BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

DYNEGY MIDWEST GENERATION, INC.,	)	
	)	
Petitioner,	)	
	)	
v.	)	**PCB 09-_____**
	)	**Variance – Air**
ILLINOIS ENVIRONMENTAL PROTECTION Agency,	)	
	)	
	)	

NOTICE OF FILING

To:

John Therriault, Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
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100 West Randolph
Chicago, Illinois 60601

Illinois Environmental Protection Agency
Division of Legal Counsel
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Springfield, Illinois 62794-9276

PLEASE TAKE NOTICE that we have today electronically filed with the Office of the Clerk of the Pollution Control Board **PETITION FOR VARIANCE, AFFIDAVIT OF ARIC D. DIERICX,** and **APPEARANCES OF KATHLEEN C. BASSI AND STEPHEN J. BONEBRAKE**, copies of which are herewith served upon you.

Kathleen C. Bassi

Kathleen C. Bassi

Dated: January 9, 2009

Kathleen C. Bassi
Stephen J. Bonebrake
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BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

DYNEGY MIDWEST GENERATION, INC., **Petitioner,** **v.** **ILLINOIS ENVIRONMENTAL PROTECTION AGENCY,**	)))))))))	**PCB 09-_____** **Variance – Air**

APPEARANCE

I, KATHLEEN C. BASSI, hereby file my appearance in this proceeding on behalf of Petitioner, DYNEGY MIDWEST GENERATION, INC.

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ILLINOIS ENVIRONMENTAL PROTECTION Agency,	)	
	)	
	)	

APPEARANCE

I, STEPHEN J. BONEBRAKE, hereby file my appearance in this proceeding on behalf of Petitioner, DYNEGY MIDWEST GENERATION, INC.

Stephen J. Bonebrake
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BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

DYNEGY MIDWEST GENERATION, INC.,	)	
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	)	**Variance – Air**
ILLINOIS ENVIRONMENTAL PROTECTION Agency,	)	
	)	
	)	
Respondent.	)	

PETITION FOR VARIANCE

NOW COMES Petitioner, DYNEGY MIDWEST GENERATION, INC. ("Petitioner" or "DMG"), by and through its attorneys, SCHIFF HARDIN, LLP, and, pursuant to Sections 35 and 37 of the Environmental Protection Act ("Act"), 415 ILCS 5/35, 37, and 35 Ill.Adm.Code Part 104, Subpart B, respectfully requests that the Board grant the Petitioner a variance from certain provisions of the Illinois Multi-Pollutant Standard ("MPS"), 35 Ill.Adm.Code § 225.233, as applied to Unit 3 at the Baldwin Energy Complex for the limited period beginning July 1, 2009, and ending March 31, 2010. Specifically, DMG seeks a variance at Baldwin Unit 3 from the MPS requirement in Sections 225.233(c)(1)(A) and 225.233(c)(2) to inject, beginning July 1, 2009, halogenated activated carbon[1] at a minimum injection rate of 5.0 pounds per million actual cubic feet ("lbs/macf") exhaust gas flow and from related monitoring, recordkeeping, and reporting provisions at Sections 225.210(b) and (d) and

[1] Note: "halogenated activated carbon" and "sorbent" are used interchangeably in this Petition.

225.233(c)(5). DMG will suffer arbitrary or unreasonable hardship if the Board does not grant this requested variance. In support of its Petition, DMG states as follows:

A. DMG GENERATES ELECTRICITY IN ILLINOIS AT FIVE COAL-FIRED POWER STATIONS.

1. DMG owns and operates five coal-fired electricity generating power plants in located in downstate Illinois. The Baldwin Energy Complex ("Baldwin"), whose Unit 3 is the subject this variance request, is located in Randolph County. The two other coal-fired power plants affected by DMG's proposed conditions to this requested variance are the Havana Power Station ("Havana") located in Mason County and the Hennepin Power Station ("Hennepin") located in Putnam County. DMG's other two coal-fired power plants are the Vermilion Power Station located in Vermilion County, and the Wood River Power Station located in Madison County. A map depicting the location of each of DMG's coal-fired power plants is provided in Exhibit 1. The addresses of the five power stations, their identification numbers assigned by the Illinois Environmental Protection Agency ("Agency"), age, permit application numbers, and other pertinent information regarding their output, pollution control equipment, and mercury emissions are provided in Exhibit 2. DMG employs approximately 588 persons at these five power stations, of whom approximately 175 are employed at Baldwin.

2. The air monitoring stations maintained by the Agency that are nearest to Baldwin, as well as Havana and Hennepin, are identified in Exhibit 1.[2] Randolph County, the location of Baldwin, is designated nonattainment for PM2.5 and attainment

[2] Exhibit 1 identifies the locations of all five of DMG's coal-fired power plants, including Baldwin, Havana and Hennepin, on a copy of the map from the Agency's *Illinois Annual Air Quality Report 2006* (at p. 34), which identifies the locations of the Agency's air quality monitoring stations.

(or unclassifiable/attainment) for all other criteria pollutants. Mason and Putnam Counties, the respective locations of Havana and Hennepin, are designated attainment (or unclassifiable/attainment) for all criteria pollutants. *See* 40 CFR § 81.314; USEPA's Green Book (list of national attainment and nonattainment designations) at http://www.epa.gov/oar/oaqps/greenbk/.

3. The principal emissions at DMG's coal-fired power plants are sulfur dioxide ("SO_2"), nitrogen oxides ("NOx"), and particulate matter ("PM"). As relevant to this Petition, coal-fired power plants also emit mercury. SO_2 is currently generally controlled through the use of low sulfur coal. Additionally, DMG has construction permits for and is constructing spray dryer absorbers (*i.e.*, dry scrubbers) with fabric filter (*i.e.*, baghouse) systems on all three Baldwin units, as well as on Havana Unit 6, and DMG is installing a fabric filter on Hennepin Unit 2. All of these dry scrubbers are scheduled to be placed into service by December 31, 2012. In fact, the Baldwin Unit 3 outage scheduled to begin in March 2010 will be used to install its dry scrubber and fabric filter. DMG did not defer its plans to install dry scrubbers in light of the remand of the federal Clean Air Interstate Rule ("CAIR") in *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008).[3] When placed into service, these dry scrubbers will significantly reduce DMG's system-wide[4] SO_2 emission rate. NOx emissions are generally controlled by various combinations of low sulfur coal, low NOx burners, over-fire air, and selective

[3] As of the date of submittal of this Petition for Variance to the Board, the court in *North Carolina* has remanded the CAIR to the U.S. Environmental Protection Agency ("USEPA") without vacatur. *See North Carolina v. EPA*, No. 05-1244 ((D.C. Cir. Dec. 23, 2008) (Order remanding rule without vacatur).

[4] "System-wide" refers only to DMG's coal-fired units subject to the Illinois mercury rule, 35 Ill.Adm.Code Part 225.Subpart B.

catalytic reduction systems ("SCRs"). PM is generally controlled through the use of flue gas conditioning, electrostatic precipitators ("ESPs"), and fabric filter systems. In accordance with the provisions of the MPS established in the Illinois mercury rule, DMG will control mercury emissions by injection of halogenated activated carbon in conjunction with SCRs, dry scrubbers, ESPs, and fabric filters.

4. DMG has never previously sought or obtained a variance from the Board. To the best of DMG's knowledge, a prior owner of Baldwin once before obtained a Board variance for Baldwin on an unrelated matter (*i.e.*, PCB 1999-0002, granting a 45-day provisional variance from conditions and effluent discharge limits in 35 Ill.Adm.Code §§ 304.120 and 304.141(b) in July 1998) but not concerning similar relief.

B. DMG SUPPORTED THE MPS IN 2006 TO COORDINATE MERCURY EMISSION CONTROLS WITH OTHER EMISSION CONTROL REQUIREMENTS.

5. In May 2005, USEPA promulgated the Clean Air Mercury Rule ("CAMR"), 70 Fed. Reg. 28606 (May 18, 2005), to reduce mercury emissions from coal-fired electric generating units ("EGUs") in the lower 48 states. The federal CAMR, which applied to EGUs with nameplate capacities greater than 25 megawatts, established caps on the mercury emissions for each affected state and allowed states to participate in USEPA-administered emissions trading programs if their state programs met certain minimum requirements. DMG's coal-fired power plants are EGUs that were subject to the federal CAMR.

6. In December 2006, the Board adopted the Illinois mercury rule at R06-25 to satisfy the federal CAMR requirements in Illinois. The rule adopted by the Board differs significantly from the federal CAMR in a very important way: the Illinois

mercury rule adopts a command-and-control approach that requires affected coal-fired power plants to achieve a 90% reduction from input mercury or an emission rate of 0.0080 lb mercury/GWh gross electrical output[5] and rejects participation in the federal mercury emissions trading program.[6]

7. In 2006, when the Agency was developing its mercury rule, DMG was also simultaneously faced with developing a compliance strategy to meet future emission reduction requirements under both the Illinois CAIR and the Consent Decree DMG had entered with, among others, the federal government.[7] The CAIR establishes a state-wide cap on SO_2 and NOx emissions from EGUs that must be implemented through emission reductions and/or emissions allowance trading. In general, the Consent Decree requires DMG to reduce SO_2, NOx, and PM emissions at its five coal-fired power plants and mercury at the Vermilion Power Station through a combination of enforceable emission limits, installation of mandatory pollution control and monitoring technology, and SO_2 and NOx allowance restrictions, with full compliance to be achieved by the end of 2012.

8. DMG evaluated its environmental compliance strategy in light of the available pollution control technologies, including use of potential co-benefit emission control technologies that reduce not only mercury but also NOx and/or SO_2. DMG

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[5] Hereinafter, this Petition refers only to the 90% reduction compliance option for the sake of simplicity.

[6] The CAMR was vacated by *State of New Jersey v. Environmental Protection Agency*, 517 F.3d 574 (D.C. Cir. 2008), *pet. for cert. filed*, 77 U.S.L.W. 3253 (U.S. Oct. 17, 2008) (No. 08-512).

[7] *United States, et al. v. Illinois Power Co., et al.*, No. 99-CV-833-MJR (S.D. Ill.) (Consent Decree entered May 27, 2005) (a copy of the Consent Decree as originally entered is available at < www.epa.gov/compliance/resources/cases/civil/caa/illinoispower.html > under the link "Consent Decree."

determined that the best approach to implementing reasonable and effective air emissions reductions from its coal-fired power plants was for the Agency to adopt a comprehensive approach that would address mercury emissions in coordination with other air emission reduction requirements. While recognizing that the injection of halogenated activated carbon can reduce mercury emissions, DMG did not believe that considerably high levels of mercury removal at all units could be achieved in the short run or that the reductions could be measured with sufficient accuracy to assure compliance with the Illinois mercury emission limits.

9. DMG determined that compliance with its Consent Decree, the Illinois CAIR and the Illinois mercury rule could require the installation of various combinations of pollution control equipment. The pollution control equipment necessary for DMG to meet its NOx limits (*i.e.*, SCRs) and SO_2 limits (*i.e.*, dry scrubbers) for the CAIR, as well as fabric filters for PM control under the Consent Decree, also enhance a source's ability to reduce mercury emissions and, therefore, enhance DMG's ability to ensure compliance with Illinois' mercury emissions limits. These same combinations of control technologies were necessary for DMG to comply with the Consent Decree, the CAIR, and the Illinois mercury rule; however, all of the pollution control equipment could not be installed by the earliest compliance date, *i.e.*, July 1, 2009, the initial compliance deadline for the Illinois mercury rule. Thus, coordination of these separate regulatory emission reduction requirements was essential.

10. For these reasons, DMG (and other electricity generators in Illinois) worked with the Agency on a proposal to coordinate the intertwined mercury, NOx, and SO_2 emissions control planning. That effort resulted in the MPS, which was adopted by

the Board as part of the Illinois mercury rule at Section 225.233. DMG opted in to the MPS on November 26, 2007, *see* Ex. 3.[8]

11. The MPS requires DMG to install and operate halogenated activated carbon injection systems to control mercury emissions but extends the deadline to demonstrate compliance with the rule's overall 90% mercury reduction requirement until 2015. Prior to 2015 DMG units are subject to the sorbent injection rate requirements. The MPS also establishes strict, declining emissions limits for NOx and SO_2 over a period of time, including a system-wide SO_2 limit of 0.24 lb/mmBtu in 2013, declining to a rate of 0.19 lb/mmBtu in 2015, and precludes trading of any excess NOx and SO_2 allowances that may be generated by the pollution control equipment necessary to meet the applicable emissions limitations. As a result, because the MPS and the Consent Decree each restrict the emissions trading otherwise available under the CAIR, DMG must install and operate pollution control equipment and cannot rely on allowance purchases as a compliance strategy or compliance timing tool.

12. In order for it to meet the emission reduction requirements of the MPS and the Consent Decree, DMG must plan for and finance the purchase of the necessary pollution control equipment. Since the MPS and Consent Decree require compliance with specified emissions rates, DMG does not have the flexibility available to other companies to delay this equipment planning and financing through purchases of allowances to satisfy its compliance obligations until the financial, labor, and equipment markets are more advantageous. The procurement process for SO_2, PM, and mercury

[8] DMG's MPS Group includes each of the 10 individual coal-fired units located at its five power stations, as required to be included in a single MPS group by Section 225.233(a)(2).

pollution control devices – each of which alone involves significant equipment and engineering – is approximately three to five years. For example, in order for Baldwin Unit 3 to comply with its SO_2 emission rate requirements by the end of 2010, DMG commenced its procurement process in 2007. The estimated time for actual construction, tie-in, commissioning, startup, and testing of a dry scrubber is approximately three years. From engineering concept to online operation, including permitting, the period is approximately four and one-half years.

13. DMG has estimated that its capital costs of compliance with the Illinois mercury rule (including the MPS) and its Consent Decree would be a total of $973 million by 2013. These estimates may change depending on additional federal or state requirements (including any related to the CAIR remand), the ultimate outcome of any appeals relative to the CAMR vacatur, new technology, or variations in costs of material or labor, among other reasons.

14. Given the large capital and operations and maintenance ("O&M") projects involved in pollution control decisions at each of its five coal-fired power plants, DMG must proceed cautiously to maintain its financial resources and operational flexibility, as well as the integrity of the electricity generation system that supports Illinois' economy. DMG continues to evaluate compliance strategies at each of its coal-fired power plants to identify the optimal locations for investments and expenditures consistent with the goal of maintaining operational flexibility within a competitive energy market.

C. DMG REQUIRES TEMPORARY RELIEF FROM SECTIONS 225.233(c)(1)(A), SECTION 225.233(c)(2), 225.210(b), 225.210(d) AND 225.233(c)(5) AT BALDWIN UNIT 3 TO AVOID WASTING LIMITED RESOURCES AND TO PROVIDE OPERATING FLEXIBILITY IN CONJUNCTION WITH ITS OTHER ENVIRONMENTAL OBLIGATIONS.

