorescence detection combined with gold trap Hg concentration.

There are also atomic fluorescence analyzers that do not use gold trap concentration. The Thermo Hg CEMS is an example of a direct reading atomic fluorescence analyzer. The direct reading atomic florescence and atomic absorption analyzers are quite a bit simpler than the gold trap analyzers. Unfortunately, the direct reading atomic absorption analyzers have rather poor sensitivity and a high level of interference from SO_2 and I do not believe this technology will have much success in power plant Hg CEMS. The direct reading atomic fluorescence technique appears to have adequate sensitivity for Hg CEMS application and is attractive because of its simplicity relative to the gold trap analyzers.

All of the Hg analyzers/detectors respond to only elemental Hg. The stack gas from a coal-fired utility boiler contains Hg in three primary forms – elemental Hg, oxidized Hg and so called “particulate” Hg. “Particulate” Hg is Hg that is physically or chemically attached to particulate matter. “Particulate” Hg comprises a very small portion (1-2%) of the total Hg emissions and is technically impossible to measure with a Hg CEMS because the particulate must be removed from the flue gas sample before entering the Hg analyzer. Considering the very small contribution of “particulate” Hg to the total Hg, EPA specifically exempts it from measurement under the 40 CFR Part 75 Hg measurement regulations. This is also true for the Hg wet chemical reference method for Hg. Only the elemental and oxidized Hg are measured.

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that 1 microgram/m^3 is approximately equal to 0.01 lb/GWh. Therefore, the proposed Illinois emission limit of 0.0080 lb/GWh is approximately equal to 0.80 microgram/m^3. See Attachment 2 for the conversion protocol and equations.

Since elemental Hg is the only Hg that the analyzer can see, any oxidized Hg (predominately $HgCl_2$) in the sample must be converted to elemental Hg before analysis. This conversion can be a difficult process and many different approaches have been tried in the past. This conversion process is discussed more fully in the detailed Hg CEMS discussion below. There are four very important things to remember about measuring Hg emissions from a power plant smoke stack. First, the total concentration of Hg is extremely low (around 0.1 ppb v/v[5]) on a plant with an SCR and scrubber. Second, elemental Hg will amalgamate with just about any metal so metal tubing and fittings have to be coated to prevent this reaction. Third, oxidized Hg is a physically "sticky" compound and is difficult to transport through sample probes and sample lines, even at elevated temperature. Fourth, any oxidized Hg in the sample must be converted to elemental Hg to be measured by the Hg analyzer/detector.

In a laboratory or ambient application, I readily acknowledge that an atomic florescence analyzer and/or detector has a measurement sensitivity several orders of magnitude lower than necessary for stack applications. Unfortunately, when we discuss Hg CEMS technology the focus cannot be only on the analyzer or final detector device – we have to discuss the entire Hg CEMS. And we have to discuss it in the context of the 40 CFR Part 75 Hg monitoring regulations. A Hg CEMS consists of:

- a sampling probe,
- a probe controller,
- a heated sample line and calibration gas transport assembly,
- an oxidized Hg converter,
- a sample conditioning package,
- an elemental Hg calibrator,
- an oxidized Hg calibrator,
- various pumps, valves and mass flow meters/controllers,
- a control computer and software and,
- a Hg analyzer/detector.

As will be discussed more fully, the difficulty of making Hg measurements on stacks is getting a sample of the stack gas, containing the mercury to be measured, to the analyzer in a quantitative manner. This has turned out to be an extraordinarily difficult task for both the stack gas as well as the calibration gas. The fundamental fact is that mercury, at a concentration of 0.1 ppb, is very difficult to transport quantitatively from the stack or calibrator to the analyzer. We have to extract this stack gas containing 0.1 ppb Hg and maintain the integrity of the sample through the probe, dilution orifice and sample conditioning package and then transport it to the analyzer/detector completely unadulterated. That is a tall order especially since Hg is one of the most chemically reactive substances on the Periodic Table. Hg amalgamates with almost any metal and reacts with many ions; therefore, it is extremely difficult to transport from point A to

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[5] For perspective, 1 ppb is the equivalent of one drop in a 10,000 gallon railroad tank car. So 0.1 ppb is one drop in ten, 10,000 gallon railroad tank cars.

point B - especially in sub-ppb concentrations. This sample transport is the fundamental difficulty facing Hg emissions measurements.

In addition, the complexity of the Hg CEMS has resulted in a myriad of hardware failures that have destroyed any rational concept of CEMS reliability. Before I go any further, a technical review of that complexity is necessary so that the term Hg CEMS will have more meaning to the reader than a mental vision of an abstract black box or toaster oven.

Hg Monitoring Technology

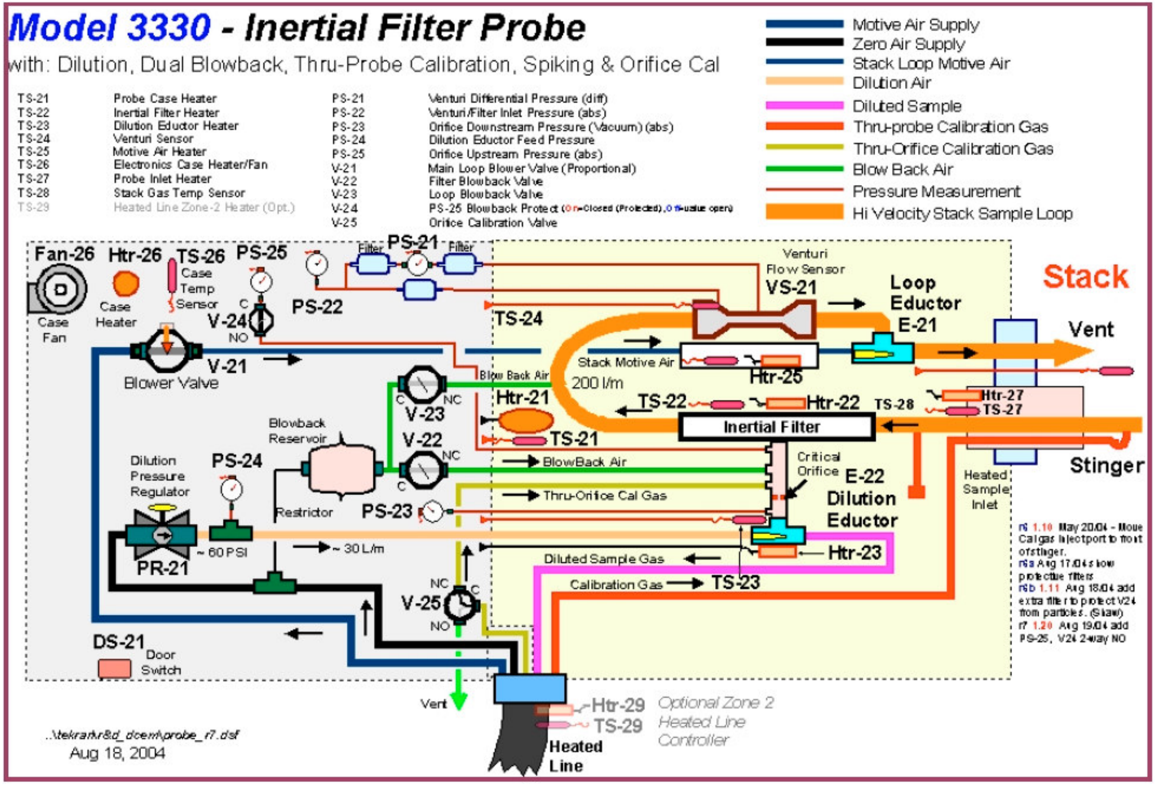
I am always amazed that regulators sit down at their desks and write Hg monitoring regulations without ever having seen a Hg CEMS or having any reasonable level of knowledge about how they work. This is exactly what was done by EPA's Clean Air Markets Division when they wrote the Hg monitoring rules in 40 CFR Part 75. To their credit, it was a rapid turn around task forced on them by politics and in certain areas of the rules, they were cautious. Unfortunately, there are certain portions of the rule that were not supported by field data and/or experience and these sections will need to be modified as additional experience is gained. It should also be noted that the Part 75 Hg monitoring regulations were patterned after the SO_2 and NO_X monitoring rules and Hg monitoring has turned out to be very different from SO_2 and NO_X monitoring.

Below I will show and describe the major components of a Hg CEMS. All of the illustrations are from a single Hg CEMS vendor's (Tekran) operations manuals. I have used those illustrations because they have excellent detail and their use does not reflect any favoritism toward or opinion regarding Tekran Hg monitoring technology.

The sampling probe and associated probe equipment is a critical component of all of the Hg CEMS. It has also been a troublesome component for all of the Hg CEMS vendors from a reliability perspective.

Figure 1 shows a flow diagram of the Tekran probe assembly. This probe design is called an inertial probe and a similar design is used by many of the Hg CEMS vendors.

Figure 1 – Tekran Hg CEMS Inertial Filter Probe



This inertial filter design uses a high velocity sampling loop where stack gas enters into the "stinger" which is colored orange on the center right of the figure. The stack gas flows through the inertial filter, makes a loop and then goes through a venturi flow measurement section into the loop eductor and is then vented back into the stack. A very small portion of the stack gas is drawn through the porous wall of the inertial filter into a critical orifice section where it is diluted 30-50/1 with ultra clean dilution air. The diluted sample (purple line) then flows down the heated sample line to the sample conditioning unit. You will notice the many heaters (Htr) in this probe assembly. It is critical that any surface in contact with the sample be maintained above 400-500° C (750-930° F) to prevent loss of Hg.

Figure 2 shows an external view of the probe box assembly. This box is about 2 ½ feet wide and about 4 feet long and weighs approximately 100 lbs. As you look at the figure, the left hand side, where the round stack mounting flange is located, is called the hot side of the box and contains all of the heated sampling components as discussed above. The right hand side of the box (note the seam down the front and along the top of the box) is called the cold side and contains all of the electronics, pressure transmitters, etc. A 5-8 foot long sample probe (stinger) is connected to the coupling extending to the left of the picture and the entire box is mounted to a stack sample port via the round flange.

It should be noted that if anything goes wrong in the hot side of the box, the technician can not just walk up, open the cover and start to work. As discussed above, everything in this hot side is much too hot to even touch.[6] Before any work can proceed, the system has to be shut down, put into continuous blowback and allowed to cool down for 30 minutes to an hour.

Figure 2 – Tekran Probe Box

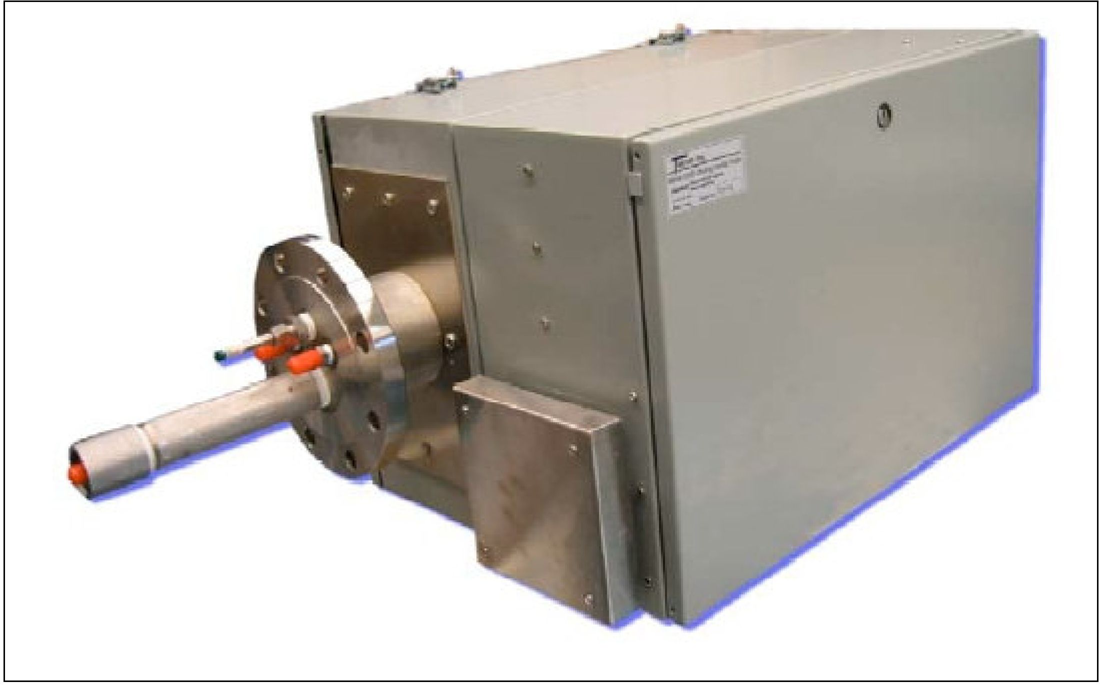


Figure 3 shows the components in the hot side of the probe box. The high temperature heat tracing wrap can be plainly seen wrapped around all of the high temperature components. This heat tracing wrap must be removed and replaced after any repair or maintenance on the hot side. We have also discovered that the tubing fittings frequently seize because of the high temperature and it is not an infrequent occurrence that a number of fittings have to be replaced. Cleaning the dilution orifice or replacing the inertial filter usually takes from two to four hours. In contrast, cleaning the dilution orifice on a SO_2 or NO_X CEMS takes about 20 minutes. It should also be noted that a SO_2, NO_X and CO_2 CEMS uses only one dilution probe assembly. It is about the size of a loaf of bread and only contains a simple dilution orifice and pressure regulator.

Please notice the area at the bottom of Figure 3 labeled “heated sample line” and “diluted sample return.” When the diluted sample leaves the probe box it must be kept very hot until it reaches the sample conditioning unit. The sample contains a mix of elemental and oxidized Hg. Oxidized Hg (generally believed to be predominately $HgCl_2$) will turn to a solid if allowed to cool. A special high temperature (~450° F) heated sample line is used to transport the sample to the sample conditioning unit.

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[6] As a reference, 100° C/212° F is the boiling point of water.

Figure 3 – Tekran Probe Box - Hot-side

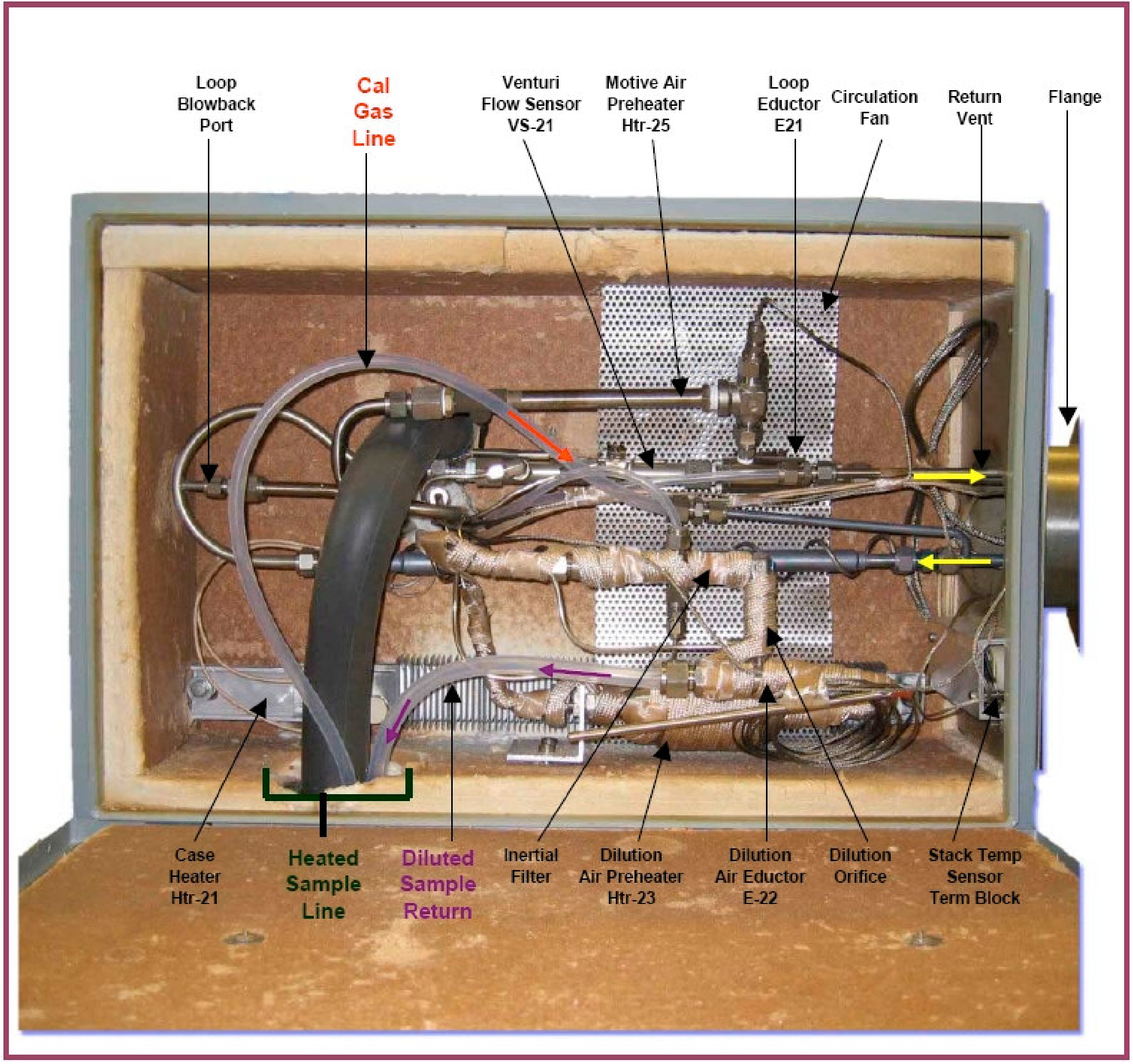
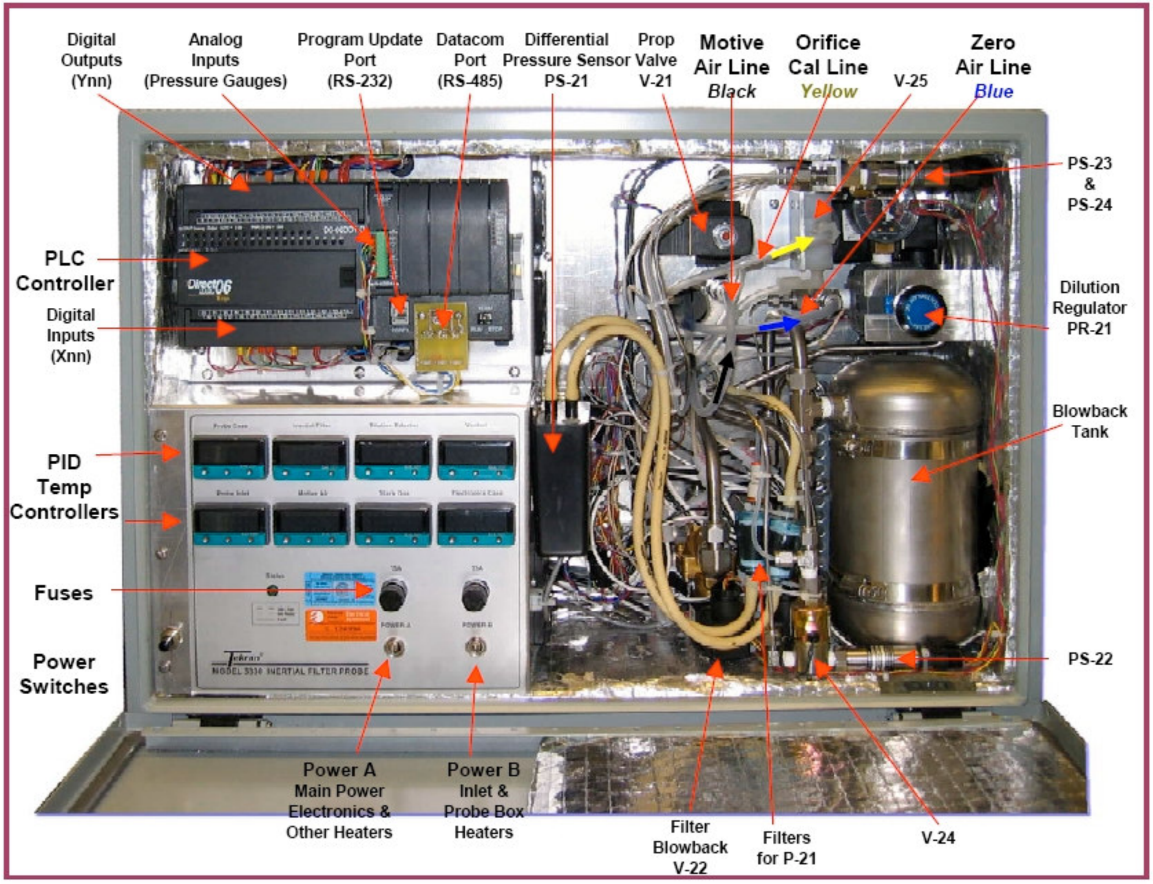


Figure 4 shows the cold side of the probe box where all of the electrical and other heat sensitive components are located. As is apparent, there is considerable complexity and it is rather crowded in this assembly. To say that this equipment is difficult to work on is an understatement – and that understatement applies to all of the Hg CEMS vendor's equipment. You might also note that there is a programmable logic controller (PLC) located in this area to control all of the various valve, differential pressure, flow and other operational functions associated with the probe. A PLC is a dedicated computer that handles specific tasks and communicates with the main system computer. For example, when the main computer says to start a calibration, the PLC opens and closes the proper valves, sets the calibration gas and sample flows and times the various operations associated with the calibration.

Figure 4 – Tekran Probe Box – Cold Side



As discussed previously, after the diluted sample of stack gas leaves the probe box, it enters a high temperature sample transport line and travels to the sample conditioner. The sample conditioner serves two functions – to convert any oxidized Hg to elemental Hg and to remove any acid gases (primarily HCl, SO_2 and SO_3) from the sample. A number of wet and dry techniques have been used in the past to accomplish these two tasks. The wet techniques have been largely abandoned because they involve handling and replenishment of dangerous, highly corrosive chemicals. Most of the modern Hg CEMS use a combination of thermal and/or catalytic converters and adsorption to accomplish the oxidized Hg conversion and removal of acid gases.[7]

Figure 5 shows the sample conditioning approach used by Tekran. The sample enters the sample conditioning unit and is immediately exposed to a very high temperature oven environment (~750° C or 1400° F). It then travels through a high temperature converter where the remaining oxidized Hg is reduced to elemental Hg.[8] Following the converter, a peristaltic pump injects deionized water into the sample flow. The water absorbs any free Cl, HCl, SO_3 and H_2SO_4 in the sample.

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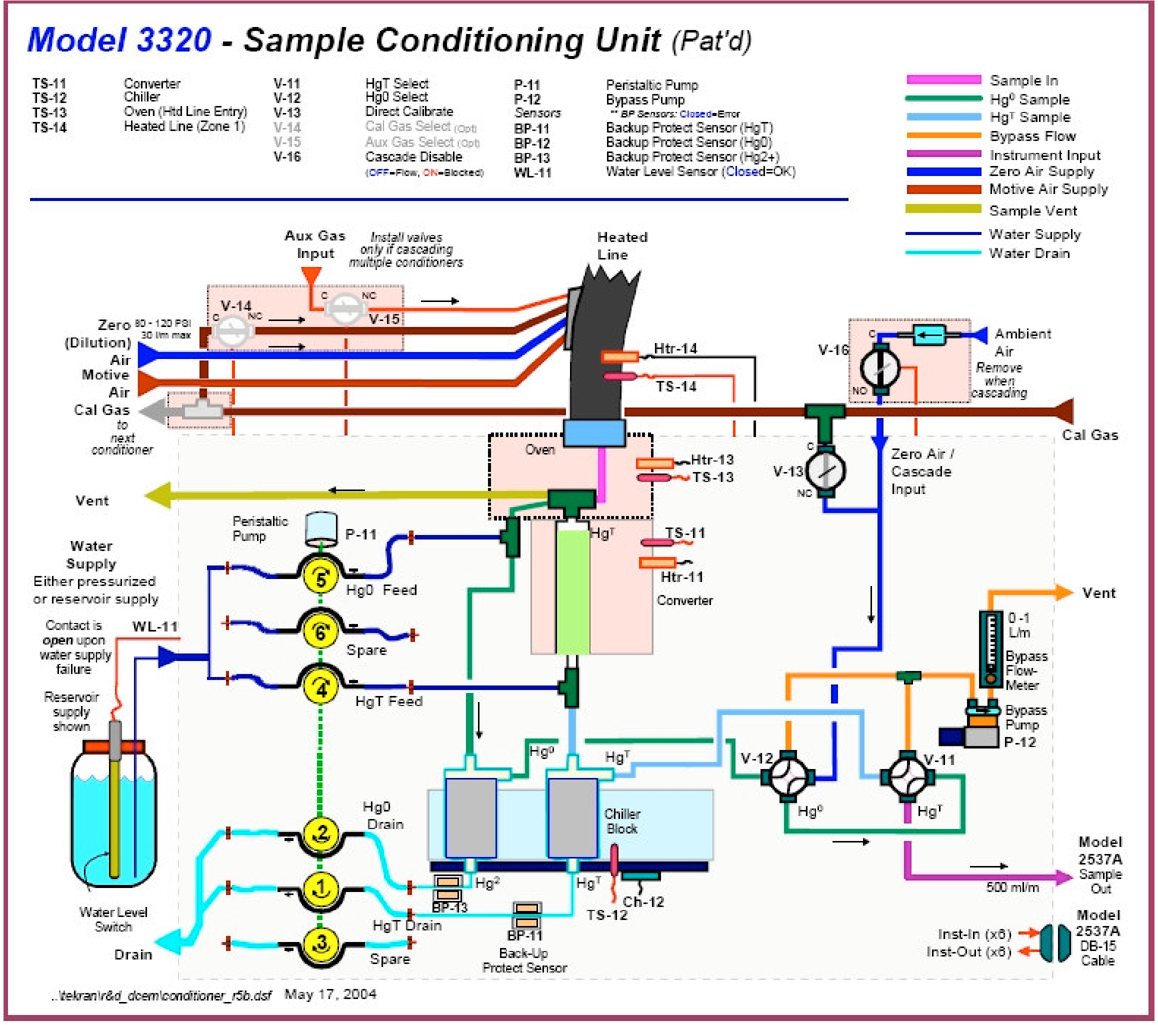
[7] It should be noted that none of this conversion and adsorption process is necessary for a SO_2 or NO_X CEM. On those, after the sample leaves the dilution orifice it travels directly to the analyzer.

[8] Please ignore any notations on the flow diagram that indicate either HgO or Hg2. We are only interested in the HgT notations which are for total Hg.

Figure 5 – Tekran Sample Conditioning Unit



Removal of the free Cl and HCl in the sample is especially critical. If they are not removed, they will recombine with the Hg to create oxidized Hg, which cannot be measured by the analyzer. The sample then enters a chiller block where the water condenses and is removed and pumped to drain by the peristaltic pump. The sample exits the chiller block and is transported to the Hg analyzer.

Figure 6 is a flow diagram of the Tekran Hg analyzer. This analyzer is typical of the "gold trapping" analyzers, uses an atomic fluorescence detector and is capable of very low level and precise measurements.[9] The sample enters the analyzer and follows the blue sample path. The sample passes through cartridge A, which contains a porous gold plug. Any Hg in the sample forms an amalgam with the gold and is collected in the cartridge. The sample leaves the cartridge, flows through a mass flow meter, the sample pump and out the vent. After an established collection period (typically 2.5 minutes for a

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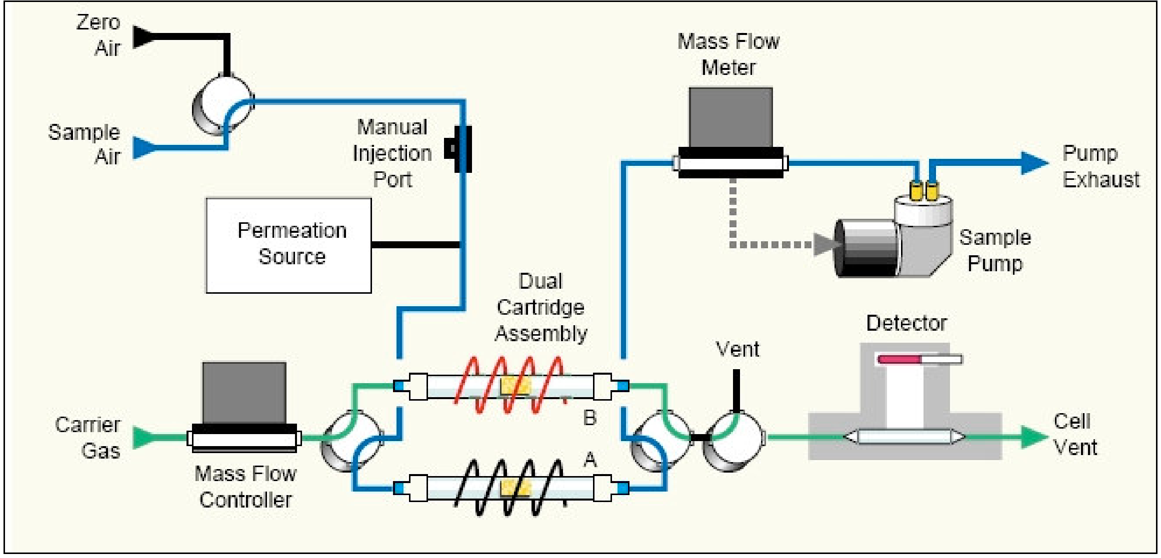
[9] As has been stated previously, the problems with Hg CEMS are not with the detector, they are with the sample handling and conditioning.

Hg CEMS), the valves switch to begin collection on the other trap. At the end of the collection period the collected Hg in the trap is discharged into the detector.

Figure 6 – Tekran Hg Analyzer Flow Diagram



That Hg discharge process is illustrated in Figure 6 by the green flow path. The first step in the discharge process is to flow argon carrier gas through a mass flow meter into the cartridge and then out a vent to purge the trap of any sample gas constituents like CO_2, N_2 and SO_2 that might remain in the trap. The vent valve is then switched so that the flow from the trap is through the detector cell. A heating element wrapped around the trap is energized and the trap is heated to a glowing red hot. The Hg collected on the gold is vaporized and transported to the detector by the argon carrier gas. The output of the detector is a bell shaped curve. The area under the curve is calculated by the system computer, appropriate corrections are applied if there are variations in the sample or carrier gas mass flow and the results are compared to the latest system calibration curve thereby deriving the concentration of Hg in the sample. Since, from the mass flow meters, we know the amount of sample gas went through the gold trap during the Hg collection period we can calculate the Hg concentration in the sample in terms of microgram/m^3.

The major advantage of the gold trap analyzers is that nothing enters the detector other than argon and Hg vapor. Therefore, there is no possibility of interference from sample matrices. It should, however, be noted that there has been no evidence of gas matrix interference on the atomic fluorescence direct reading Hg analyzers.

The major disadvantages of the gold trapping analyzers are complexity, the need for water and argon supply and slow response. Every valve and mass flow meter is a source of mechanical failure. With long sample lines it may be difficult or even impossible for the gold trap Hg CEMS to meet the 15-minute response time requirement of Part 75. Finally, routine QA/QC procedures may take so long that missing data substitution will be triggered.

I hope the above discussion has given the reader a better understanding of the complexity and difficulty of Hg monitoring relative to conventional SO_2 and NO_X CEMS from a hardware standpoint. When that level of complexity is combined with the practical difficulties of moving a sample quantitatively from the stack to the analyzer, the reader may understand my concern with the level of Hg measurement accuracy and precision that may be achieved.

Calibration Issues with Hg CEMS

Calibration of Hg CEMS is a complex subject for a variety of reasons. Among them are:

- There is no National Institute of Science and Technology (NIST) traceable elemental Hg gas standard.
- There is no EPA traceability protocol for either elemental or oxidized Hg calibration sources.
- Calibration error tests using both elemental and oxidized Hg are required by Part 75.[10]
- Head space, vapor pressure devices are the preferable calibration gas source for elemental Hg rather than compressed gas cylinders.
- Daily calibration error tests do not appear to serve as a reliable QA/QC test.

To my knowledge, the only NIST traceable standard relative to air measurements is a liquid standard, Standard Reference Material (SRM) 3133. This SRM is used by virtually all analytical laboratories that are conducting Hg analyses. I am not positive, but suspect very strongly that virtually all of the Ontario Hydro Hg tests results can be traced back to this SRM.

What ***does not*** trace back to SRM 3133 are the CEM-based ambient air Hg analyses and most of the Hg CEMS stack emissions measurements that have been made by various research organizations over the past 20 or so years. These measurements are based on calibrations made either by permeation tubes or head space, vapor pressure calibrators. Recent work[11] suggests very strongly that the measurements are equivalent but there is not broad agreement.

There is now a huge technical debate about how NIST should establish a primary standard for gaseous, head space, elemental Hg calibrators and how the EPA transfer protocol should be established. Without going into a long, laborious discussion, I will only say that the issues are serious and I hope the issues are resolved by the time Hg calibrations have to be done under a regulatory program.

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[10] The oxidized Hg test is called a system integrity test but, in reality, it is nothing but an oxidized Hg calibration error test.

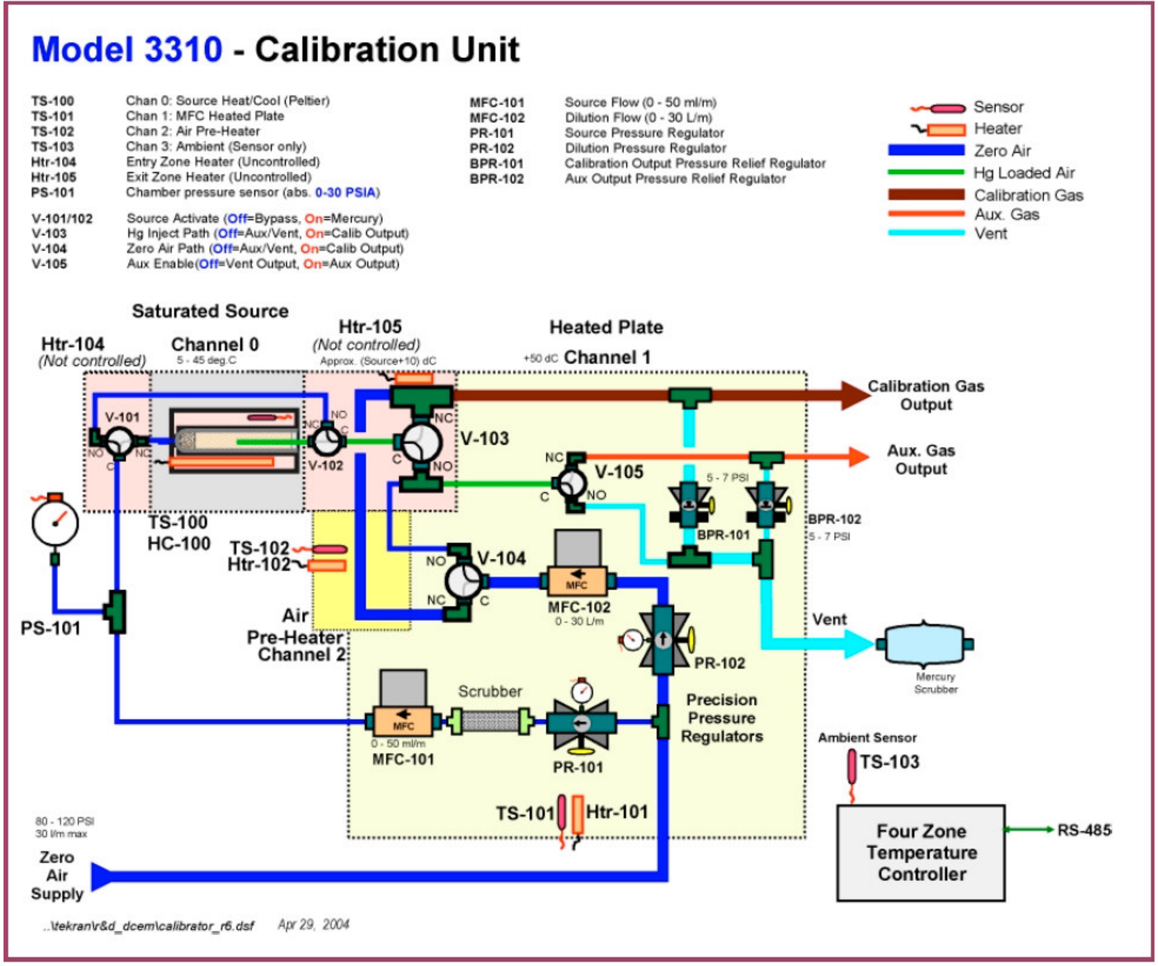
[11] "Comparison of Gaseous Mercury Vapor Calibrations with NIST Traceable Liquid Standards", F. Schaedlich, D. Babi, May 29, 2006, Unpublished

Even without an absolute standard, one can use the available head space calibrators with some confidence of day-to-day repeatability. In other words, we should achieve the same calibration value from day-to-day, even if it is wrong by a small absolute amount.

Head space elemental Hg calibrators and oxidized Hg calibrators will be an integral part of every Hg CEMS. Unlike SO_2 and NO_X CEMS, compressed cylinders are not likely to be used for Hg CEMS because of very high cost ($3500 per cylinder) and short life.

Both elemental and oxidized calibrators add to the overall Hg CEMS complexity and poor reliability. The calibrators are complex devices. Figure 7 below shows the flow diagram of a Tekran head space elemental Hg calibrator.

Figure 7 – Tekran Elemental Hg Calibrator Flow Diagram



While a simple device in concept, a head space calibrator requires very precise temperature and flow control to produce accurate Hg concentrations. The calibrator contains a saturated source of Hg that is maintained at a very precise temperature, typically slightly below or above room temperature. As can be seen in Figure 7, zero air (blue line) enters the device and a tiny flow (~20ml/min) is diverted through a mass flow controller (MFC-101) into the saturated source chamber. When that flow exits the chamber, it contains a high concentration of elemental Hg vapor and has to be mixed with additional air to reduce the Hg concentration to the level where it can be used for Hg CEMS calibration. This is accomplished via another, larger mass flow controller (MFC-102). The diluted gas is then sent to the CEMS where it is used in various calibration modes.

Figure 8 is a picture of the elemental Hg calibrator internals. Like all of the Hg CEMS components, it is complex, difficult to work on and there are lots of pieces to malfunction.

Figure 8 – Tekran Calibrator Internal View

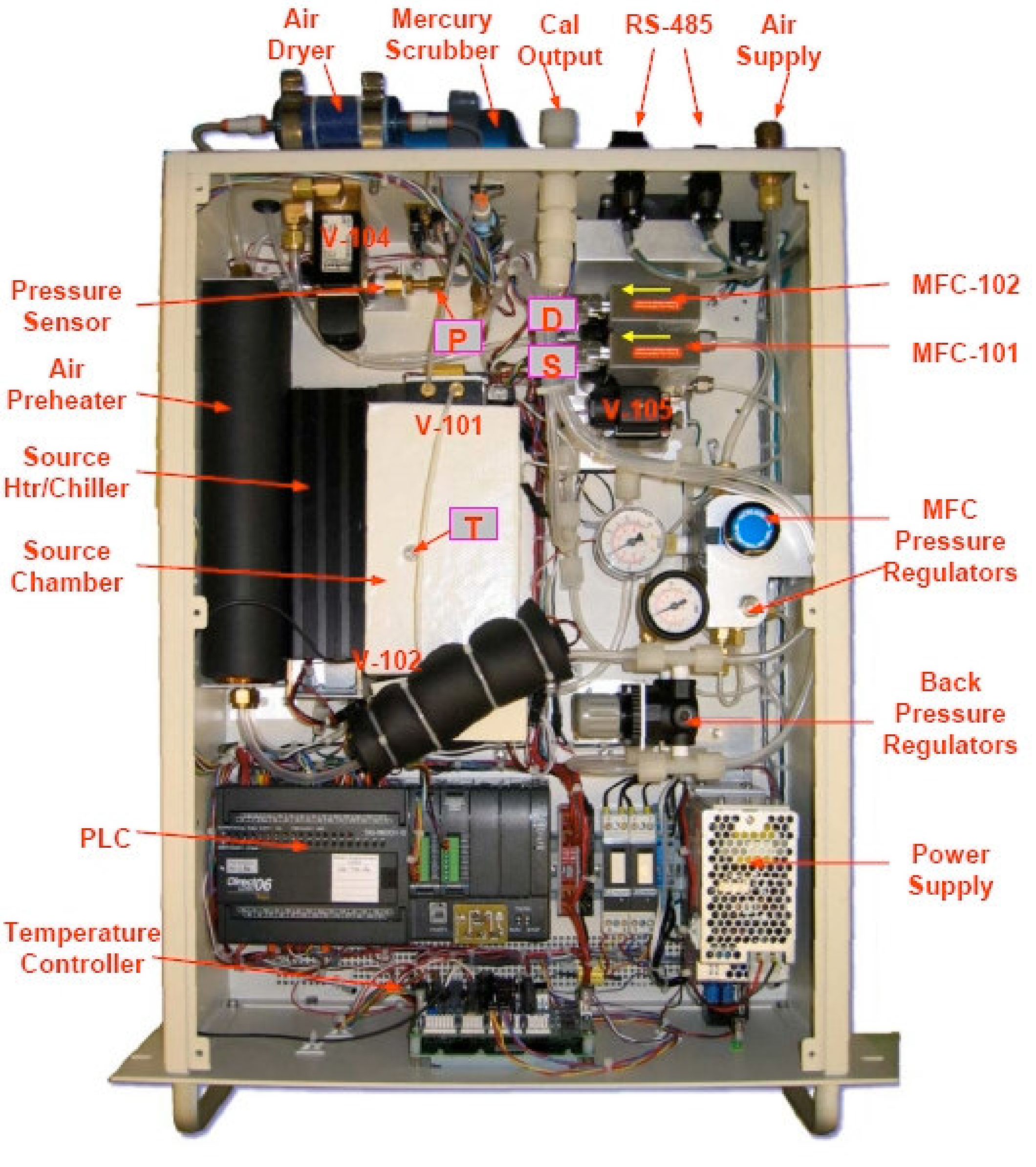
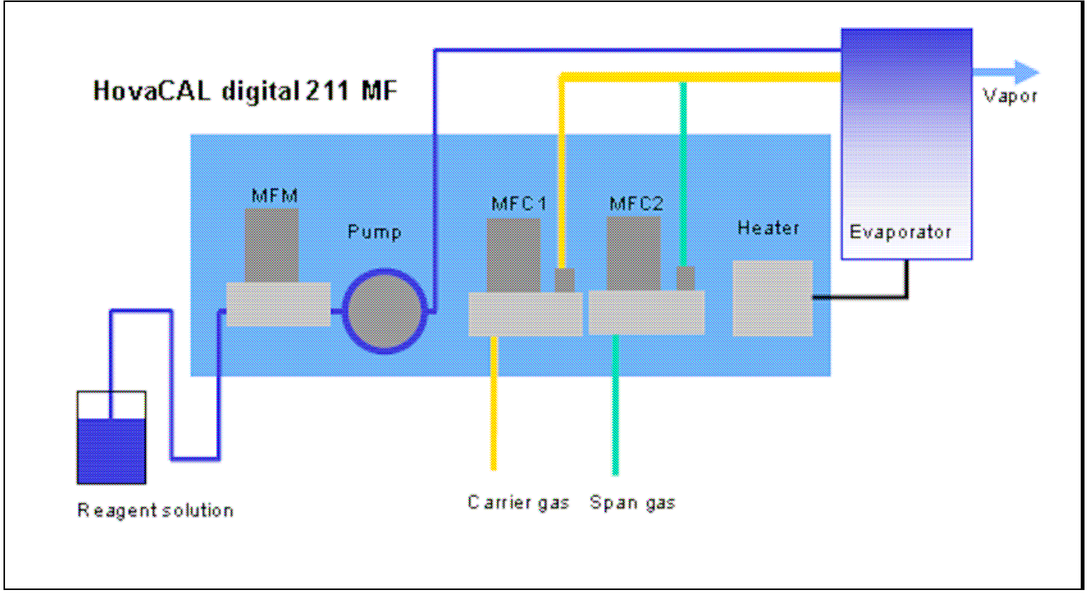


Figure 9 is the flow diagram for the oxidized Hg calibrator (Hovacal or HovaQuick depending on the model) being used in the EPA and EPRI Hg CEMS demonstration studies and by most serious researchers. It should be noted that many of the Hg CEMS being used have ***never*** (or rarely) been calibrated using oxidized Hg. The equipment is expensive and the calibration procedure is difficult. The calibration device uses liquid solutions that are prepared from NIST traceable bulk $HgCL_2$ standards. Therefore, it is the only NIST traceable calibration device available. The HovaQuick device shown in Figure 9 generates hot steam vapor containing known concentrations of $HgCl_2$. As can be seen in the figure, the liquid standard Hg solution is pumped through a mass flow meter into a vaporizer by a variable speed pump. Carrier gas (air or nitrogen) is added to the vaporizer through another mass flow meter and the resulting hot vapor carried through a heated line to the probe box where it is injected into the Hg CEMS sample probe. Broad ranges of concentration can be obtained by changing the liquid standard concentration or the pump speed.

Figure 9 – Oxidized Hg Calibrator Flow Diagram



The HovaQuick has its own dedicated computer that provides the necessary calculations and adjusts the pump speed and carrier gas flow to obtain the target concentration. Figure 10 shows the HovaQuick that is being used at the EPRI project. It is an external, manually operated arrangement because none of the Hg CEMS have provisions for an integrated oxidized Hg calibrator.

Clearly, such an unintegrated arrangement is not desirable for a permanent installation.[12] The HovaQuick has a number of undesirable attributes beside the fact that it is not integrated into any of the Hg CEMS. The need to prepare and replenish liquid standard solutions is exacting and labor intensive. In addition, the device is made in Germany and can only be repaired in Germany. We experienced a mass flow meter failure on the unit being used on the EPRI project and it took two weeks to get the HovaQuick repaired and returned.

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[12] Several of the Hg CEMS vendors are planning to supply their own design of an oxidized Hg calibrator while others are planning on integrating the HovaQuick. None of these devices are presently available.

The 40 CFR Part 75 regulations require that an elemental or oxidized Hg calibration error test be performed once each day.[13] This requirement is modeled after the SO_2 and NO_X monitoring regulations. In addition, if elemental Hg is used for the daily calibration error tests, a weekly system integrity test[14] has to be performed using oxidized Hg to verify the oxidized Hg converter performance. These calibration error tests have proven problematic in the field demonstrations, however, the oxidized Hg system integrity tests are the only traceable calibration tests available.

Figure 10 – HovaQuick Oxidized Hg Calibrator

I recognize that the above Hg CEMS description has been long and laborious. However, I believe it is critical that regulators understand that we are not discussing just another simple analyzer like SO_2 or NO_X. There is a lot of very complex equipment associated with monitoring Hg and it is difficult to operate and maintain. It is truly a different world.

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[13] It is important to understand that the rules do not specify how any CEMS is to be calibrated, only that the calibration error test has to be passed each day and the rules are very specific about how this test is to be done. While SO_2 and NO_X CEMS are usually calibrated using the same procedure as the calibration error test, Hg CEMS, depending on the vendor, may be calibrated using a variety of procedures.

[14] A system integrity test is done exactly like a calibration error test except with oxidized Hg. The purpose is to verify that the oxidized Hg converter is performing properly.

Measurement Characteristics

When measurements are discussed, whether those measurements are of emissions, time, weight, volume, etc. it is necessary to consider certain measurement characteristics that impact any measurement being made. These measurement characteristics include error, both random and systematic, bias, accuracy and precision. Regulators hate to consider measurement errors because it is a difficult technical subject loaded with mathematics. Measurement error is also difficult to deal with in an enforcement setting because there usually has to be a firm basis for bringing an enforcement action and dealing with measurement error impact on compliance measurements is difficult to explain in a legal brief.

For many years, in the Federal New Source Performance Standards (NSPS) regulatory process, the problem of measurement error was handled by setting the standards based on measurements made with EPA Reference Methods (RM). By taking this approach, any random error, bias and imprecision was buried in the RM measured values and, assuming the data were analyzed properly, reflected in the resulting emission limit. This is a very rational approach and largely solves the measurement error problem.

Unfortunately, the Maximum Achievable Control Technology (MACT) and Prevention of Significant Deterioration (PSD) initiatives have disabled this rational approach and have driven emission limits so low that many of the RMs cannot measure emissions reliably. In essence, the RMs cannot separate the measurement method noise and contamination from the actual emissions being measured.

A good example of this problem is the need to conduct a NO_X CEMS relative accuracy test audit (RATA) on a gas-fired combined cycle unit with emissions of 2 ppm NO_X. This measurement can not be done at all with the wet chemistry EPA RM 7 and is extraordinarily difficult to make using the instrumental RM 7E.

Since our interest in this report is with instrumental measurements (i.e., Hg CEMS) I will restrict the discussion only to those techniques except where the accuracy and precision problems of the Hg RM effect the instrumental measurement.

Detection Limit

As I have stated previously, the measurement capability of Hg analyzers/detectors is not an issue with the measurement of Hg stack emissions because our problem is getting the sample to the analyzer in an unadulterated form. However, since I am discussing measurement characteristics, some discussion of detection limit is in order so that the reader will understand what it is and how it is defined.

Detection limit and how to define and determine it has been the subject of much debate and discussion for many years.[15] How it is defined and determined depends on the

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[15] Several of the most often referenced papers on the subject of detection limit and other measurement characteristics were written by L.A. Currie of NIST. If the reader desires to experience a complete brain

analytical procedure or measurement being performed, however, I will focus on instrumental measurements. It is commonly believed that the detection limit is the lowest concentration that can be measured but this is incorrect. The detection limit is the point where we can detect a signal above background and say only that something is there. Measurements cannot be made at the detection limit. A real life example of detection limit is standing in a field on a dark, foggy night and seeing some flicker of movement in the distance. You can tell something or someone is there but you cannot even identify if it is human. You surely cannot identify if it is a man or a woman. That's detection limit.

In its sales literature, Tekran quotes a detection limit for the Hg analyzer of 0.05 microgram/m^3. If we take the standard spectroscopy definition of limit of quantification,[16] the point where we might be able to make quantifiable measurements, then we must multiple the detection limit by 3.3. In the case of the Tekran analyzer, this would result in a limit of quantification of 0.2 microgram/m^3 (rounded). I would not argue with this value in the absence of Hg sample transport and conditioning issues. Unfortunately, we have to deal with those sample transport and conditioning issues on a Hg CEMS. Based on my experience, these issues significantly increase the limit of quantification.

Random Errors

There are random errors in any measurement – they cannot be avoided. It is widely believed that a long averaging time, like the 12-month rolling average used in the proposed Illinois rule averages out the measurement error. This is only true if ***all of the errors*** are random ***and*** the data are normally distributed around the mean value (average).

Figure 11 is an example of a normal distribution with only random error. It can be seen that the frequency of measurements peaks right at the emission limit (0.80 microgram/m^3). If the true measurement distribution looked like Figure 11, a source could control right at the emission limit and be in compliance because the random errors on each side of the mean would cancel. It is important to recognize that if there is any bias (positive or negative offset) in the measurements, long averaging times will not correct this problem. When there is a bias associated with a normal distribution, the distribution curve moves left or right and any bias just moves the mean.

When the emissions data have a log normal distribution, which is always the case with emissions after a control device, a long averaging time still helps but does not average out the measurement error because the error and, more importantly, the measurements are not evenly distributed. Figure 12 is an example of a log normal distribution of emission measurements that one observes after a control device.

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melt down, they may enjoy his paper "Detection: International update, and some emerging di-lemmas involving calibration, the blank, and multiple detection decisions," Chemometrics and Intelligent Laboratory Systems 37 (1997) 151-181.

[16] V. Thompson, D. Schatzlein, D. Mercuro, "Limits of Detection in Spectroscopy," Spectroscopy 18(12) (December 2003) 112-114

Figure 11 – Example Normal Distribution

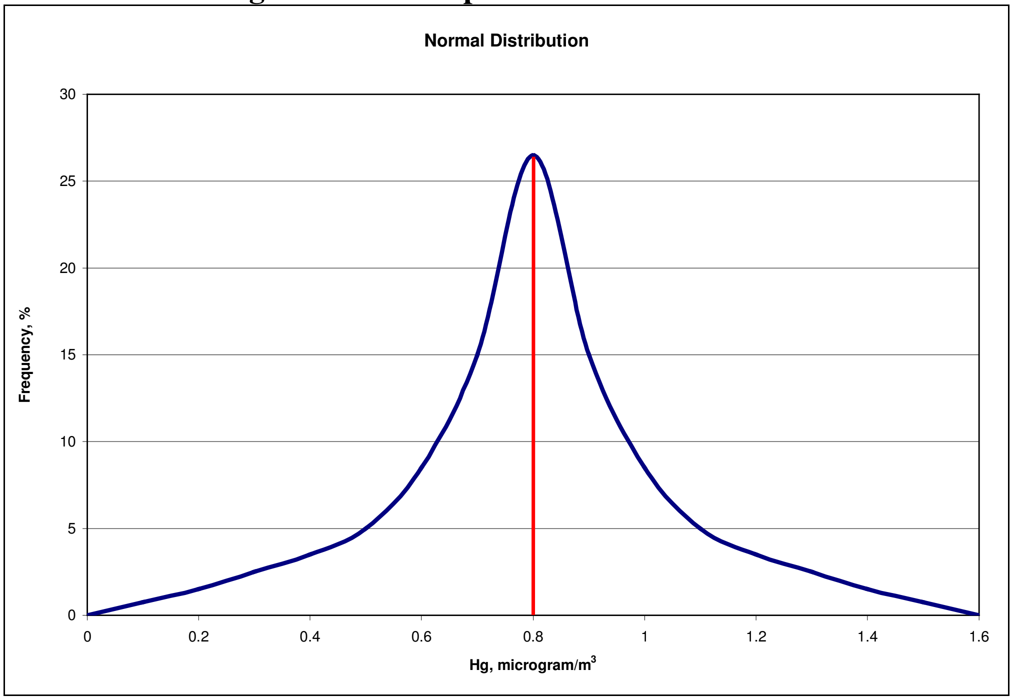
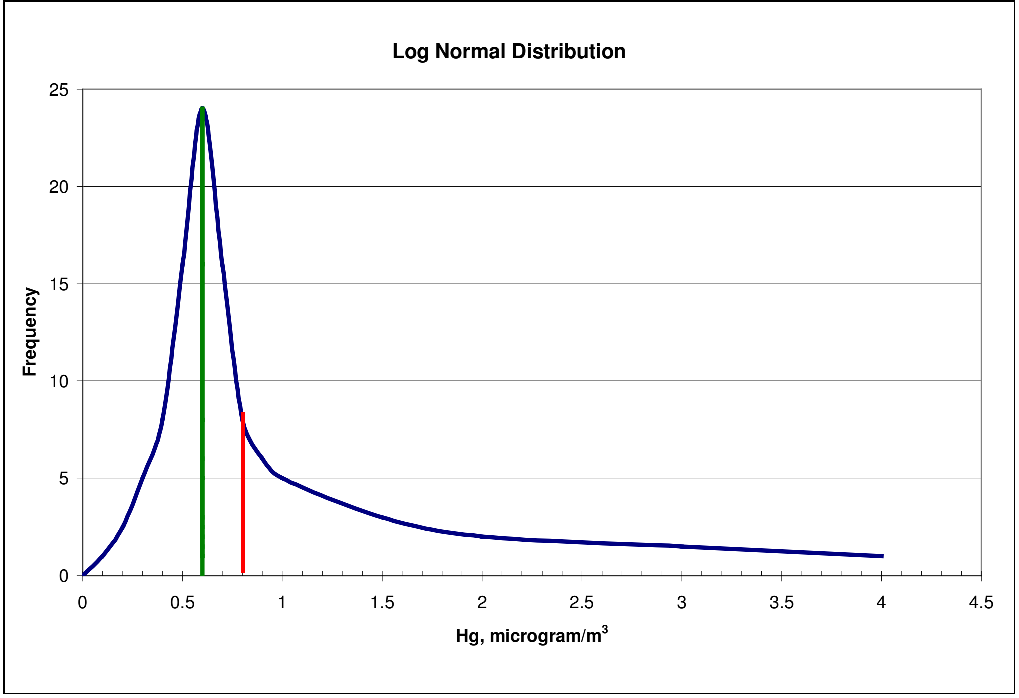


Figure 12 – Example Log Normal Distribution



The problem that has to be addressed when the emissions have a log normal distribution is the long tail to the right, which represents emissions above the emission limit. This long tail is generally caused by a combination of control device problems (i.e., equipment failures) and inlet pollutant variability. In the case of a control program that incorporates missing data substitution, as contemplated by the proposed Illinois rule, the long tail also contains much of the substituted data. The long tail cannot be eliminated because mechanical and electrical equipment fails from time to time and control devices are nothing but mechanical and electrical equipment.

To account for the long tail on the emissions distribution, the source has to set an operating control point (green line in Figure 12) some distance below the emission limit (red line in Figure 12). Exactly how far below depends on the shape of the long tail. It should be noted that a regulator desiring to set a hard cap emission limit also has to consider the long tail relative to the level of the emission limit and the capability of the control technology. For example, to achieve an average of 90% emissions reduction, the control technology may have to achieve 94-95% reduction for the vast majority of its operating time to average out the long tail effect. Therefore, the regulator must ask if the emissions control technology can achieve the 94-95% reduction over the long term.

Bias

A measurement bias in any measurement system is extremely undesirable because it effects each and every data point, either positively or negatively. Measurement bias is very difficult to identify and eliminate in any measurement system because detection of bias depends on another measurement that is independent of the primary measurement system. If the independent measurement system does not have as good, or better, measurement accuracy and precision as the primary measurement system, bias hides in the measurement noise. We have not detected any particular bias in the continuous Hg CEMS measurements, however, as will be discussed later, the measurements are so noisy that a small bias would be virtually impossible to detect.

There is a classic example of measurement bias effecting CEM measurements. In the early days of the Acid Rain program many utilities began to identify a positive SO_2 and heat input/heat rate bias in the CEM data in comparison to convention measurements of unit heat rate. When there were only a few initial reports, this problem was thought to be a simple error issue. However, as more reports came in it was obvious that there was a high bias because in almost every case the bias was high - and not by a small amount. Biases as high as 30% were being reported and 15-20% were common. After considerable research, the source of the error was identified as stack swirl that caused a high measurement of stack flow that was ultimately traced to EPA Reference Method 2. It was then necessary to develop a new reference method that could measure three dimensional flow. In addition, EPA then had to promulgate the new 3-D flow reference method. This research and regulatory activity took a considerable amount of time to accomplish and for several years many utilities had to live with the swirl induced high bias. It is likely that this simple bias error resulted in million dollars of cost in lost and/or purchased SO_2 allowances.

Accuracy and Precision

Accuracy and precision are often confused and will be discussed together. Accuracy, in science and engineering, is the degree of conformity of a measured quantity to its actual (true) value. The true value is generally determined by a standard that is traceable to a NIST primary standard. Precision (also called reproducibility or repeatability) is the degree to which individual, independent measurements or calculations will show the same or similar results. The results of a measurement can be accurate but not precise, precise but not accurate, neither, or both.

The concepts of accuracy and precision can be illustrated by an example of a marksman shooting at a target. Figure 13 shows an example of a target where the marksman had high accuracy but low precision while Figure 14 shows an example of high precision but low accuracy.

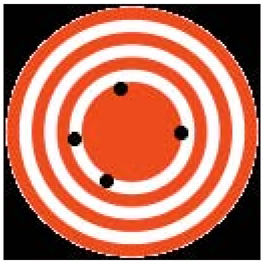


Figure 13 - High accuracy but low precision

Figure 14 - High precision but low accuracy

If the four shots in Figure 14 were moved into the bulls eye, it would show both high accuracy and high precision. Figure 14 also shows an example of bias – all shots are low and to the left. Note that measurements cannot have a high level of accuracy in the presence of bias. It should also be noted that it is not possible to achieve accuracy in ***individual*** measurements without precision - if the shots are not grouped close to one another, they cannot all be close to the bulls eye.

I recognize that the above data characteristics discussion may have been painful for those that are not accustomed to making measurements. It is, however, essential to understand measurement issues when Hg measurements are considered in relation to rule requirements. It is a simple fact that a regulation cannot contain an emissions limit that requires measurements that cannot be made to an acceptable level of accuracy and precision.

Description of Hg Monitoring and Demonstration Research Projects

EPA Projects and Results

The U.S. EPA has conducted two Hg CEMS demonstration projects to evaluate the ability of Hg CEMS to make the necessary measurements and achieve the QA/QC requirements of the 40 CFR Part 75 regulations. These two projects were conducted at the Cape Fear Plant of Progress Energy and at the Trimble County Plant of LG&E Energy.

The Cape Fear unit is a conventional pulverized coal-fired unit with a capacity of approximately 200 MW. It is equipped with an electrostatic precipitator (ESP) for particulate control. It does not have a selective catalytic reactor for NO_X control or a SO_2 scrubber for SO_2 control and, thus, has a dry stack. The dry stack makes the unit somewhat atypical when we look into the future because most units are expected to be equipped with SO_2 scrubbers in the future in response to the Clean Air Interstate Rule (CAIR). In addition, the absence of a SO_2 scrubber results is higher Hg emissions and the combination of higher Hg emissions and the dry stack makes Hg monitoring much easier than on a wet stack with low Hg emissions.

The Trimble County unit is more typical of what we believe power plants will look like in a few years. It is a pulverized coal-fired unit with a capacity of approximately 545 Mw. It is equipped with an ESP for particulate control, a SCR for NO_X control and a wet scrubber for SO_2 control. Consequently, it has a wet stack and much lower Hg emissions than does the Cape Fear unit.[17] These two factors dictate that Hg measurements are much more difficult to make at Trimble County than at Cape Fear.

Since most utility coal-fired units are likely to be equipped with wet scrubbers and wet stacks as a result of the CAIR rule, I plan to focus my discussion on the prior EPA and electric utility industry Hg monitoring research work at Trimble County. The combination of a wet stack and low Hg concentrations makes this a demanding site for Hg monitors. However, it is no less demanding than most sites are expected to be in the future.