15. DMG seeks this variance because making capital and operating expenditures to install and operate a halogenated activated carbon injection system on Baldwin Unit 3 that will need to be removed and re-located nine months after July 1, 2009, upon installation of the dry scrubber and fabric filter systems on Baldwin Unit 3 is not financially prudent, would divert capital and operating expenditures that could be otherwise better spent, and will result in adverse environmental effects. DMG faces arbitrary and unreasonable hardship if it is not granted the variance and allowed to make responsible operating decisions regarding the best combinations of actions to address the myriad compliance requirements of the MPS and Consent Decree.

16. Specifically, DMG seeks relief from the requirement in Sections 225.233(c)(1)(A) and 225.233(c)(2) that it inject halogenated activated carbon in Baldwin Unit 3 beginning July 1, 2009, at a rate of 5.0 lbs/macf exhaust gas and from the related monitoring, recordkeeping, and reporting provisions of Sections 225.210(b) and (d) and 225.233(c)(5). Sections 225.233(c)(1)(A) and 225.233(c)(2) of the MPS provide, in relevant part:[9]

c) Control Technology Requirements for Emissions of Mercury.

1) Requirements for EGUs in an MPS Group.

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[9] Excluding amendments currently proposed in Docket R09-10 to add sorbent manufacturers to the approved list; DMG would expect to be able to use the additional sorbent manufacturers if the Board adopts those amendments.

A) For each EGU in an MPS Group other than an EGU that is addressed by subsection (c)(1)(B) of this Section for the period beginning July 1, 2009 . . . and ending December 31, 2014 . . . , the owner or operator of the EGU must install, to the extent not already installed, and properly operate and maintain one of the following emission control devices:

i) A Halogenated Activated Carbon Injection System, complying with the sorbent injection requirements of subsection (2) of this Section . . . ;

* * *

2) For each EGU for which injection of halogenated activated carbon is required by subsection (c)(1) of this Section, the owner or operator of the EGU must inject halogenated activated carbon in an optimum manner, which, except as provided in subsection (c)(4) of this Section, is defined as all of the following:

A) The use of an injection system designed for effective absorption of mercury, considering the configuration of the EGU and its ductwork;

B) The injection of halogenated activated carbon manufactured by Alstom, Norit, or Sorbent Technologies, or the injection of any other halogenated activated carbon or sorbent that the owner or operator of the EGU has demonstrated to have similar or better effectiveness for control of mercury emissions; and

C) The injection of sorbent at the following minimum rates, as applicable:

i) For an EGU firing subbituminous coal, 5.0 lbs per million actual cubic feet or, for any cyclone-fired EGU that will install a scrubber and baghouse by December 31, 2012, and which already meets an emission rate of 0.020 lb mercury/GWh gross electrical output or at least 75 percent reduction of input mercury, 2.5 lbs per million actual cubic feet;

ii) For an EGU firing bituminous coal, 10.0 lbs per million actual cubic feet or for any cyclone-fired EGU that will install a scrubber and baghouse by December 31, 2012, and which already meets an emission rate of 0.020 lb mercury/GWh gross electrical output or at least 75 percent reduction of input mercury, 5.0 lbs per million actual cubic feet;

iii) For an EGU firing a blend of subbituminous and bituminous coal, a rate that is the weighted average of the above rates, based on the blend of coal being fired; or

iv) A rate or rates set lower by the Agency, in writing, than the rate specified in any of subsections (c)(2)(C)(i), (c)(2)(C)(ii), or (c)(2)(C)(iii) of this Section on a unit-specific basis, provided that the owner or operator of the EGU has demonstrated that such rate or rates are needed so that carbon injection will not increase particulate matter emissions or opacity so as to threaten noncompliance with applicable requirements for particulate matter or opacity.

D) For the purposes of subsection (c)(2)(C) of this Section, the flue gas flow rate must be determined for the point of sorbent injection; provided that this flow rate may be assumed to be identical to the stack flow rate if the gas temperatures at the point of injection and the stack are normally within 100° F, or the flue gas flow rate may otherwise be calculated from the stack flow rate, corrected for the difference in gas temperatures.

Sections 225.210(b) and (d) require that the owners or operators of EGUs subject to the mercury rule comply with the monitoring, recordkeeping, and reporting requirements of Sections 225.240 through 225.290. Section 225.233(c)(5) sets forth additional monitoring, recordkeeping, and reporting requirements applicable to EGUs that have opted in to the MPS. Although DMG believes that it would not be subject to these monitoring, recordkeeping, and reporting requirements if it were granted relief from the underlying substantive requirements, nevertheless, DMG is seeking relief from these monitoring, recordkeeping, and reporting requirements to ensure that there are no questions in this regard.

17. In accordance with the MPS, DMG must begin injecting halogenated activated carbon at (i) four of its coal-fired units on July 1, 2009 (Baldwin Units 1-3, Wood River Unit 5), and (ii) five of its units on December 31, 2009 (Havana Unit 6, Hennepin Units 1 and 2, Vermilion Units 1 and 2).[10] DMG has obtained construction permits to install sorbent injection equipment at these nine units. These nine units represent approximately 97% of DMG's installed coal-fired capacity.

18. At the minimum sorbent injection rate specified in the MPS, DMG estimates it would need to inject approximately 20 million pounds of sorbent during each 12-month period. At the MPS' minimum injection rate, over the period July 1, 2009, through December 31, 2014, DMG would inject more than 115 million pounds of sorbent system-wide. With vendor bids for halogenated activated carbon plus delivery currently in excess of $1 per pound, the injection of sorbent will represent a significant operating expense for DMG's MPS units. At the minimum injection rate of the MPS, DMG estimates that sorbent injection at Baldwin Unit 3 alone, from July 1, 2009, through

[10] As required by the Consent Decree, DMG has already installed and is operating a fabric filter system with sorbent injection at its Vermilion Power Station. Wood River Unit 4 is not required to begin injecting sorbent until January 1, 2013.

March 31, 2010, would amount to 4 million pounds of sorbent at an approximate cost of $4 million.[11]

19. Baldwin Unit 3 emissions are currently controlled by a cold-side ESP, which includes SO_3 injection. If subject to the MPS mercury requirements beginning July 1, 2009, DMG would be required to install a sorbent injection system upstream of the cold-side ESP in order for the mercury/halogenated activated carbon residue to be removed from the flue gas prior to being emitted. In its scheduled spring 2010 outage, Baldwin Unit 3 will be retrofitted with a dry scrubber and a new fabric filter system to meet emission reduction requirements under the Illinois CAIR and the Consent Decree. As a result, when Baldwin Unit 3 resumes operation in 2010 after the spring outage, it will be re-configured with a sorbent injection system located downstream of the ESP and upstream of the fabric filter system. This configuration will allow DMG to collect fly ash in the ESP prior to the injection of activated carbon into the flue gas stream, with the activated carbon residue removed in the fabric filter system and subsequently disposed.

20. The installation of sorbent injection lances in the ductwork upstream of the ESP on Baldwin Unit 3 in order to meet the MPS mercury requirements beginning July 1, 2009, would require a multi-day unit outage and result in the loss of operating revenue (*i.e.*, this unplanned outage would not be required if the injection equipment was installed as part of the spring 2010 fabric filter retrofit outage). DMG estimates that it will cost approximately $100,000 to install the injection equipment upstream of the ESP; re-locating it after nine months to a location downstream of the ESP would increase these

[11] Notably, in the economic analysis to support its mercury rule, the Agency estimated the cost of halogenated activated carbon at only 80 cents per pound. R06-25, Tr. at 81 (June 22, 2006).

installation costs accordingly. Injection into the flue gas stream upstream of an ESP provides an opportunity for mercury removal only while the sorbent is suspended in the flue gas stream. In contrast, injection upstream of a fabric filter system provides opportunity for mercury removal while the activated carbon is suspended in the flue gas stream and even greater mercury removal when the sorbent is located on the surface of the bags. The increased contact between the flue gas and mercury particles increases the mercury removal efficiency.

21. An evaluation of DMG's fleet has revealed a viable alternative to the installation and operation of a sorbent injection system on Baldwin Unit 3 prior to the installation of the fabric filter system in spring 2010. Rather than wasting resources at Baldwin Unit 3 by installing a sorbent injection system upstream of the cold-side ESP in order to meet the July 1, 2009, MPS sorbent injection deadline, only to have to remove it within nine months, DMG proposes an alternative that will result in a net environmental benefit.

22. Specifically, instead of injecting sorbent beginning July 1, 2009, at Baldwin Unit 3, DMG proposes to inject sorbent at Havana Unit 6 and Hennepin Unit 2 six months before the MPS deadline applicable to these units. The overall mercury reductions to be achieved by Havana Unit 6 and Hennepin Unit 2 will be largely contemporaneous with the time period sorbent would have been injected into Baldwin Unit 3. In addition, the proposed variance will result in collateral environmental benefits with regard to fly ash re-use and carbon dioxide ("CO_2") emission reductions.

23. Havana Unit 6 and Hennepin Unit 2 will be retrofitted with fabric filter particulate collection systems and sorbent injection systems by July 1, 2009. These two

fabric filter and sorbent injection systems will remove at least as much mercury as sorbent injection upstream of the ESP at Baldwin Unit 3 and are likely to remove more mercury emissions than the cold-side ESP on Baldwin Unit 3, which includes SO_3 injection to aid in particulate collection. *See* Ex. 4. In addition, even at lower injection rates, fabric filter systems are more effective at removing mercury than ESP-controlled units with SO_3 injection, which somewhat inhibits mercury removal. *See* Exs. 5 and 4. The net effect of injecting sorbent upstream of the Havana Unit 6 and Hennepin Unit 2 fabric filter systems will be much more cost-effective mercury removal. Moreover, the combined generating capability of Havana Unit 6 and Hennepin Unit 2 is greater than that of Baldwin Unit 3 (*i.e.*, 645 MW net (aggregate) for Havana Unit 6 and Hennepin Unit 2 compared to 600 MW net for Baldwin Unit 3). Therefore, the fabric filter/sorbent injection systems at Havana Unit 6 and Hennepin Unit 2 could generate even more mercury reductions than the cold-side ESP plus sorbent injection system at Baldwin Unit 3 alone. DMG estimates that mercury reductions at Havana Unit 6 and Hennepin Unit 2 from July 1, 2009, through December 31, 2009, would aggregate up to 19 pounds more mercury reduction than would have been achieved at Baldwin Unit 3 from July 1, 2009, through commencement of the spring 2010 planned outage. *See* Ex. 6. Additionally, relying on Havana Unit 6 and Hennepin Unit 2, rather than Baldwin Unit 3, for mercury reductions would avoid the need for an unplanned forced outage in early 2009 and the cost of relocating the injection system on Baldwin Unit 3. Under the proposed alternative of commencing sorbent injection at Havana Unit 6 and Hennepin Unit 2 on July 1, 2009, these units could inject about 2.5 million fewer pounds of sorbent than at Baldwin Unit 3 from July 1, 2009, through March 31, 2010.

24. To ensure the generation of mercury emission reductions at Havana Unit 6 and Hennepin Unit 2, DMG would begin injecting halogenated activated carbon at Havana Unit 6 and Hennepin Unit 2 six months before the MPS deadline (on July 1, 2009, instead of December 31, 2009) applicable to those units. DMG would inject sorbent at Havana Unit 6 and Hennepin Unit 2 at a rate of 5 lbs/macf unless or until DMG informs the Agency that these units, individually or averaged together, achieve mercury reductions of 90% (or comply with the mercury emission rate of 0.0080 lb/GWhr) as determined by a stack test performed in accordance with proposed Sections 225.239(d)(4) and (5), (e), and (f)(1), assuming those sections adopted are substantially the same as proposed.

25. Because DMG is still evaluating, installing, and testing its mercury control systems, it is unable at this time to determine exactly how much mercury will be controlled at Havana Unit 6 and Hennepin Unit 2. Likewise, DMG is uncertain as to the precise amount of mercury that will be emitted by Baldwin Unit 3. However, on the basis of historic operating data in conjunction with load forecasts and best engineering judgment concerning the early operation of DMG's mercury removal equipment at Havana Unit 6 and Hennepin Unit 2, DMG estimates that Havana Unit 6 and Hennepin Unit 2, in aggregate, will reduce mercury by up to 19 pounds more than would be reduced from Baldwin Unit 3 during the timeframes covered by this Petition. *See* Ex. 6.

26. Importantly, DMG does <u>not</u> seek changes to any other requirements of the MPS. DMG remains committed to the previously agreed-to SO_2 and NOx reductions reflected in the MPS rule and does not seek a change to the requirement that it install SO_2 or NOx controls on its coal-fired EGUs by any of the deadlines established by the MPS.

DMG also does not seek relief from the rate at which sorbent is required to be injected at any other of its plants affected by the MPS rule, including the requirement that it inject sorbent at a rate of 5 lbs/macf at Havana Unit 6 and Hennepin Unit 2 beginning December 31, 2009, even though DMG believes the mercury removal efficiency at those two units will achieve the mercury removal efficiency anticipated by the MPS. The only relief that DMG seeks is from the requirement that it inject sorbent at Baldwin Unit 3 beginning July 1, 2009.

27. During the next several months, DMG will continue to evaluate the best combination of capital equipment and operating costs to comply with applicable MPS requirements. It will proceed with the appropriate procurement process to construct and install the equipment and secure appropriate quantities of sorbent necessary for it to meet the remainder of the MPS requirements.

28. DMG has met with the Agency to discuss its requested variance. As a result of these discussions, DMG understands that the Agency agrees that there is potentially a net environmental benefit that would result from the Board granting this variance and, at the worst, no environmental harm. DMG further understands that the Agency does not oppose this variance as proposed, though it may not actively support it.

D. THE VARIANCE WILL RESULT IN A NET ENVIRONMENTAL BENEFIT BECAUSE MERCURY EMISSION REDUCTIONS AT HAVANA UNIT 6 AND HENNEPIN UNIT 2 WILL BE GREATER THAN WOULD HAVE BEEN ACHIEVED BY BALDWIN UNIT 3.

29. A net environmental benefit will result from the requested relief. During the requested variance period, DMG will have fabric filter controls systems online at Havana Unit 6 and Hennepin Unit 2 that will reduce mercury emissions in an amount that is more than Baldwin Unit 3 would reduce with its ESP and SO_3 injection.

30. While DMG does not have data that addresses the qualitative and quantitative impact of its mercury emissions on human health and the environment, USEPA has found that emissions from the coal-fired electric power generation sector as a whole tend to affect a large region of the country with relatively minimal impacts in the immediate vicinity of an individual plant. 70 Fed.Reg. 25162, 25245-49 (May 12, 2005). Consistent with that finding, mercury emissions from the affected DMG power plants contribute to the mix of regional pollutants that are transported on weather patterns and impact areas hundreds of miles downwind. In fact, the purpose of the vacated CAMR was to address this regional impact by capping regional mercury emissions. In other words, the reductions in mercury from a single EGU generally have little measurable effect in local downwind areas. Moreover, because DMG will contemporaneously offset the effect of this variance with mercury reductions from Havana Unit 6 and Hennepin Unit 2, the difference in the downwind impact may not even be measurable, though any downwind impact should be lessened because of the greater aggregate mercury removal that will occur from Havana Unit 6 and Hennepin Unit 2.