EPA's test program at Trimble County was basically focused on demonstrating that the Hg CEMS could pass the initial CEMS certification tests. These initial certification tests include a 7-day calibration error test, linearity test, converter efficiency test, measurement error test, zero and upscale drift test, relative accuracy test and cycle time test. These are all one-time tests to initially qualify the Hg CEMS. On a periodic basis thereafter, some of these tests are conducted as on-going QA/QC tests. For example, a zero and span calibration error test is required every day and a system integrity (converter efficiency) test is required weekly. There are criteria for passing these tests in the 40 CFR Part 75 monitoring regulations. As an example, the daily zero and span calibration requirement

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[17] The comparison of Hg emissions between Cape Fear and Trimble County is relative. Hg emissions are highly variable because of coal Hg content variability. On average, Trimble County has lower Hg emissions but, on any given day, the Hg emissions may be higher than at Cape Fear.

is 5% of span or ±1.0 microgram/m^3, whichever is greater. The Hg CEMS relative accuracy test is also tied to the ±1.0 microgram/m^3 specification. This ±1.0 microgram/m^3 specification has turned out to be very important.

To illustrate the importance of the ±1.0 microgram/m^3 specification, I will review the two RATA tests that were done by EPA at the Trimble County site. For those that may not be familiar with a RATA test, it is simply a series of comparisons between an EPA Reference Method test (that is assumed to be absolutely accurate and precise) and the CEMS being evaluated. At least nine valid comparison tests are required to support the statistical analysis of the RATA results, therefore, 12 tests are usually performed. These extra tests are especially important for a Hg RATA test because the EPA reference method is an ASTM test method called the Ontario Hydro method. This test method is a wet chemistry test and it is very difficult to conduct in the field. In addition, the Ontario Hydro analytical laboratory procedures are difficult and exacting and laboratory problems frequently occur. Finally, EPA decided to require paired Ontario Hydro test trains and the pair of analyses must agree within 10% for the individual test run to be acceptable.[18]

The overall RATA acceptance criteria is 20% relative accuracy if the mean reference method value is greater than or equal to 5.0 micrograms/m^3. If the mean reference method value is less than 5.0 micrograms/m^3, then the acceptance criteria is 20% relative accuracy or ±1.0 microgram/m^3, whichever is less restrictive.[19] During both RATAs conducted at Trimble County the mean Hg concentration was less than 5.0 micrograms/m^3 so the ±1.0 microgram/m^3 criteria became the controlling factor. As you will notice in the tables below, it is a good thing that criteria was included.

The tables below show the results for those RATA's.

Table 1 - RATA 1 Results From Trimble County

RATA Criteria	Tekran	Thermo	Horiba	Forney
Relative Accuracy, %	11.7	29.9	40.7	70.1
Mean Difference, μg/m^3	0.2	0.8	1.3	1.5

Mean Reference Method Concentration = 3.6 μg/m^3
SCR Off

It can be readily seen that the Tekran Hg CEMS is the only system that passed both the relative accuracy requirement as well as the ±1.0 microgram/m^3 requirement during the first RATA. The Thermo passed the ±1.0 microgram/m^3 requirement but not the relative

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[18] EPA is presently rethinking the paired train requirement because it is basically physically impossible to conduct the test according to the written method. EPA has ***never*** traversed with a paired Ontario Hydro test train. All RATA tests conducted by EPA at the demonstration sites were conducted at a single point while the method requires traversing. In addition, the paired train 10% agreement criteria results in considerable lost reference method data.

[19] Of course, this means that the RATA acceptance criteria for Hg CEMS used in the Illinois Hg control program will be subject to the ±1.0 microgram/m^3 value. Since the compliance level is 0.80 microgram/m^3 any value between 1.8 and -0.2 microgram/m^3 will be acceptable during a RATA.

accuracy and the Horiba and Forney Hg CEMS failed both. With respect to the proposed Illinois rule, it is not enough to say that the Tekran and Thermo passed the Part 75 Hg RATA requirements. We have to ask - with what level of accuracy? The answer is somewhere between 12% and 30% accuracy.

Table 2 - RATA 2 Results From Trimble County

RATA Criteria	Tekran	Thermo	Opsis	Durag
Relative Accuracy, %	11.8	84.8	30.7	42.9
Mean Difference, $\mu g/m^3$	0.2	0.9	0.4	-0.2

Mean Reference Method Concentration = 2.0 $\mu g/m^3$
SCR On

During the second RATA, again Tekran was the only Hg CEMS to pass both the relative accuracy and mean difference criteria. All analyzers passed the mean difference criteria, even the Thermo, which was out-of-service and reading zero for four of the nine runs. I am not sure we should call that a pass, but according to the rule, it did. If we exclude the Thermo, the other Hg CEMS passed certification with 12% to 43% accuracy.

In general, I do not consider these RATA results to be very good. The relative accuracy is extremely high relative to what we normally experience with SO_2 and NO_X CEMS (2-3%). The bottom line is that without the ±1.0 microgram/m^3 mean difference criteria, there is little hope of passing the RATA test. What good is passing a ±1.0 microgram/m^3 performance criteria when the emission limit is 0.80 microgram/m^3 as proposed in the Illinois rule?

There are also have significant difficulties even making accurate reference method measurements. In each of the Trimble RATAs, there were only eight valid runs rather than nine. Four of the runs in each RATA failed to meet to meet the paired train criteria of 10% agreement. ***Therefore, by the 40 CFR Part 75 rules, the RATAs were invalid.*** In order to get any idea about the CEMS performance, the calculations shown in Tables 1 and 2 above included the best 9 of 12 runs irrespective of whether the run passed the 10% agreement criteria. It should be noted again that ***no one, not even EPA,*** has ever made a Hg Reference Method test that is in compliance with the Reference Method procedure (Ontario Hydro method) contained in the Federal rules and proposed Illinois rules because no one has ever traversed with paired trains.

There are additional problems with the Ontario Hydro EPA Reference Method. The 12 runs take about six-seven days to complete because only two runs per day can be done. The laboratory analysis takes another three-four weeks so the source has no idea whether they have passed the RATA for a month. If they fail, then they have to repeat the RATA and are “out-of-control” from the time the first RATA was failed. That means at least a month of data substitution. It should also be noted that an Ontario Hydro RATA costs about $50,000. Finally, if one looks at the precision specifications in ASTM 6784 (Ontario Hydro) it will be discovered that the precision of the test below 3 micrograms/m^3 is listed as 34%. I expect these precision calculations were done on a series of tests that were just below 3 micrograms/m^3 and that no one has any idea what the precision is at 0.80 microgram/m^3. I would guess above 50% and perhaps as high as 100% since measurement precision always goes up as the concentration goes down. In other words, the Ontario Hg reference method does not appear to insure precise and accurate measurements at the 0.80 microgram/m^3 level.

Finally, it should be noted that EPA has only published several tables of CEMS "certification" results from the two demonstration sites. In over two years of research, EPA has ***not published*** any of the hourly Hg CEMS data, any of the daily calibration error test data, any of the CEMS reliability data or any of the system integrity test data.

EPRI Hg Monitoring Demonstration Project and Results

The EPRI electric utility industry Hg CEMS study is being supported by a large group of utility companies at the Trimble County scrubber equipped power plant in Kentucky. This study is a continuation of a prior EPA study at the same site. The EPA study was conducted to demonstrate that a Hg monitoring system could pass a certification per the requirements of 40 CFR Part 75. The results of the EPA study have already been discussed in this report and it is clear that the objective was not achieved since both certifications were invalid. However, a lot was learned from the difficulties encountered during the EPA study. When EPA decided to discontinue support for the Trimble County project, the electric utility industry decided to support continuation of the project with different objectives and initiated an EPRI Tailored Collaboration (TC) project.[20] RMB Consulting & Research, Inc. was chosen to be the prime contractor for the EPRI project.

The objectives of the industry study are to operate the Hg CEMS, to the extent possible, as if the Hg monitoring rule was in effect and to provide the Hg CEMS vendors with a technology development site. It was clear from the EPA study that considerable technology development was needed with respect to reliability and operability. The Hg CEMS are now being operated continuously and all daily and weekly QA/QC tests are being performed. There are presently four Hg CEMS in the project. There are two Thermo systems equipped with sampling probes of different design. There is also a Tekran and a GE/PSA Hg CEMS. The reliability of the Hg CEMS has been poor; the accuracy and precision has been poor; there is wide disagreement among experts on fundamental calibration issues (NIST has no Hg vapor pressure calibration standard) and the daily/weekly QA/QC calibration error tests are failed frequently for no apparent reason. In short, there are a variety of unresolved problems with making Hg measurements in flue gas and those problems are compounded when the measurements have to be made at concentrations less than 1.0 microgram/m^3, as will be the case under the proposed Illinois rules.

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[20] A TC project is outside the normal EPRI base research budget. It is initiated and funded by one or more EPRI members that have a particular technical issue that they believe needs to be addressed.

Figure 13 – Inertial Probe Loop Exit Plugging

In the initial stages of the EPRI project it was evident that Hg CEMS reliability was a serious problem. There was a design flaw in the inertial probes being used by all of the Hg CEMS vendors and they were plugging every 7-10 days. In general, a plugged probe requires that the probe box be removed or largely disassembled and the repair consumes about a day. Figure 13 is an example of the probe discharge plugging that was experienced. At the present time, the probe design flaws that were causing the plugging problem appear to have been rectified with design changes to the inertial loop.

This is not to suggest that overall Hg measurement reliability has improved to the point needed for a Hg CEMS used in a regulatory program. The fact that the instruments are operating and writing Hg values to the computer hard drive does not mean that the values are correct.

We have had periods of two weeks or longer where various Hg CEMS are completely out of service with vendor personnel working full time to repair the problems. Several of the failures have required a virtual rebuild of the CEMS. On one system, loss of the probe heaters due to a tripped breaker resulted in a Hg CEMS outage of over a week because of “internal contamination.” Overall Hg CEMS reliability remains poor even with extensive vendor and RMB effort.

The most pressing problem at present is the inability of the Hg CEMS to pass the daily and weekly QA/QC tests on a routine basis. Table 3 shows the daily calibration error tests from one of the Hg CEMS for April 2006 and the shaded values are all failures. Of the 22 operating days, the calibration error test was failed on 17 days or 77% of the operating days in the month.

Table 3. Calibration Error Test Results - CEMS X - April 2006

Date	Zero Response	Error (% of Span)	Span Response (Expected 9.8ug/m^3)	Error (% of Span)
April 1, 2006	0.1	0.7%	8.4	7.0%
April 2, 2006	0.3	1.7%	8.6	6.0%
April 3, 2006	0.4	2.0%	9.0	4.0%
April 4, 2006	1.2	6.0%	9.3	2.5%
April 5, 2006	0.7	3.5%	8.5	6.5%
April 6, 2006	0.2	1.0%	8.2	8.0%
April 14, 2006	0.0	0.0%	3.1	33.5%
April 15, 2006	0.0	0.0%	3.4	32.0%
April 16, 2006	0.0	0.0%	3.3	32.5%
April 17, 2006	0.0	0.0%	3.2	33.0%
April 18, 2006	0.0	0.0%	3.0	34.0%
April 20, 2006	0.0	0.0%	8.9	4.5%
April 21, 2006	0.0	0.0%	8.9	4.5%
April 22, 2006	0.0	0.0%	8.6	6.0%
April 23, 2006	0.0	0.0%	8.4	7.0%
April 24, 2006	0.0	0.0%	8.4	7.0%
April 25, 2006	0.0	0.0%	8.2	8.0%
April 26, 2006	0.5	2.5%	9.3	2.5%
April 27, 2006	0.3	1.5%	8.9	4.5%
April 28, 2006	0.3	1.5%	8.6	6.0%
April 29, 2006	0.0	0.0%	8.1	8.5%
April 30, 2006	0.0	0.0%	7.9	9.5%

Table 4 shows the calibration error test results for the same Hg CEMS for May 2006. During this month, the Hg CEMS was in service for 26 days and failed the calibration error test on 14 days for a failure rate of 54%.

Table 4. Calibration Error Test Results - CEMS X - May 2006

Date	Analyzer Zero Response	Error (% of Span)	Analyzer Span Response	Error (% of Span)	Span Expected
May 3, 2006	0.4	2.0%	5.4	1.5%	5.7
May 4, 2006	0.1	0.5%	5.5	1.0%	5.7
May 5, 2006	0.1	0.5%	5.7	0.0%	5.7
May 6, 2006	0.1	0.5%	5.5	1.0%	5.7
May 7, 2006	0.0	0.0%	4.0	8.5%	5.7
May 8, 2006	0.0	0.0%	3.8	9.5%	5.7
May 9, 2006	0.1	0.5%	8.6	14.5%	5.7
May 10, 2006	0.0	0.0%	8.9	16.0%	5.7
May 11, 2006	0.1	0.5%	8.7	15.0%	5.7
May 12, 2006	3.3	16.5%	11.8	1.5%	11.5
May 15, 2006	0.3	1.5%	11.3	1.0%	11.5
May 16, 2006	0.4	2.0%	9.1	12.0%	11.5
May 17, 2006	0.4	2.0%	4.1	37.0%	11.5
May 18, 2006	0.4	2.0%	9.6	9.5%	11.5
May 20, 2006	0.9	4.5%	11.8	1.5%	11.5
May 21, 2006	0.4	2.0%	11.7	1.0%	11.5
May 22, 2006	0.3	1.5%	7.0	22.5%	11.5
May 23, 2006	0.1	0.5%	6.8	23.5%	11.5
May 24, 2006	0.2	1.0%	11.2	1.5%	11.5
May 25, 2006	0.6	3.0%	10.3	6.0%	11.5
May 26, 2006	0.6	3.0%	11.6	0.5%	11.5
May 27, 2006	0.4	2.0%	8.7	14.0%	11.5
May 28, 2006	0.4	2.0%	8.4	15.5%	11.5
May 29, 2006	0.4	2.0%	11.0	2.5%	11.5
May 30, 2006	0.3	1.5%	11.5	0.0%	11.5
May 31, 2006	0.3	1.5%	11.4	0.5%	11.5

To be fair, one of the Hg CEMS had a reasonably good month with calibration error tests during May 2006. Table 5 shows those results and there were only two failures out of 25 days that the system operated for a failure rate of 8%. Unfortunately, during that same month this analyzer failed a couple of system integrity tests.

Table 5. Calibration Error Test Results – CEMS Y - May 2006

Date	Analyzer Zero Response	Error (% of Span)	Analzyer Span Response (Expected 10.0ug/m^3)	Error (% of Span)
May 1, 2006	0.0	0.0%	10.1	0.5%
May 2, 2006	0.2	1.0%	10.1	0.5%
May 3, 2006	0.1	0.5%	10.2	1.0%
May 4, 2006	0.0	0.0%	9.5	2.5%
May 5, 2006	0.1	0.5%	10.3	1.5%
May 6, 2006	0.2	1.0%	9.9	0.5%
May 7, 2006	0.3	1.5%	10.8	4.0%
May 8, 2006	0.3	1.5%	10.3	1.5%
May 9, 2006	0.3	1.5%	10.3	1.5%
May 10, 2006	0.1	0.5%	9.4	3.0%
May 11, 2006	0.2	1.0%	9.9	0.5%
May 12, 2006	0.3	1.5%	10.2	1.0%
May 13, 2006	0.2	1.0%	4.7	26.5%
May 14, 2006	0.0	0.0%	9.2	4.0%
May 15, 2006	0.3	1.5%	10.0	0.0%
May 16, 2006	0.3	1.5%	10.7	3.5%
May 17, 2006	0.3	1.5%	10.9	4.5%
May 18, 2006	0.3	1.5%	10.5	2.5%
May 19, 2006	0.0	0.0%	10.3	1.5%
May 20, 2006	0.0	0.0%	5.3	23.5%
May 21, 2006	-0.1	0.5%	10.8	4.0%
May 22, 2006	0.1	0.5%	10.7	3.5%
May 23, 2006	0.1	0.5%	10.5	2.5%
May 24, 2006	0.0	0.0%	9.8	1.0%
May 25, 2006	0.0	0.0%	9.5	2.5%

There is another important feature of these calibration error tables that is related to the proposed Illinois rule. As the reader may recall from earlier discussion, the Part 75 rules allow a daily calibration error check limit of 5% of span or ±1.0 microgram/m^3. For convenience, we have assumed that the span of the Hg CEMS at Trimble is 20 micrograms/m^3. That way, 5% and ±1.0 microgram/m^3 is the same number.

To measure Hg with some reasonable level of accuracy at the 0.80 microgram/m^3 level as specified by the proposed Illinois rule, one would certainly desire to have a calibration error of no greater than ±0.1 microgram/m^3 (12.5% of the emission limit). If one scans down the "Analyzer Span Response" column in Table 5, I believe there are only five days where that criteria is met. In other words, based on the calibration error data, even the ***best performing*** Hg CEMS at Trimble does not illustrate the level of accuracy and precision required by the proposed Illinois rule.

It is very troublesome that the daily calibration error test is not a reliable QA/QC test for Hg CEMS. However, if one considers that the absolute level of Hg is 0.1 ppb or less, it is not particularly surprising that this tiny concentration is difficult to transport reliably from the stack to the detector. What is even more troubling is the possibility of the effect of missing data substitution on the federal trading program and on the proposed Illinois Hg control rule.

Missing Data Substitution

Missing data substitution is a concept introduced in the Acid Rain program that grew out of the need to account for all of the tons of SO_2 that were emitted. In essence, the missing data procedures contained in the Acid Rain rules uses various missing data algorithms that are tied to CEMS availability and duration of CEMS outage. As CEMS availability gets worse and the outage time gets longer, progressively more onerous data substitution procedures are used not only to provide for missing data but also to impose a penalty on the source for poor monitor availability.

The missing data substitution procedures result in data that are biased high,[21] sometime by a wide margin. In addition to being biased, the missing data are not real – they are created by the applicable algorithm and are totally unrelated to real emissions. While I do not approve the practice of "making up" data, which is all the missing data algorithms do, the procedure is generally not a terrible problem for conventional SO_2, NO_X, CO_2 and stack flow monitors.[22] There are two reasons why missing data is not a serious problem under the existing Acid Rain program. First, the SO_2, NO_X, CO_2 and flow measurement CEMS are very reliable monitoring systems with availability of 98-99%. Second, under the SO_2 and NO_X trading program no specific unit or utility has a hard cap on SO_2 or NO_X emissions. Therefore, if additional allowances are needed to account for missing data, those allowances can be bought in the open market.

In the case of an emissions program where each specific unit or source has a defined emission limit or a percent removal requirement (like the Illinois Hg control rule), the use of missing data is a very bad idea because missing data substitution always biases the data high and this bias may cause non-compliance with the emission limit. It does not make any sense that "imaginary, made up" data could have the potential to cause an out-of-compliance situation. It should be noted that the Federal Hg emissions limit regulations for new sources at 40 CFR Part 60, Subpart Da, at Section 60.49a(p)(4)(ii), specifically exclude the use of missing data substitution or bias corrected data.

Obviously, if the 40 CFR Part 75 missing data procedures are used in the Illinois Hg control program as specified in Section 225.260, "imaginary, made up" and biased data

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[21] The least punitive missing data procedure, the average of the hour before and hour after the CEMS outage may be biased high or low depending on the data pattern. All other missing data procedures are biased high.

[22] In the case of an extended monitor problem, like a lightening strike where long periods of data may be lost, the missing data procedures can become very problematic.

would be used in the emission calculation. From a practical standpoint, it would seem that a violation of an emission limit would be very difficult for any regulatory agency to explain to a judge when "imaginary, made up" and deliberately biased data are used in the emission calculation. In my opinion, the use of missing data substitution in a hard cap emission limit is very bad science and public policy.

Coal Sampling and Analysis Error Sources

In order to demonstrate 90% reduction in Hg from the coal input to the stack, the effected sources in Illinois will have to perform coal sampling and analysis to determine the Hg input to the units. Section 225.265 (a)(1) of the proposed rule states, "Perform daily sampling of the coal combusted in the EGU for mercury content. The owner....shall collect a minimum of one 2-lb grab sample per day.........boiler. Such sample.......provide a representative mercury content for the coal burned on that day." Section 225.265 (2) specifies that each coal sample shall be analyzed for heat content, moisture and Hg content and lists the applicable ASTM analytical standards. It is also interesting to note that Section 225.265 (a)(4) states, " to determine the mercury content in terms of lbs/trillion Btu." These coal sampling and analysis requirements are a bit unusual.

As a general matter, federal EPA regulations that require coal sampling and analysis reference 40 CFR Part 60, Appendix A, Method 19 for the applicable coal sampling and analysis procedures. In turn, Method 19 uses extensive references to ASTM standards and practices.

For example, Section 12.5.2.1.1 of Method 19 provides the specifications for solid fuel sampling. In general, ASTM Standard D 2234, Type 1, Conditions A, B or C with systematic spacing is specified for fuel sampling. Systematic spacing means evenly spaced sample collection intervals based on time or fuel weight. Type I means no human discretion in the location, timing or pieces of coal selected. To conform with Condition A, B or C, the coal sample would have to be either taken from a conveyor belt crosscut or from a falling stream of coal. Scooping a single 2-lb sample from the belt, as seems to be contemplated by the proposed Illinois rule, is clearly a Condition D sampling process. This section of Method 19 also specifies that the number of sample increments in each fuel lot be determined according to D 2234. In turn, D 2234 states that the minimum number of increments is either 15 or 35, depending on whether the coal is "mechanically cleaned" or "raw." This increment number specification is for a gross sample (lot size) up to 1000 tons. For lot sizes greater than 1000 tons, more increments are required.

Section 12.5.2.1.2 of Method 19 discusses lot size[23] relative to fuel pretreatment and mentions lot sizes of one day to 90 days. ASTM Standard D 2234 defines a lot of fuel with considerable flexibility. Basically the size of a lot of fuel is used to define the sampling frequency or the sampling frequency can be used to define a lot. A lot can be any quantity of fuel that can be defined in terms of size or time. For example, a lot can be the amount of coal in a unit train from a single vendor (approximately 10,000-12,000 tons). A lot can also be the amount of coal delivered in a day, week or month from a

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[23] Lot size is important because this is the quantity of fuel that will be analyzed by a single test.

given vendor or to a single unit or plant. In other words, a lot can be virtually any size depending on the intent of the fuel sampling and analysis. A single 2-lb grab sample cannot be a lot because the amount of coal it represents cannot be defined in terms of size or time.

I have undertaken the above coal sampling discussion to relate correct sampling and analytical practice to the proposed Illinois rule. The rule is deficient because it under states the need for appropriate sampling and over states the need for frequent analysis. The sampling problem is very serious because it will not detect the variability in coal mercury content. We know, without a doubt, that coal has considerable Hg content variability and that dictates frequent sampling. At the same time, if the sampling is done properly according to ASTM 2234, there is less need for frequent analysis. In fact, even if the sampling is done poorly, a composite can be made from, say a week's samples and a single analysis performed. There is just no need for daily analysis because analysis is not typically the source of Hg variability.

I believe that an automated crosscut coal sampler will be required to obtain a representative coal sample for the input Hg determination. These types of samplers are expensive ($250,000-$500,000) and require considerable maintenance. It is not known how many Illinois electric utility plants are equipped with crosscut coal samplers. Many plants that were originally equipped with the samplers have discontinued their use because of the maintenance burden. Vendor supplied coal analysis is the general norm for many utilities. Given the sampling language in the proposed Illinois regulations, it would be surprising if the cost of installing and maintaining crosscut samplers was included in the cost analysis of the regulations.

Finally, how does the State of Illinois propose to calculate the input lbs of Hg? The equation at 225.230 (a)(3) states that lbs Hg emissions and lbs Hg coal content are the input for the control efficiency equation. Obviously, Equation F-28 in 40 CFR Part 75, Appendix F can be used to calculate the lbs of Hg in the emissions. There is, however, no calculation in the proposed regulation for calculation of the input lbs Hg. One might also suspect that propagation of error has not been considered with respect to the control efficiency calculation.

Propagation of Error

When measurements are made and then several measurement results are used to calculate a final answer, the error in the final answer is effected by the error in each underlying measurement. This effect is called the propagation of error. The error in that final answer can be estimated by what is generally called the "square root of the sum of the squares" rule. This rule states that the potential error in any final calculation is determined by the square root of the sum of the squares of the individual measurement errors. If we use Equation F-28 in 40 CFR Part 75 as an example, there are two inputs to that calculation of oz Hg emissions – Hg monitor value and stack flow rate. If we assume that each of those measurements has a potential error of 10% (well within reason) then the final answer has a potential error of 14% $[(10^2+10^2)^{0.5}]$. Obviously, because each measurement has error, the more measurements are involved in any final calculation, the higher the error will be in the final answer.

Propagation of error is a real effect on the accuracy of any series of measurement calculations. Unfortunately, this additional source of error, like the initial measurement error, is typically ignored by regulatory personnel and I expect this is the case for the proposed Illinois rule.

Hg Data Discussion

I expect that most of the readers have never seen any real Hg continuous data. Since these data are not an abstract concept, I would like to share some data plots from the EPRI Trimble County Hg CEMS Project. The plots are in a separate section following this discussion because they are in landscape format. As might be recalled, there are four Hg CEMS installed at Trimble and all are operating continuously – at least when they operate. I have included three graphs that include the data for all four Hg CEMS for the period of 04/17/2006 through 05/05/2006. I have also included an expanded scale graph of the period 04/27/06 through 05/01/06 to provide additional detail. The graphs have been edited only to remove the vendor identifications and I will be discussing the various CEMS only by the graph trace color identifiers – black, red, blue and magenta. There is some very important Hg CEMS information contained in these graphs and I hope the reader will take the time to study them carefully in concert with the text description.

The first graph is Figure 14 and as a matter of orientation, it shows the red, blue and black CEMS operating at the beginning of this graph. The excursions above about 4 micrograms/m^3 are various QA/QC/calibration tests. The periodic excursions down to the 0.5 microgram range are probe blowbacks to keep the sampling probe clean. These QA/QC and blowback excursions would normally be excluded from reported data.

At the start of the first graph (04/17) the red and blue CEMS are reading about 3.5 micrograms/m^3 but that there is a problem with the red CEMS. The excursions on the red analyzer on 04/17 and 04/18 show where RMB personnel are attempting to calibrate the red analyzer. It was finally removed from service mid-morning on the 19th for repair. The black CEMS is also having problems because it starts the period reading less than 1 microgram/m^3 and, after unsuccessful attempts to calibrate the system, was finally remove from service at about noon on the 18th for repair. The black system was put back into service about 1 pm on the 19th, calibrations were performed and the system was still reading low. It ran low all night and this is a good example of what might happen in real life.

We have a huge advantage at Trimble because we have four Hg CEMS operating and can compare one to the other. Without the blue system for comparison, the instrument technician may never know that the black system was reading low. Too close the story on the black system, the problems were a partially plugged probe and orifice assembly. These "apparently" simple problems took vendor personnel two full days to troubleshoot and repair. Another point is that from the 17th to the 20th, there was only one Hg CEMS in service that was performing properly. The other three had various problems and missing data substitution would have to be used during the out-of service periods.

About noon on the 20th, an attempt was made to return all of the Hg CEMS to service. The black and magenta CEMS are successful, while there is still a problem with the red CEMS. Now I will call your attention to the data traces for the black, magenta and blue systems starting about noon on 4/21 to the end of the graph. All three of these Hg CEMS are operating well and have passed all calibration error test criteria. Note the width of the combined trace of all three analyzers – it is from about 1.8 up to about 3.0 micrograms/m^3. In other words, there is a spread of about 1.2 micrograms/m^3 between the three Hg CEMS at an average level of about 2.5 microgram/m3. If we assume the average is close to correct (perhaps a bad assumption), then the accuracy is close to ±50% at the 2.5 microgram/m^3 level.

Moving on to Figure 15, we can see that an unsuccessful attempt was made to put the red CEMS back in service. The other three Hg CEMS are working well and tracking well but the spread of the measurements is still about 1.2 micrograms/m^3. About noon on 4/25 something happened in the plant that elevated and created considerable variability in the Hg emissions. We do not have the full details on the cause of this excursion and are investigating further. I will state that such excursions, with the exception of the long duration are not uncommon. Any sudden load change will cause a short-term (several hours to a day) excursion that looks much like Figure 15. Unit startups and shutdowns cause significant excursions. Scrubber module maintenance and module changes cause excursions. It is just the nature of Hg emissions.

I must emphasize that a carbon injection system will not stop such excursions because some time will be required for the Hg CEMS to see the start of the excursion and the operator to increase the carbon feed rate. So what will happen is that the front of the excursion will look the same and the length of the excursion will be moderated. The level of moderation will depend on the design of the carbon injection system.

Finally, on Figure 15 one can see the immediate drop in Hg emissions when the SCR is put into service, even without ammonia injection. This immediate drop in Hg emissions is because the SCR oxidizes some of the elemental Hg in the flue gas and that oxidized Hg is removed by the scrubber. Ammonia injection is not necessary for the Hg oxidization. After the SCR is put into service, the spread between the three analyzers appears to be reduced to about 1 microgram/m^3.

Figure 16 is a day-by-day continuation of the Hg emissions trace. The red analyzer is still not operational despite over a week of effort by Hg CEMS vendor personnel. The two-day (5/1 to 5/3) outage on the black Hg CEMS was for the vendor to replace the entire system with one of “improved design.” The one-day outage (5/1 to 5/2) on the blue Hg CEMS was to replace the Hg converter. In retrospect, this outage could have been reduced to eight hours because that is the time it took the new converter to stabilize. But a minimum of eight hours of missing data would have been required.

The magenta Hg CEMS begins to slide low on 5/2 (this would never be caught by routine QA because all tests were being passed). The magenta CEMS readings were erratic on 5/3 but the daily QA tests were still satisfactory. On 5/4, the daily calibration error test was failed and a "full system" calibration was performed and the magenta CEMS returned to reading consistent with the blue and black Hg CEMS (again the advantage of having multiple CEMS at a research site). Also, another unsuccessful attempt by vendor personnel is made to bring the red Hg CEMS back into service.

There is one final observation that can be made from Figure 16. If we look at the blue, black and magenta traces right at the end of the chart, it can be observed that the width of the traces has been reduced to about 0.8 microgram/m^3. The best trace width we have ever seen is about 0.5 microgram/m^3.

Figure 17 is an expanded time scale graph of the period when the SCR was put into service to provide better time resolution. I also expanded the Y-axis for better resolution and this cut off some of the higher concentration readings. I also noted when the ammonia injection started.

I believe this data presentation is valuable because it illustrates with real data a number of the issues raised by the Hg CEMS technology relative to the proposed Illinois rule. These issues include:

- It is going to be virtually impossible to accurately quantify emissions at 0.80 microgram/m^3 when the data spread is 0.5-1.0 microgram/m^3.
- Hg excursions will happen and Hg control systems will require some time to respond. This causes the tail of the log normal distribution to grow.
- Hg CEMS reliability is poor and missing data substitution will be frequent. This causes the tail of the log normal distribution to grow.
- Hg CEMS failures require a long time to repair and missing data substitution will be frequent. This causes the tail of the log normal distribution to grow.