31. Adverse cross-media impacts are not an issue in this matter. The variance that DMG seeks does not impact its SO_2 or NOx reduction obligations under the MPS or otherwise affect its SO_2 or NOx emissions. Since overall mercury emissions will decrease or remain the same during the pendency of the variance, there will be no significant impact on water quality.

32. In addition to an overall reduction in mercury emissions, there are other environmental benefits associated with granting the requested variance. Specifically, the requested variance would avoid wasting the fly ash from Baldwin Unit 3, which is likely

to occur when contaminated with halogenated activated carbon residue. The majority of fly ash from Baldwin Unit 3 is currently re-used as an additive in the production of concrete. Injection of sorbent upstream of the Baldwin Unit 3 ESP, as would be required by the MPS before Baldwin Unit 3's spring 2010 outage, will likely force all of this coal combustion by-product to be disposed rather than beneficially reused. Without the relief requested by this variance, the fly ash contamination would occur from July 1, 2009, until the start of the Baldwin Unit 3 planned outage when it will be retrofitted with a dry scrubber and fabric filter system. The quantity of fly ash at risk from July 1, 2009 through the scheduled start of the Baldwin Unit 3 outage in March 2010 is over 55,000 tons. When Baldwin Unit 3 resumes operation in 2010, it will be configured with sorbent injection downstream of the ESP and upstream of the fabric filter system. This configuration will allow DMG to collect fly ash in the ESP prior to the injection of sorbent into the flue gas stream, with the halogenated activated carbon residue removed in the fabric filter system and disposed.

33. Another potential benefit of DMG's variance will be a reduction in the production of CO_2 emissions. By injecting sorbent into fabric filter systems at Havana Unit 6 and Hennepin Unit 2, DMG expects to remove as much or even more mercury (than injection at Baldwin Unit 3) while using substantially less sorbent. According to Praxair, it typically takes the combustion of five pounds of coal to produce one pound of activated carbon (*i.e.*, 20% yield). Therefore, a reduction in sorbent demand will produce a corresponding reduction in indirect CO_2 emissions. For example, avoiding the production of 2 million pounds of sorbent avoids the release of over 17 million pounds of CO_2.

E. DMG'S SUGGESTED CONDITIONS FOR THE VARIANCE AND COMPLIANCE PLAN.

34. Dynegy requests that the term of the variance for Baldwin Unit 3 begin on July 1, 2009, and terminate March 31, 2010.

35. DMG proposes that the following conditions apply to this variance:

A. Prior to and during the term of the variance, Baldwin Unit 3 shall be not subject to the requirements of Section 225.233(c)(1)(A), Section 225.233(c)(2), Sections 225.210(b) and (d), and Section 225.233(c)(5).

B. Beginning December 31, 2009, Havana Unit 6 and Hennepin Unit 2 shall comply with all applicable MPS requirements, as otherwise required.

C. Likewise, upon restarting operations following its spring 2010 outage, Baldwin Unit 3 shall comply with all applicable MPS requirements.

36. The compliance plan shall include the following provisions:

A. From July 1, 2009, through December 30, 2009, Havana Unit 6 and Hennepin Unit 2 shall inject sorbent at a minimum rate of 5 lbs/macf at each of those units until or unless DMG informs the Agency that these two units, either individually or averaged together, will achieve mercury reductions of 90% or will meet the emission rate of 0.0080 lb/GWhr. Unless expressly stated, such notification shall not commit the units to achieve a 90% reduction or achieve a rate of 0.0080 lb/GWhr after December 30, 2009. If DMG chooses to comply with this variance by achieving a 90% reduction in mercury emissions at Havana Unit 6 or Hennepin Unit 2, the mercury removal rate shall be determined by performing a single stack test on the applicable unit or units in accordance with proposed Section 225.239(d)(4) and (5), (e), and (f)(1), assuming those sections as adopted in the Board's Docket R09-10 are substantively the same as proposed.

B. Only sorbents listed in or manufactured by the companies listed in Section 225.233(c)(2)(B) or demonstrated as effective as the listed sorbents as allowed by Section 225.233(c)(4) may be injected unless or until DMG informs the Agency that these two units, either individually or averaged together, will achieve mercury reductions of 90% or will meet the emission rate of 0.0080 lb/GWhr.

C. If DMG elects to comply with this variance pursuant to the 90% removal or 0.0080 lb/GWhr option under Paragraph 36(A), above, through December 30, 2009, Havana Unit 6 and Hennepin Unit 2 shall inject sorbent at a rate no less than the rate injected during mercury removal performance tests to achieve an emission rate of 0.0080 lb/GWhr or 90% removal. For example, if during stack testing, DMG demonstrated a 90% removal injecting sorbent at a rate of 2 lb/macf, then DMG would continue, throughout the rest of the variance period, to inject at the minimum two-pound rate rather than at a five-pound rate.

D. For Havana Unit 6 and Hennepin Unit 2, DMG shall maintain records of the sorbent injection rate and flue gas flow rate from July 1, 2009, through December 30, 2009.

39. DMG does not, through this Petition, seek for Havana Unit 6 or Hennepin Unit 2 to be subject to the MPS at any date earlier than December 31, 2009. In addition, at this time, DMG does not, through this Petition, seek to make any of its units subject to the 90% mercury removal requirement of the Illinois mercury rule.

40. This request for variance would alter the effective dates of the Section 225 requirements identified in the construction permit (Application Number 07110065; I.D. Number 125804AAB) issued for Baldwin Unit 3 on March 3, 2008, to authorize the construction and operation of a fabric filter, dry scrubber, and sorbent injection system for this unit. *See* Ex. 7.

F. DMG'S REQUESTED VARIANCE IS NOT CONTRARY TO ANY FEDERAL LAW.

41. The Board may grant the requested variance consistent with federal law and, specifically, with the Clean Air Act, 42 U.S.C. §§ 7401 *et seq*. There is no federal law that requires these DMG units to comply with any mercury emission rate limit. The MPS was submitted to USEPA for approval as part of Illinois' mercury rule, but with vacatur of the CAMR there is no longer any authority for USEPA to approve or disapprove Illinois' mercury rule. DMG is not aware of any other submittal to USEPA

that would raise the MPS to a federally enforceable regulation. Consequently, the Board's grant of this variance request would not be inconsistent with federal law.

42. Additionally, the relief sought here will neither impact nor be impacted by any future state implementation plans that the Agency may submit to USEPA regarding compliance with ozone or PM2.5 national ambient air quality standards.

G. DMG DOES NOT REQUEST A HEARING.

43. DMG does not request that the Board hold a hearing in this matter. DMG believes that this Petition, including its exhibits, sufficiently informs the Board of the issues involved without the need for a hearing. Further, because the variance is not subject to any federal Clean Air Act requirements, a hearing is not necessary to satisfy any federal requirements.

WHEREFORE, for the reasons set forth above, Petitioner DYNEGY MIDWEST GENERATION, INC. respectfully requests that the Board grant DMG a variance from the MPS requirement that Baldwin Unit 3 inject halogenated activated carbon during the period from July 1, 2009, through March 31, 2010.

Respectfully submitted,

DYNEGY MIDWEST GENERATION, INC.,

by:

Kathleen Bassi

One of Its Attorneys

Dated: January 9, 2009

Kathleen C. Bassi
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STATE OF ILLINOIS)
) **SS**
MADISON COUNTY)

AFFIDAVIT OF ARIC D. DIERICX

I, ARIC D. DIERICX, having first been duly sworn, state as follows:

1. I am an employee of DYNEGY MIDWEST GENERATION, INC. I am the Senior Director-Operations Environmental Compliance. I have been employed in this and similar positions at Dynegy for the past eight years. Previously, I was employed by Illinois Power Company since 1979 in its environmental department. Illinois Power and Dynegy merged in 1999/2000. As part of my duties, I oversee permitting and regulatory development and compliance for Air, Water, and Waste issues.

2. I have read the preceding Petition for Variance.

3. The statements of facts contained therein are true and correct to the best of my knowledge and belief.

FURTHER, AFFIANT SAYETH NOT.

Aric D. Diericx

Subscribed and sworn to before me this 9th day of January, 2008.

Lisa A. Engelman

NOTARY PUBLIC

"OFFICIAL SEAL"
LISA A ENGELMAN
NOTARY PUBLIC, STATE OF ILLINOIS
MY COMMISSION EXPIRES 09-28-2012

Exhibit List

Exhibit No.	
1	Map of the air quality monitoring network and the locations of Dynegy's five power stations.
2	Table of information about DMG's five power stations.
3	DMG's letter notifying the Agency that DMG was opting in to the MPS (November 26, 2007).
4	Chang, Ramsay, *et al.*, *Near and Long Term Options for Controlling Mercury Emissions from Power Plants*, Paper # 25 MEGA Symposium (2008).
5	Feeley, Thomas J. III, *et al.*, *DOE/NETL's Mercury Control Technology R&D Program – Taking Technology from Concept to Commercial Reality*, Paper # 42 MEGA Symposium (2008).
6	Sargent & Lundy, "Mercury Off-set for Baldwin Unit 3," Proj.No. 12111-003 Dynegy (November 26, 2008).
7	Construction permit issued for Baldwin Unit 3, as stayed by the Board on May 15, 2008, in Docket 08-66.

Exhibit 1

Map of the air quality monitoring network and the locations of Dynegy's five power stations

1 – Hennepin
2 – Havana
3 – Vermilion
4 – Wood River
5 – Baldwin

Statewide Map of Air Monitoring Locations

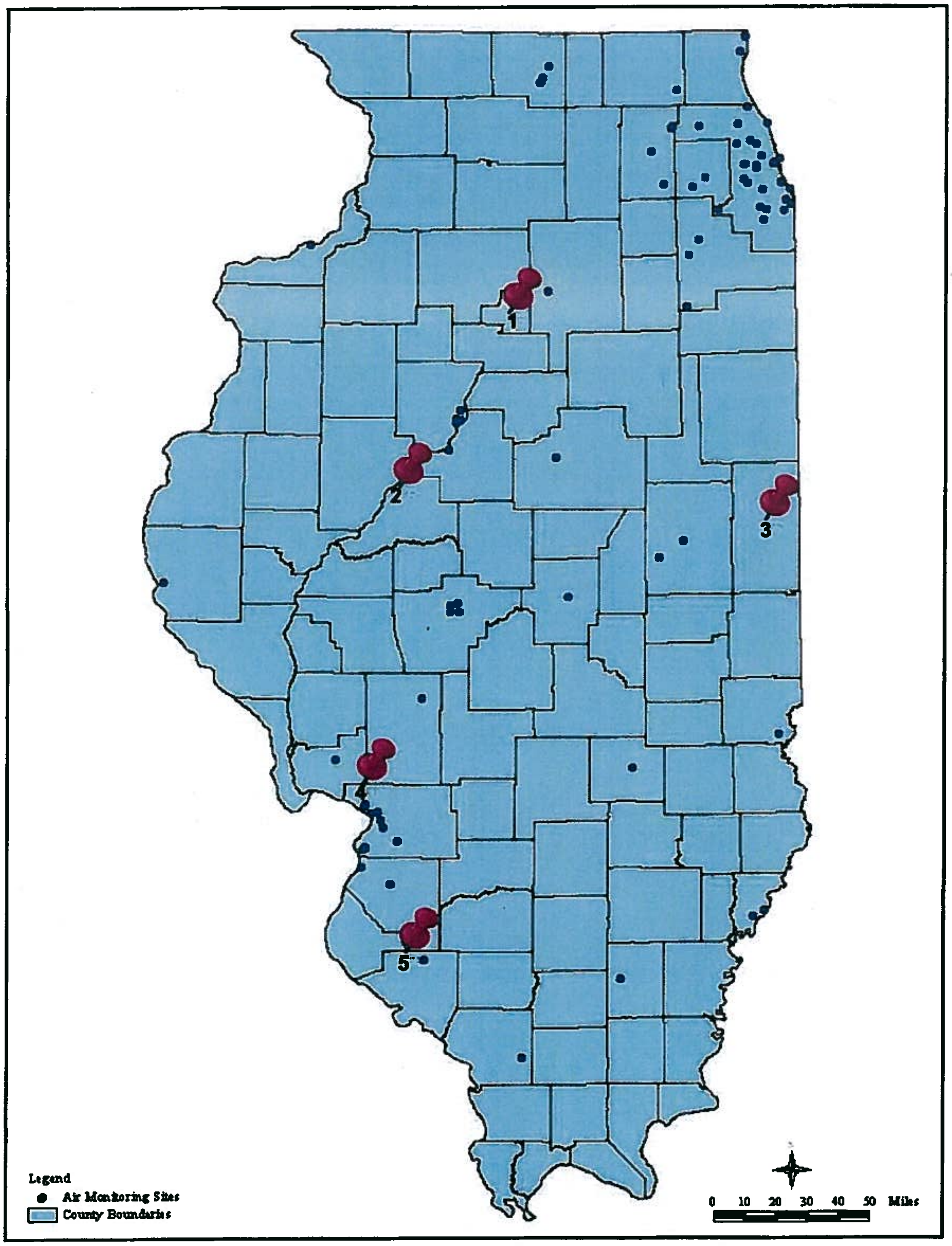


Exhibit 2

Table of information about DMG's five power stations

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes			Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Baldwin Energy Complex (Site I.D. No. 157851AAA)						
10901 Baldwin Road Baldwin, IL 62217 Baldwin Township Randolph County 175 employees	Unit 1 Net Load 600 MW Cyclone Fired Boiler w/ Wet Bottom Ash (7/13/1970)	Unit 2 Net Load 600 MW Cyclone Fired Boiler w/ Wet Bottom Ash (5/21/1973)	Unit 3 Net Load 600 MW Tangentially Fired Boiler w/ Dry Bottom Ash (6/20/1975)	<u>Units 1 and 2</u> OFA, SCR, ESP w/ FGC (as needed), SDA, Baghouse, and ACI. <u>Unit 3</u> Low-NO_x Burners, OFA, ESP w/ FGC, SDA (scrubber), Baghouse, and ACI. Note: SDA and Baghouse for Units 1, 2, and 3 are to be operational in 2011, 2012, and 2010, respectively. ACI systems are to be operational in 2009 except for Unit 3 if	<u>Unit 1</u> Hg emission rate = 0.98 lb/tBtu Hg emissions = 0.023 tons/yr <u>Unit 2</u> Hg emission rate = 0.98 lb/tBtu Hg emissions = 0.023 tons/yr <u>Unit 3</u> Hg emission rate = 5.85 lb/tBtu Hg emissions = 0.140 tons/yr	<u>State Operating Permits</u>: Unit 1 Issued August 17, 2000 Application No. 73010750 Unit 2 Issued August 11, 2000 Application No. 73010751 Unit 3 Issued June 26, 1997 Application No. 75040091

[1] OFA – Over Fired Air, SCR – Selective Catalytic Reduction, ESP – Electrostatic Precipitator, FGC – Flue Gas Conditioning, SDA – Spray Dryer Absorber (scrubber), ACI – Activated Carbon Injection

[2] Mercury emissions are based on a coal Hg content of 6.5 lb/trillion-btu (lb/tbtu) with the estimated inherent Hg reduction associated with the boiler type and particulate matter controls taken into account. The Hg values presented are estimates and are considered baseline values prior to the addition of any activated carbon injection systems. Annual heat input (HI) values utilized in the calculations are the maximum annual HI from the last three years of operation (2005, 2006, or 2007).

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes			Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Baldwin Energy Complex (Site I.D. No. 157851AAA)						
				requested variance is granted.		<u>Construction Permits</u>: Issued March 3, 2008 Application No. 07110065 Baghouse, Scrubber, and Sorbent Injection Systems for Unit 3 Appealed April 9, 2008 (PCB 08-66) Partial Stay Granted May 15, 2008 Issued June 19, 2008 Application No. 08020075 Baghouse, Scrubber, and Sorbent Injection Systems for Units 1 and 2 Appealed July 29, 2008 (PCB 09-9) Partial Stay Granted August 21, 2008 <u>CAAPP Permit</u>: Submitted September 6, 2005 Application No. 95090026 Issued September 29, 2005 Expires September 29, 2010 Appealed November 3, 2005 (PCB 06-063) Stayed February 16, 2006

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes	Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Havana Power Station (Site I.D. No. 125804AAB)				
15260 North State Route 78 Havana, IL 62644 Havana Township Mason County 81 employees	Unit 6 (Boiler 9) Net Load 424 MW Opposed Horizontally Fired Boiler w/ Dry Bottom Ash (6/22/1978)	<u>Unit 6</u> Low-NO_x Burners, OFA, SCR, Hot-side ESP w/ FGC, SDA (scrubber), Baghouse, and ACI. Note: SDA and Baghouse for Unit 6 are to be operational in 2012, and 2009, respectively. The ACI system is to be operational in 2009.	<u>Unit 6</u> Hg emission rate = 6.18 lb/tBtu Hg emissions = 0.110 tons/yr	<u>State Operating Permit</u>: Unit 6 (Boiler 9) Issued March 22, 2000 Application No. 78110004 <u>Construction Permits</u>: Issued April 16, 2007 Application No. 07010031 Baghouse, Scrubber, and Sorbent Injection Systems for Unit 6 Appealed August 22, 2007 (PCB 07-115) Partial Stay Granted October 4, 2007

[1] OFA – Over Fired Air, SCR – Selective Catalytic Reduction, ESP – Electrostatic Precipitator, FGC – Flue Gas Conditioning, SDA – Spray Dryer Absorber (scrubber), ACI – Activated Carbon Injection

[2] Mercury emissions are based on a coal Hg content of 6.5 lb/trillion-btu (lb/tbtu) with the estimated inherent Hg reduction associated with the boiler type and particulate matter controls taken into account. The Hg values presented are estimates and are considered baseline values prior to the addition of any activated carbon injection systems. Annual heat input (HI) values utilized in the calculations are the maximum annual HI from the last three years of operation (2005, 2006, or 2007).

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes	Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Havana Power Station (Site I.D. No. 125804AAB)				
				<u>CAAPP Permit</u>: Submitted September 7, 2005 Application No. 95090053 Issued September 29, 2005 Expires September 29, 2010 Appealed November 3, 2005 (PCB 06-071) Stayed February 16, 2006

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes		Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Hennepin Power Station (Site I.D. No. 155010AAA)					
13498 E. 800 St. Hennepin, IL 61327 Hennepin Township Putnam County 57 employees	Unit 1 Net Load 70 MW Tangentially Fired Boiler w/ Dry Bottom Ash (6/1/1953)	Unit 2 Net Load 221 MW Tangentially Fired Boiler w/ Dry Bottom Ash (5/14/1959)	<u>Unit 1</u> OFA, ESP w/ FGC (as needed), Baghouse, and ACI. <u>Unit 2</u> Low-NO_x Burners, OFA, ESP w/ FGC (as needed), Baghouse, and ACI. Note: The ACI system is to be operational in 2009.	<u>Unit 1</u> Hg emission rate = 5.85 lb/tBtu Hg emissions = 0.016 tons/yr <u>Unit 2</u> Hg emission rate = 5.85 lb/tBtu Hg emissions = 0.050 tons/yr	<u>State Operating Permit</u>: Unit 1 Issued September 30, 2002 Application No. 73010752 Unit 2 Issued September 30, 2002 Application No. 73010721 <u>Construction/Joint Operating Permits</u>: Issued May 29, 2007 Application No. 07020036 Baghouse and Sorbent Injection Systems for Units 1 and 2 Appealed October 4, 2008 (PCB 07-123) Partial Stay Granted November 1, 2007

[1] OFA – Over Fired Air, SCR – Selective Catalytic Reduction, ESP – Electrostatic Precipitator, FGC – Flue Gas Conditioning, SDA – Spray Dryer Absorber (scrubber), ACI – Activated Carbon Injection

[2] Mercury emissions are based on a coal Hg content of 6.5 lb/trillion-btu (lb/tbtu) with the estimated inherent Hg reduction associated with the boiler type and particulate matter controls taken into account. The Hg values presented are estimates and are considered baseline values prior to the addition of any activated carbon injection systems. Annual heat input (HI) values utilized in the calculations are the maximum annual HI from the last three years of operation (2005, 2006, or 2007).

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes		Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Hennepin Power Station (Site I.D. No. 155010AAA)					
					<u>CAAPP Permit</u>: Submitted September 7, 2005 Application No. 95090052 Issued September 29, 2005 Expires September 29, 2010 Appealed November 3, 2005 (PCB 06-072) Stayed February 16, 2006

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes		Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Vermilion Power Station (Site I.D. No. 183814AAA)					
10188 East 2150 North Road Oakwood, IL 61858 Pilot Township Crawford County 63 employees	Unit 1 Net Load 65 MW Tangentially Fired Boiler w/ Dry Bottom Ash (5/19/1955)	Unit 2 Net Load 99 MW Tangentially Fired Boiler w/ Dry Bottom Ash (11/25/1956)	<u>Unit 1</u> Rotating OFA, ESP w/ FGC (as needed), Baghouse, and ACI. <u>Unit 2</u> Low-NO_x Burners, OFA, ESP w/ FGC (as needed), Baghouse, and ACI.	<u>Unit 1</u> Hg emission rate = 0.65 to 0.78 lb/tBtu Hg emissions = 0.0012 to 0.0014 tons/yr <u>Unit 2</u> Hg emission rate = 0.65 to 0.78 lb/tBtu Hg emissions = 0.0020 to 0.0024 tons/yr	<u>State Operating Permit</u>: Unit 1 Issued November 25, 1997 Application No. 73020064 Unit 2 Issued November 25, 1997 Application No. 73020063 <u>Construction/Joint Operating Permits</u>: Issued May 30, 2006 Application No. 06030002 Baghouse and Sorbent Injection Systems for Units 1 and 2 Appealed October 3, 2006 (PCB 06-194) Partial Stay Granted October 19, 2006

[1] OFA – Over Fired Air, SCR – Selective Catalytic Reduction, ESP – Electrostatic Precipitator, FGC – Flue Gas Conditioning, SDA – Spray Dryer Absorber (scrubber), ACI – Activated Carbon Injection

[2] Mercury emissions are based on a coal Hg content of 6.5 lb/trillion-btu (lb/tbtu) with the estimated inherent Hg reduction associated with the boiler type and particulate matter controls taken into account. The Hg values presented are estimates and are considered baseline values prior to the addition of any activated carbon injection systems. Annual heat input (HI) values utilized in the calculations are the maximum annual HI from the last three years of operation (2005, 2006, or 2007).

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes		Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Vermilion Power Station (Site I.D. No. 183814AAA)					
					CAAPP Permit: Submitted September 7, 2005 Application No. 95090050 Issued September 29, 2005 Expires September 29, 2010 Appealed November 3, 2005 (PCB 06-073) Stayed February 16, 2006

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes		Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Wood River Power Station (Site I.D. No. 119020AAE)					
#1 Chessen Lane Alton, IL 62002 Alton Township Madison County 98 employees	Unit 4 Net Load 85 MW Tangentially Fired Boiler w/ Dry Bottom Ash (6/1/1954)	Unit 5 Net Load 372 MW Tangentially Fired Boiler w/ Dry Bottom Ash (7/31/1964)	Unit 4 Low-NO_x Burners, OFA, and ESP w/ FGC (as needed). Unit 5 Low-NO_x Burners, OFA, ESP, and ACI. Note: The ACI system is to be operational in 2009.	Unit 4 Hg emission rate = 5.85 lb/tBtu Hg emissions = 0.022 tons/yr Unit 5 Hg emission rate = 5.85 lb/tBtu Hg emissions = 0.075 tons/yr	State Operating Permit: Unit 4 Issued April 19, 2002 Application No. 73020062 Unit 5 Issued March 10, 1997 Application No. 73010719 Construction/Joint Operating Permits: Issued June 12, 2008 Application No. 08020011 Sorbent Injection System for Unit 5 Appealed July 21, 2008 (PCB 09-6) Partial Stay Granted August 21, 2008

[1] OFA – Over Fired Air, SCR – Selective Catalytic Reduction, ESP – Electrostatic Precipitator, FGC – Flue Gas Conditioning, SDA – Spray Dryer Absorber (scrubber), ACI – Activated Carbon Injection

[2] Mercury emissions are based on a coal Hg content of 6.5 lb/trillion-btu (lb/tbtu) with the estimated inherent Hg reduction associated with the boiler type and particulate matter controls taken into account. The Hg values presented are estimates and are considered baseline values prior to the addition of any activated carbon injection systems. Annual heat input (HI) values utilized in the calculations are the maximum annual HI from the last three years of operation (2005, 2006, or 2007).

Exhibit 2
Power Stations and Units Comprising the MPS Group
(§ 104.204(b))

Address Number of Employees	Boilers and Sizes		Pollution Control Equipment[1]	Mercury (Hg) Emissions in Rate and TPY[2]	Permits
Wood River Power Station (Site I.D. No. 119020AAE)					
					<u>CAAPP Permit</u>: Submitted September 7, 2005 Application No. 95090096 Issued September 29, 2005 Expires September 29, 2010 Appealed November 3, 2005 (PCB 06-074) Stayed February 16, 2006

Exhibit 3

DMG's letter notifying the Agency that DMG was opting in to the MPS (November 26, 2007)

Keith McFarland
Vice President
Midwest Fleet Operations

Dynegy Generation
A Division of Dynegy Inc
3890 North Illinois Street
Swansea, Illinois 62226

DYNEGY

November 26, 2007

Mr. Raymond Pilapil
Manager
Compliance & Enforcement Section
Illinois EPA
Bureau of Air
PO Box 19276
Springfield, Illinois 62794-9276

Re: CAIR Rule - 35 IAC 225
Notice of Intent to Participate in MPS

Dear Mr. Pilapil:

Dynegy Midwest Generation, Inc. (DMG) is giving notice of its intent to elect its units in the Multi-Pollutant Standards group as per Section 225.233 as its means of complying with Subpart B of Part 225. The following information accompanies this notification:

1. The identification of each EGU that will be complying with this Subpart B by means of the multi-pollutant standards contained in this Section, with evidence that the owner has identified all EGUs that it owned in Illinois as of July 1, 2006 and which commenced commercial operation on or before December 31, 2004;
2. The Base Emission Rates for the EGUs, with copies of supporting data and calculations;
3. A summary of the current control devices installed and operating on each EGU and identification of the additional control devices that will likely be needed to comply with emission control requirements of this Section, including identification of each EGU in the MPS group that will be addressed by subsection (c)(1)(B) of this Section, with information showing that the eligibility criteria for this subsection (b) are satisfied.

This information is in the attachments to this letter. Attachment 1 lists all the units (EGUs) owned by Dynegy Midwest Generation, Inc. that utilize coal in Illinois. All of the units were owned before July 1, 2006 and began operation before December 31, 2004. Attachment 2 lists the Base Emission Rate for the EGUs (values from 2003, 2004 and 2005). Attachment 3 gives a table of the control devices currently installed and future installations. Future installations are indicated with a proposed date. EGUs addressed by subsection (c)(1)(B) are identified along with gross generation and percent generation of the MPS group.

This letter also serves as notice under 225.270 and 40CFR Part 75.61 that Hennepin (ORIS 892) Unit 1 and Unit 2 are served and monitored by a common stack. Vermilion (ORIS 897) Unit 1 and Unit 2 are also served and monitored by a common stack.

"I am authorized to make this submission on behalf of the owners and operators of the NOX Budget sources or NOX Budget units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

Sincerely,
DYNEGY MIDWEST GENERATION, INC.

Keith A. McFarland
Vice President
Midwest Fleet Operations

Attachments

Attachment 1

EGUs owned by Dynegy Midwest Generation, Inc. and elected for MPS

Station	Unit ID	ORIS	Date of Commercial Operation	Gross Generation [1] (GMW)
Baldwin	1	889	7/13/70	624
Baldwin	2	889	5/21/73	629
Baldwin	3	889	6/20/75	629
Havana	9	891	6/22/78	487
Hennepin	1	892	6/1/53	81
Hennepin	2	892	5/14/59	240
Vermilion	1	897	5/19/55	84
Vermilion	2	897	5/25/56	113
Wood River [2]	4	898	6/1/54	105
Wood River	5	898	7/31/64	383
			Total Generation	3375

[1] Gross Generation as listed in the Consent Decree.

[2] The Gross Generation for Wood River Unit ~~for~~ 4 is less than 4% of the total Gross Generation for the MPS group (225.233 (c)(1)(b))

Attachment 2

Base Emission Rates and calculations

	lb/mmBtu			Tons			mmBtu		
	2003	2004	2005	2003	2004	2005	2003	2004	2005
Seasonal NOx	0.209	0.102	0.087	9704	3824	4360	92894369	74935571	99783984
Annual NOx	0.261	0.215	0.096	28455	23281	10639	218427022	216363263	221703763
Annual SO2	0.583	0.562	0.491	63622	60806	54394	218427022	216363263	221703763

Values taken from IEPA handout which indicates values obtained from USEPA Clean Air Markets Division

Average Values

Program	Average Rate	Reduction	Limit
Seasonal NOx	0.133	20%	0.106
Annual NOx	0.191	48%	0.099
Annual SO2 P1 2013-2014	0.545	56%	0.240
Annual SO2 P2	0.545	65%	0.191

Attachment 3

Table of Control Devices

Station	Unit ID	ESP	Fabric Filter	SCR	Spray Dryer Absorber	ACI
Baldwin	1	X	2011	X	2011	2009
Baldwin	2	X	2012	X	2012	2009
Baldwin	3	X	2010		2010	2009
Havana	9	X	2009	X	2009 - 2010	2009
Hennepin	1	X	2008			2009
Hennepin	2	X	2008			2009
Vermilion	1	X	X			X
Vermilion	2	X	X			X
Wood River [3]	4	X				
Wood River	5	X				2009

X = Device currently installed
Future installation indicated by date of anticipated operation.