Figure 14 – Hg CEMS Readings – Trimble County

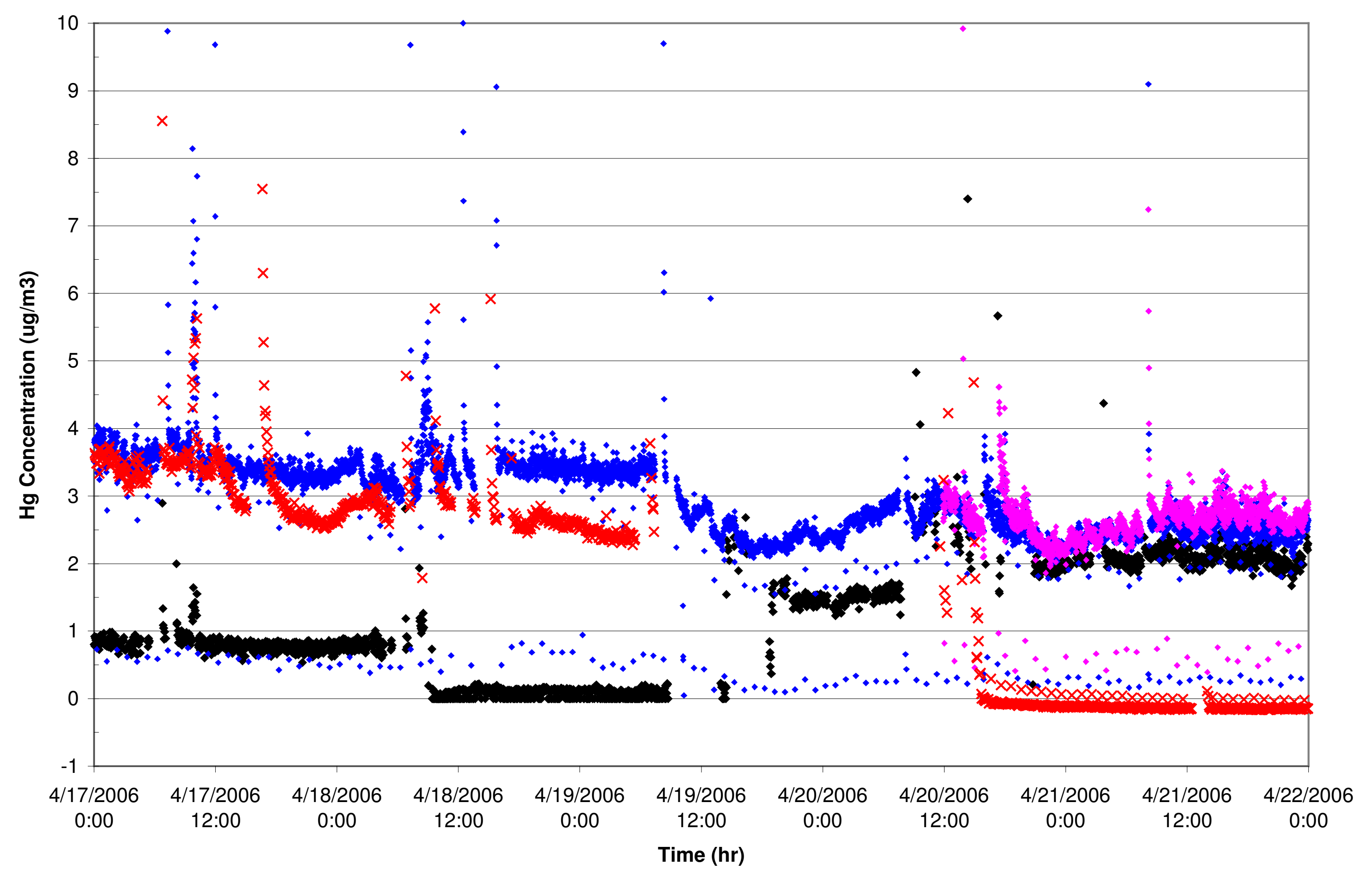


Figure 15 – Hg CEMS Readings – Trimble County

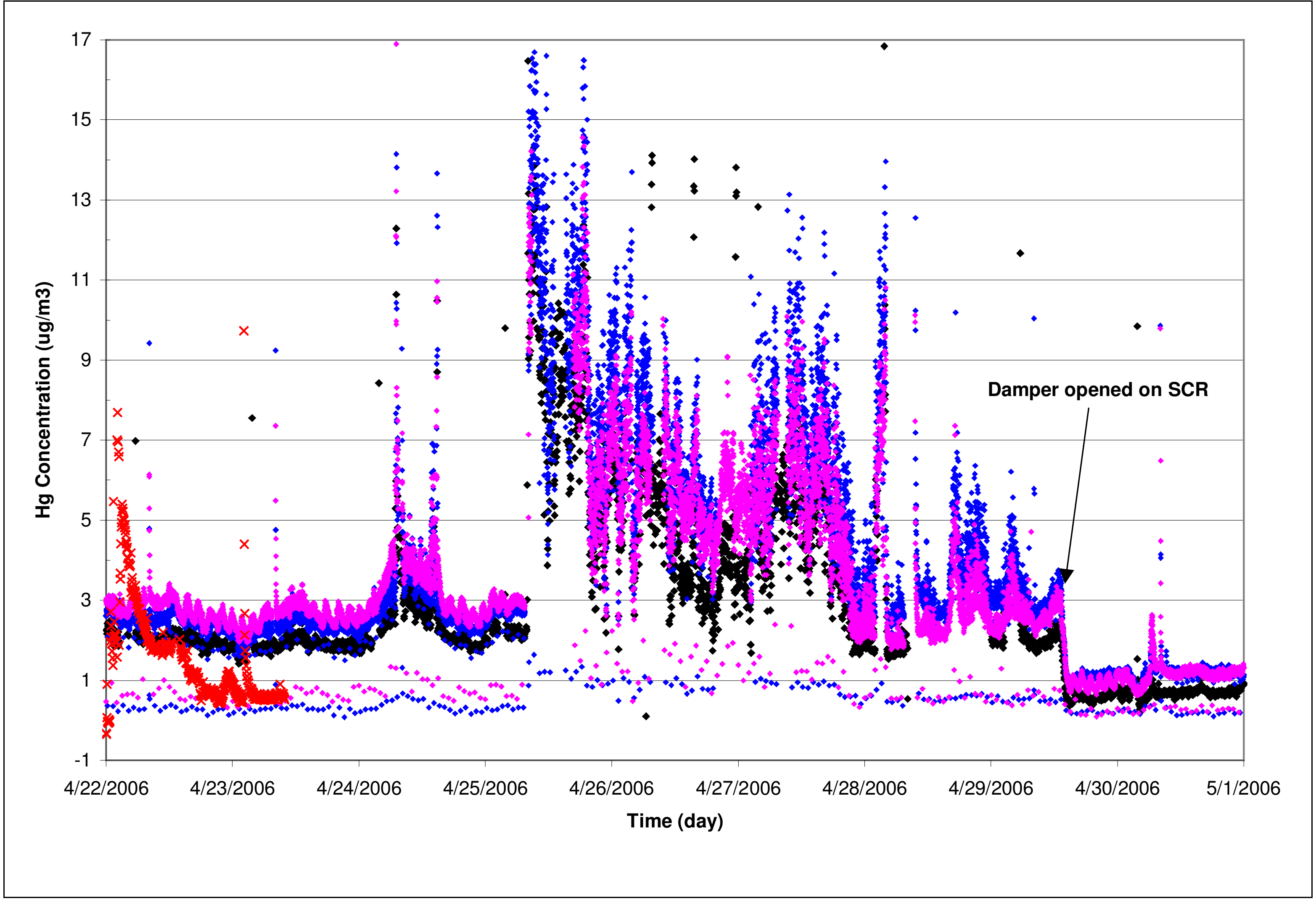


Figure 16 – Hg CEMS Readings – Trimble County

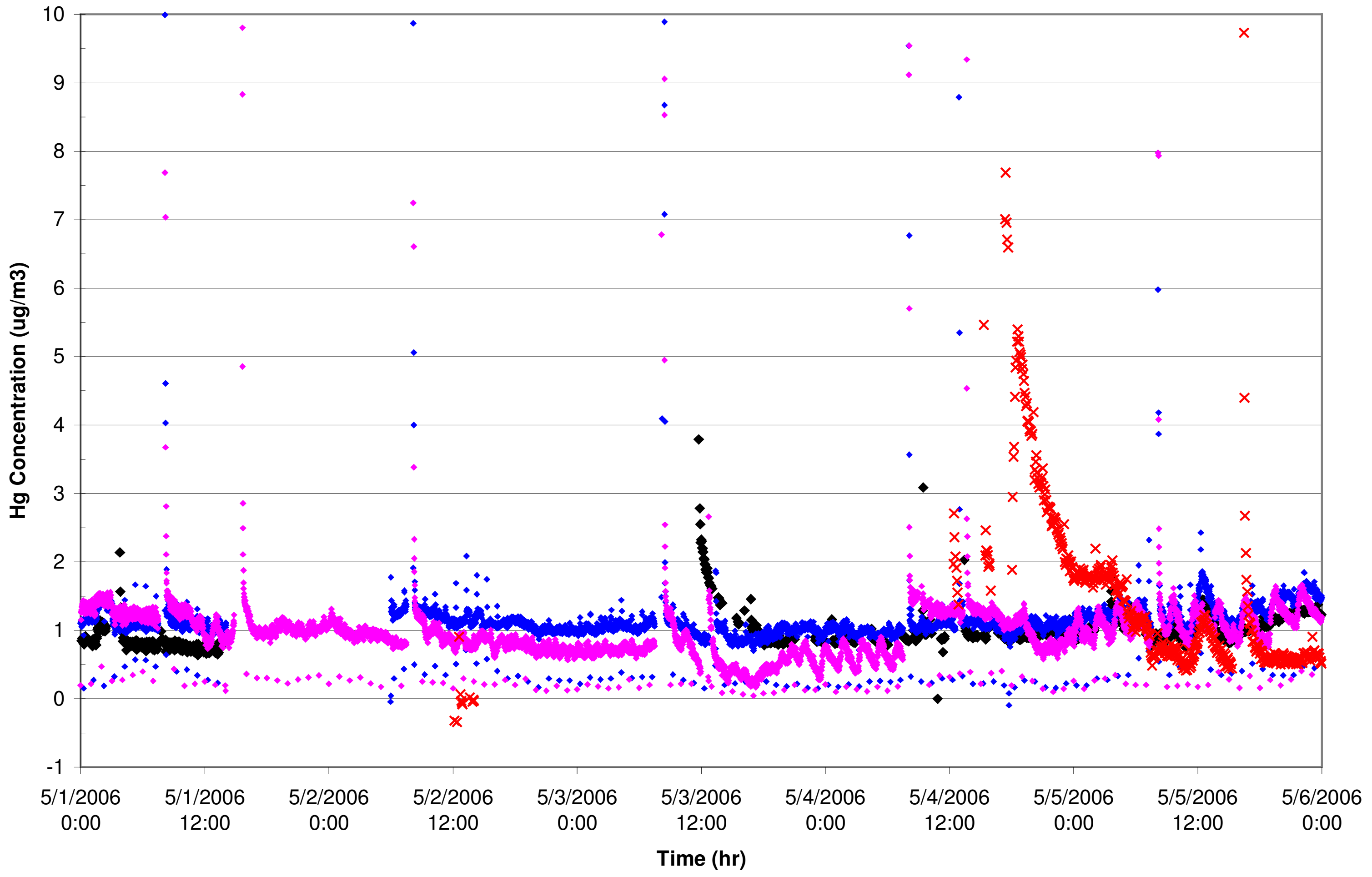
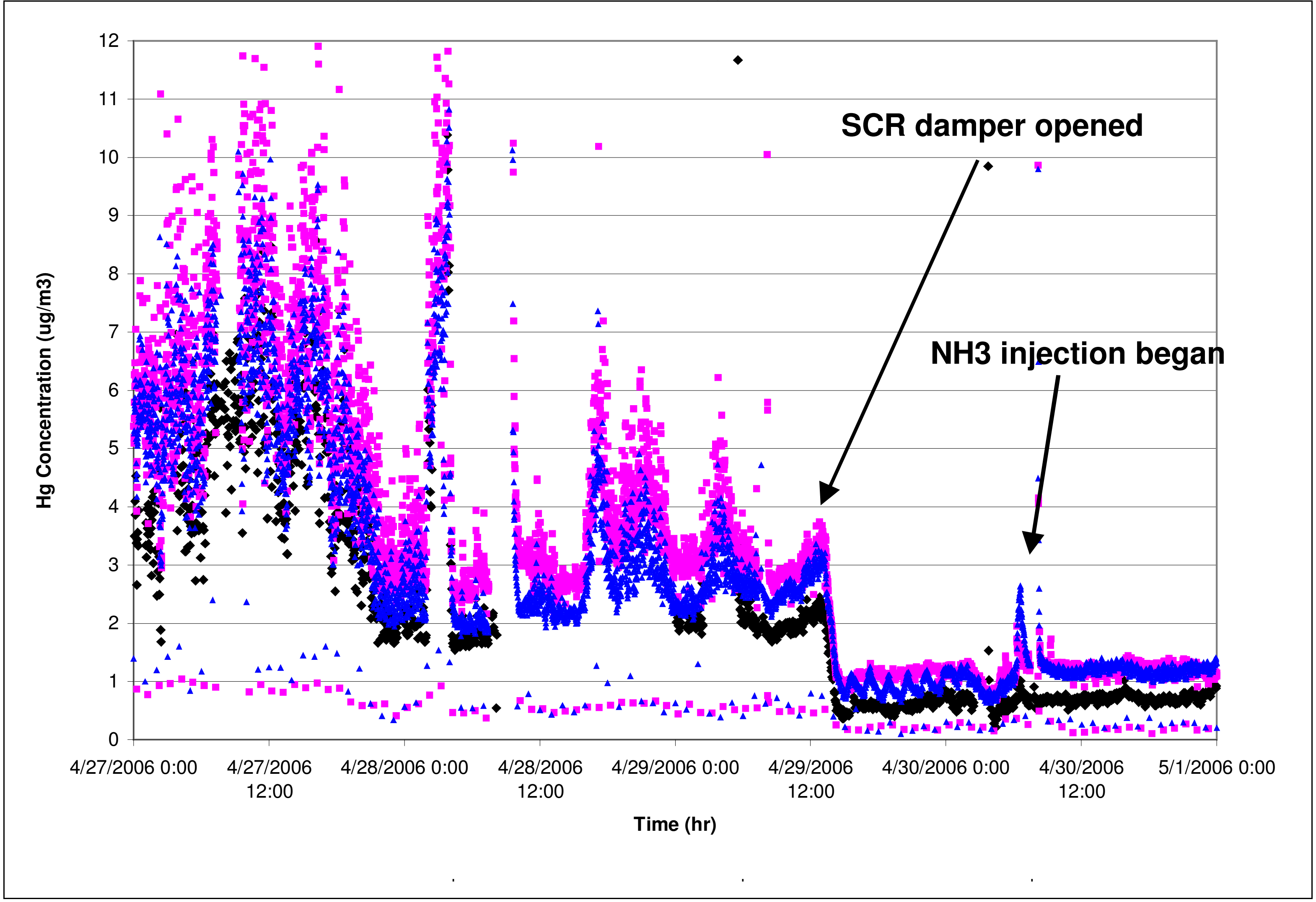


Figure 17 – Hg CEMS Readings – Trimble County



Conclusions

1. The proposed Illinois Hg control regulations are a high risk gamble that are predicated on two fundamental assumptions. The first assumption is that Hg carbon injection control systems will work reliably and at a level necessary to achieve the desired percent reduction or emissions limit. The second assumption is that the Hg input and emissions measurements necessary to demonstrate compliance with the regulations can be made accurately and precisely.
2. The high element of risk is enhanced by the apparent lack of a fall back position.
3. Apparently there was no consideration of Hg measurement issues during the drafting of the proposed regulations. There is no mention of Hg measurement accuracy and/or precision in the Technical Support Document.
4. Hg CEMS are very complex pieces of equipment that contain many components that are subject to failure. The level of complexity is probably a factor of 10 greater than conventional SO_2 and NO_X CEMS.
5. The overall reliability of Hg CEMS is not satisfactory for a hard cap emissions regulatory program.
6. When a Hg CEMS malfunctions, the repair can require many hours and even days to complete.
7. Poor Hg CEMS reliability will result in considerable missing data substitution and, thus, high bias in the Hg emissions calculations.
8. Reliable elemental and oxidized calibration error test techniques are not yet available to all of the Hg CEMS vendors. This problem may be rectified with better equipment design but the probability of success is undefined.
9. Calibration error and system integrity tests have been unreliable QA/QC tests. Therefore, it is very difficult to discern if the Hg CEMS is operating properly.
10. The proposed Illinois Hg Control Rule requires 90% Hg reduction or a hard cap emission rate of 0.00080 lb/GWh. The Hg emission rate under both cases will be in the 0.5 - 0.8 microgram/m^3 range (0.06 – 0.10 ppb v/v) and accurate and precise Hg measurements at these levels may not be possible.
11. The EPA Reference Method for Hg measurements has a precision of 34% at 3 micrograms/m^3. This is equivalent to ±1 microgram/m^3.
12. Measurement theory suggests that the precision (expressed as a percent) of the EPA Reference Method will be significantly higher than 34% at 0.8 microgram/m^3.
13. To my knowledge, a successful paired-train, 9-run, traversing reference method Hg RATA, as specified in 40 CFR Part 75, has never been done.
14. The precision and accuracy of Hg CEMS, especially at low measurement levels is unknown. The available RATA data, however, suggest that ±1 microgram/m^3 is a reasonable estimate of the accuracy.
15. The proposed Illinois regulation requires the use of missing data substitution, which will bias all of the Hg emissions data high.
16. Missing data substitution is not appropriate for a hard cap emissions limit or percent reduction regulation.
17. Missing data substitution is specifically not allowed under similar federal regulations at 40 CFR Part 60, Subpart Da.

18. Missing data substitution will add emissions data to the data base that are totally made up and absolutely incorrect.
19. The coal sampling and analysis procedures specified in the proposed Illinois regulations are not likely to result in an accurate estimate of the input Hg.
20. The cost of appropriate coal sampling equipment has likely not been included in the Technical Support Document cost impact analysis.
21. Field data from the EPRI Hg CEMS demonstration and development site indicated normal calibration and system error/variability to be 0.5-1.0 microgram/m^3 at concentration levels of 1-2 micrograms/m^3. This level of error/variability is consistent with recent RATA tests.
22. Since a hard cap or percent reduction emission limit does not take error/variability into account, the effected sources will have to reduce emissions well below the emission limit to insure compliance.

Appendix 1

RESUME

RICHARD D. McRANIE

SPECIALIZED TECHNICAL EXPERTISE

- Continuous emissions monitoring - design, applications, CEM system audits, regulatory interpretation
- Electrostatic precipitator - design, application, modeling, troubleshooting
- Research project management
- Consulting in combustion, boiler performance, emission reduction, performance testing, NO_x and particulate control
- Regulatory activities support
- Litigation support

PROFESSIONAL EXPERIENCE

Mr. McRanie, is a principal and cofounder of RMB Consulting & Research, Inc. (RMB). He has extensive experience in developing, implementing, and managing utility-related environmental services and research projects. He has managed projects involving investigation of existing and new particulate control devices; testing reliability of boiler operation; and technical interface at the national level regarding EPA regulatory rulemakings affecting compliance, measurement methods, and standards implementation. Mr. McRanie has managed personnel responsible for (1) investigating the special requirements of baghouses when used on units firing high sulfur coal; (2) investigating methods for improving performance of hotside precipitators; (3) testing the burning of synthetic fuels at a power company plant; (4) evaluating operating procedures of a boiler at an electric system plant; and (5) evaluating the relative slagging and fouling potential of coals using a small-scale combustor.

Mr. McRanie is a primary consultant for the Electric Power Research Institute (EPRI) technical committees that focus on continuous and manual emissions measurement technology and electrostatic precipitator applications and models. He is also the primary consultant to the Utility Air Regulatory Group (UARG) Measurement Techniques Committee where he focuses on compliance measurement methods for electric utility sources. Most recently, Mr. McRanie has been involved in research and regulatory activity relating to mercury monitoring, stack volumetric flow measurement problems, low-level NO_X measurement accuracy issues on combustion turbines and combined cycle units, compliance measurement methodology for combined cycle units subject to 40 CFR Part 60, Subpart Da and Compliance Assurance Monitoring (CAM) Protocol development for electrostatic precipitators.

Prior to the formation of RMB, Mr. McRanie was Director of Utility Services at Systems Applications International and Kilkelly Environmental Associates. At both companies, Mr. McRanie was responsible for developing, implementing, and managing industrial and utility-related services; provided regulatory activities support and program management for the Utility Air Regulatory Group; provided consulting services in the areas of particulate control, combustion, boiler performance, emission reduction, and performance testing

While with Southern Company Services, Inc. as Manager of Plant Performance Improvement Section, Mr. McRanie oversaw planning, development, and implementation of several programs and managed personnel who provided specialized research services to the operating companies of the Southern electric system. Specific responsibilities included (1) investigation of new improved particulate control devices; (2) evaluation, testing, and performance improvement of existing particulate control devices; (3) combustion NO_x including burners and boiler operating practices; (4) fuel and ash related slagging, fouling, and corrosion; (5) reliability and performance related to boiler operation; and (6) regulatory technical interfaces at the national level related to Environmental Protection Agency rulemakings that affected compliance, measurement methods, and standards implementation.

Also while with Southern Company Services, Inc., Mr. McRanie managed personnel working in the Plant Performance Improvement Section performing research and field programs to support these responsibilities. The section also had responsibilities in the instrumentation area for the evaluation and maintenance of instruments and procedures to support the field programs.

Earlier in his career with Southern Company Services, Inc., Mr. McRanie provided project management of the first full scale (28 MW) commercial Solvent Refined Coal Burn Test. He developed the concept, specified the equipment, and directed the installation of the Gulf Power Company ambient air monitoring system. This system consists of four computerized central data acquisition systems with 16 remote stations monitoring SO_2, NO_x and particulate levels. Mr. McRanie managed a project to evaluate and compare over 20 SO_2, NO_x and opacity continuous emission monitoring systems for a 1-year period under typical operating conditions.

PROFESSIONAL AFFILIATIONS

- American Society for Testing and Materials
- Air and Waste Management Association
- Stack Evaluation Society

SELECTED PUBLIC DOMAIN PAPERS AND PRESENTATIONS

“Trimble County Development Project – Hg Monitors for Wet Stacks” EPRI CEM Users Group Meeting, May 2006

“Hg Continuous Emissions Monitoring - Significant Technical Issues From The Utility Industry Perspective” EPRI CEM Users Group Meeting, May 2005

“Hg Continuous Emissions Monitoring - Significant Technical Issues Associated With The Technology” EUEC Conference, January 2005

“The Proposed Combustion Turbine and Industrial Boiler MACT Rules – Potential Impact On The Utility Industry” EPRI CEM Users Group Meeting, May 2003

"Evaluation of Particulate Emission Measurement Estimation Techniques for Coal-Fired Utility

Boilers With Electrostatic Precipitators" (with R.L. Roberson) EPRI Technical Review Report, (Product ID 1000644), November 2000

"Low Level NO_X Measurement" EPRI Interim Topical Report, Product ID 1000307, August 2000

"Continuous Emission Monitoring Guidelines - 1999 Update" (with RMB Staff), EPRI Final Technical Report TR-111165, November 1999

"Compliance Assurance Monitoring - Field Test Program" EPRI Technical Assessment Report TE-114178, November 1999

"Compliance Assurance Monitoring Field Test Program - Evaluation of Electrostatic Precipitator Performance Models to Estimate Particulate Emissions From Coal-Fired Utility Boilers," EPRI CEM Users Group Meeting, Cincinnati, OH (May 12-14, 1999)

"Compliance Assurance Monitoring - Protocol Development" EPRI Final Technical Report TR-111478, October 1998

"Evaluation of Heat Rate Discrepancy from Continuous Emission Monitoring Systems" (with Norfleet, Muzio and Martz), EPRI Final Technical Report TR-108110, July 1997

"The Electric Power Research Institute Continuous Emissions Monitoring Heat Rate Discrepancy Project - What Has Been Learned and Future Activities" (with Norfleet and Dene), 1997 EPRI CEM Users Group Meeting, Denver Colorado (May 14-16, 1997)

"The Electric Power Research Institute Continuous Emissions Monitoring Heat Rate Discrepancy Project - An Update Report" (with Dene), AWMA Acid Rain & Electric Utilities II Conference, Scottsdale, Arizona (January 21-22, 1997)

"Compliance Assurance Monitoring Plans for Electrostatic Precipitators - A Technical Discussion" EPRI CAM TC Project Sponsor Report, November 1996

"Establishing Trigger Values for Compliance Assurance Monitoring" EPRI CAM TC Project Sponsor Report, October, 1996

"Flue Gas Flow Rate Measurement Errors" (with Norfleet, Muzio and Martz), EPRI Final Technical Report, TR-106698, June 1996

"Performance of Electrostatic Precipitators and Fabric Filter Particulate Controls on Oil-Fired Electric Utility Boilers" (with S.S. Baker), EPRI Technical Report TR-105592, September 1995

"Guidelines for Flue Gas Flow Rate Monitoring" (with S.S. Baker, S.K. Norfleet, R.J. Etterna and T.D. Martz), EPRI Technical Report TR-104527, June 1995

"Enhanced Monitoring - Where Do We Go From Here?," EPRI CEM Users Group Meeting, Atlanta, Georgia (May 3-5, 1995)

"Coffeen Units 1 & 2 Low Sulfur Coal Burn Test and Comparison With Baseline High Sulfur Coal Burn Test - Boiler Efficiency and Electrostatic Precipitator Tests to Evaluate the Impact of Future Fuel Changes," EPRI/CIPS Technical Report, February 1995

"Application of 40 CFR Part 75 Appendix D and E Regulations," EPRI CEM Users Group Meeting, Minneapolis, Minnesota (April 6-8, 1994)

"EPRI Flow Monitoring Database" (with S.S. Baker), EPRI CEM Users Group Meeting, Baltimore, Maryland (April 13-15, 1993)

"An Evaluation and Comparison of the EPRI ESPMGEMS Electrostatic Precipitator Performance Model with Field Data and Other Models" (with L.S. Gough), EPRI Tenth Particulate Control Symposium, (April 5-8, 1993)

"Overview of CEMS Regulations, Technology, and Program Implementation." Presented at the MAPP CEMS Workshop, Minneapolis, MN (October 6-7, 1992)

"Overview of the Electric Power Research Institute Electrostatic Precipitator Performance Model (ESPM)" (with L. S. Gough). Presented at the Southern Electric System Advances in Particulate Control Technology Seminar, Atlanta, GA (August 24-25, 1992)

"Overview of the Clean Air Act Amendments of 1990 and Associated Permitting, Continuous Emissions Monitoring and Low NO_x Burner Technology Regulations." Presented at a seminar for various electric utility companies (1992)

"Continuous Emissions Monitors (CEMS). What They Can Do; What They Cannot Do." Presented at the MAPP Clean Air Workshop, Minneapolis, MN (February 27-28, 1991)

"Technical Comments on the Environmental Protection Agency's October 12, 1990 Proposal of Method 202 to Measure Condensible Emissions." The Utility Air Regulatory Group (January 1991)

"Continuous Emissions Monitoring: Looking Beyond the Horizon." Power (December 1990)

"Evaluation of Continuous Emissions Monitoring System at Brayton Point Power Station." New England Power (August 1990)

"Low Opacity Startup of Coal and Oil-Fired Utility Boilers." Presented at the Fourteenth Annual EPA/AWMA/ASME Environmental Information Meeting, Raleigh, NC (December 5-6, 1989)

"Duck Creek Pulverizer Inspection Report and Recommended Test Plan." Central Illinois Light Company (November 1989)

"Analysis of Duck Creek Primary Air and Pulverizer Performance." Central Illinois Light Company (October 1989)

"Technical Comments on the Environmental Protection Agency June 6, 1989, Proposal on PM10 Emissions Test Methods 201 and 201A." The Utility Air Regulatory Group (July 1989)

"An Analysis of the Proposed Changes to the Indiana Air Quality Rules." The Indiana Electric Association and the Utility Air Regulatory Group (April 1989)

"A Review of Technical Issues Associated with Condensible Measurements of Fossil Fuel-Fired Utility Boilers." The Utility Air Regulatory Group (April 1989)

"Evaluation of Intermittent Energization on a Hot-Side Electrostatic Precipitator at Plant Daniel." The Southern Electric System (June 1988)

"Minimizing Opacity during Startup and Shutdown of Utility Boilers." Presented at the Southern Electric System Electrostatic Precipitator Seminar, Birmingham, AL (December 8-9, 1988)

"Past Mistakes and Future Opportunities in Particulate Control." Proceedings published. Presented at the Pittsburgh Coal Conference (September 13-15, 1988)

"A Technical and Cost Analysis Plan for the Full-Scale Evaluation of the Cooled-Pipe Precharger." The Southern Electric System (March 1988)

"Controlling opacity excursions of hotside precipitators." Power Engineering (August 1984)

"Quality Assurance Related to Continuous Emission Measurements from Coal-Fired Boilers." Presented at the Conference on Quality Assurance for Environmental Measurements. University of Colorado (August 1983)

"Utility Industry Perspective on ESP Research & Development." Presented at the Electric Power Research Institute Conference on Electrostatic Precipitator Technology for Coal-Fired Power Plants. Proceedings published (July 14, 1982)

"Effects of Sodium Conditioning and Pulsed Energization on Measured Fine Particulate Charge in a Hot-Side Precipitator" (with others) (August 1981)

"Improvement of Hot-Side Precipitator Performance with Sodium Conditioning - An Interim Report" (with others). Journal of the Air Pollution Control Association, Volume 31, No. 3 (March 1981)

"Integrated Particulate Emission Control" (with R. C. Carr). Presented at the Integrated Environmental Control for Coal-Fired Power Plants Symposium. Proceedings published (February 1981)

"Experiences with Hot Side Precipitators." Presented at the EPRI Flue Gas Conditioning Symposium, Birmingham, AL (September 1980)

"Operating Experience with Hotside Precipitators and Their Future Role." (with F. E. Ehrensperger). Presented at the Southeastern Electric Exchange Engineering and Operating Division Conference. Published by Electrical World Magazine, Paper G-346 (April 1980)

"Solvent Refined Coal Burn Test - Final Report." Southern Company Services, Inc., R&D staff, Department of Energy Contract No. EX-76-C-01-2222 (July 1979)

"Burning Solvent Refined Coal." Presented at the American Chemical Society Annual Meeting, Anaheim, CA. Proceedings published (March 1978)

"A Computerized Ambient Air Monitoring System - Solution or Problem?" Presented at the Pollution Engineering Congress, Cleveland, OH. Proceedings published (October, 1975)

"A Comprehensive Air Monitoring System with High Speed Computer Data Handling." Presented at the Instrument Society of America Southern Section Annual Meeting, Huntsville, AL. Proceedings published (April 1975)

"Evaluation of Sample Conditioners and Continuous Stack Monitors for the Measurement of Sulfur Dioxide, Nitrogen Oxides, and Opacity in Flue Gas from a Coal-Fired Steam Generator" (with others). Published by Southern Services, Inc. (October 1974)

"A Study of Instrumentation for Monitoring Emissions from Coal-Fired Boilers." Presented at the Instrument Society of America Conference, Houston, TX. Proceedings published (October 1973)

MISCELLANEOUS

Former Chairman, Utility Air Regulatory Group (UARG) Standards Implementation and Compliance Committee - 6 years

Past Chairman, Electric Power Research Institute Environmental Control Systems Task Force - 1 year

Past Chairman, Electric Power Research Institute Air Quality Control Program Committee - 2 years

EMPLOYMENT HISTORY

RMB Consulting & Research, Inc.	Principal	1994 to present
Systems Applications International	Director, Utility Services	1992-1994
Kilkelly Environmental Associates	Director, Utility Services	1987-1992

Southern Company Services, Inc.	Research and Development Department	
Manager, Plant Performance Improvement Section		1981-1987
Senior Research Specialist,		1971-1981
Georgia Power Company	Startup Specialist	1964-1971

Appendix 2

Conversion Protocol
lb/GWh Hg to microgram/m^3 Hg

First, we convert the proposed Illinois output based emissions limit of 0.0080 pounds of mercury per gigawatt hour to an input-based limit, using a nominal unit heat rate of 10,000 Btu/kW-hr.

$$\mathbf{\frac{0.008\,lbHg}{GW-hr}\times\frac{1\,GW}{1\times10^{6}kW}\times\frac{1\,kW-hr}{10{,}000Btu}=\frac{0.80\,lb\,Hg}{10^{12}Btu}=\frac{0.80\times10^{-6}\,lb\,Hg}{10^{6}Btu}} \qquad \textbf{Equation 1}$$

Next, we use one of EPA's f-factor equations to convert the input-based limit to a flue gas concentration. We assume a nominal flue gas CO_2 concentration = 11.3 percent, wet basis.

$$\mathbf{E=C_w\times F_c\times\frac{100}{\%CO_{2w}}} \qquad \textbf{Equation 2}$$

Where:
E = Hg emission rate, lb/10^6 Btu
C_w = Hg concentration, wet basis, lb/wscf
F_c = f-factor = volume of CO_2 in flue gas per unit of heat input, scf/10^6 Btu
1,800 for bituminous and subbituminous coal
CO_{2w} = concentration of carbon dioxide in flue gas, wet basis, %

Rearranging the terms in Equation 2

$$\mathbf{C_w=\frac{E}{F_c}\times\frac{\%CO_{2w}}{100}} \qquad \textbf{Equation 3}$$

$$\mathbf{C_w=\frac{0.80\times10^{-6}}{1{,}800}\times\frac{11.3}{100}=5.02\times10^{-11}lb/wscf} \qquad \textbf{Equation 4}$$

Next, we convert to metric units.

$$\mathbf{C=5.02\times10^{-11}\,lb/wscf\times453.6\times10^{6}\,\mu g/lb\times35.31\,f^{3}/m^{3}=0.80\,\mu g/m^{3}}$$

One can readily observe that this conversion factor will change if the unit heat rate is not 10,000 Btu/kWh or the flue gas CO_2 is not 11.3% as has been assumed. A reasonable range might be from 0.7 - 0.9 µg/m^3. We find the 0.0080 lb/GWh to 0.80 µg/m^3 conversion convenient for general discussion.