[3] Wood River Unit 4 (ORIS 898) is electing to use (c)(1)(b) of Subpart B of Part 225.233

Exhibit 4

Chang, Ramsay, *et al.*, *Near and Long Term Options for Controlling Mercury Emissions from Power Plants*, Paper # 25 MEGA Symposium (2008)

Near and Long Term Options for Controlling Mercury Emissions from Power Plants

Paper #25

Ramsay Chang
EPRI, 3412 Hillview Avenue, Palo Alto, CA 94304

Katherine Dombrowski
URS Corporation, 9400 Amberglen Boulevard, Austin, TX 78729

Constance Senior
Reaction Engineering International, 77 W. 200 S., Suite 210, Salt Lake City, UT 84101

ABSTRACT

The Electric Power Research Institute (EPRI) and individual electric power generating companies have worked closely with the U.S. Department of Energy (DOE), pollution control suppliers, and engineering consulting firms to develop and evaluate mercury controls for coal-fired power plants. As a result of these efforts, mercury controls for a number of coals and basic unit configurations are nearing commercial readiness. At the same time, novel mercury control approaches are also being proposed and tested. Much data from testing at many power plant sites, encompassing a variety of configurations, operating conditions, and coal type have been gathered in the past ten years by EPRI and others. This paper will summarize field data obtained to date from various test sites documenting mercury control technologies and their effectiveness, trends, issues that need to be addressed, implications on current cost for mercury control, and newer technologies that are under development.

INTRODUCTION

A recent District of Columbia Appeals Court ruling remanded the Clean Air Mercury Rule back to the Environmental Protection Agency for reconsideration, opening the possibility that high mercury removals may be required for each U.S. coal-fired power plant unit. Power producers will need to reduce mercury emissions for compliance with both federal and state regulations. Since some states currently mandate mercury removals greater than 90%, mercury controls will have to perform *above* that standard to meet long-term emission goals.

To address these concerns, this paper considers the performance of the most promising near-term approaches for controlling mercury emissions from coal-fired power plants: activated carbon injection into flue gas and bromide addition into the boiler. It also responds to challenges that must be met for cost-effective, long-term compliance.

SUCCESS WITH SORBENTS

At units employing activated carbon injection (ACI) for mercury control, powdered activated carbon is injected into flue gas before a particulate control device, such as a fabric filter (FF) or electrostatic precipitator (ESP). The activated carbon adsorbs flue gas mercury, which is removed when the mercury-laden carbon particles are captured in the FF or ESP. In some cases, activated carbon is injected upstream of a spray dryer (SD) and captured in a downstream particulate control device.

This paper discusses the use of untreated activated carbon (AC) or brominated activated carbon (BAC) as mercury sorbents. AC sorbents are made from coal or biomass. BAC sorbents belong to a class of chemically treated carbons impregnated with halogens such as bromine or chlorine. Only BAC sorbents have proven to be cost-effective for flue gas mercury removal (see Mercury Control Costs below). None of the non-carbon sorbents tested to date have achieved high mercury removals. Boiler bromide additives (discussed below in Success with Broiler Bromide Additives) can enhance ACI performance for low-chlorine coals; this pairing removes mercury as effectively as brominated ACI.

For the majority of tests discussed in this paper, mercury flue gas concentrations were measured upstream of sorbent injection and downstream of a particulate control device. Mercury removal across the device was calculated as the difference between the two measurements. Mercury semi-continuous emission monitors (SCEMs) and the Ontario Hydro Method were used to measure mercury concentrations.

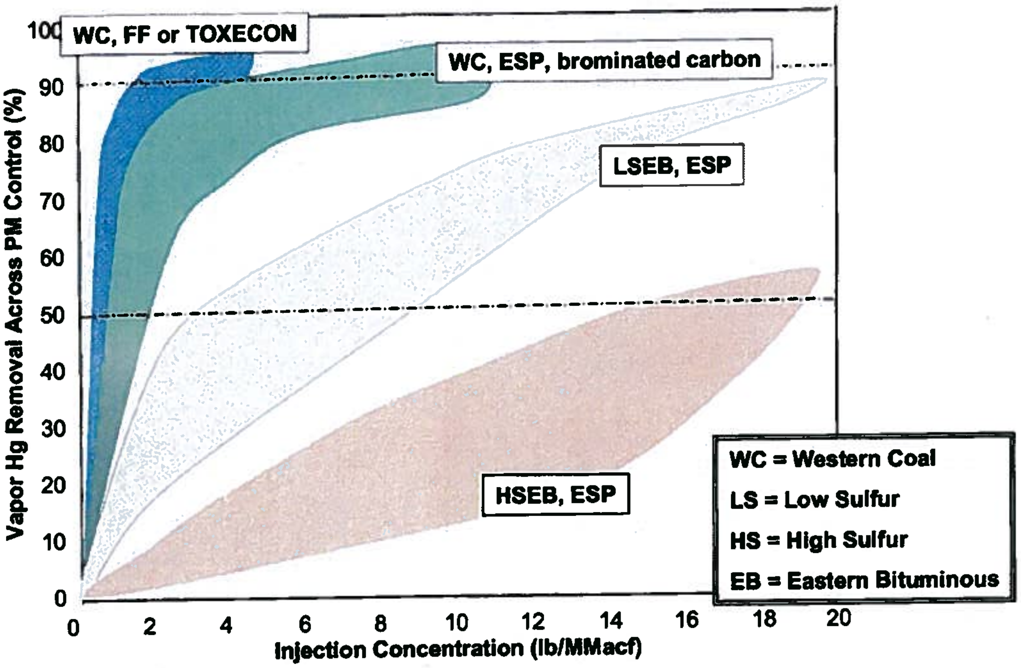
Mercury Removal Performance

Full-scale ACI and brominated ACI tests were conducted at 40 units. Among particulate controls at these units there were 28 ESPs, 3 TOXECON™s, 2 FFs, 6 SD-FFs and 1 SD-ESP.[1]

Figure 1 summarizes typical mercury removal ranges seen to date for ACI or brominated ACI at units firing western or eastern bituminous coals. These data show that high mercury removals (> 90%) at reasonable injection rates (5 lb/MMacf or less) are attainable at units with FFs, TOXECONs, or ESPs firing western coals. The ongoing challenge is to maintain this performance level during long-term operation.

In contrast, mercury removals at units with ESPs firing eastern bituminous coals—especially those firing high-sulfur eastern bituminous (HSEB) coal—fall well below the high-performance achieved for western coals. Since the majority of coal-fired units in the United States have ESPs, many firing eastern bituminous coals, there is an urgent need to understand and mitigate the factors that degrade their performance.

Figure 1. Mercury Removal by Activated Carbon Injection for Western and Eastern Bituminous Coals



Tables 1 and 2 summarize mercury removals seen in full-scale tests. In some cases, high removals represent data from one unit or procedures that are experimental, and thus are not included in Figure 1. The tables also provide additional information for western coal-fired units with SDs and eastern bituminous coal-fired units with FFs or TOXECONs, since these configurations offer high mercury removal at reasonable injection rates. The tables note factors influencing performance; these are discussed below in Challenges and Responses.

Western Coals

Western coals described in Table 1 include Powder River Basin (PRB) subbituminous and North Dakota lignite (NDL). Low-chloride Texas lignite (TxL) is sometimes blended with these coals. Flue gas associated with combustion of western coals is relatively low in chloride and high in elemental mercury. Thus, using brominated ACI (which can capture elemental mercury in a low-halogen flue gas) or increasing flue gas oxidized mercury by adding bromide directly into the boiler in conjunction with ACI typically improves performance over ACI for western coals. Available data from four units firing low-chloride western coals show that using boiler calcium bromide additives to supplement ACI can significantly increase mercury removal across FFs, ESPs, SD-FFs, and SD-ESPs.

Table 1. Summary of Mercury Removal Performance for Sorbent Injection at Units Firing Western Coals

			Range of Observed Hg Removal at			
APCD	**Coal**	**Type of Sorbent Injection**	**2 lb/MMacf**	**5 lb/MMacf**	**10 lb/MMacf**	**Factors Influencing Performance**
FF or TOXECON	PRB	ACI	70–95%	> 95%	–	Temperature, improvement with BCA plus ACI
		Brominated ACI	80–95%	> 95%	–	Temperature
ESP (No FGC*)	PRB	ACI	–	40–95%	50–95%	Improvement with BCA plus ACI; temperature effect not demonstrated, but suspected
		Brominated ACI	65– > 95%	80– > 95%	–	Mer-Cure process reported > 95% at one plant; temperature effect not demonstrated, but suspected
SD	PRB	ACI	25–60%	45–90%	60–90%	Higher removals possible with BCA plus ACI or with upstream SCR
		Brominated ACI	60–95%	85– > 95%	–	Mer-Cure process reported up to 95% at one plant

* FGC: flue gas conditioning, injection of SO_3 or SO_3 plus NH_3 upstream of an ESP to improve collection efficiency

Eastern Bituminous Coals

Eastern bituminous coals described in Table 2 are categorized as low-sulfur (LSEB), medium-sulfur (MSEB), or high-sulfur (HSEB). Flue gas associated with combustion of bituminous coals is relatively high in chloride and high in oxidized mercury. Thus, the use of brominated ACI to increase flue gas oxidized mercury does little to improve performance over ACI for bituminous coals.

Table 2. Summary of Mercury Removal Performance for Sorbent Injection at Units Firing Eastern Bituminous Coals

			Range of Observed Hg Removal at			
APCD	**Coal**	**Type of Sorbent Injection**	**2 lb/MMacf**	**5 lb/MMacf**	**10 lb/MMacf**	**Factors Influencing Performance**
FF or TOXECON	LSEB	ACI	75–90%	> 90%	–	Temperature, air-to-cloth ratio, no improvement with brominated ACI
ESP (no FGC)	LSEB	ACI	20–60%	20–70%	20–75%	Temperature
		Brominated ACI	30–40%	35–60%	60– > 80%	Temperature
ESP	MSEB or HSEB	ACI	0–35%	0–70%	5–80%	Temperature, SO_3 concentration; co-injection of SO_3 sorbent with ACI; use of "SO_3-tolerant" sorbents
		Brominated ACI	0–35%	0–70%	10– > 90%	Temperature, SO_3 concentration; Mer-Cure only demonstrated process > 80% for one MSEB plant

SUCCESS WITH BOILER BROMIDE ADDITIVES

Halogen compounds, such as bromide or chloride salts, are employed as boiler chemical additives (BCAs). In liquid form, they are sprayed onto the feed coal or injected directly into the high-temperature zone of the boiler. In solid form, they are added to coal on the conveyor belt upstream of the pulverizer. Boiler chemical additives oxidize elemental mercury, increasing the fraction of oxidized mercury in flue gas available for capture in downstream particulate control devices and wet or dry SO_2 scrubbers. They improve mercury removal for units firing low-chlorine western coals and offer an alternative to brominated ACI when paired with ACI (as discussed above in Success with Sorbents).

Bromide salts are the most effective BCAs in terms of performance and cost (see Mercury Control Costs below). Adding small amounts of bromine compounds to the boiler to oxidize mercury in coal-fired flue gas containing sulfur dioxide has been patented by Dr. Bernhard Vosteen and licensed to Alstom for applications in North America. KNX™ is Alstom's name for its mercury control technology that uses the commodity chemical, calcium bromide. Proprietary SEA1 and SEA2 additives were used by the Energy & Environmental Research Center (EERC) at the University of North Dakota.

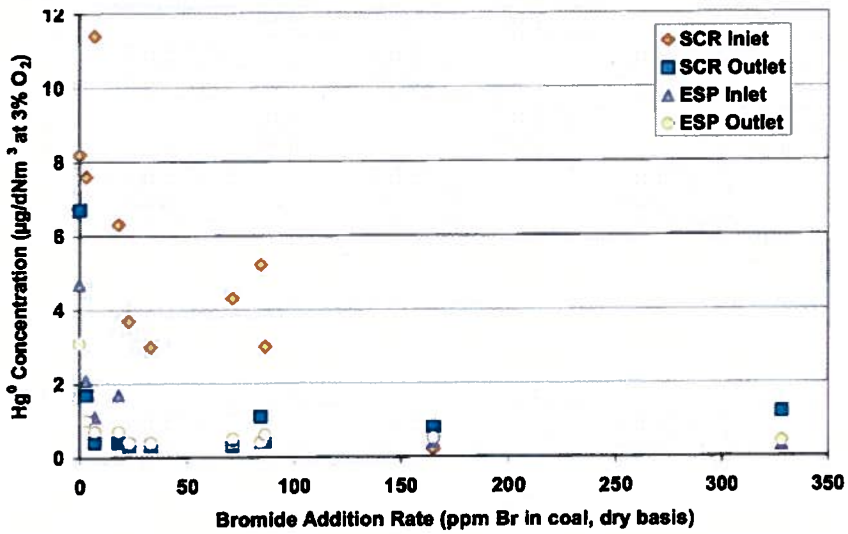
Mercury Removal Performance

Full-scale boiler chemical additive (BCA) tests were conducted at 14 units firing low-chloride PRB or Texas lignite coals.[2] Seven units hosted continuous tests lasting from 2 to 14 days.

In these tests, more than 90% of flue gas mercury appeared in oxidized form at boiler bromide additions equivalent to 25 to 300 parts per million by weight in coal. With calcium chloride addition, less than 60% mercury oxidation was achieved at more than 1000 parts per million chloride in coal.

The oxidation effect of bromide was magnified at one unit with selective catalytic reduction (SCR), where 90% mercury oxidation was achieved with boiler bromide addition of less than 20 parts per million in coal (Figure 2). Finally, at four of five units with wet SO_2 scrubbers, bromine-oxidized mercury was readily removed by the scrubber.

Figure 2. SCR Enhances Bromide Oxidation Effectiveness Even Further



MERCURY CONTROL COSTS

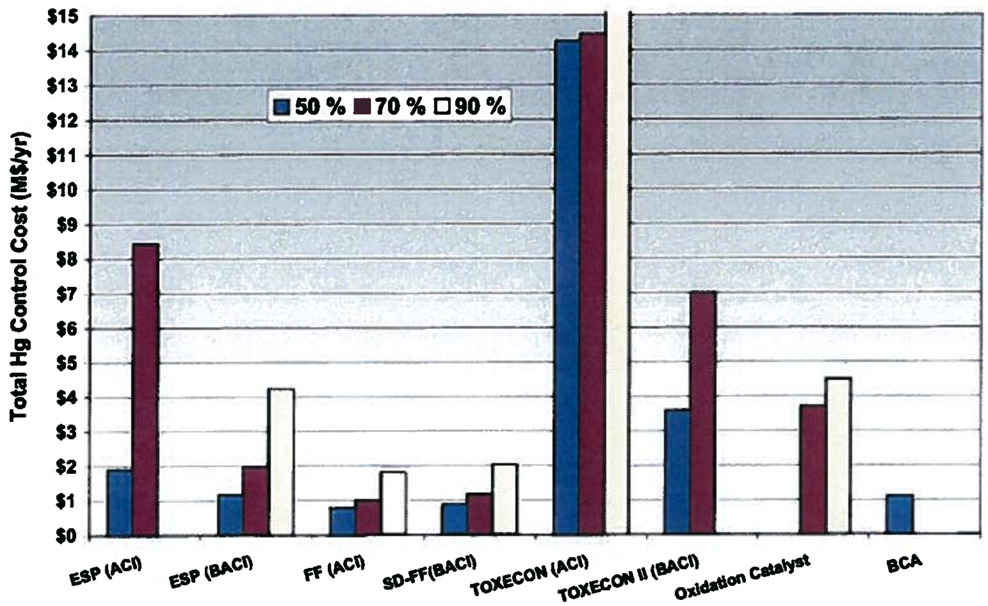
Sorbents

Brominated activated carbon currently costs (FOB manufacturing plant) about $1.00/lb versus $0.70/lb for untreated activated carbon. However, the performance of brominated ACI is significantly better than that of ACI for western coal applications, making it a more cost-effective approach for these coals. To date, no significant differences have been observed between ACI and brominated ACI at units with FFs firing western or bituminous coals.

Figures 3 and 4 show total annual mercury control costs for a 500 MWe plant firing western or low-sulfur eastern bituminous coals. These projections are for units that do not sell fly ash. At units where fly ash sales are lost due to sorbent injection, annual control costs increase by about $2 million in disposal fees and lost revenue.

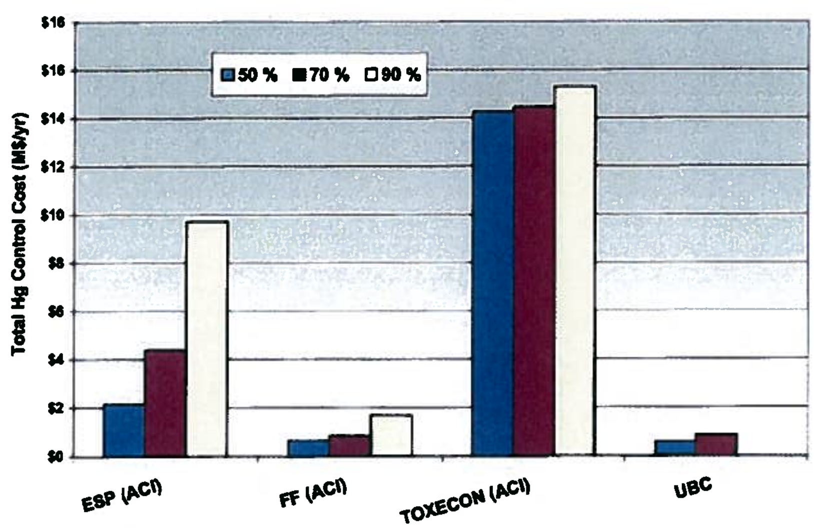
Cost projections are based on estimated average mercury removals. The projections assume a 500 MWe plant with a flue gas flow rate of 2 Macfm, 0.65 capacity factor, and mercury flue gas concentration of 10 $\mu g/Nm^3$, resulting in mercury emissions of approximately 275 lb/yr. Equipment costs are amortized using a capital recovery factor of 0.15. A constant 2008 dollar analysis is used.

Figure 3. Total Annual Cost of Mercury Control for PRB and ND Lignite Coals, Assuming No Ash Sales (500 MWe Plant)



Oxidation catalyst (not discussed in this paper) and boiler chemical additive removals are for ESP-equipped units with FGD. BACI: brominated activated carbon injection.

Figure 4. Total Annual Cost of Mercury Control for Low-Sulfur Eastern Bituminous Coals, Assuming No Ash Sales (500 MWe Plant)



Unburned carbon (UBC) removals (not discussed in this paper) are for units equipped with ESPs.

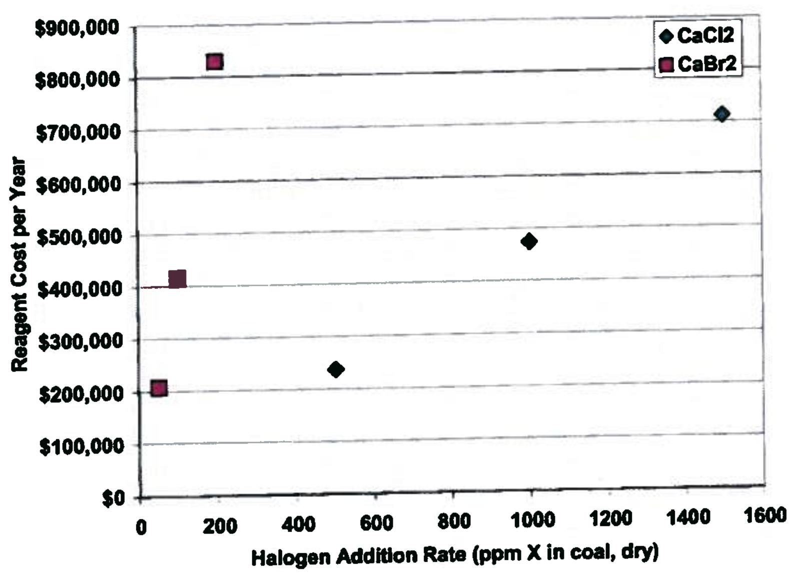
TOXECON is the high-cost option for all coals and establishes the high-cost limit for controlling mercury. Although TOXECON appears to be a costly option for mercury control, it offers the potential to further segregate mercury sorbent from fly ash, minimizing waste generation. It also offers the potential to further separate and stabilize adsorbed mercury, and perhaps to recycle/reuse the mercury sorbent. TOXECON can be used with other sorbents to remove additional pollutants such as SOx, NOx, and trace air toxics—especially as a polishing step. Finally, use of TOXECON's fabric filter as a final particulate collection device ensures very low outlet particulate matter and trace metal emissions.

Boiler Chemical Additives

Calcium bromide salts used as boiler chemical additives cost (FOB manufacturing plant) \$1.44/lb salt or \$10.70 (52 wt% solution)/gallon solution. Calcium chloride salts cost \$0.15/lb salt or \$0.70 (38 wt% solution)/gallon solution.

Figure 5 shows the projected annual chemical cost of adding calcium bromide or chloride salts to the boiler of a 500 MWe plant. Costs increase with halogen addition rate, very steeply for bromide and less steeply for chloride. However, available data show that bromide salts oxidize mercury much more effectively than chloride salts. The figure does not include capital costs or—in the case of bromide addition—a per-site, negotiated license fee payable to Alstom for use of the technology patented by Dr. Bernhard Vosteen. Figure 3 above shows total annual mercury control costs of BCA for a 500 MWe plant firing western coals.

Figure 5. Projected Annual Chemical Cost of Halogen Boiler Addition at a 500 MWe Plant



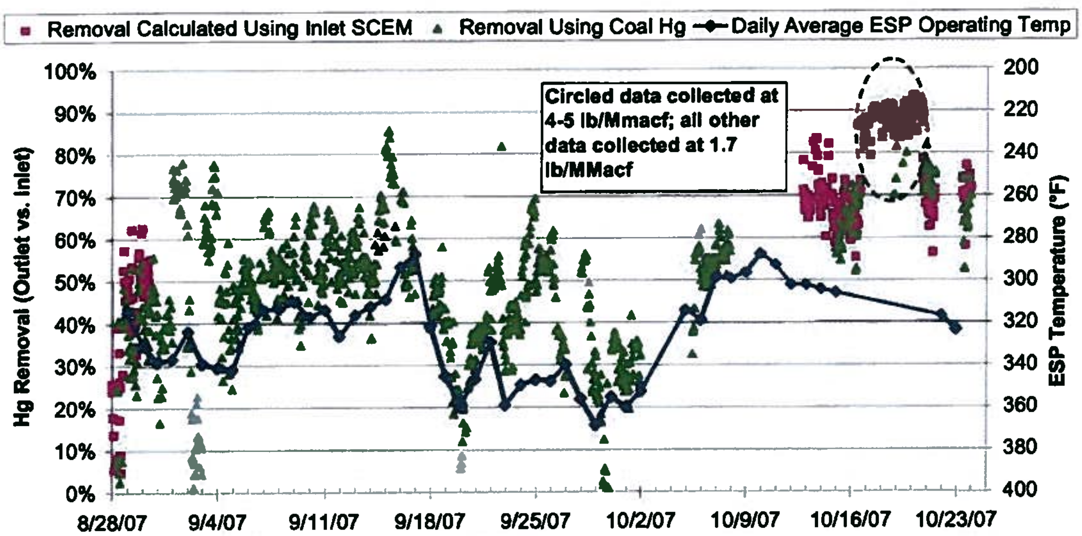
CHALLENGES AND RESPONSES

1. Achieve > 90% removal with consistent and predictable performance from activated carbons and other sorbents

To meet this challenge, EPRI and others are collecting more field data from longer-term studies. They will use these data to develop predictive models combining information on mass transfer, sorbent properties, and process conditions.

Flue gas temperature is a process condition meriting further study. Recent observations show that mercury removals across an ESP correlate with fluctuations in temperature at a PRB-fired unit (Figure 6), and there are probably effects of temperature variations for other coals.

Figure 6. Variations in ACI Mercury Removal Correlate with Temperature at PRB Unit with ESP



EPRI has undertaken a study to characterize key sorbent properties affecting mercury removal, including the size distribution of sorbent particles, pore size and surface area, and surface groups active in mercury adsorption. This study, based on performance and physical/chemical analyses of 6 to 8 different types of sorbents from 10 field sites, will help the project team develop specifications for activated carbon procurement. Currently, there are no specifications to help buyers choose the best sorbent for a given application by ensuring uniform carbon quality, consistency, and performance.

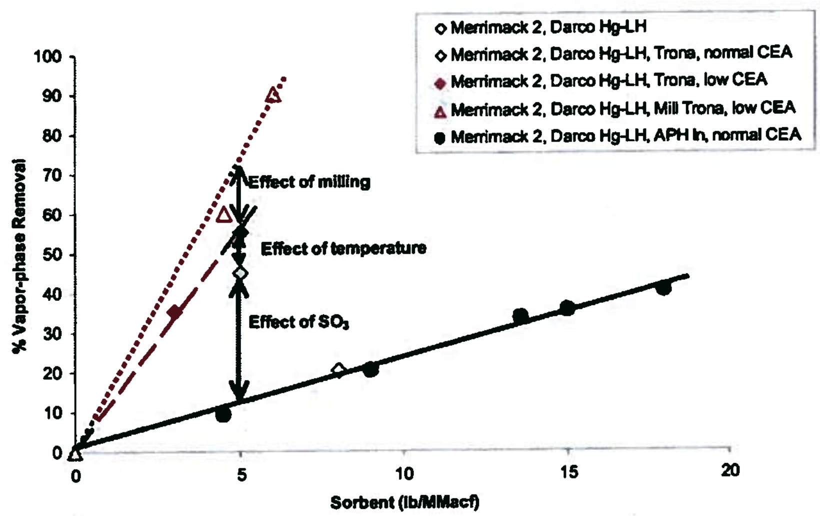
2. Improve sorbent effectiveness in the presence of SO_3

High concentrations of SO_3 in flue gas have a large, negative impact on ACI performance for both western and eastern bituminous coals. In practice, SO_3 may be present because it is used as a flue gas conditioner to improve ESP performance, because it is a constituent of HSEB coal, or because a lower-sulfur eastern bituminous-fired unit has an SCR.

One way to improve mercury removal across ESPs with flue gas conditioning is to inject sorbent upstream of the air preheater, before conditioning comes into play. This is accomplished for either western or LSEB coals by using Alstom's Mer-Cure™ process.

Another way to improve mercury removal is to reduce flue gas SO_3 concentration with alkali co-injection. Alkali sorbents adsorb SO_3, freeing sites on the activated carbon for mercury adsorption and allowing operation at lower temperatures after the air preheater. During ACI, trona was injected upstream of the air preheater at a unit with an SCR firing MSEB (Figure 7). This reduced the downstream SO_3 concentration from ~ 20 ppmv to ~ 8 ppmv, lowered the downstream flue gas temperature, and increased mercury removal by as much as 40%. Milling the trona to finer size enhanced its effectiveness.

Figure 7. Impact of SO_3, Temperature, and Sorbent Size on ACI Performance



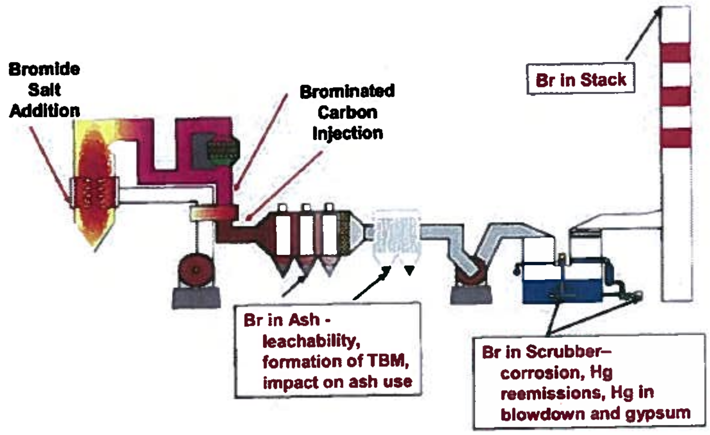
CEA: coal-end average temperature

Alternatives to the use of SO_3 flue gas conditioning to improve ESP performance should be investigated. These include the use of other conditioning chemicals or advanced ESP power supplies that modify the shape and frequency of the ESP voltage and current. Finally, "SO_3-resistant" carbon sorbents are under development, but none have demonstrated significant improvement in mercury removal to date.

3. Realize benefits of bromine and other halogens with known, manageable impacts

EPRI and others continue to evaluate how effectively bromine oxidizes mercury and how well that oxidized mercury is removed by particulate controls and wet scrubbers at units firing various coals with and without an SCR. Figure 8 illustrates potential bromine balance-of-plant impacts.

Figure 8. Understanding Bromine Balance-of-Plant Impacts



TBM: tribromomethane

Because the fate of the bromine compounds in the various power plant streams and their potential balance-of-plant impacts are poorly understood, EPRI is conducting a bromine balance-of-plant impacts assessment at several field demonstration sites. Parameters under investigation include:

- Bromine partitioning between gas and solids along the flue gas path
- Effect of bromine on fly ash for concrete use
- Leachability of bromine from fly ash
- Effectiveness of bromine capture by wet FGD
- Bromine concentrations and partitioning in wet FGD systems (liquor vs. solids)
- Bromine corrosion potential in the boiler and wet FGD
- Effect of bromine on mercury partitioning between wet FGD liquor and solids
- Effect of bromine on mercury re-emissions from wet FGD.

Preliminary data presented in Table 3 trace the fate of bromine, from brominated ACI, in a PRB-fired unit with a fabric filter. As injection rate increases, so do bromine concentrations at the fabric filter outlet and in the fly ash leachate.