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	**)**	
	)	
PROPOSED NEW 35 ILL.ADM.CODE PART 225	**)**	**PCB R06-25**
CONTROL OF EMISSIONS FROM	**)**	
LARGE COMBUSTION SOURCES	**)**	

Testimony of
Ishwar Prasad Murarka, Ph.D.

Effects of Activated Carbon Injection on Utilization of Coal Fly Ash in Illinois

Introduction:

My name is Ishwar Prasad Murarka. I am a naturalized U.S. citizen and an environmental consultant specializing in Fossil Fuel Combustion By-products Management and in the assessment and remediation of former Manufactured Gas Plant (MGP) sites. My office address is 804 Salem Woods Drive, Suite 201B, Raleigh, NC 27615. I have been retained to provide technical expert testimony on the effects activated carbon injection installed upstream of the existing ESP or fabric filter will have on the utilization of coal ash produced in Illinois. My testimony will cover the following points:

a. Use of activated carbon injection (ACI) will increase the loss-on-ignition (LOI) content in fly ash which is detrimental to its use in concrete.

b. Use of ACI will darken the color of the fly ash which is detrimental to its use in concrete.

c. Use of ACI will result in an un-acceptable Foam Index which is detrimental to its use in concrete.

d. Reduced utilization of fly ash in concrete will result in increased land disposal.

Qualifications:

I received my primary and secondary education in India and graduated from Calcutta University with a Master of Arts degree in Geography in 1964. I pursued postgraduate research activities on “glacial and periglacial morphology” of a portion of the Eastern Himalayas until I came to the U.S.A. in September 1966. I received a Master of Science and a Ph.D. degree from Oregon State University in 1968 and 1971, respectively. I majored in Soil Science with a minor in Statistics for the Masters and Doctoral programs at Oregon State. I was a NIH post-doctoral fellow in Biomathematics at North Carolina State University from mid-1971 through early 1973. I received a Master of Business Administration (MBA) degree from the University of Chicago in 1979. I have taught at NC State University, Northern Illinois University and Argonne National Laboratory.

I have worked for Texas Instruments, Argonne National Laboratory and Electric Power Research Institute (EPRI) covering the period 1973 through 1998. I retired from EPRI in April 1998 and founded Ish Inc., an environmental consulting company specializing in Land and Water issues. At EPRI, I was a project manager, a program manager and then a Technical Executive, directing and managing research projects on disposal and utilization of coal combustion by-products and management of manufactured gas plant sites.

Over the 30 years of working on environmental issues, I have developed an in-depth scientific and practical understanding of and specialized in two major areas: (1) Coal Combustion By-products Management, and (2) Assessment and Remediation of Former Manufactured Gas Plant (MGP) Sites.

During my professional career I have performed and directed research on the release, transport and fate of inorganic and organic constituents in soils, groundwater and surface water environments. I have conduced and directed technical and scientific work in geochemical, hydrological, and to some extent abiotic/biotic processes that control release and migration of inorganic and organic constituents in land and water.

I have published papers and reports on the various topics and have presented numerous papers pertaining to the topics of coal combustion by-products management, leaching of chemicals from solid matrices, and attenuation and degradation of constituents during transport and modeling analyses. I have been involved in characterizing coal combustion by-products, the disposal of coal combustion by-products in landfills and impoundments, and the utilization of coal combustion by-products in various applications including concrete, structural fills, highway embankments, road base/sub-base, mine-filling and agricultural uses. I have also devoted a significant portion of my professional life conducting and directing site investigations, evaluation of data/information, feasibility analyses of remediation alternatives, and implementation of remediation projects at former MGP sites.

I have served as a peer reviewer and as a technical advisor for a number of organizations. My most notable service has been as a member of the U.S. EPA Science Advisory Board (SAB) since 1988. During this time, I served on the Executive Committee of the SAB and on the Research Advisory Committee of the SAB. I served as the chairman of the Environmental Engineering Committee of the SAB and also chaired the Environmental Regulatory Models Committee. I am continuing to serve as a member of the External Advisory Board for the Institute for Environmental Science and Policy for the University of Illinois at Chicago. I am also serving on the Discovery Park Advisory Council at Purdue University.

A copy of my resume is attached hereto as Appendix A.

Background on Coal Fly Ash

Fly ash is a by-product of coal combusted in a boiler at a power generating plant. The burning of coal results in a certain amount of non-burnable residue material that either settles to the bottom of the boiler (slag/bottom ash) or remains airborne in the flue gas (fly ash). The fly ash is removed by mechanical collectors from the flue gas before the flue gas is vented to the atmosphere from the stacks.

Fly ash is used as an ingredient in brick, block, paving, cement raw feed, soil/asphalt stabilization, structural fills, mine-filling, road base/sub-base and as a substitute for cement in concrete. In Illinois, the market for the use of fly ash as a substitute for cement in concrete is the largest utilization market and has the potential to yield more revenue than the sale of fly ash for other uses.

Concrete:

Concrete is a composite material comprising of a binding medium (typically Portland cement), embedded with fine aggregate (typically sand) and coarse aggregate (typically gravel). Pozzolans both natural and artificial (fly ash, silica fume) are often used as a cementitious ingredient in concrete. Typically, a concrete mix is about 10% to 15% cement, 60% to 75% aggregates and about 15% to 20% water. Entrained air in concrete mixes accounts for another 5%.

Use of Fly Ash as Cement Substitute in Concrete:

Fly ash as a substitute for cement in concrete was first used in the U.S. in 1929 for the Hoover Dam. It is now used regularly as a substitute for cement in concrete across the country. Consisting mostly of silica, alumina and iron, fly ash is a pozzolan -- a substance containing aluminous and siliceous materials which in the presence of water reacts with calcium hydroxide to produce cementitious compounds. The spherical shape of the fly ash particles reduces internal friction thereby increasing the concrete’s consistency and mobility, permitting longer pumping distances. Fly ash in concrete also increases the life of concrete roads and structures by improving the concrete’s durability. Although fly ash itself is less dense than cement, the concrete that contains fly ash is denser and has a smoother surface with sharper detail.

Current Production and Utilization of Coal Fly Ash in the United States and Illinois:

The American Coal Ash Association (2006) reported that in 2004, 70.8 million tons of fly ash were produced in the U.S. from electric power plants that burned coal, of which 28 million tons (i.e. 39.65%) were utilized beneficially. 14.1 million tons of fly ash were used in concrete and another 2.35 million tons were used in cement/raw feed for clinker material to produce Portland Cement. Fly ash utilization across the country has been increasing over the years and thus benefiting the environment because less fly ash is being land disposed.

As set forth in Table 8.8 of the Technical Support Document (March 2006), 40% of fly ash generated in Illinois in 2004 was utilized.

1. **Use of activated carbon injection will increase the loss-on-ignition content in fly ash which is detrimental to its use in concrete.**

Loss-on-Ignition is a measure of the unburned carbon in fly ash and is one of the most important indicators of its suitability for replacement for cement in concrete. Use of fly ash in concrete provides performance benefits that include greater resistance to chemical attack, increased strength, and improved workability. (Dodson, 1990). The American Society for Testing & Materials (ASTM) standard C618 provides specifications for fly ash used in concrete where cementitious or pozzolanic action or both is desired. The ASTM standard specifies a 6% LOI limit for fly ash for its use as a cement substitute in concrete. The American Association of State Highway & Transportation Officials (AASHTO) standard M295 also provides specifications for fly ash used in concrete and is very similar to ASTM standard C618 but requires a 5% LOI limit for fly ash. While the ASTM and AASHTO standards place a 6% and 5% limit on LOI respectively, the real world LOI limit is 1%. The Illinois power plants that have contracts to sell fly ash as a substitute for cement in concrete are required to meet a 1% limit on LOI content in fly ash sold. Furthermore, the marketers also desire that the LOI content of the fly ash remains fairly constant over time.

When activated carbon is injected upstream of the existing ESP or fabric filter to remove mercury, it directly adds carbon to the collected fly ash, thus increasing the LOI content. Figure 8.16 in the Technical Support Document (March 2006) provides the estimated carbon loading in fly ash at different activated carbon injection rates. It can be seen from this figure that a linear relationship exists between the injection rate and the carbon loading and as the injection rate increases so does the amount of carbon loading. According to Figure 8.16, an ACI rate of about 2 lb/MMacf causes an incremental carbon loading of approximately 1%. Because, ash marketing contracts typically restrict carbon content to less than 1%, the incremental carbon loading that will result from an ACI rate of 2 lb/MMacf or more will make the fly ash unsaleable as a substitute for cement in concrete.

The Technical Support Document (March 2006), mentions that the increased LOI could be addressed by (1) separation of carbonaceous material from the mineral portion of the fly ash, or (2) using ozone passivation for neutralizing the sorbent properties that impact AEA additive. The carbon separation technology is commercially available but is being used at a few power plants for fly ash which has 5% to 25% LOI content and the carbon content of the fly ash after separation is still over 1%. Furthermore, the technology is costly and requires equipment and O&M for fly ash processing. (Bittner & Gasiorowski, 2005). The ozone passivation technology is in the experimental and research testing phase and is not yet commercially available.

The Technical Support Document (March 2006) also mentions that “cement friendly” sorbents and miner-based sorbents “that will not have any impact on fly ash” are being demonstrated. These demonstrations, however, are not complete and it has not been established that these sorbents will be able to achieve a 90% reduction in mercury emissions and will not adversely impact the marketability of fly ash.

2. Use of ACI will darken the color of the fly ash which is detrimental to its use in concrete.

The carbon content of fly ash affects the color of the fly ash. The higher the carbon content the darker the fly ash. Most Illinois power plants that sell fly ash as a substitute for cement in concrete are required to monitor the color of their fly ash. Most fly ash marketing contracts use a reference sample to compare and accept or reject fly ash as a substitute for cement in concrete. These reference samples typically are light in color and have an LOI of less than 1%. Because, ash marketing contracts typically prohibit the sale of dark fly ash, the incremental carbon loading that will result from ACI installed upstream of the existing ESP or fabric filter makes the fly ash unsaleable as a substitute for cement in concrete.

3. Use of ACI will result in an un-acceptable foam index which is detrimental to its use in concrete.

The Foam index test is often used to determine if fly ash can be used as a substitute for cement in concrete. The Foam Index test determines the degree of interference that fly ash components (mostly carbon) can cause with the action of air-entraining admixtures (AEAs) to form stable air bubbles. Lower Foam Index values are desired. As reported in Starns *et al* (2002), an activated carbon injection rate of 1 lb/MMacf can result in a fly ash failing the Foam Index test.

4. Reduced utilization of fly ash in concrete will result in increased land disposal.

If fly ash is not being used as a substitute for cement in concrete, then it will likely be deposited in a landfill or an impoundment, because the remaining utilization markets are not large enough to offset the amount of fly ash that is no longer being used as a substitute for cement in concrete.

There are also economic implications of this switch from “fly ash use” to “fly ash disposal.” Illinois power plants utilized approximately 40% of fly ash produced in 2004 as a substitute for cement in concrete. Accepting a $25/ton differential between lost revenue from sales and increased costs from disposal, as set forth in the Technical Support Document (March 2006), establishes that the total annual cost to the Illinois power plants is significant.

5. USEPA has expressed concerns with using fly ash in cement manufacturing when the fly ash has been in contact with an activated carbon sorbent.

The USEPA has expressed concerns that the use of activated carbon injection could increase the mercury content in fly ash which in turn could be emitted into the atmosphere when cement kilns burn the fly ash. Therefore, USEPA has considered a possible ban on the burning of fly ash at Portland Cement manufacturing facilities. Any such ban would further increase the amount of fly ash being deposited in landfills and impoundments.

Overall Conclusions:

It is almost a forgone conclusion that activated carbon injection will reduce/eliminate the use of fly ash as a substitute for cement in concrete, increasing the economic burden the proposed rule will place on Illinois power plants and increase the potential for environmental impacts from land disposal operations.

REFERENCES:

AASHTO M295: Standard specification for fly ash or raw natural Calcined pozzolan for use as mineral admixture in Portland Cement Concrete.

ACAA 2006: 2004–Coal Combustion products (CCP) Production and Use.

ASTM C618: Standard specification for fly ash or raw natural Calcined pozzolan for use as mineral admixture in Portland Cement Concrete. ASTM Annual Book of Standards.

Bittner, J.D. and S.A.Gasiorowski, 2005: Triboelectrostatic Fly Ash Beneficiation: An Update on Separation Technologies' International Operations.

Constance Senior et al 2003: Characterization of fly ash from full-scale demonstration of sorbent injection for mercury control on coal fired power plant.

Dodson V. H. 1990: Concrete Admixtures. New York: Van Nordtand Reinhold.

EPA 2006: Characterization of mercury enriched coal combustion residues from electric utilities using sorbents for mercury control.EPA/600/R-06/008.

IEPA March 14, 2006 Technical Support Document for Reducing Mercury Emissions from Coal Fired Electric Generating Units.

Inside EPA, March 23, 2006

Starns, T. et al 2002 Full Scale Test of Mercury control with Sorbent Injection and an ESP at Wisconsin Electric's Pleasant Prairie Plant. Air & Waste Management Association Annual Meeting.

Appendix A

Resume

Ish Inc.
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Raleigh, NC 27615-3313

Business Phone: 919-844-9890
Fax Number 919-844-0917
Mobile Phone: 408-892-3233

Email: ishinc@earthlink.net
Websites: www.ishincusa.com

Education:

Ph. D.	*1971*	*Soil Science and Statistics, Oregon State University*
MBA	*1979*	*Management Science, University of Chicago*
MS	*1968*	*Soil Science, Oregon State University*
MA	*1964*	*Geography, Calcutta University*

1971 - 1973 NIH Post-doctoral Fellow in Bio-mathematics,
N.C. State University, Raleigh, NC

Current Employment

February 2003 – present, University of Illinois at Chicago

Visiting Research Associate to engage in basic research on environmental processes and behavior of chemicals and to collaborate with university research faculty on environmental engineering projects

April 1998 – Present, Ish Inc.

Founder, President, and Executive Scientist of an exciting new science and technology consulting company that specializes in addressing the following issues:

- Contaminated sites
- Combustion waste disposal and use
- Soils
- Groundwater
- Sediments
- Surface water
- Solid & Hazardous waste management**.**
- Statistical and Mathematical analysis of Monitoring data

Previous Employment

1979-1998	*Project Manager, Program Manager, Technical Executive,* *Electric Power Research Institute (EPRI)* *Land and Groundwater Protection and Remediation Business Area*
1974-1979	*Environmental Scientist, Environmental Impact Studies,* *Argonne National Laboratory -*
1973-1974	*Statistician, Texas Instruments, Indian Point, NY-* *Ecological Studies*

Business Experience

- *Building and managing a premier R & D Program at EPRI, (over $12 million in annual revenue) for diverse projects covering all environmental aspects of soils, sediments, groundwater, combustion wastes and surface water.*
- *Budgeting, technical and financial management for developing, delivering and applying Research Results.*
- *Planning, bidding, negotiating and establishing contracts.*
- *Serving U.S. and international clients in the utility industry.*
- *Assisting in technical issues on Coal Ash and MGP Sites for Attorneys and providing some litigation support*

Technical and Professional Experience

- *Experience in dealing with organic compounds include:*
  - *Extensive technical work in characterizing, assessing and remediating manufactured gas plant sites. Directed and completed several field investigations at MGP sites to delineate the distribution of coal tar (NAPL) in the subsurface as well as MAHs and PAHs in sediments, soils and groundwater.*
  - *Defining and implementing laboratory and field investigations and modeling projects to solve regulatory and science/engineering issues in the delineation, containment and restoration of contaminated sites including sites with non-aqueous phase liquids (i.e., coal tar, petroleum products).*
  - *Using treatment technologies such as thermal desorption and coburning of soils and tar in utility boilers.*
  - *Implementing treatability tests for stabilization, containment and removal of coal tar.*

  - *Interpreting chemical analysis data for fingerprinting and source differentiation.*
  - *Collaboration in the development of methods for establishing partitioning and release of PAHs from contaminated soils and coal tar.*
  - *Some experience in field-scale use of air-sparging and bioventing technologies.*
  - *Extensive knowledge in delineating and defining the speciation, transport and fate of cyanides in groundwater.*
  - *Familiarity with chemometrics evaluation methods for interpretation of groundwater quality data.*
  - *Conceiving and managing the development and use of water quality data management and data analysis software (i.e., MANAGES).*
  - *Designing and implementing projects on source removal/containment and natural attenuation for restoration of groundwater.*
  - *Developing and sustaining a research portfolio on the release, fate and remediation of hydrocarbons and chlorinated compounds used in the Transmission & Distribution systems of the electric utilities.*
  - *Developing and directing research on metals in fossil fuel combustion wastes from the standpoint of disposal and use practices for environmental protection and regulatory compliance.*
  - *Extensive experience in working with utilization of coal combustion byproducts focusing on the mine fills by CCBs.*

- *Extensive technical experience in dealing with metals in soils and groundwater including:*
  - *The fundamental geochemistry of Cadmium for adsorption-desorption reactions, and for precipitation-dissolution reactions involving a number of solubility controlling solids.*
  - *The detailed geochemistry of Selenium, Arsenic, and Iron.*
  - *Broad familiarity with inorganic chemicals e.g., Boron, Lead, Sulfur compounds, Barium, Molybdenum, Nickel, Vanadium, Copper, and Zinc.*
  - *The fundamental geochemistry of Chromium for redox effects, absorption-desorption reactions, and for precipitation-dissolution reactions involving a number of solubility controlling solids.*

- *Extensive technical experience in use of transport and fate models to predict the migration of dissolved chemicals. Responsible for the development and use of software's such as MYGRT, ROAM and FOWL-GH. MYGRT is an analytical groundwater transport/fate model. ROAM is a remediation options analysis model to predict performance of contemplated remedial actions at a site with groundwater restoration needs. FOWL-GH is a leaching chemistry software specifically designed to calculate leachate concentrations of the inorganic constituents which may be dissolved from combustion wastes.*

- *Extensive technical experiences in field measurements and use of data analysis methods (statistical and through models) for water quality impact evaluations.*

- *Extensive involvement in regulatory deliberations at state and federal government level.*

National Committees Experience

- *Served through the end of September 1997 as the Chair and through September 1998 as the Past Chair of the Environmental Engineering Committee. Served as a member of the Executive Committee of the U.S. EPA's Science Advisory Board from October 1993 to September 1997.*

- *From October 1997 to September 2001, served as a member of the Research Strategies Advisory Committee of the U. S. EPA's Science Advisory Board.*

- *From October 1997 through December 1999, served as the Chair of the, Subcommittee on Environmental Regulatory Modeling for the Executive Committee of the EPA Science Advisory Board.*

- *Have served in a Blue Ribbon panel of the National Research Council on irrigation water issues.*

- *Have served on several University sponsored research steering and review committees including the Rice University's Department of Defense program on site remediation*

- *Served for four years on the Board of Directors for CAST (Council for Agricultural Science and Technology)*

Publication and Presentations

- *Author and editor of 3 books*

- *Over 5 oral presentations annually to regulators, scientific gatherings and at symposiums/conferences*

- *Over 100 publications in various journals, symposium proceedings and technical reports.*

Current Service on University Committees

- *Member External Advisory Board, University of Illinois at Chicago*
- *Member, Discovery Park Advisory Council, Purdue University*

Recently completed and ongoing projects on Coal Ash Management

- *Technical support to AES Somerset plant on stabilized sludge landfill permitting issues (May 2005 – July 2005)*
- *Providing technical consulting services on leaching and attenuation of constituents from coal ash generated from using TRONA at a power plant (January 2006 – continuing). Client – Mirant Corporation*
- *Providing consulting services on coal ash placement and potentially impacted water supply wells for a utility company and its attorneys. (March 2004 -- continuing)*
- *Providing technical consulting including field scale assessment of hydrology and groundwater impacts with arsenic from retired coal ash basins. Client- PPL (2003-continuing)*
- *Providing technical consulting and field work for the assessment of seeps in a large coal ash Basin and helping in developing abatement options. Client; PPL (2004-continuing).*
- *Providing technical support on the leaching and groundwater impacts from an ash impoundment/landfill. Client – IKEC (2003-continuing)*
- *Conducting laboratory batch and column studies on the attenuation of arsenic species, selenium species, and boron for soils from three power plant sites. Client – EPRI and DOE (2003-2006)*
- *Prepared and published a report on leaching of inorganic constituents from coal combustion byproducts under field and laboratory conditions (Nov. 1998). Client-EPRI.*
- *Prepared and published a literature review report on attenuation of arsenic species by soils. Client-EPRI (2000).*

- *Carried out laboratory leaching tests and modeling for assessment of groundwater protection requirements for a new coal ash landfill in Nebraska (March 2000-March 2001). Client-Nebraska Public Power District.*

- *Completed leaching and attenuation work on arsenic, cadmium, selenium, iron, and manganese from coal ash from Belews Creek power plant. (September 2000-December 2001). Client-Duke Power Company.*

- *Completed field and laboratory studies on leaching, attenuation and fate of manganese from coal ash impoundments (June 1999-June 2002).
Clients-EPRI, DMG Corporation.*

- *Completed laboratory and field studies on ammoniated ash to determine leaching, conversion, and fate of several constituents in groundwater (October 2001-December 2004). Client-Allegheny Energy and EPRI*

- *Carrying out field and laboratory studies of minefilling with coal ash at the Universal site in Indiana (February 2000-September 2005). Clients-Department of Energy/Combustion Byproducts Reuse Consortium; Cinergy Corporation; EPRI, ACAA.*

- *Completed analysis of ash composition and leaching characteristics information for an FBC power plant in Hawaii. Also supporting work for the permit renewal for the use and disposal of the FBC ash. (October 2000-June 2002). Client-AES Hawaii.*

- *Served as an external peer-reviewer to EPA Office of Solid Waste on its continuing activities on Minefilling of the Fossil Fuel Combustion Wastes (January 2001-December 2001)._Client-U.S. EPA.*

BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
PROPOSED NEW 35 ILL.ADM.CODE PART 225	)	**PCB R06-25**
CONTROL OF EMISSIONS FROM	)	**Rulemaking - Air**
LARGE COMBUSTION SOURCES	)	

TESTIMONY OF KRISH VIJAYARAGHAVAN

I. INTRODUCTION

A. AER credentials

Atmospheric and Environmental Research, Inc. (AER) was founded in 1977 to provide government and industry with research and consulting services in the atmospheric and environmental sciences. AER is recognized for its significant contributions in the areas of atmospheric chemistry, air quality, remote sensing, numerical weather prediction, systems engineering, radiative transfer, climate change, and diagnostic studies and modeling of the atmosphere and oceans. The company has received several awards including the *1993 American Meteorological Society Award for Outstanding Services to Meteorology by a Corporation*. In addition to its headquarters in Lexington, Massachusetts, the company has offices in the San Francisco Bay Area, California; Omaha, Nebraska and Oklahoma. The San Francisco Bay Area office specializes in air quality studies; it was started in 1996. Over the past ten years, it has made significant contributions to air quality science, as exemplified by more than fifty publications in the peer-reviewed literature.

B. Witness credentials

Mr. Krishnakumar ("Krish") Vijayaraghavan is a Staff Engineer at Atmospheric and Environmental Research, Inc. (AER) in the San Francisco Bay Area, California. He has about ten years experience in air quality modeling. He specializes in the atmospheric modeling of mercury, ozone, and particulate matter. He has a Bachelors degree in Chemical Engineering from the Indian Institute of Technology (IIT). He also has a

Masters degree in Environmental Engineering from the Georgia Institute of Technology and a Masters degree in Chemical Engineering from the University of Kansas.

Mr. Vijayaraghavan has conducted numerous modeling studies of the emissions, transport, chemical transformations and atmospheric deposition of mercury. In particular, he has performed studies of the modeling of the atmospheric deposition of mercury in Wisconsin, Michigan and the Great Lakes Region, in Indiana, New York, the Southeast, and the continental United States. He has also performed global mercury modeling coupled with simulations over North America to examine source attribution of mercury deposition in different regions in the United States. He is a co-Principal Investigator in the North American Mercury Model Intercomparison Study (NAMMIS) being coordinated by the USEPA. He was an invited speaker at the annual technical meeting of the National Atmospheric Deposition Program in October 2005. His research has also included the development of state-of-the-science particulate matter (PM) modeling modules and plume-in-grid representations of the plumes from elevated point sources. He is currently a co-Principal Investigator in a three-year NASA project that seeks to quantify the effect of regional pollution on global climate and vice versa using the satellite remote sensing of air quality.

Mr. Vijayaraghavan has authored or co-authored about twenty peer-reviewed scientific papers, over forty conference presentations and over thirty technical reports. The majority of these have been on the modeling of atmospheric mercury. He was recently honored by the USEPA-funded Community Modeling and Analysis System (CMAS) center at the University of North Carolina for outstanding achievements in advancing and promoting the ideals of the air quality community modeling paradigm. A copy of his curriculum vitae is provided as Attachment A.

II. ATMOSPHERIC MERCURY

Mercury is present in the atmosphere mostly as elemental mercury, Hg^0, and oxidized mercury species. The oxidized mercury species are in oxidation state two and are also referred to as divalent mercury. Divalent mercury can be present in the gas phase or in the particulate phase. When in the gas phase, divalent mercury is referred to as Hg^{II} or as reactive gaseous mercury, RGM (due to its “reactivity” with surfaces) and includes mercury chloride, $HgCl_2$, mercury hydroxide, $Hg(OH)_2$, and mercury oxide, HgO. Particulate mercury (Hg_p) in the atmosphere could arise from divalent mercury bound to particulate matter, or primary particulate mercury. In the global atmosphere, Hg^0 accounts on average for more than 90% of total mercury, Hg^{II} accounts for a few % and Hg_p accounts for less than 1%. The relative proportions of Hg^0, Hg^{II} and Hg_p differ in time and location and the fractions of Hg^{II} and Hg_p can be considerably larger near man-made (anthropogenic) sources.

Mercury is emitted from natural sources as well as from anthropogenic sources. In addition, some of the mercury from both of these types of sources deposited to the Earth’s surface is re-emitted to the atmosphere (mostly as Hg^0). Current total (both natural and anthropogenic) emissions of mercury are estimated to be between 6000 and 7000 Mg/year (1 Mg = 1 metric ton = 1.1 ton); this estimate is uncertain by about a factor of two, with emissions being more likely to be greater than the current estimate. For example, anthropogenic emissions from Asia could be underestimated by a factor of two (Jaffe et al., 2005) and emissions from volcanoes could be underestimated by as much as a factor of 5 (Pyle and Mather, 2003). About half of world-wide anthropogenic emissions are estimated to originate from Asia. Current U.S. anthropogenic emissions are estimated to be less than 200 Mg/year with emissions from U.S. coal-fired power plants being about 44 Mg/year. Therefore, U.S. coal-fired power plants contribute less than 1% to the total world-wide emissions of mercury.

The relative fractions of Hg^0, Hg^{II} and Hg_p vary among the sources of mercury. Natural sources (oceans, volcanoes, mercuriferous soils) emit mostly Hg^0. Emission of mercury from soils, water and vegetation occurs mostly as Hg^0. Anthropogenic sources emit Hg^0, Hg^{II} and Hg_p in different proportions depending on the source type. Incinerators tend to emit mostly Hg^{II}, chlor-alkali plants emit mostly Hg^0 and coal-fired power plants emit a combination of Hg^0 and Hg^{II} with proportions that depend on the type of coal burned, the type of boiler, and the type of emission control equipment.

Hg^0, Hg^{II}, and Hg_p have very different deposition characteristics. The removal of Hg^0 from the atmosphere via dry and wet deposition is very slow because Hg^0 is believed to have a low dry deposition velocity and is not very soluble. If we assume a planetary boundary layer[1] height of 1000 m and a typical dry deposition velocity of 0.01 cm/s on average over land, the half-life of Hg^0 with respect to atmospheric deposition within that layer is 2.7 months over land. Hg^0 is also not removed significantly by wet deposition because of its very low solubility in water. Thus Hg^0 can be transported globally. Removal of Hg^{II} from the atmosphere occurs more rapidly than that of Hg^0 because Hg^{II} species are soluble and adsorb readily on most surfaces. If we assume an average dry deposition velocity of 0.5 cm/s and a 1000 m height for the planetary boundary layer, the half-life of Hg^{II} with respect to atmospheric deposition is 1.6 days. Hg^{II} has an even shorter half-life in the presence of precipitation because of its high solubility in water (Hg^{II} is about a million times more soluble than Hg^0). As a result, the Hg^{II} concentration field presents much stronger spatial gradients than the Hg^0 concentration field. Hg_p can be present in particles of various sizes. Fine particles have an atmospheric lifetime of several days in the absence of precipitation; coarse particles are removed faster than fine particles from the atmosphere.

The atmospheric lifetime of mercury is estimated to be in the range of 0.5 to 1.5 years based on estimates of global emissions and the global pool of atmospheric mercury. It must be noted, however, that Hg can cycle several times between the Hg^{II} and Hg^0 species before being removed from the atmosphere.

III. CHEMICAL TRANSPORT MODELS

Chemical transport models (CTMs) of the atmosphere are mathematical representations of the physical and chemical processes that govern the behavior of chemical species in the atmosphere. They use as inputs the emissions into the atmosphere of the chemical species of interest, the meteorology (winds, temperature,

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[1] Planetary boundary layer is the lowest part of the atmosphere that is directly influenced by its contact with the planetary surface.

pressure, humidity, clouds and precipitation), land use (urban area, forest, water, etc.) and upwind concentrations of the chemical species of interest. Most CTMs that are applied to large domains (such as a region, a continent or the globe) use a gridded representation of the atmosphere where the atmosphere is divided into a three-dimensional mesh of contiguous volumes (grid cells). For each grid cell, the CTM calculates as a function of location and time the evolution of the concentrations of the chemical species of interest due to emissions from anthropogenic and natural sources, transport by the winds, dispersion due to atmospheric turbulence, chemical transformations due to reactions in the gas phase, particles and droplets (clouds or fogs), and deposition to the Earth's surface by wet and dry processes. The output of a CTM includes the concentrations of the simulated chemical species in each grid cell and their deposition to the Earth's surface for each surface grid cell.

CTMs have been used for the past thirty years to simulate air quality, e.g. ozone and particulate matter (PM) concentrations, and to assist decision makers for the development of cost-effective emission control strategies. CTMs have also been used to address atmospheric deposition including, for example, acid deposition as part of the National Acid Precipitation Assessment Program (NAPAP) and mercury deposition as part of the Clean Air Mercury Rule (CAMR).

CTMs are needed to estimate the effect of future reductions or growth in emissions of air pollutants on air quality and atmospheric deposition because changes in emissions vary in time and space and, in some cases, may not have a proportional effect on the air pollutant concentrations. For example, reductions in mercury emissions due to installation of equipment to control SO_2 and NO_x emissions from coal-fired power plants may occur along with changes in the speciation of the mercury emissions. Because the different mercury species have distinct atmospheric behaviors, the changes in mercury deposition cannot be estimated directly from the changes in total mercury emissions. Therefore, a CTM that represents the atmospheric processes governing the spatial and temporal evolution of mercury species is needed to calculate the effect of emission changes on atmospheric mercury deposition patterns.

Before a CTM can be applied to simulate the effect of emission changes, it is important to (1) ensure that the current scientific understanding of atmospheric processes is taken into account in the model formulation and (2) evaluate the ability of the model to reproduce available measurements of the pollutant concentrations and deposition fluxes. For mercury, available measurements include wet deposition fluxes available from the Mercury Deposition Network (MDN) and ambient concentrations of speciated mercury (Hg^0, Hg^{II} and Hg_p) at a few locations.

In addition, CTMs should be compared with other CTMs as well as with other modeling techniques such as receptor models. If there are large discrepancies among the models, then, the results should be reconciled and, if warranted, the model(s) (or model inputs) should be improved. For example, a recent comparison of the global AER mercury CTM (which is used to provide upwind mercury concentrations to TEAM, the CTM used in this study) with the Harvard University mercury CTM (GEOS-Chem) suggests that the global AER CTM may underestimate the contribution of non-U.S. sources to mercury deposition in the U.S. (Seigneur et al., 2004; Selin et al., 2006). A comparison of the TEAM simulation results with receptor modeling conducted using Positive Matrix Factorization (PMF) and UNMIX for source attribution of mercury deposition at Steubenville, Ohio, has shown that the two distinct modeling approaches led to overlapping results (see discussion below). Such comparisons bring credibility for the application of CTMs when simulating future emission scenarios. (Note that receptor modeling techniques such as PMF and UNMIX cannot be used to predict the effect of future emission scenarios because they cannot account for the spatial and temporal distribution of the mercury emission changes and changes in mercury speciation).

IV. THE TRACE ELEMENT ANALYSIS MODEL (TEAM)

The Trace Element Analysis Model (TEAM) is a three-dimensional grid-based CTM that simulates the emissions, transport, chemical and physical transformations, and wet and dry deposition of atmospheric mercury species. The atmosphere is approximated by a three-dimensional grid mesh. Mercury species move between grid cells according to the winds and atmospheric turbulence, which are obtained from a computer simulation performed at the National Oceanic and Atmospheric Administration (NOAA). Within each grid cell, chemical transformations occur that oxidize Hg^0 to Hg^{II} and, in the presence of clouds, reduce Hg^{II} to Hg^0. The mercury chemical mechanism used in TEAM and the AER global mercury CTM has been reported by Seigneur et al. (2006a). The speciated mercury emissions inventory used in this modeling system has been described by Seigneur et al. (2004). Precipitation removes Hg^{II} and Hg_p from the atmosphere and wet deposition is calculated accordingly in TEAM.

In the lowest grid cell layer of the model (i.e., near the surface of the Earth), dry deposition of Hg^0, Hg^{II} and Hg_p occurs and those species are removed from the atmosphere. Clouds and precipitation are obtained from actual data available from the National Center for Atmospheric Research (NCAR) and the National Atmospheric Deposition Program (NADP). The TEAM simulations presented here used 1998 meteorology. The concentrations of the species reacting with mercury are obtained from results of model simulations conducted at Harvard University. It is possible to use the values of the species reacting with mercury as an input to the model because mercury concentrations are so low that they have a negligible effect on the concentrations of the other species with which it reacts. The concentrations of mercury species that are transported from upwind (i.e. global background) into the modeling domain (i.e., North America) are obtained from a global model simulation. The global model simulates the same processes as TEAM but uses a coarser spatial resolution to cover the entire globe. In this application to North America, the horizontal grid resolution of TEAM is 100 km for the western United States and about 20 km for the eastern United States (including Illinois). The vertical resolution consists of six layers from the surface to 6 km altitude with finer resolution near the surface (the layer interfaces are at 60, 150, 450, 850 and 2000 m).

TEAM calculates the concentrations of mercury species (Hg^0, Hg^{II} and Hg_p) in every grid cell for every hour of the year and the wet and dry deposition fluxes (i.e.

deposition rate per unit surface area) of these mercury species in every surface grid cell for every hour of the year. Concentrations of mercury species are typically expressed in ng/m^3 for Hg^0 and pg/m^3 for Hg^{II} and Hg_p. Deposition fluxes are typically reported for Hg^{II} and Hg_p because most Hg^0 that is dry deposited is assumed to be re-emitted (see discussion of re-emissions of mercury above). These model output values are then added for the entire year to provide dry, wet and total (i.e., dry + wet) deposition fluxes of mercury; they are expressed in µg/m^2-year.

Grid-based chemical transport models such as TEAM and the EPA CMAQ model use emissions of mercury as an input and simulate (with other inputs such as meteorology and upwind concentrations) the atmospheric processes that govern the behavior of mercury species as a function of time. Therefore, the chemical transport models simulate what happens in the atmosphere to the best extent possible. There are uncertainties due to our imperfect knowledge of the emissions, upwind concentrations, and meteorology inputs as well as the representation of the physics and chemistry that govern the evolution of mercury species. The effect of those uncertainties on the model predictions can be estimated by comparing the model outputs to actual measurements of concentrations and deposition..

TEAM has been used over the past ten years to simulate mercury deposition over North America and various regions of the United States. Its ability to predict mercury deposition has been evaluated against available data for mercury wet deposition that are available from the MDN and available concentrations of mercury species collected by various research groups. TEAM can explain more than half of the variance observed in the mercury wet deposition across the United States; its performance is, therefore, considered satisfactory and represents the current state of the science (Seigneur et al., 2004). TEAM has also been used to estimate mercury deposition to the five Great Lakes. Mercury deposition over Lake Michigan simulated with TEAM is comparable to that estimated by Landis and Keeler (2002) in the Lake Michigan Mass Balance Study in 1994-95 (Vijayaraghavan, 2005).

The development, evaluation and applications of TEAM have been reported in eight peer-reviewed publications in scientific journals and in numerous technical reports and conference presentations. The development and evaluation of TEAM have been funded by the Electric Power Research Institute (EPRI). Under a project sponsored by the New York State Energy Research and Development Agency (NYSERDA), TEAM was transferred to the New York State Department of Environmental Conservation (NYSDEC). Under a project sponsored by the Wisconsin Department of Natural Resources (WDNR), the mercury chemistry of TEAM was transferred to another air quality model typically used to predict ozone and particulate matter (PM). Under funding from EPRI and some electric utilities, TEAM has been applied to various power plant emission scenarios including CAIR and CAMR. TEAM is currently part of the North American Mercury Model Intercomparison Study (NAMMIS) that includes several mercury models developed by the U.S. EPA, Environment Canada, AER, Harvard University and others.

V. USE OF TEAM TO EVALUATE THE EFFECT OF EMISSION SCENARIOS ON MERCURY DEPOSITION

TEAM was used here to simulate atmospheric mercury deposition over the central and eastern United States to compare the Illinois mercury control proposed rule (90% reduction of coal-fired power plant mercury) to several other scenarios. The emission scenarios considered included:

1. 2006 base case (Figure 1)
2. 2006 case with no U.S. coal-fired power plant emissions (Figure 2)
3. 2010 case applying CAIR and CAMR (the Clean Air Interstate Rule and Clean Air Mercury Rule, respectively) (Figure 3)
4. 2010 case with 90% mercury control for Illinois coal-fired power plants and CAIR and CAMR for all other states (Figure 4)
5. 2020 case with CAIR and CAMR for all states (Figure 5)

All simulations used the 1998 meteorology mentioned earlier. Emissions of mercury were for 1998 except that incinerator emissions were updated to reflect the installation of maximum achievable control technology (MACT) that occurred after 1998 and the emissions from an Illinois petroleum facility were reduced to reflect the value reported in the 2001 EPA emission inventory. The TEAM scenarios differ only by the U.S. coal-fired power plant emissions since we are investigating here the effect that different changes in U.S. coal-fired power plant emissions would have on mercury deposition in Illinois. These power plant speciated mercury emissions for all states including Illinois were provided to AER by CRA International (CRAI).

A comparison of the 2006 base simulation with the simulation conducted with no U.S. coal-fired power plant emissions shows that U.S. coal-fired power plants are calculated to contribute 19% of mercury deposition in Illinois in 2006 (see Table 1). For the Illinois grid cells, only 4 out of 474 20-km x 20-km grid cells receive more than half of their mercury deposition from U.S. coal-fired power plant emissions in this simulation; that is, less than 1% of the Illinois land area has a U.S. coal-fired power plant contribution greater than 50% in 2006.

The 2010 CAIR/CAMR simulation (scenario #3) leads mostly to decreases in mercury deposition from 2006 with the largest decreases predicted to occur in the eastern United States (Ohio, West Virginia, Pennsylvania, North Carolina and South Carolina) (see Figures 6 and 7). There are only a few grid cells that show increases in mercury deposition and those increases are all less than 10%. Illinois grid cells show decreases in mercury deposition of up to 51%. There is only one grid cell in Illinois that shows an increase (<1%) in mercury deposition. Under this emission scenario, U.S. coal-fired power plants are calculated to contribute 15% of mercury deposition in Illinois.

In the 2010 CAIR/CAMR simulation with 90% mercury control of Illinois coal-fired power plants (scenario #4), U.S. coal-fired power plants are calculated to contribute 11% of mercury deposition in Illinois, i.e., a decrease of 4% from the 2010 CAIR/CAMR scenario (#3). Mercury deposition in Illinois is about 4% lower in scenario #4 than in scenario #3 (decreasing from 3.314 Mg/y to 3.168 Mg/y; see Table 1). The decreases in mercury deposition are mostly limited to 2 µg/m^2-year, with only a few grid cells with decreases ranging from 2 to 13 µg/m^2-year (Figure 8). In relative terms, most of the Illinois area shows decreases of 1 to 5% due to the Illinois 90% emission reduction with only a few grid cells with decreases in the 15 to 35% range (Figure 9). Note that the modeling did not account for the Temporary Technology Based Standard (TTBS) and so simulated reductions in deposition (i.e. benefits) could be over-estimates. Increases in mercury deposition are simulated in 2010 in Texas, Maryland, Georgia and South Carolina in the Illinois 90% reduction simulation because this scenario results in slight changes in the Hg, SO_2, and NO_x allowance markets that suggest a delay in the timing of the retrofits at units at these locations. These increases are all eliminated by 2015, however.

The 2010 CAIR/CAMR simulation with 90% mercury control of Illinois coal-fired power plants can also be compared to the 2020 CAIR/CAMR simulation (scenario #5). The 2020 CAIR/CAMR simulation leads to lower mercury deposition in Illinois than the 2010 CAIR/CAMR simulation with 90% Illinois mercury control except for 3 grid cells in Illinois where very small increases are predicted; those increases are less than 1 µg/m^2-year and correspond to less than 3% increases (Figures 10 and 11). Under the 2020 CAIR/CAMR scenario, U.S. coal-fired power plants are calculated to contribute only 6% to mercury deposition in Illinois.

It should be noted that the TEAM simulation results are more likely to overestimate than underestimate mercury deposition due to U.S. coal-fired power plants. This likely overestimation is due to the following reasons:

- The grid-based model TEAM overestimates mercury deposition in the proximity of large elevated point sources such as power plant stacks over an area commensurate with the resolution of the grid-based model. This overestimation is up to a factor of two and is due to the fact that grid-based models tend to overestimate the vertical mixing of plumes, thus artificially enhancing dispersion to the earth's surface and hence the dry deposition (Seigneur et al., 2006b).

- There is some evidence that the Hg^{II} fraction in power plant plumes downwind of the stacks is lower than the assumed Hg^{II} fraction of the coal-fired power plant emission inventory. This may be due to an overestimation of the Hg^{II} fraction in the emission inventory or to a chemical reduction of Hg^{II} to Hg^0 in the power plant plumes (Edgerton et al., 2006; Lohman et al., 2006). Since Hg^{II} is deposited faster than Hg^0, this overestimation of the Hg^{II} fraction would lead to an overestimation of mercury deposition.

- There is some evidence that Hg^{II} and Hg_p dominate the mercury speciation in the lower stratosphere and, possibly, in the upper troposphere (Murphy et al., 2006; Selin et al., 2006); this global pool of soluble mercury could contribute to mercury wet deposition when large thunderstorms extend vertically up to the tropopause.

- TEAM tends to overestimate mercury wet deposition downwind of the Ohio Valley. Another grid-based model CMAQ-MADRID also tends to overpredict mercury wet deposition downwind of the Ohio Valley but predicts sulfate wet deposition satisfactorily; therefore, the overprediction seems to be specific to mercury (Vijayaraghavan et al., 2006); this mercury overprediction could be due to an overprediction of the Hg^{II} fraction in the power plant plumes, as suggested above.

VI. COMPARISON OF TEAM SIMULATION RESULTS WITH OTHER INFORMATION IN THE ILLINOIS PCB RECORD

Mercury wet deposition in Steubenville, Ohio

Dr. Keeler in his testimony reports that according to a receptor modeling analysis, coal-fired power plants are estimated to contribute about 70% of mercury wet deposition in Steubenville, Ohio with an uncertainty of about 15%.

TEAM predicts that U.S. coal-fired power plants contribute 62% of mercury wet deposition in the grid cell (20 km x 20 km) where Steubenville is located. This value is well within the range proposed by Dr. Keeler via receptor modeling (a more rigorous comparison is not possible due to the unavailability of the receptor modeling data). Therefore, the receptor modeling results are consistent with the TEAM simulation results, thereby providing additional confirmation that TEAM performs satisfactorily.

EPA, using CMAQ, predicted that U.S. coal-fired power plants contribute 43% to mercury wet deposition in the grid cell (36 km x 36 km) where Steubenville is located. This value is lower than that calculated with TEAM. This lower value is due in part to the fact that CMAQ uses a coarser grid resolution. The lower value of CMAQ is due also to differences in inputs and formulation (for example, the global concentrations may contribute more to mercury deposition in the United States in CMAQ than in TEAM). Thus, TEAM tends to predict higher contribution of U.S. coal-fired power plants to mercury deposition than CMAQ.

One must note, however, that both TEAM and the receptor modeling technique have uncertainties and are more likely to overestimate mercury deposition than to underestimate mercury deposition. In particular, TEAM is likely to overestimate mercury deposition in that area. For example, TEAM predicts mercury wet deposition of 31 $\mu g/m^2$-year in 2004 compared to 18 $\mu g/m^2$-year in the Steubenville measurements reported by Dr. Landis of EPA (Landis, 2005) for 2004.

It is also important to note that mercury emissions from coal-fired power plants near Steubenville are much larger in magnitude and have a higher Hg^{II} component than those from Illinois plants due to the significantly larger use of bituminous coal in the plants near Steubenville. Coal-fired power plants within 150 km (i.e. ~100 miles) of

Steubenville emit annually 9744 lbs of mercury, of which 6325 lbs (or 65%) constitute Hg^{II} emissions (based on 2006 estimates by CRAI). In contrast, all coal-fired power plants in Illinois put together emit annually a total of 5254 lbs of which only 2202 lbs (or 42%) are Hg^{II} due to the significant use of PRB coal in Illinois. Thus, Hg^{II} emissions from all coal-fired power plants in Illinois total only about one-third that from the plants near Steubenville while being spread over a land area that is twice as much. Thus, Illinois power plant contributions to mercury deposition in Illinois are expected to be much lower than the contributions estimated in Steubenville.

VII. OTHER COMMENTS ON INFORMATION IN THE ILLINOIS PCB RECORD

Receptor-based models

Receptor-based models use data and mathematical techniques to identify the sources that contribute to mercury concentrations or deposition at a certain location. The fundamental principles of receptor modeling are that mass conservation can be assumed and a mass balance analysis can be used to identify and, in some cases, apportion, sources of mercury. Such techniques can be qualitative (e.g., principal component analysis) or quantitative (e.g., PMF or UNMIX). Sometimes, a receptor-modeling approach is combined with a back-trajectory analysis (going back in time according to the mean wind flow) to attempt to identify the source areas. There are uncertainties associated with receptor modeling as with any modeling technique. The mass balance principle mentioned above may not hold as chemical species deposit to the ground. If back-trajectories are used, the wind field used to construct those trajectories and the number of days used to go back to the source areas can have large effects on the results. The source profiles that are derived from the data via the mathematical analysis need to be assigned to specific sources or source categories (e.g., mobile sources, coal-fired power plants). Some source profiles may resemble one another and it may not be possible to differentiate between them. For example, it may not be possible to differentiate between the source profile of U.S. coal-fired power plants and that of Asian coal-fired power plants burning the same type of coal. Also, receptor models such as PMF and UNMIX do not account for the chemical transformations of mercury in the atmosphere.

Meteorological analysis of Dr. Keeler

In his testimony, Dr. Keeler mentions that he conducted a meteorological analysis of mercury wet deposition events at Steubenville. That analysis involved backtracking the storm systems that led to the major mercury wet deposition events. Although no detailed technical information on that analysis is currently available, it is possible that Dr. Keeler assumed that all RGM (i.e., Hg^{II}) that was deposited at Steubenville was locally/regionally produced either by emissions or chemical reaction. It should be noted that there is increasing evidence of a global pool of Hg^{II} and Hg_p in the free upper troposphere and lower stratosphere (Murphy et al., 2006; Holmes et al., 2006). Such Hg^{II} and Hg_p are produced by the oxidation of Hg^0 at a global scale and their concentrations near the tropopause exceed the Hg^0 concentrations. Large convective storms may extend to altitudes that reach into the upper troposphere and may, therefore, lead to precipitation of some of this global Hg^{II} and Hg_p. Not taking such a global pool into account in a meteorological analysis is likely to lead to an underestimation of the contribution of the global mercury pool to wet deposition at Steubenville and, consequently, to an overestimation of the local/regional contribution.

Massachusetts analysis

The Massachusetts Department of Environmental Protection has conducted an analysis of mercury concentrations in fish and mercury emissions from incinerators over the 1999-2004 period (MA DEP, 2006). This analysis shows that mercury concentrations in fish have decreased in some lakes although increases or no discernible changes are also observed. Our objective here is not to conduct a detailed critique of the analysis conducted by the MA DEP but to place some perspective on this type of analysis with respect to its potential implications for coal-fired power plant emission impacts.

First, mercury emissions from incinerators differ significantly from mercury emissions from coal-fired power plants. Most of mercury emissions from incinerators are believed to be Hg^{II} (Dvonch et al., 1999) whereas mercury emissions from coal-fired power plants may consist of a more balanced combination of Hg^{II} and Hg^{0}. In addition, there is some evidence that some Hg^{II} reduction to Hg^{0} takes place in power plant plumes or that the Hg^{II} fraction is overestimated in the current power plant emission inventories (Edgerton et al., 2006; Lohman et al. 2006). There is no such evidence for Hg^{II} chemical reduction or emission overestimation for incinerators.

Second, stacks from medical waste incinerators and municipal waste combustors are typically shorter than stacks from coal-fired power plants. Therefore, emissions from incinerators tend to remain aloft for a shorter period of time than emissions from coal-fired power plants.

These two aspects, greater Hg^{II} fraction and shorter stacks for the incinerator emissions compared to the coal-fired power plant emissions, imply that mercury emissions from incinerators are more likely to deposit closer to the source than mercury emissions from coal-fired power plants. Therefore, it is inappropriate to extrapolate the results of an incinerator emission reduction program to the potential effects of a coal-fired power plant emission reduction program.

Florida analysis

The Florida Department of Environmental Protection has conducted an integrated study of mercury deposition and aquatic cycling in South Florida (FL DEP, 2003). This report points out that some decreases in mercury fish concentrations have been observed at several sites in the Everglades. Modeling of the aquatic cycling of mercury suggests that such a decrease could be due to changes in atmospheric deposition. One should note, however, that changes in water chemistry may also affect mercury concentrations in fish; for example, sulfate concentrations may affect the rate of methylation of Hg^{II} and, therefore, may also affect mercury concentrations in fish (Jeremiason et al., 2006).

Decreases in mercury emissions from incinerators have been estimated to occur in Florida although the timing of the peak emissions differs depending on the methodology used to estimate the emissions (Figure 20 of the FL DEP report). The effect of the decreases in incinerator emissions on mercury deposition depends on the contribution of those emissions to total mercury deposition. Dvonch et al. (1999) estimated that about 71% of the mercury wet deposition at five sites in the Everglades was due to local emissions. On the other hand, Guentzel et al. (2001) estimated that local sources contributed only 30 to 46% of the mercury wet deposition and that waste incinerators in southern Florida are not the dominant RGM sources for rainfall Hg over southern Florida. More recent modeling studies have led to even lower contributions from local/regional sources: Seigneur et al. (2004) calculated that less than 20% of mercury total (i.e., wet + dry) deposition originated from North America and Selin et al. (2006) calculated that less than 10% of mercury total deposition originated from North America.

As mentioned above with regard to the Massachusetts analysis, mercury emissions from waste incinerators have different impacts on mercury deposition than mercury emissions from coal-fired power plants. Therefore, caution is advised when applying results of past emission reductions to future emission reductions from a different source category.

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Table 1. Simulated State-wide Mercury Deposition Totals in Illinois

	Wet deposition (Mg/y)	Dry deposition (Mg/y)	Wet + Dry deposition (Mg/y)	% Decrease in wet + dry deposition from 2006 Base	% Contribution of U.S. coal-fired power plants
2006 Base	2.419	1.083	3.502	----	19%
2010 CAIR/CAMR	2.307	1.007	3.314	5%	15%
2010 CAIR/CAMR + IL controls	2.229	0.939	3.168	10%	11%
2020 CAIR/CAMR	2.138	0.864	3.002	14%	6%
Zero-out all U.S. coal-fired power plants	2.044	0.787	2.831	19%	----

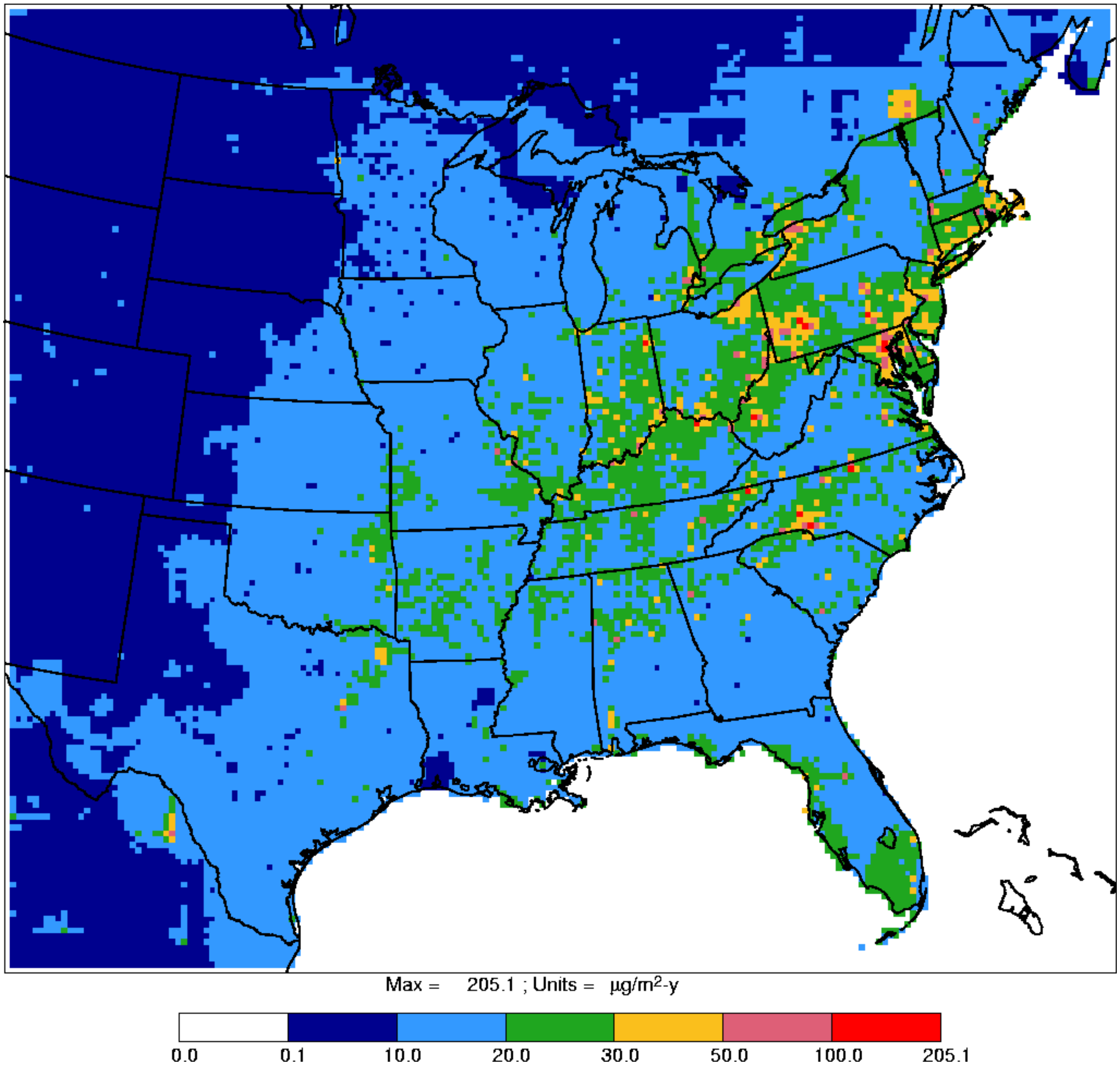

Figure 1. Annual total deposition of Hg ($\mu g/m^2$-y) in 2006 base case (scenario #1).

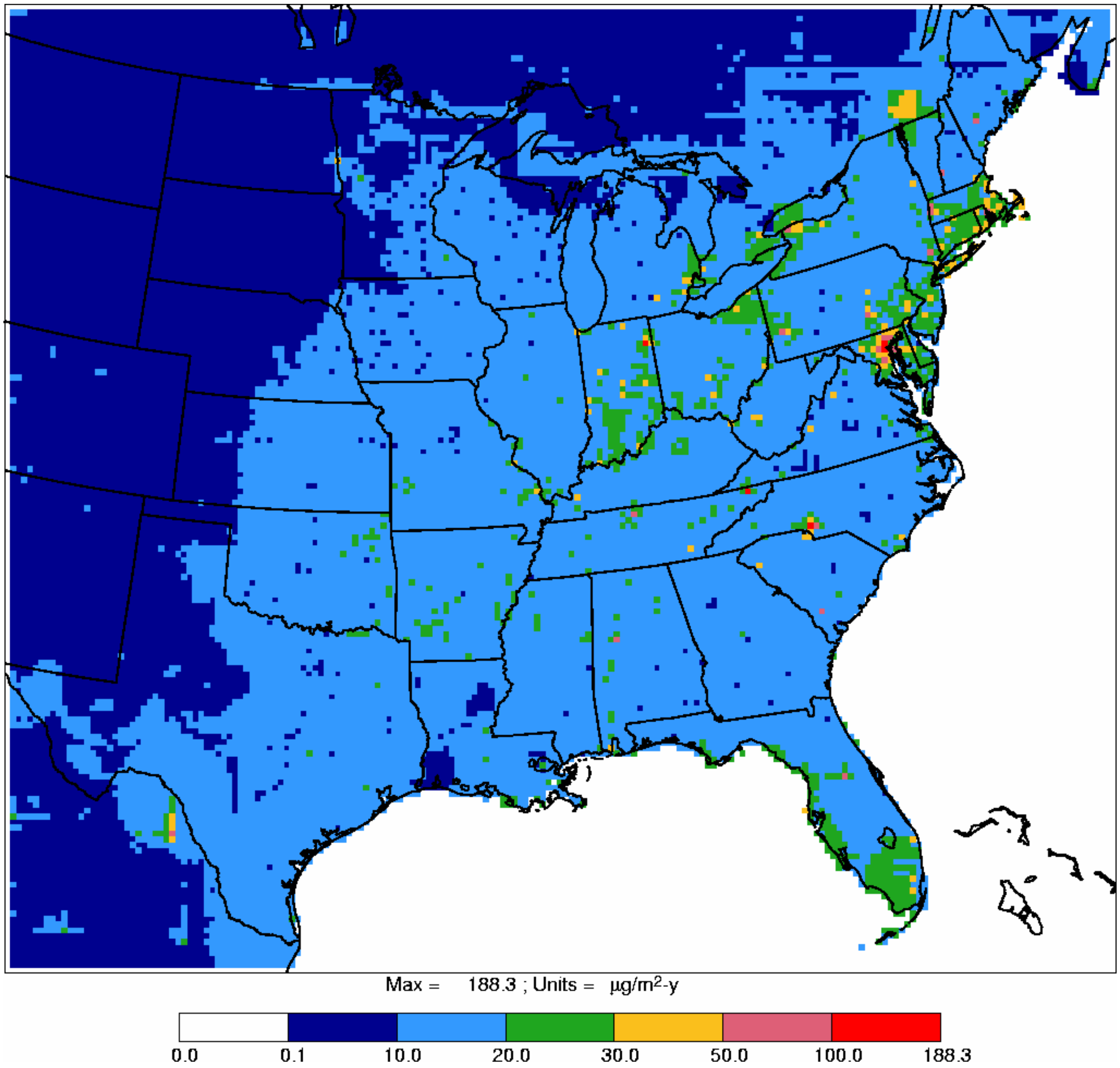

Figure 2. Annual total deposition of Hg (µg/m^2-y) in 2006 case with no U.S. coal-fired power plant emissions (scenario #2).