Table 3. Fate of Bromine in PRB Fabric Filter Unit

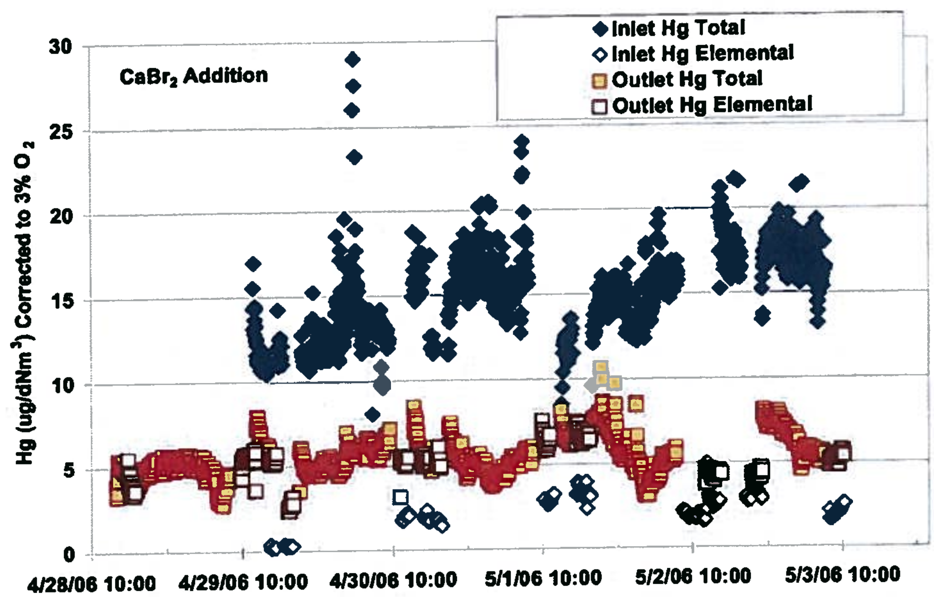
	Baseline	CF Plus*	CF Plus	KNX/Darco Hg**
Average Injection Rate (lb/MMacf)/(ppmw Br in coal)	0.0	0.5	1.0	0.25/41
Coal Bromine Concentration (ppmw)	5.65	5.74	5.65	5.55
Average Fabric Filter Outlet Flue Gas Bromine Concentration, (ppmv), dry at 3% O_2	0.03	0.5	0.10	–
Fly Ash Bromine Leachate Concentration (ppmw)	0.35	2.76	9.82	1.93

*CF Plus is a proprietary "ash friendly" BAC.
**KNX is a calcium bromide-based BCA process used with Darco Hg AC.

Previous laboratory studies have shown that bromine present in scrubber water can increase the corrosion of some metals used in the scrubbers, especially at the higher concentrations encountered in closed loop units and in conjunction with chlorides already present.

Mercury re-emissions occur when oxidized mercury is absorbed by the FGD liquor and then chemically converted to elemental mercury that exits with flue gas from the scrubber. Re-emissions are marked by an increase in elemental mercury concentrations across the scrubber, as shown in Figure 9 for a western coal-fired unit with an ESP and wet FGD employing calcium bromide addition. Re-emissions limit the net mercury removal of a system. There appears to be increased potential for re-emissions in scrubbers with appreciable mercury concentrations in the liquor phase. Since calcium bromide addition can significantly increase the mercury concentration of the liquor, re-emissions may become a problem.

Figure 9. Potential Mercury Re-Emissions with Calcium Bromide Addition



4. **Control small particulate matter increases (<0.003 lb/MBtu) that can trigger New Source Review for a 500 MWe plant**

ACI upstream of ESPs can increase fine particulate matter (PM) emissions at the stack. This effect is generally seen at plants with smaller ESPs (SCAs ~ 300 or lower). Over time, EPRI will conduct extensive PM measurements at units with ESPs and fabric filters to develop strategies to reduce PM emissions. In tests to date, researchers have used EPA Methods 17 and 5 to measure ESP outlet particulate concentrations during long-term ACI tests at a unit firing western coal. Both methods showed increased particulate loading during injection, compared to baseline, but it was unclear whether stack PM emissions increased as a result.

EPRI is also developing low-cost technologies to control fine PM releases from ESPs. One example is the PMScreen™ which uses novel filter materials and an electrical charge supplied by the ESP itself to increase fine PM capture at minimal pressure drop. Its modular filter assemblies mount within the ESP's outlet cone.

Finally, strategies that reduce the amount of sorbent needed to meet mercury removal goals will also reduce fine PM emissions. Some of these strategies are discussed below.

5. Maintain ash use with ACI

Many power companies sell fly ash from western coals to replace portland cement in concrete. To date, adding modest amounts of activated carbon to PRB fly ash has not caused the properties of concrete made with sorbent-fly ash mixtures to fall outside acceptable limits for many of the sites tested—but it has caused a 3- to 4-fold increase in the amount of air entraining agent (AEA) needed in concrete manufacture. Some ash wholesalers have been willing to accept these conditions as long as the amounts of carbon in the ash remain relatively constant so amounts of air entraining agent need not vary.

Thus, the best strategy for preserving ash sales is to maintain fly ash consistency by

- injecting carbon at a constant rate to meet mercury removal targets,
- injecting small (0.5 lb/MMacf) amounts of carbon, and
- reducing carbon usage.

The effect of short-term boiler bromide addition on fly ash suitability for concrete manufacturing was tested at two PRB-fired units. Ash from one unit passed a compressive strength test while ash from the other unit failed. EPRI is pursuing additional research on the use of sorbent-bearing fly ash in concrete manufacturing.

EPRI continues to evaluate ways to preserve ash sales for concrete manufacturing, including the use of

- "passivated" carbons treated with ozone or a proprietary surfactant to block AEA adsorption,
- so-called "ash-friendly" carbon or non-carbon sorbents that require more AEA but allow fly ash to pass concrete wholesalers' screening tests, and
- ash beneficiation processes that recycle carbon sorbents or remove them by burning them out of the ash.

Of course, plant owners can side-step the problem of carbon sorbent in ash by installing TOXECONs. TOXECON™ is an EPRI-patented process that injects sorbent between an existing particulate control device (ESP or FF) and a downstream FF; TOXECON™ II injects sorbent between the first fields of an ESP. These installations produce two ash streams—one that is uncontaminated with activated carbon and can continue to be sold, and one that consists mostly of activated carbon.

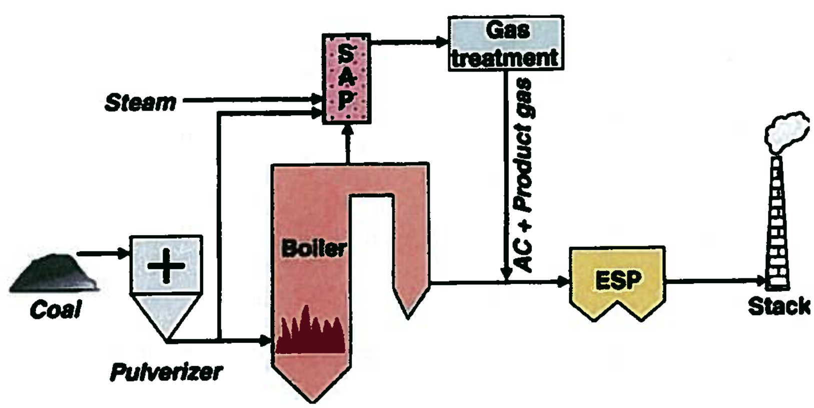
6. Improve sorbent effectiveness, reduce sorbent use and cost

Mercury control has been enhanced by on-site grinding to reduce sorbent size and injection before the air preheater to maximize contact time (Alstom's Mer-Cure process), as well as by optimizing sorbent injection design and mixing (especially for TOXECON applications). Future tests will look for additional ways to improve sorbent effectiveness while reducing use and containing costs. Some improvements will come from novel concepts described below.

7. Develop lower cost alternatives to ACI and halogen addition

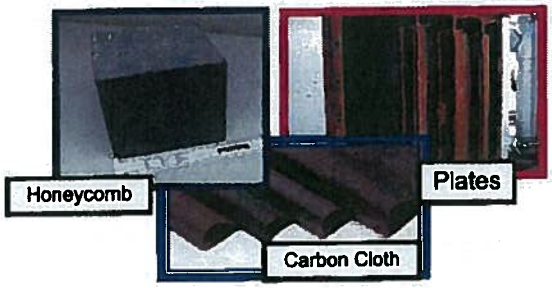
EPRI is pursuing novel mercury control concepts that could be highly efficient and cost-effective. The first example is the Sorbent Activation Process (SAP), patented jointly by EPRI and the Illinois State Geological Survey (Figure 10). In SAP, activated carbon is produced on-site from facility coal which is processing in an entrained, steam-driven activation reactor and then injected directly into the flue gas upstream of a particulate control device. SAP can be used to prepare activated carbons with various surface areas, pore structures, and surface chemistries (halogenated AC) from western and eastern bituminous coals.

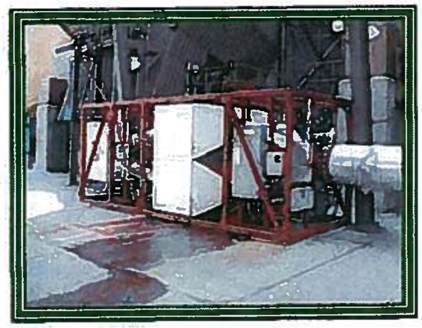
Figure 10. SAP system incorporated in an existing power plant



The second example involves fixed carbon structures—such as honeycombs, woven screens, or plates—installed just downstream of a particulate control device (Figure 11). These fixed structures capture flue gas mercury very efficiently, without affecting fly ash, and their carbon base can be regenerated using standard commercial processes. EPRI's project team has designed and fabricated a 2 MWe pilot unit to test this technology.

Figure 11. Fixed Structure Concepts with 2 MWe Pilot Unit





SUMMARY

High levels of mercury removal (> 90%) are attainable using ACI at western coal-fired units with fabric filters and TOXECONs. Similar performance requires brominated ACI at units with ESPs. Alternately, units firing western coals can use boiler bromide addition alone to increase flue gas mercury oxidation and downstream capture in a wet scrubber, or to enhance mercury removal by ACI. Thus, SD-FFs or SD-ESPs use brominated ACI or ACI plus boiler bromide addition for high removals. Mercury removals at eastern bituminous-fired units with ESPs fall short of these levels, largely due to the high sulfur content of the coal or the use of SO_3 flue gas conditioning to improve ESP performance.

Although ACI and, to a lesser extent, boiler bromide addition are nearing commercial readiness, significant issues stand in the way of confident performance and cost predictions. Resolution of these issues will involve full understanding of the factors that affect mercury removal performance, the fate of mercury and sorbents in plant waste streams, and the unintended impacts of these control technologies on power plant operation. Furthermore, most full-scale tests discussed in this paper have demonstrated high mercury removals for periods of less than a month. Only issue resolution and successful, long-term performance testing will allow the electric utility industry to guarantee compliance with mercury emission standards set by federal and state regulators. Meanwhile, EPRI is responding to challenges presented by the need for more effective, less costly long-term mercury control.

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KEY WORDS

activated carbon injection
brominated activated carbon injection
boiler bromide addition
mercury control costs

Exhibit 5

Feeley, Thomas J. III, *et al.*, *DOE/NETL's Mercury Control Technology R&D Program – Taking Technology from Concept to Commercial Reality*, Paper # 42 MEGA Symposium (2008)

DOE/NETL's Mercury Control Technology R&D Program – *Taking Technology from Concept to Commercial Reality*

Paper # 42

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ABSTRACT

DOE/NETL has worked with industry, research organizations, and academia to develop advanced mercury (Hg) control technology for coal-based power systems. Over the past seven years, this research has focused on the full-scale and slip-stream field testing of activated carbon injection (ACI) and flue gas desulfurization enhancements at nearly 50 U.S. coal-fired power plants. The goal of the field testing was to demonstrate high levels (50 to 90 percent) of Hg capture over an extended period of operation, while also reducing the cost of Hg removal. The field testing program has successfully met this goal. Due in large part to this success, coal-fired power plant operators have initiated commercial deployment of Hg control technology. As of April 2008, nearly 90 full-scale ACI systems have been ordered by U.S. coal-fired power generators, accounting for over 44 gigawatts of coal-fired electric generating capacity. This paper will provide an update on DOE/NETL's Hg control technology R&D program, including an assessment of the cost of capture.

INTRODUCTION

Since first being identified for potential regulation in the 1990 Clean Air Act Amendments, there has been concern within the industry whether it would be possible to develop cost-effective emission control technologies for mercury (Hg) because of its low concentration and reactivity during coal combustion. However, while technical issues remain, the U.S. Department of Energy's National Energy Technology Laboratory (NETL) has been successful, through public-private partnerships, in significantly improving both the cost and performance of Hg control technology.

Under the Office of Fossil Energy's Innovations for Existing Plants (IEP) Program, NETL has carried out a comprehensive Hg research and development (R&D) program for coal-fired power generation facilities since the mid-1990s.[1] Working collaboratively with the U.S. Environmental Protection Agency (EPA), the Electric Power Research Institute (EPRI), the University of North Dakota Energy and Environmental Research Center, power plant operators, state and local agencies, and a host of research organizations and academic institutions, the IEP Program has fostered the development of reliable measurement techniques for the different chemical forms of Hg. And through sampling and data analysis, identified the primary factors that affect Hg speciation and capture in coal combustion flue gas, ultimately leading to the development of cost-effective Hg control technologies.

Analysis of flue gas samples has revealed that the trace amount of Hg present in coal is volatilized during combustion and converted to gaseous elemental mercury (Hg^0). Subsequent cooling of the flue gas and interaction of Hg^0 with other flue gas constituents, such as chlorine and unburned carbon, result in a portion of the Hg^0 being converted to gaseous oxidized forms of mercury (Hg^{2+}) and particulate-bound mercury (Hg_P).[2]

As a result, coal combustion flue gas contains varying percentages of Hg_P, Hg^{2+}, and Hg^0 and the exact speciation has a profound effect on the Hg capture efficiency of existing air pollution control device (APCD) configurations, which has been found to range from 0 to over 90 percent.[3] The Hg_P fraction is typically removed by a particulate control device such as an electrostatic precipitator (ESP) or fabric filter (FF). The Hg^{2+} portion is water-soluble and therefore a relatively high percent can be captured in wet flue gas desulfurization (FGD) systems, while the Hg^0 fraction is generally not captured by existing APCD. In addition, operation of a selective catalytic reduction system has been shown to promote Hg^0 oxidation and enhance Hg capture across a downstream FGD.[4]

Generally speaking, Hg speciation research spearheaded by NETL has revealed that: (1) several key factors influence Hg speciation in coal combustion flue gas; (2) Hg speciation impacts the level of Hg control achieved by existing APCD configurations; and (3) "co-benefit" Hg capture across existing APCD configurations can be enhanced.

EXPERIMENTAL METHOD

This knowledge was subsequently funneled into the development of a suite of Hg control technologies for the diverse fleet of U.S. coal-fired power plants. NETL initiated an R&D program in the mid-1990s directed at two general approaches for controlling Hg -- (1) Hg-specific control technology such as sorbent injection and (2) Hg^0 oxidation concepts that maximize co-benefit removal of Hg^{2+} in wet FGD systems. In 2000, following laboratory through pilot-scale development of these approaches, NETL launched a three-phase field testing program. This program called for the installation and full-scale and slip-stream testing of the most promising Hg control technologies at operating coal-fired power plants.