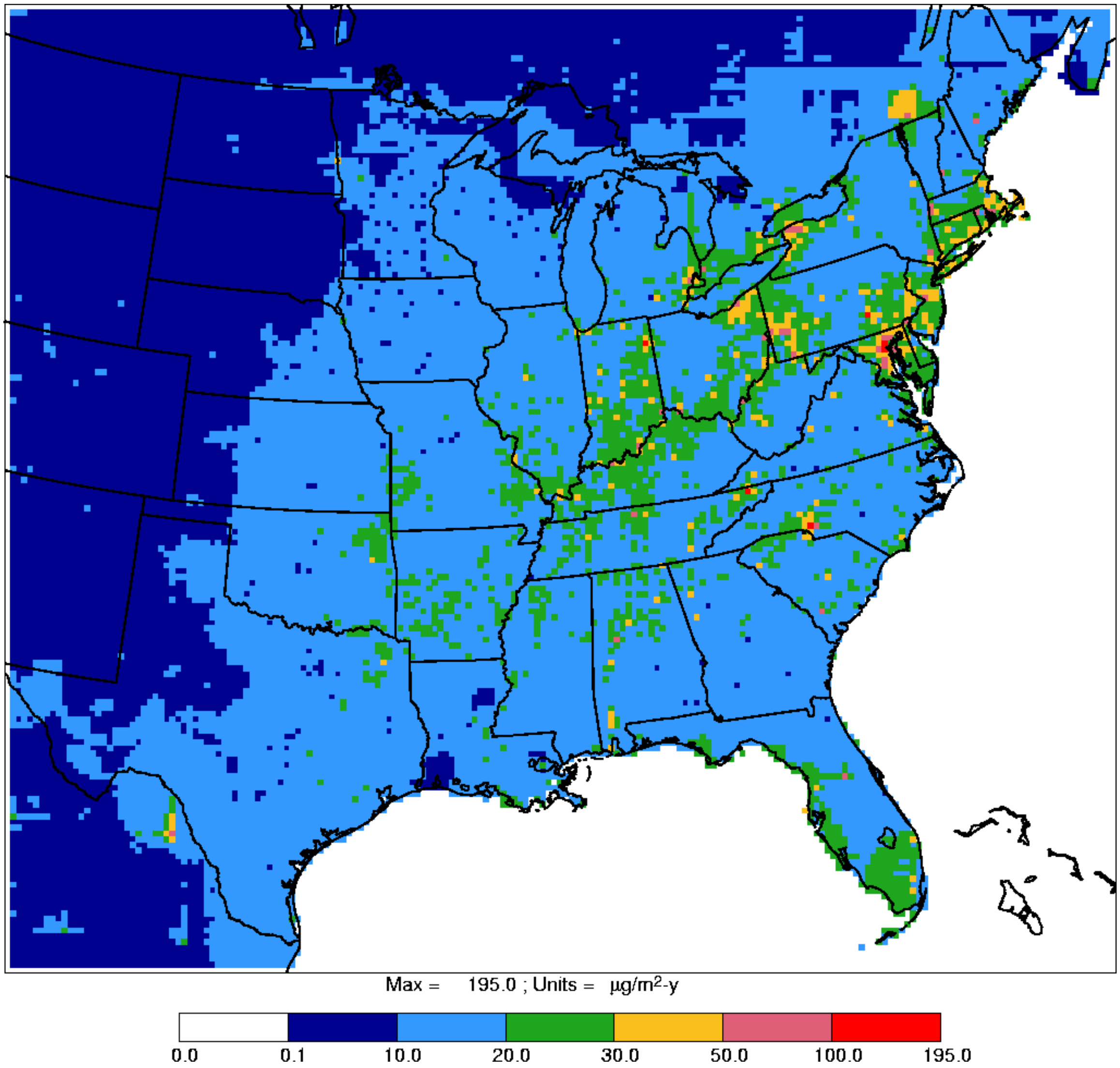

Figure 3. Annual total deposition of Hg (µg/m^2-y) in 2010 case with CAIR/CAMR for all states (scenario #3).

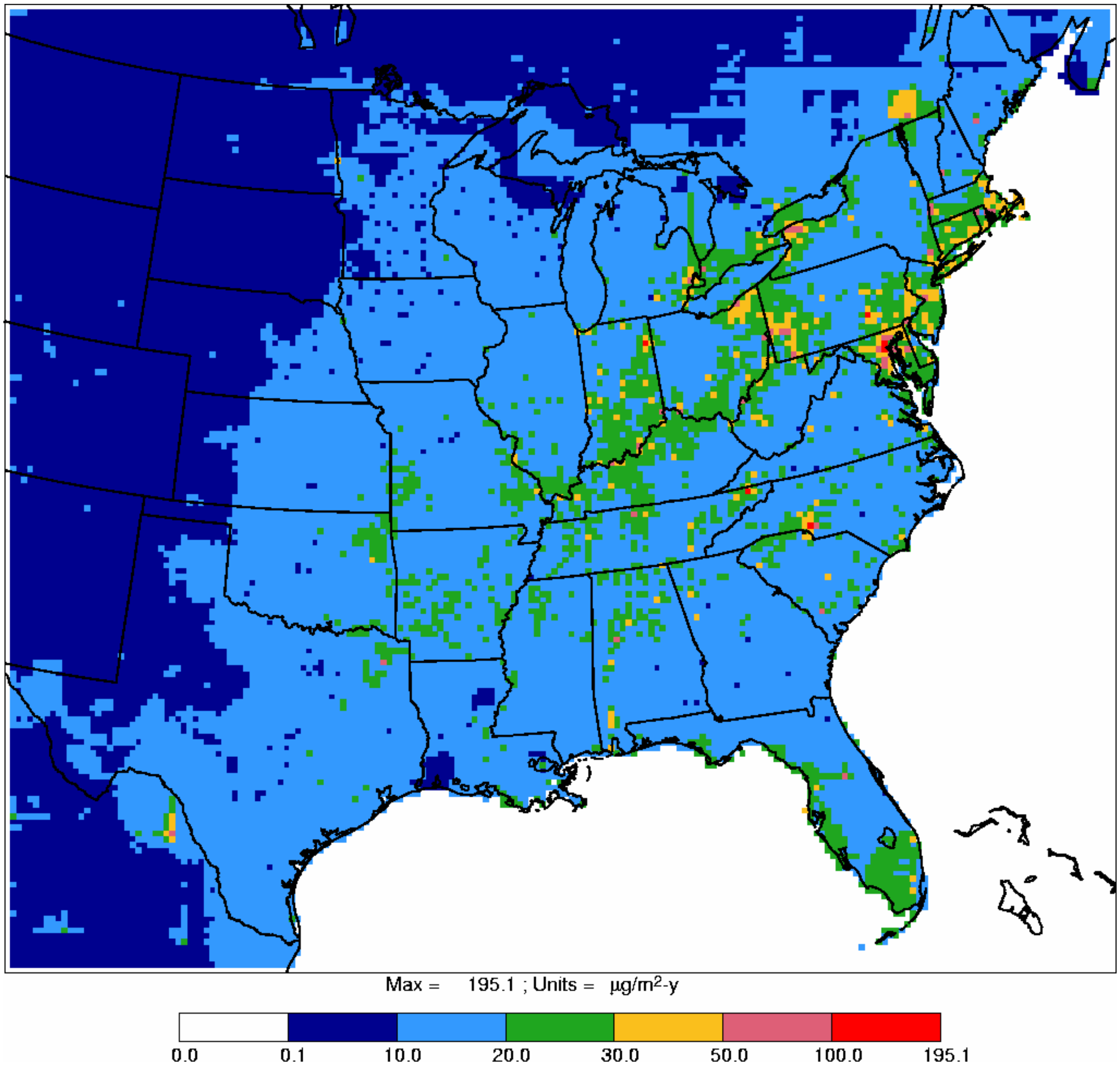

Figure 4. Annual total deposition of Hg (µg/m^2-y) in 2010 case with 90% mercury control for Illinois coal-fired power plants and CAIR/CAMR for all other states (scenario #4).

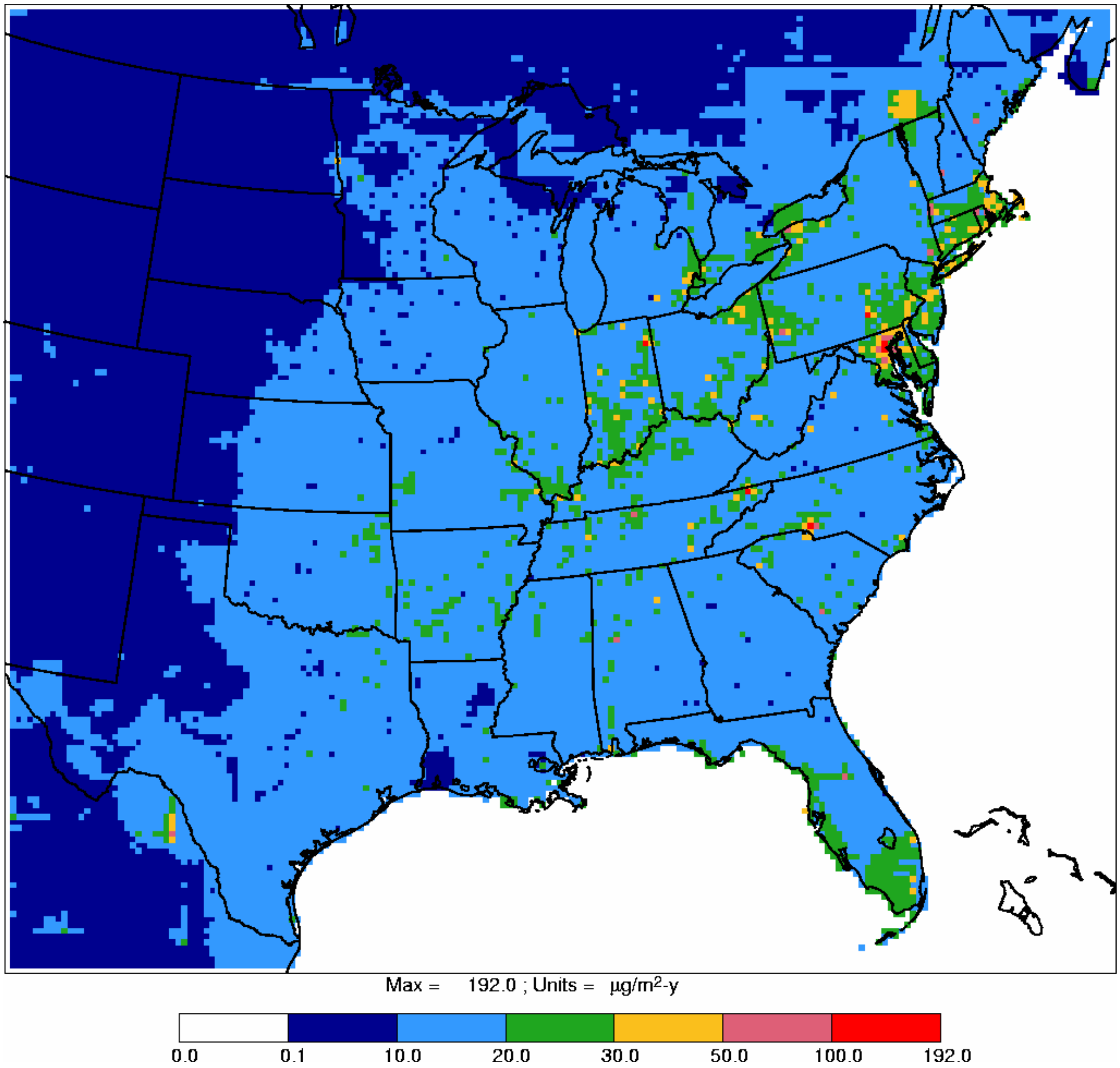

Figure 5. Annual total deposition of Hg (µg/m^2-y) in 2020 case with CAIR/CAMR for all states (scenario #5).

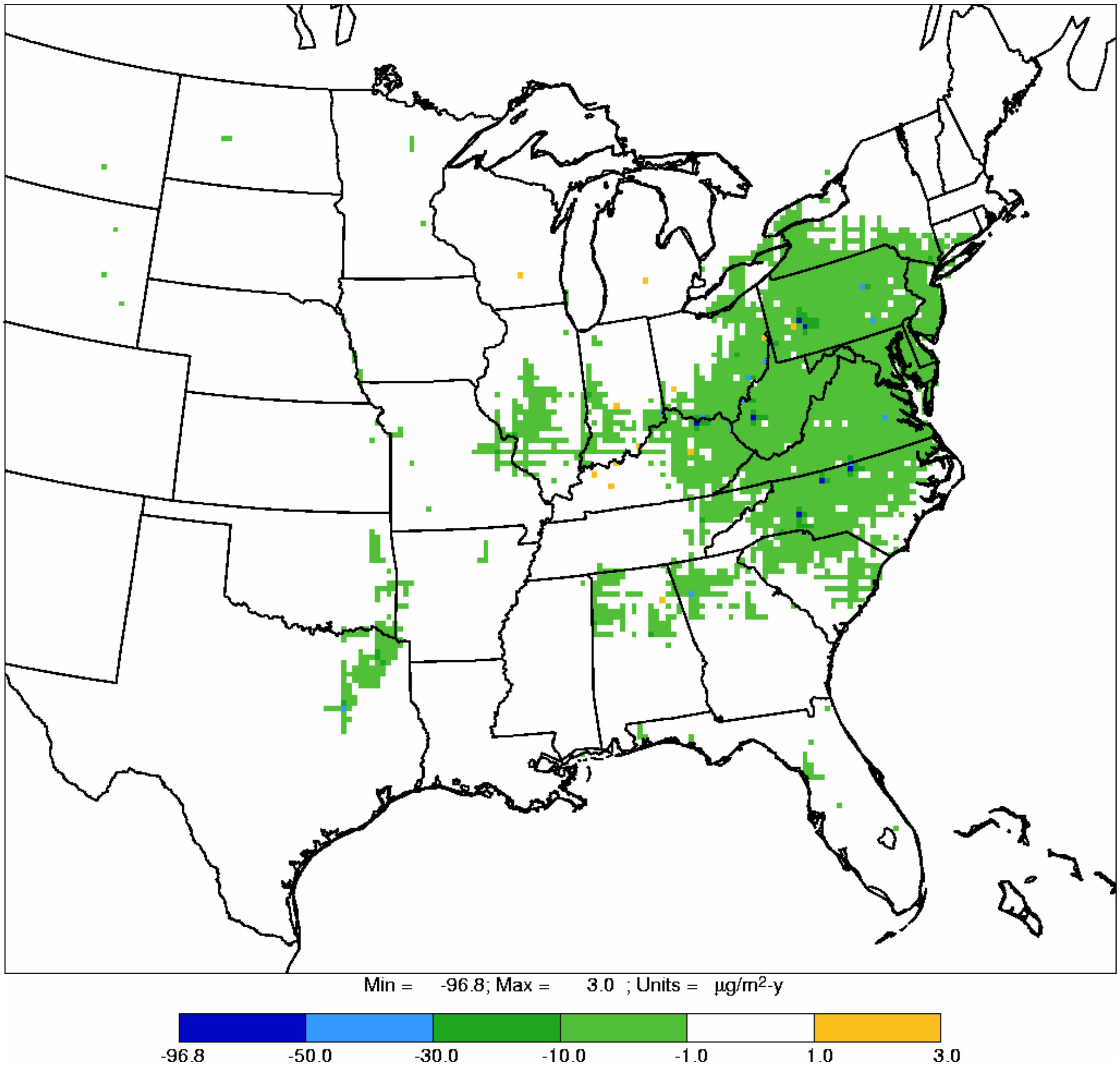

Figure 6. Change in annual total deposition of Hg (µg/m^2-y) between 2006 base and 2010 CAIR/CAMR for all states. Values shown are (2010 CAIR/CAMR – 2006 base).

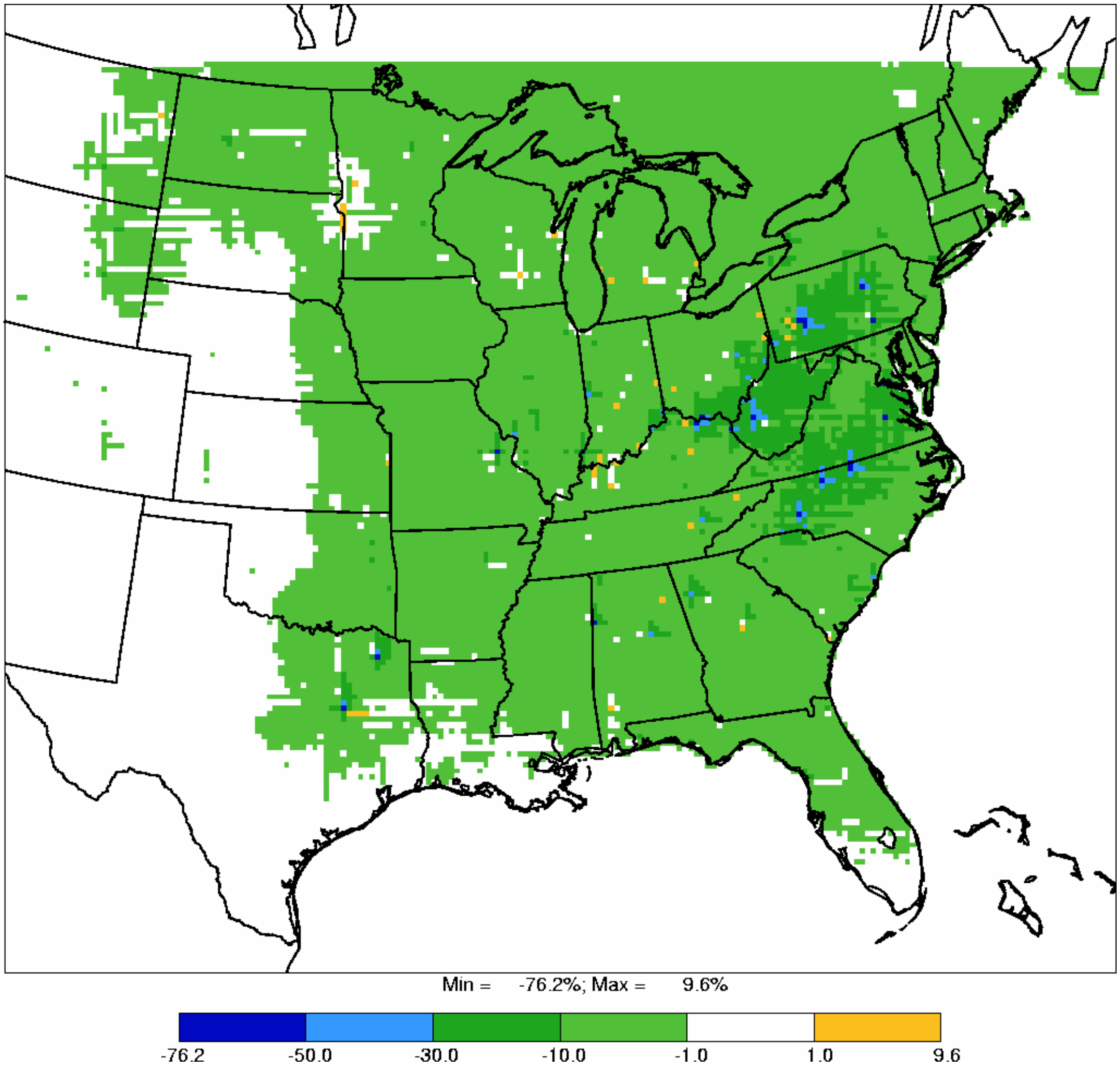

Figure 7. Percent change in annual total deposition of Hg between 2006 base and 2010 CAIR/CAMR for all states. Values shown are (2010 CAIR/CAMR – 2006 base)/(2006 base) x 100.

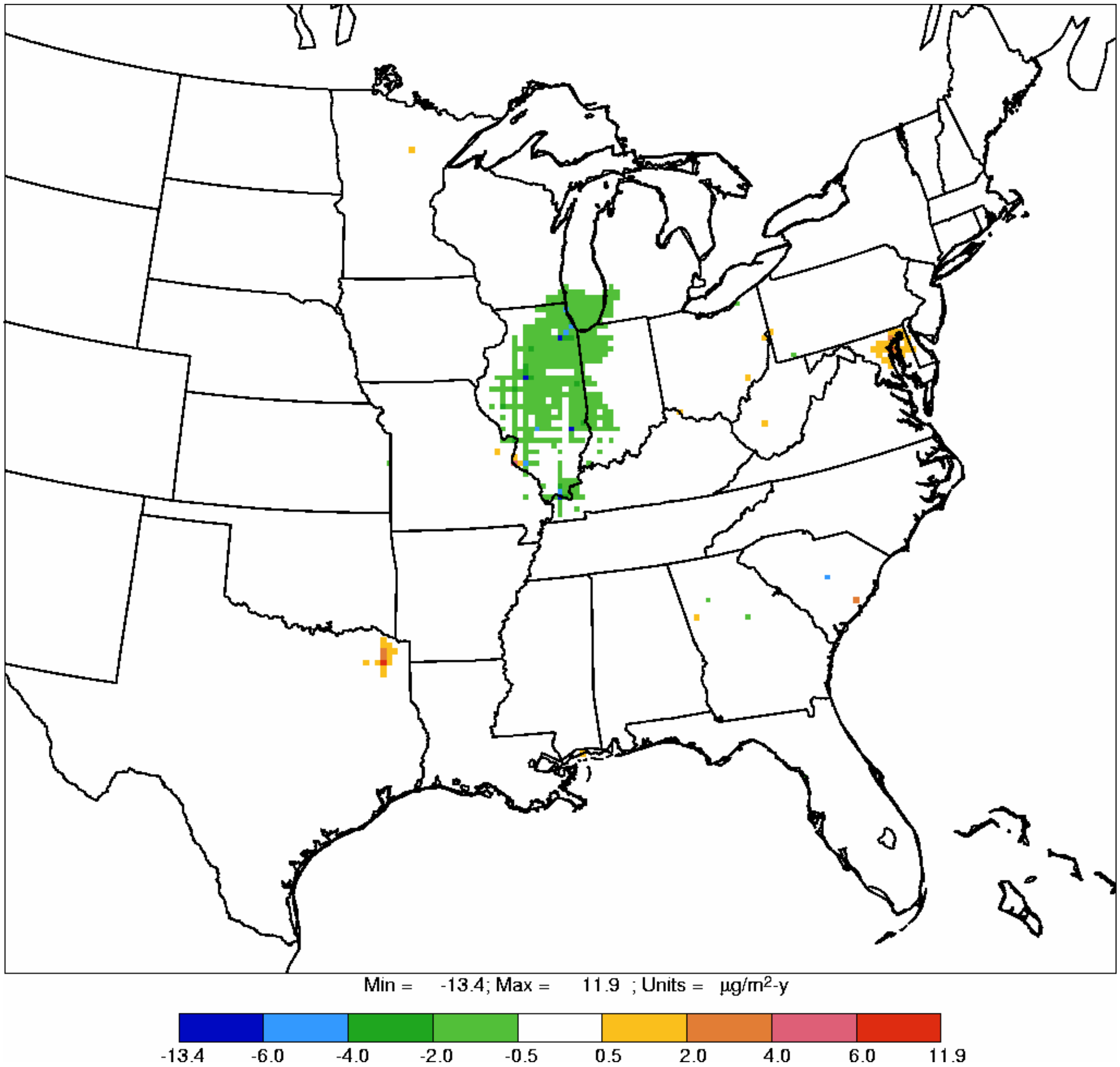

Figure 8. Change in annual total deposition of Hg (μg/m^2-y) between scenario #3 (2010 CAIR/CAMR for all states) and scenario #4 (2010 case with 90% mercury control for Illinois coal-fired power plants and CAIR/CAMR for all other states). Values shown are (scenario #4 – scenario #3).

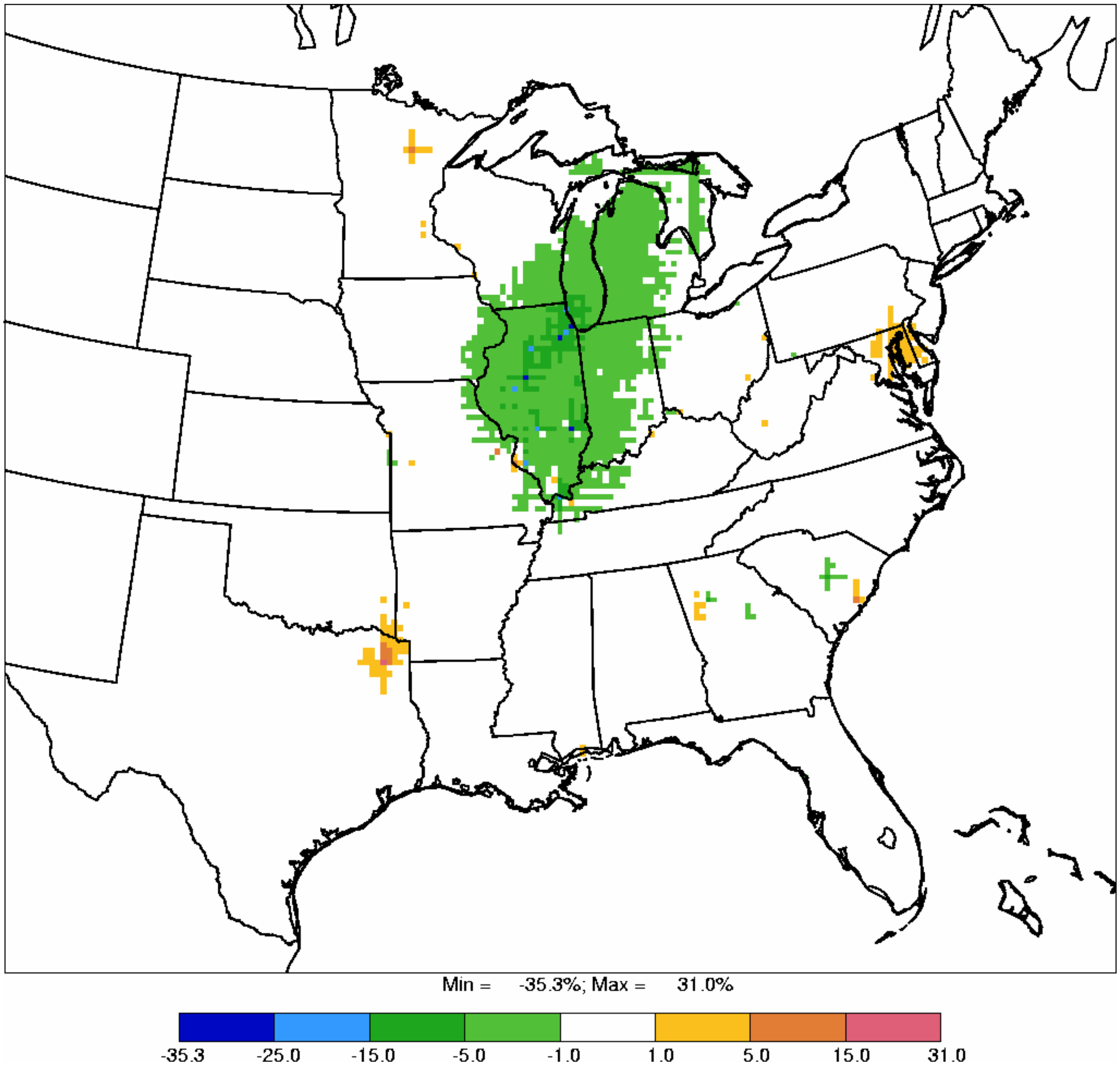

Figure 9. Percent change in annual total deposition of Hg between scenario #3 (2010 CAIR/CAMR for all states) and scenario #4 (2010 case with 90% mercury control for Illinois coal-fired power plants and CAIR/CAMR for all other states). Values shown are (scenario #4 – scenario #3)/(scenario #3) x 100.

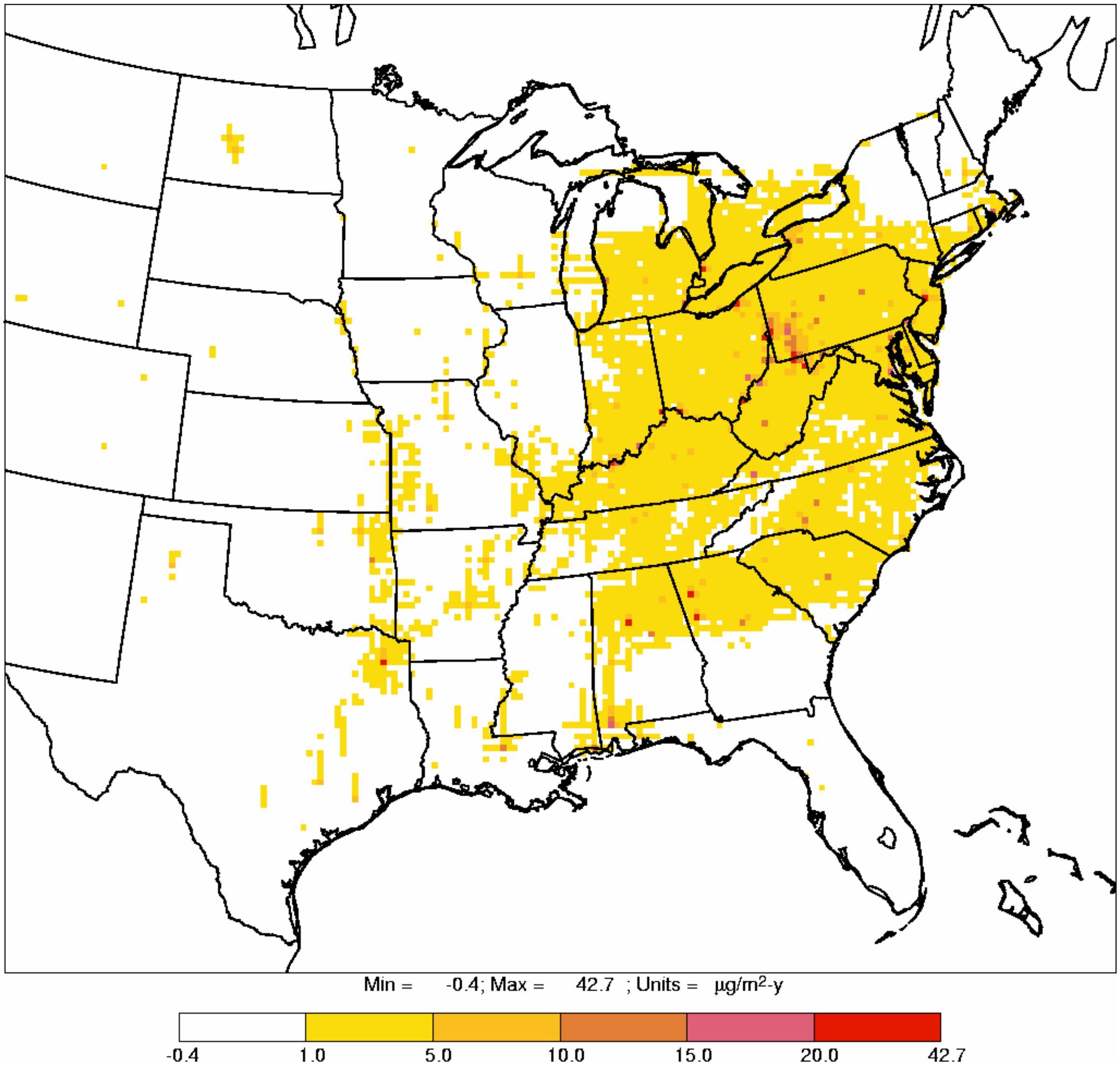

Figure 10. Change in annual total deposition of Hg (µg/m^2-y) between scenario #4 (2010 case with 90% mercury control for Illinois coal-fired power plants and CAIR/CAMR for all other states) and scenario #5 (2020 CAIR/CAMR for all states). Values shown are (scenario #4 – scenario #5).

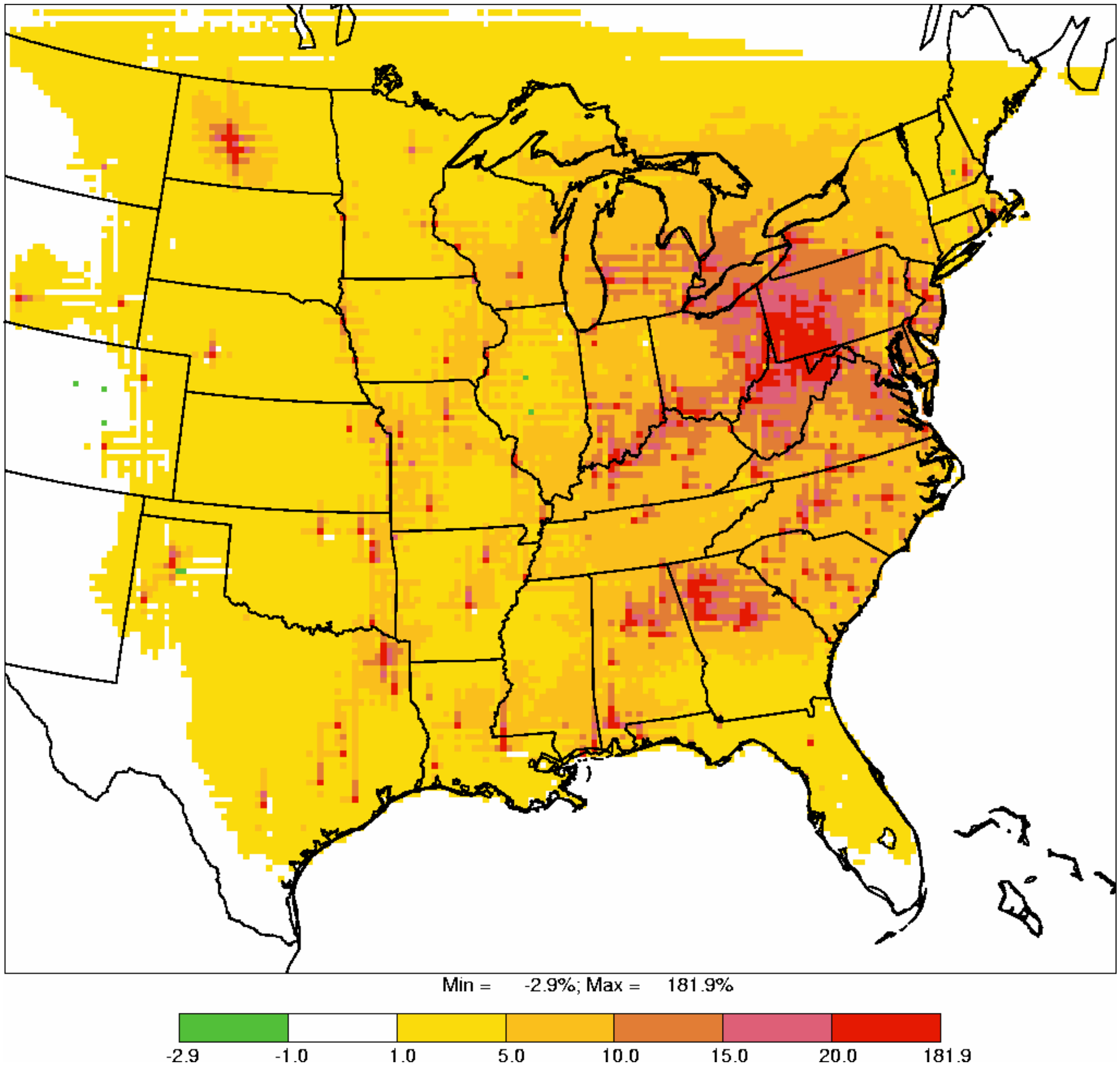

Figure 11. Percent change in annual total deposition of Hg between scenario #4 (2010 case with 90% mercury control for Illinois coal-fired power plants and CAIR/CAMR for all other states) and scenario #5 (2020 CAIR/CAMR for all states). Values shown are (scenario #4 – scenario #5)/ (scenario #5) x 100.

Attachment A

Curriculum Vitae

Krish Vijayaraghavan

Curriculum Vitae

KRISH VIJAYARAGHAVAN

EDUCATION:

M.S.	Environmental Engineering, Georgia Institute of Technology
M.S.	Chemical Engineering, University of Kansas
B.S.	Chemical Engineering, Indian Institute of Technology

EXPERIENCE:

Atmospheric and Environmental Research, Inc. **August 1997 - present**

Air Quality Division - San Ramon, CA

Staff Engineer	August 2002 – present
Associate Engineer	August 1997 – July 2002

Aspen Technology, Inc., Cambridge, MA

Engineering Intern **March 1997 – June 1997**

PROFESSIONAL QUALIFICATIONS AND AFFILIATIONS:

- Certified Engineer-in-Training, California Board for Professional Engineers and Land Surveyors
- Member, Air and Waste Management Association

HONORS AND AWARDS:

2005	Outstanding achievement in advancing and promoting the ideals of the air quality community modeling paradigm, CMAS Center, University of North Carolina
1994	Outstanding MS Research in Chemical Engineering, Dept. of Chemical and Petroleum Engineering, University of Kansas

PEER-REVIEWED PUBLICATIONS:

Vijayaraghavan, K. and K.S. Surana. p-Version Least-Squares Finite Element Formulation of a System of Convection-Reaction Nonlinear Equations - Fixed Bed o-Xylene Oxidation, *Computers and Structures*, **62**, 539-554 (1996).

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Zhang, Y., B. Pun, S.-Y. Wu, K. Vijayaraghavan, G. Yelluru and C. Seigneur. Modeling particulate matter with two three-dimensional models: CAMQ and PM-CAMx, Annual American Association for Aerosol Research Conference, 20-24 October 2003, Anaheim, California.

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Vijayaraghavan, K., C. Seigneur, K. Lohman, S-Y. Chen, P. Karamchandani, Modeling of atmospheric mercury deposition in the Great Lakes region, International Association for Great Lakes Research 47th Annual Conference, 23-27 May 2005, Ann Arbor, Michigan.

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Vijayaraghavan, K., P. Karamchandani, K. Lohman, C. Seigneur and L. Levin, Modeling of atmospheric mercury deposition over North America using CMAQ-MADRID-Hg, 9th Electric Utilities Environmental Conference – Clean air, Mercury, Global Warming and Renewable Energy, 23-25 January 2006, Tucson, Arizona

Zhang, Y., K. Vijayaraghavan, J-P. Huang and M.Z. Jacobson, Probing into Regional O3 and PM Pollution: A 1-year CMAQ Simulation and Process Analysis over the United States, 86th Annual Meeting of the American Meteorological Society, January 30 – February 2, 2006, Atlanta, Georgia.

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Addendum of Anne E. Smith, Ph.D.
to the Testimony of Krish Vijayaraghavan and James Marchetti

As an expert on modeling impacts of emissions control policies on electricity markets and electric sector investment decisions, I prepared, and documented in this Addendum, the projections of elemental and divalent emissions from individual stacks serving coal-fired electric generating units throughout the United States used as inputs to the mercury deposition analysis that Mr. Krish Vijayaragahavan describes in his testimony. This Addendum also documents the assumptions and data provided as inputs to Mr. James Marchetti regarding unit-level generation and coal choices of Illinois coal-fired units and emissions allowance prices.

I. BACKGROUND AND QUALIFICATIONS

I am an economist and decision analyst who has specialized for the past thirty years in environmental risk assessment, cost and economic impact assessment, and integrated assessment to support environmental policy decisions. In my career, I have worked for government and private sector clients on a global basis. From 1977 to 1979, I served as an economist in the Office of Policy Planning and Evaluation of the U.S. Environmental Protection Agency ("U.S. EPA"). From 1979 through 1985, I consulted on risk assessment and risk management for environmental policy to the U.S. EPA, to governments in Europe, and on United Nations expert committees convened in Geneva, Rome, and Thailand. From 1985 through 1998, I was employed by Decision Focus International (later named Talus Solutions, Incorporated), which was a risk analysis consulting firm that had substantial practices supporting electric utility operating and business decisions, and supporting policy assessment for the U.S. EPA. From 1988 to 1990, I advised the Director of the National Acid Precipitation Assessment Program ("NAPAP") on integrated assessment of the costs and benefits of policies to control SO_2 and NO_X. Since 1998, I have been a Vice President of CRA International, a global economics consulting firm with a substantial practice on issues related to energy and the environment.

I have also served as a member of several committees of the National Academy of Sciences focusing on risk assessment and risk-based decision making. I have testified several times before committees of the U.S. Senate on risks from fine particulate matter, on costs and benefits associated with regional haze policies, and on costs of climate change policies.

I have been analyzing multi-pollutant policies for the U.S. utility sector, including mercury, SO_2, NO_X, and other emissions limitations, for the past six years. Under funding from the Edison Electric Institute, and with technical support on data from the Electric Power Institute ("EPRI"), I led a team that developed the leading alternative model to the IPM model that U.S. EPA uses for all of its electric-sector multi-pollutant policy modeling. I supported the utility industry in assessing impacts of alternative mercury MACT controls under Section 112 of the Clean Air Act, and I also prepared an expert report on the costs and effectiveness of the proposed Clean Air Mercury Rule ("CAMR") that was used in comments submitted by EPRI on the proposed CAMR rule, and later also on the Notice of Data Availability ("NODA") regarding the proposed CAMR. My projections of speciated mercury emissions were used as a key input to the mercury deposition modeling that EPRI has also documented in comments on the proposed CAMR rule, in response to the mercury NODA, and in comments on the reconsideration of the CAMR rule. I also developed a cost-effectiveness framework for evaluating mercury control policies that was published as an EPRI report in 2003. The latter study demonstrated how to integrate projections of cost, deposition, exposure, and health risks for alterative mercury control approaches.

I received my Ph.D. (1984) in economics with a Ph.D. minor in engineering-economic systems from Stanford University. My M.A. (1981) in economics was also from Stanford University. I received my B.A. (1977) in economics from Duke University, *summa cum laude*. A copy of my curriculum vitae with my major publications is attached.

II. ANALYSIS OF ELECTRICITY MARKET OPERATIONS

A. Overview

I have performed two simulations of the U.S. electricity market using a model that is described below. The first simulation is one in which the Clean Air Interstate Rule ("CAIR"), the Clean Air Visibility Rule ("CAVR"), and CAMR are applicable throughout the United States, including Illinois. I will call this the "CAIR/CAMR" scenario. The second simulation also includes CAIR, CAVR, and CAMR, but Illinois' proposed mercury rule replaces the CAMR for units in Illinois. I will call this the "IL Rule."[2]

The results of my simulations include speciated mercury emissions for each coal-fired plant stack in the continental United States. I have provided these speciated mercury emissions to Mr. Krish Vijayaraghavan of AER, Incorporated. Other results include annual generation and coal choices for Illinois coal-fired generators and allowance prices for SO_2, NO_X and mercury for both the CAIR and CAMR policies. I have provided these results to Mr. James Marchetti.

B. CRA's North American Electricity and Environment Model

My simulations have been conducted using CRA's North American Electricity and Environment Model ("NEEM"). NEEM is a linear programming model that simulates a competitive electricity market for the continental United States by minimizing the present value of incremental costs to the electric sector while meeting electricity demand and complying with relevant environmental limits. NEEM was designed specifically to be able to simultaneously model least-cost compliance with all state, regional and national, seasonal and annual emissions caps for SO_2, NO_X and Hg. The least-cost outcome is the expected result in a competitive wholesale electricity market.

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[2] This case starts with the CAIR/CAMR case and removes Illinois coal generators from CAMR. The CAMR cap applied to the remaining states is reduced by the amount of Illinois' allocations in 2010 and 2018, respectively. Each Illinois coal unit in excess of 25 MW is then required to meet the 0.008 lbs/GWh mercury constraint, or 90% removal constraint starting in 2009. The IL Rule case does not address the proposed TTBS.

NEEM is a process-based model of U.S. electricity markets and portions of the Canadian system. U.S. electricity markets are divided into 24 individual demand regions (based on NERC sub-regions) and interconnected by limited transmission capabilities (also based on NERC data). Coal units in particular are represented in detail as these are most affected by environmental regulation. All coal units greater than 200 MW in size are individually represented in the simulation.[3] All non-coal generating units in the United States are also represented in the model with some level of unit aggregation. Units are dispatched to load duration curves within each region. There are 20 load segments spread over three different seasons.

NEEM produces forecasts of short-term and long-term decisions such as coal choices, investments in pollution control equipment, new capacity additions, unit utilization, unit retirements, and unit emissions. NEEM also produces associated projections of wholesale electricity prices by region, capacity values, and allowance prices for emissions that are subject to a cap.

CRA International has used NEEM extensively to assess electric sector responses to many different types of national, regional and state environmental policies in analyses for EPRI, the Edison Electric Institute, the National Rural Electric Cooperatives Association, and for a number of individual utilities and other companies. NEEM has also been licensed to clients for their in-house modeling purposes.

NEEM is a similar model to the IPM model that is used extensively by the U.S. EPA, and also has been used by the IEPA in this proceeding. Both models are dynamic, linear programming models of the U.S. electricity sector. The models both minimize the present value of incremental costs subject to a set of operational constraints. The primary difference between NEEM and IPM is in the exogenous assumptions used in the respective models, such as cost and effectiveness of control technologies, fuel prices, and future electricity demand levels.

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[3] For this analysis, even the smallest coal units in Illinois were individually represented in NEEM to provide greater accuracy.

This type of model is particularly well suited to evaluate environmental policies that affect the electric sector, as it has a long-term focus necessary to assess major capital investments like retrofit decisions and a national scope necessary to simulate emissions markets that affect compliance planning. This type of model is usually used to compare between alternative scenarios, thus providing a "controlled experiment" regarding the relative impacts of two possible future policy paths. This comparative format is useful because it mitigates much of the uncertainty that is associated with any single projection. The appropriateness of this type of model is reflected in the fact that it has been used to evaluate every major electricity sector emissions policy in the last twenty years. The extensive use of these models has also made them well understood in the modeling community, and implies that their internal computations have withstood repeated scrutiny and critique. The primary concern when evaluating new simulations from NEEM or IPM should be focused on the quality of their input assumptions.

C. Key Modeling Assumptions

As discussed above, the NEEM model is a national model of the electricity sector. From the model outputs, I have provided national emissions results to Mr. Vijayaraghavan. I have provided unit-specific results for Illinois units to Mr. Marchetti, along with national emissions allowance prices. The results provided to Mr. Vijayaraghavan and Mr. Marchetti are from the same model runs and, therefore, are mutually consistent with each other.

I provided speciated mercury emissions outputs to Mr. Vijayaraghavan for coal-fired units for the entire continental U.S. However, as the focus of the impacts is on Illinois, I summarize my assumptions for the Illinois coal units in detail here.

I began by defining the relevant set of Illinois coal plants and their existing equipment. This starting point determines the need for future controls to comply with the more stringent requirements of the CAIR, CAMR and the Illinois' proposed mercury rule. Table 1 includes the 22 coal plants in Illinois that would be subject to the proposed mercury rule. There are 51 operating coal units at these plants that account for 15 GW of capacity.[4]

Table 1: Coal Plants in Illinois

Plant Name	# of Units	MW	Existing Equipment
Baldwin	3	1,751	SCR (1,2), CSESP (1,2,3)
Coffeen	2	900	SCR (1,2), CSESP (1,2)
Crawford	2	532	CSESP (1,2)
Dallman	3	365	Wet FGD/SCR/CSESP (1,2,3)
Duck Creek	1	366	Wet FGD/SCR/Fabric Filter
E.D. Edwards	3	740	SCR (3), CSESP (1,2,3)
Fisk	1	326	CSESP
Havana	1	428	SCR, HSESP
Hennepin	2	289	CSESP (1,2)
Hutsonville	2	153	CSESP (1,2)
Joliet 29	2	1,036	CSESP (1,2)
Joliet 9	1	314	CSESP
Joppa	6	1,020	CSESP (1-6)
Kincaid	2	1,158	SCR (1,2), CSESP (1,2)
Marion	2	272	Wet FGD/SCR (1), CFB (2)
Meredosia	3	339	CSESP (1,2,3)
Newton	2	1,110	CSESP (1,2)
Powerton	2	1,538	CSESP (1,2)
Vermilion	2	176	CSESP (1,2)
Waukegan	3	789	HSESP (1), CSESP (2,3)
Will County	4	1,060	HSESP (1), CSESP (2,3,4)
Wood River	2	468	CSESP (1,2)

I have relied upon information provided by Mr. Ed Cichanowicz (and included as Appendix C to Mr. Marchetti's testimony) for the costs and characteristics of mercury controls in my analysis. Available mercury-specific controls include activated carbon injection ("ACI"), halogenated activated carbon injection ("HACI"), and ACI plus Fabric Filter. Some mercury is also removed by existing particulate control equipment, and mercury removal can be further enhanced by wet or dry scrubbers ("wet FGD" and "dry FGD," respectively) and selective catalytic reduction ("SCR"). These reductions, sometimes called "co-benefits" vary by type of plant and coal rank. I have also relied

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[4] This table does not include the two CWLP units at Lakeside as these are slated to retire prior to needing to install controls to comply with the proposed mercury rule.

upon Mr. Cichanowicz for the mercury emission modification factors ("EMFs") that reflect these co-benefits.

Mr. Vijayaraghavan's mercury deposition analysis requires that mercury emissions be speciated between elemental mercury and divalent mercury.[5] The speciation of the mercury that is emitted is a function of the rank of coal and the equipment configuration of the coal unit. Table 2 reports the percentage of mercury that I assumed to be emitted as elemental mercury for each equipment configuration and coal rank; the remainder is emitted as divalent mercury. EPRI developed the values in Table 2 based on data from EPA's 1999 Information Collection Request[6] ("ICR"), and adjusted by EPRI researchers based on post-ICR field experience. These values are documented in EPRI's formal written comments to U.S. EPA on the proposed CAMR rule.[7]

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[5] Particulate mercury is considered *de minimis* and is not provided to AER. It is my understanding that Mr. Vijayaraghavan has apportioned a small fraction of the divalent mercury emissions as particulate mercury.

[6] See http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html for details.

[7] Part of Docket No. OAR-2002-0056 and available at http://epa.gov/mercury/pdfs/OAR-2002-0056-2578.pdf.

Table 2: Speciation of Mercury Emissions (% Elemental)

Equipment	Bituminous	Subbituminous	Lignite
FF/Dry FGD	70%	90%	95%
FF/Dry FGD/SCR	30%	90%	95%
FF/Wet FGD	45%	85%	85%
FF/Wet FGD/SCR	40%	85%	85%
FF	5%	30%	30%
FF/SCR	5%	30%	30%
CSESP/Dry FGD	90%	95%	95%
CSESP/Dry FGD/SCR	60%	95%	95%
CSESP/Wet FGD	85%	90%	90%
CSESP/Wet FGD/SCR	60%	90%	90%
CSESP	35%	60%	55%
CSESP/SCR	10%	60%	55%
HSESP/Dry FGD	40%	80%	80%
HSESP/Dry FGD/SCR	40%	80%	80%
HSESP/Wet FGD	80%	98%	95%
HSESP/Wet FGD/SCR	60%	98%	95%
HSESP	40%	70%	70%
HSESP/SCR	10%	70%	70%
New Coal Units	40%	85%	85%
FF = Fabric Filter; FGD = Flue Gas Desulfurization; SCR = Selective Catalytic Reduction; CSESP = Cold-Side ESP; HSESP = Hot-Side ESP			

The characteristics of the coals burned by Illinois generators are another important input to NEEM. The majority of Illinois generators are currently burning Powder River Basin (“PRB”) coal, which is subbituminous coal from Wyoming that has relatively low sulfur content. Some Illinois generators burn Illinois Basin coals that are mined in Illinois, Indiana and Kentucky which is a bituminous coal. Table 3 shows the characteristics of these coals assumed in NEEM, which are based on ICR data reported to the U.S. EPA.

Table 3: Characteristics of Coals Burned by Illinois Generators

Coal Description	Heating Value (Btu/lb)	SO_2 Content (lbs/MMBtu)	Hg Content (lbs/TBtu)
Illinois Basin – High Sulfur	11,395	5.20	6.44
Illinois Basin – Medium Sulfur	11,395	2.80	6.44
Illinois Basin – Low Sulfur	11,395	1.70	6.44
PRB – North	8,380	0.89	7.08
PRB – Central	8,562	0.75	5.42
PRB - South	8,854	0.65	5.76

D. Emissions Results Provided to Mr. Vijayaraghavan

I have provided to Mr. Vijayaraghavan speciated mercury for each power plant stack that emits Hg from coal-fired generating units. I provided this information for the CAIR/CAMR case for 2006, 2010 and 2020 and for the IL Rule for 2010. Summary state-level speciated emissions for these scenarios are included in Table 3, Table 4, Table 5 and Table 6, respectively.

Table 3: CAIR/CAMR 2006 Mercury Emissions from Coal-Fired Units (Pounds)

State	Elemental	Divalent	Total
AL	1,899	2,239	4,138
AR	915	591	1,506
AZ	1,184	167	1,351
CA	28	23	51
CO	747	437	1,183
CT	51	94	145
DE	182	318	500
FL	2,124	1,127	3,251
GA	1,810	2,704	4,514
IA	1,238	743	1,980
IL	3,052	2,202	5,254
IN	2,091	2,364	4,455
KS	1,626	402	2,028
KY	1,480	1,407	2,887
LA	807	545	1,353
MA	104	343	447
MD	548	1,482	2,031
MI	1,688	1,622	3,310
MN	1,174	437	1,611
MO	2,528	1,579	4,107
MS	295	316	611
MT	1,026	104	1,130
NC	1,125	3,520	4,644
ND	1,787	524	2,311
NE	699	472	1,170
NH	33	119	151
NJ	135	463	597
NM	669	95	763
NV	144	72	216
NY	599	1,024	1,622
OH	1,892	4,337	6,229
OK	1,307	802	2,109
OR	89	73	161
PA	2,320	4,436	6,757
SC	438	1,208	1,646
SD	70	46	116
TN	1,121	1,031	2,152
TX	5,044	2,469	7,513
UT	597	167	764
VA	748	1,216	1,964
WA	524	58	582
WI	858	543	1,401
WV	1,195	2,952	4,147
WY	2,156	482	2,638
Total	50,144	47,351	97,495

Table 4: CAIR/CAMR 2010 Mercury Emissions from Coal-Fired Units (Pounds)

State	Elemental	Divalent	Total
AL	2,050	1,637	3,686
AR	794	476	1,269
AZ	1,187	167	1,354
CA	28	23	51
CO	742	417	1,159
CT	51	94	145
DE	137	205	342
FL	691	545	1,236
GA	2,351	2,010	4,361
IA	1,167	687	1,853
IL	2,766	1,707	4,472
IN	2,006	1,603	3,609
KS	1,070	340	1,410
KY	1,489	1,091	2,580
LA	894	557	1,451
MA	104	343	447
MD	386	821	1,207
MI	1,811	1,703	3,514
MN	864	229	1,093
MO	1,801	1,015	2,815
MS	295	298	593
MT	848	119	968
NC	1,566	1,212	2,778
ND	1,150	419	1,569
NE	533	360	894
NH	33	119	151
NJ	126	344	470
NM	671	95	766
NV	146	72	217
NY	371	639	1,009
OH	1,606	2,071	3,677
OK	1,121	640	1,761
OR	90	73	162
PA	1,663	2,108	3,771
SC	583	719	1,303
SD	114	75	190
TN	1,283	850	2,133
TX	5,331	1,587	6,918
UT	604	167	771
VA	633	804	1,436
WA	403	45	448
WI	1,105	472	1,577
WV	1,016	1,208	2,223
WY	1,799	375	2,174
Total	45,477	30,537	76,013

Table 5: CAIR/CAMR 2020 Mercury Emissions from Coal-Fired Units (Pounds)

State	Elemental	Divalent	Total
AL	1,011	491	1,502
AR	990	135	1,125
AZ	908	130	1,038
CA	42	28	70
CO	760	353	1,113
CT	29	53	82
DE	98	81	179
FL	632	228	860
GA	852	432	1,284
IA	432	248	680
IL	943	415	1,358
IN	704	469	1,173
KS	338	110	448
KY	778	522	1,301
LA	200	42	242
MA	75	193	268
MD	310	242	552
MI	486	338	824
MN	304	100	405
MO	944	416	1,360
MS	183	31	215
MT	300	93	393
NC	1,256	578	1,834
ND	630	120	749
NE	605	249	854
NH	42	57	99
NJ	117	81	198
NM	436	82	518
NV	84	63	146
NY	163	199	362
OH	792	562	1,355
OK	985	192	1,178
OR	23	18	41
PA	1,073	739	1,811
SC	512	311	823
SD	119	13	132
TN	936	609	1,545
TX	2,391	502	2,893
UT	401	98	499
VA	473	317	790
WA	103	11	114
WI	578	129	707
WV	629	415	1,044
WY	653	240	893
Total	24,321	10,736	35,057

Table 6: IL Rule 2010 Mercury Emissions from Coal-Fired Units (Pounds)

State	Elemental	Divalent	Total
AL	2,050	1,634	3,684
AR	801	478	1,279
AZ	1,187	167	1,354
CA	28	23	51
CO	743	418	1,161
CT	51	94	145
DE	137	205	342
FL	708	527	1,235
GA	2,408	1,984	4,391
IA	1,177	691	1,868
IL	528	327	855
IN	2,008	1,614	3,622
KS	1,062	329	1,391
KY	1,499	1,105	2,604
LA	896	555	1,451
MA	104	343	447
MD	381	1,003	1,384
MI	1,819	1,717	3,536
MN	971	281	1,252
MO	1,938	1,108	3,046
MS	309	310	619
MT	849	120	968
NC	1,573	1,220	2,794
ND	1,150	419	1,569
NE	535	361	896
NH	33	119	151
NJ	126	344	470
NM	671	95	766
NV	146	72	217
NY	371	639	1,009
OH	1,632	2,096	3,728
OK	1,138	643	1,780
OR	90	73	162
PA	1,701	2,110	3,811
SC	710	741	1,451
SD	114	75	190
TN	1,279	850	2,129
TX	5,473	1,681	7,154
UT	604	167	772
VA	635	808	1,443
WA	403	45	448
WI	1,139	496	1,635
WV	1,017	1,210	2,226
WY	1,800	376	2,176
Total	43,992	29,669	73,661

E. Results Provided to Mr. Marchetti

For each scenario, I have provided annual generation levels for Illinois generating units to Mr. Marchetti. I have also provided coal consumption and delivered coal prices, SO_2 and NO_X allowance prices, and delivered natural gas prices. All of these data, with the exception of natural gas prices, are direct outputs from the NEEM simulations of CAIR/CAMR and the IL Rule. Natural gas prices are an input to NEEM based on historical basis differentials, Henry Hub futures prices from the New York Mercantile Exchange ("NYMEX") and the Energy Information Administration's Annual Energy Outlook 2006 wellhead natural gas price projections.

Coal prices are determined based on national demand for coal and coal supply curves that CRA has prepared based on industry data. Because the coal prices are based upon national demand for coal, changes in Illinois demand have little impact and the coal prices in the two scenarios (CAIR/CAMR and the IL Rule) are nearly identical.

Table 9 presents the SO_2 and NO_X allowance prices for each scenario.

Table 7: Summary Generation from Illinois Coal Plants (GWh)

Policy	2006	2008	2009	2010	2013	2015	2018
CAIR/CAMR	107,609	107,164	107,819	109,862	122,430	122,730	122,343
IL Rule	107,592	107,169	102,516	105,073	120,647	122,073	121,759

** Generation figures in both policies include approximately 16,000 GWh from new coal-fired generators starting in 2013*

Table 8: Coal Consumption by Illinois Coal Plants (TBtu)

Coal Type	2006	2008	2009	2010	2013	2015	2018
CAIR/CAMR							
Illinois Basin	141	122	130	118	376	259	257
PRB	903	914	916	965	804	968	965
Other	40	42	42	29	40	2	2
TOTAL	1,084	1,078	1,088	1,112	1,220	1,229	1,224
IL Rule							
Illinois Basin	141	122	214	228	385	365	363
PRB	902	913	769	819	780	835	833
Other	41	43	51	16	38	20	20
TOTAL	1,084	1,078	1,034	1,063	1,203	1,220	1,217

Table 9: Allowance Prices Projected in NEEM Scenarios (2003$)

Allowance Type	2006	2008	2009	2010	2013	2015	2018
CAIR/CAMR							
NO_X annual ($/ton)			1833	1962	1,698	1,944	2,381
NO_X SIP Call ($/ton)	500	500					
SO_2($/allowance)	1,308	617	661	353	433	347	425
Mercury ($/lb)				29,815	31,065	35,565	43,570
IL Rule							
NO_X annual ($/ton)			1,823	1,951	1,683	1,926	2,360
NO_X SIP Call ($/ton)	500	500					
SO_2($/allowance)	1,313	611	653	350	428	343	420
Mercury ($/lb)				29,610	31,535	36,105	44,230

CERTIFICATE OF SERVICE

I, the undersigned, certify that on this 28th day of July, 2006, I have served electronically the attached **Testimony** of **Peter M. Chapman, Ph.D.; Gail Charnley, Ph.D., and Attached Exhibits; J.E. Cichanowicz; William DePriest and Attached Exhibits; James Marchetti; Richard D. McRanie; Ishwar Prasad Murarka, Ph.D.;** and **Krish Vijayaraghavan**., upon the following persons:

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