The initial field testing (Phase I) focused on untreated activated carbon injection (ACI) and improving the capture of Hg across wet FGD systems, while Phase II, which began in 2003, was expanded to include longer-term, full-scale field testing of chemically-treated ACI, sorbent enhancement additives (SEA), and sorbent-based technologies designed to preserve fly ash quality. Phase II also included evaluations of chemical additives and Hg^0 oxidation catalysts designed to enhance FGD Hg capture. The goal of Phases I and II was to develop Hg control technologies (available for commercial demonstration by year-end 2007 for all coal ranks) that could achieve 50 to 70 percent Hg capture at costs 25 to 50 percent less than the baseline (1999) estimate of about \$60,000 per pound of Hg removed (\$/lb Hg removed).

Although 30-day long-term tests were conducted in Phase II, the test period was not sufficient to answer many fundamental questions about long-term consistency of Hg removal and reliability of the system when integrated with plant processes. To assess potential balance-of-plant impacts associated with continuously operating a Hg-specific control technology for several months to years, NETL awarded nine new projects in 2006 to conduct Hg control tests of mature technologies at full-scale coal-fired units and novel concepts in the laboratory. The Phase III projects support the IEP Program's longer-term goal of developing advanced Hg control technologies (available for commercial demonstration by 2010) that could achieve at least 90 percent capture at costs 50 to 75 percent less than $60,000/lb Hg removed.

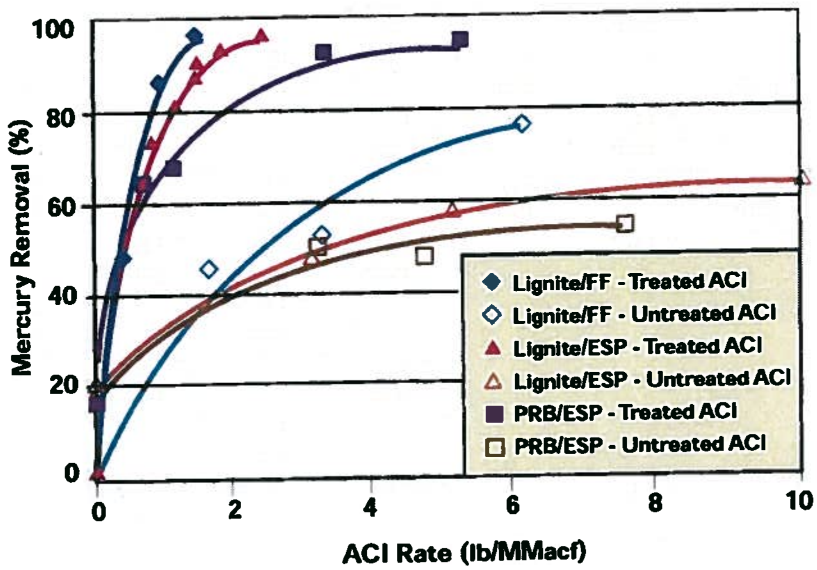
RESULTS AND DISCUSSION

Over the past seven years, the IEP Program has managed full-scale field tests of Hg control technologies at nearly 50 U.S. coal-fired power plants. The flexibility of the IEP Program allowed NETL to quickly incorporate insights and lessons learned from its partners into the development of advanced Hg control technologies tailored to specific areas of need. For instance, a determination that chlorine released during coal combustion promotes Hg oxidation in flue gas led to field testing of technologies designed to provide a halogen "boost" for coals, such as subbituminous and lignite, that tend to contain low levels of chlorine. NETL has observed a step-change improvement in both the cost and performance of Hg control during full-scale field tests of chemically-treated ACI upstream of a particulate control device, and coal treatment with an aqueous calcium bromide ($CaBr_2$) solution at plants equipped with a wet FGD system.

Chemically-treated Sorbent Injection

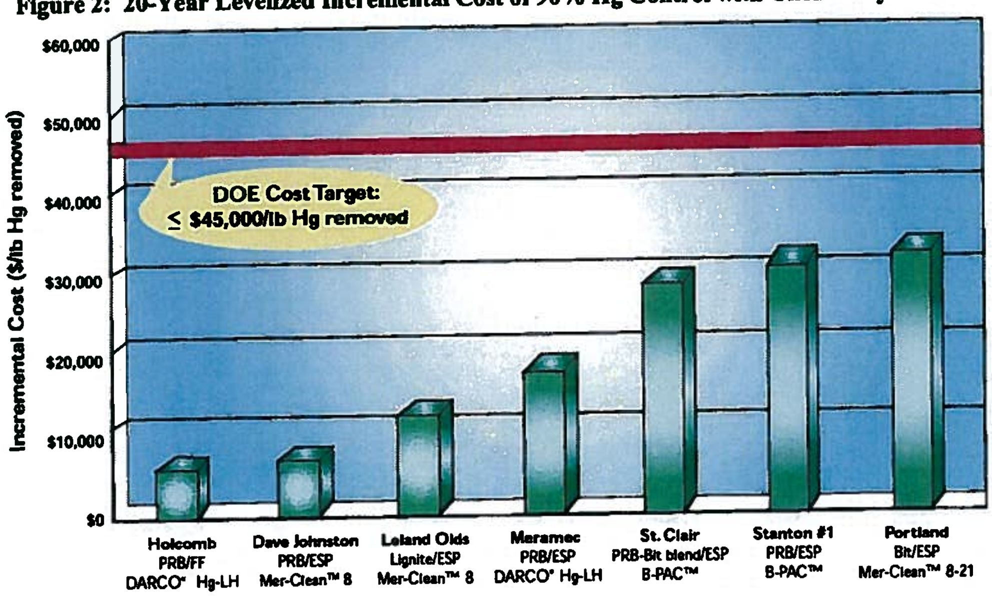
The development, and subsequent field testing, of chemically-treated ACI represents a concerted effort to enhance Hg capture at units firing low-rank coal after Phase I results at We Energies' Powder River Basin (PRB) subbituminous coal-fired Pleasant Prairie Unit 2 showed total Hg removal via untreated ACI was limited to about 65 percent.[5] Figure 1 provides a comparison of untreated and chemically-treated ACI performance at three of NETL's Phase II field testing sites: (1) Great River Energy's Stanton Station Unit 10 (lignite/FF); (2) Basin Electric's Leland Olds Station Unit 1 (lignite/ESP); and (3) Stanton Station Unit 1 (PRB/ESP). These parametric data curves illustrate the improved Hg capture efficiency of chemically-treated sorbents at power plants burning lower-rank coals as high levels of Hg capture are attainable at relatively low injection rates. In fact, the treated sorbents achieved at least 90 percent total Hg capture at an injection rate of 3 pounds per million actual cubic feet (lb/MMacf) of flue gas or less at these Phase II field testing sites.

Figure 1: Comparison of Untreated and Chemically-treated ACI Performance at Facilities Burning Lower-Rank Coals



An NETL economic analysis[6] released in May 2007 indicates that the high Hg capture efficiency of chemically-treated sorbents has drastically reduced the estimated cost of Hg control due to a reduction in the injection rate required to achieve a given level of control, which offsets the higher cost of these treated sorbents. As shown in Figure 2, the 20-year (current dollar) levelized incremental cost of 90 percent ACI Hg control ranges from about $30,000 to less than $10,000/lb Hg removed for seven of NETL's Phase II field testing sites where chemically-treated ACI was evaluated. These results point to the fact that NETL has surpassed the Hg control cost goal set forth by the IEP Program.

Figure 2: 20-Year Levelized Incremental Cost of 90% Hg Control with Chemically-treated ACI



Technical Issues Associated with Sorbent Injection

While the advent of chemically-treated ACI has yielded improvements in Hg control cost and performance, technical uncertainties remain. The following issues, if resolved, will further enhance the efficiency, economics, applicability, and reliability of sorbent-based Hg control technologies.

Fly Ash Impacts

The typical ACI system is located upstream of a particulate control device to enable simultaneous capture of the spent sorbent and fly ash. This Hg control strategy leads to commingling of the sorbent and fly ash that can prohibit certain fly ash recycling efforts. One of the highest-value reuse applications for fly ash is as a substitute for Portland cement in concrete production.[7] The utilization of fly ash in concrete production is particularly sensitive to carbon content as well as the surface area of the carbon present in the fly ash. Accordingly, NETL's Hg control technology portfolio includes alternative sorbent injection technologies designed to minimize fly ash carbon contamination caused by ACI upstream of a particulate control device.

<u>TOXECON™ Configuration</u>
The toxic emissions control (TOXECON™) configuration, developed by EPRI, will not impact fly ash utilization since the ash is removed by an ESP upstream of the sorbent injection location, while the spent sorbent is captured by a downstream FF. TOXECON™ was selected for a first-of-a-kind commercial Hg control technology demonstration at We Energies' Presque Isle Power Plant in Marquette, Michigan, under DOE's Clean Coal Power Initiative. Operational since 2006, the TOXECON™ configuration maintained greater than 90 percent total Hg removal for 48 consecutive days. Sorbent injection rates of about 1.7 and 1.2 lb/MMacf are required to achieve at least 90 percent total Hg removal with untreated DARCO® Hg and brominated DARCO® Hg-LH, respectively.[8]

<u>TOXECON II™ Configuration</u>
EPRI's TOXECON II™ technology injects sorbents directly into the downstream collecting field(s) of an ESP. Since the majority of fly ash (~90 percent) is collected in the upstream ESP fields, only a small portion of the total collected ash contains spent sorbent. During full-scale TOXECON II™ testing at Entergy's PRB-fired Independence Station Unit 1, DARCO® Hg-LH injection at 5.5 lb/MMacf achieved 90 percent total Hg removal.[9] A remaining concern with any Hg control strategy involving sorbent injection, particularly the TOXECON II™ configuration that limits ESP residence time, is the potential for increased particulate emissions that could trigger New Source Review requirements.

<u>"Ash-friendly" Sorbents</u>
Activated carbon sorbents passivated during production could potentially allow coal-fired power generators to continue marketing fly ash commingled with the spent sorbent as a suitable replacement for Portland cement in concrete. Sorbent Technologies conducted a 30-day long-term evaluation of their brominated, "concrete-friendly" C-PAC™ sorbent at Midwest Generation's PRB-fired Crawford Station Unit 7.[10] Total Hg removal averaged 81 percent with C-PAC™ injection upstream of the ESP at about 4.6 lb/MMacf.

More recently, a high-temperature version of C-PAC™ was tested at Midwest Generation's PRB-fired Will County Unit 3, which is equipped with a hot-side ESP.[11] During a six-day continuous test, Hg removal ranged from about 60 to 73 percent with C-PAC™ injection at 5 lb/MMacf. Most importantly, preliminary results indicate that fly ash collected during C-PAC™ injection at these sites remains suitable for reuse in concrete production.

During Phase III testing at Lower Colorado River Authority's PRB-fired Fayette Unit 3, ALSTOM evaluated three sorbents (eSorb™ 11, eSorb™ 13, and eSorb™ 18) designed by Envergex to preserve fly ash quality.[12] Results indicate that fly ash remains marketable with eSorb™ 13 at about 0.5 lb/MMacf (~85 percent ACI Hg capture).

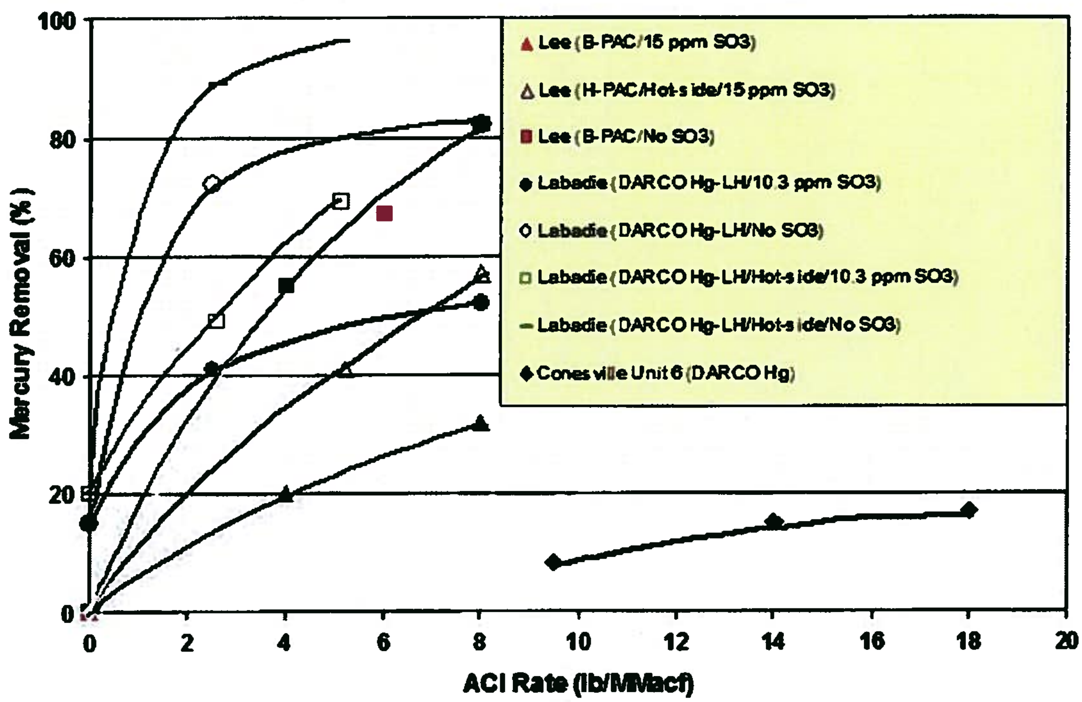
Sulfur Trioxide Interference

Field testing has shown that sulfur trioxide (SO_3) in the flue gas, even at low concentrations, can impede the performance of ACI. It appears that SO_3 competes with Hg for adsorption sites on the sorbent surface thereby limiting its performance.[13]

During Phase II field testing at AEP's high-sulfur (3 to 4 percent) bituminous-fired Conesville Station Unit 6, total Hg removal was limited to approximately 30 percent with chemically-treated ACI at 12 lb/MMacf.[14] Consequently, a long-term field test was not conducted at this unit; instead, NETL funding was used to evaluate the impact of SO_3 flue gas conditioning (FGC) on ACI performance at AmerenUE's PRB-fired Labadie Station Unit 2.[15] As shown in Figure 3, turning the SO_3 FGC system off at Labadie increased total Hg removal from about 50 to 80 percent with DARCO® Hg-LH injection at 8 lb/MMacf. Greater than 90 percent Hg removal was observed with no SO_3 injection and DARCO® Hg-LH injection upstream of the air preheater (APH) at about 5 lb/MMacf. The performance of brominated B-PAC™ was also impacted by SO_3 FGC at Progress Energy's Lee Station Unit 1.[16] With B-PAC™ injection at 8 lb/MMacf, Hg capture increased from 32 to 82 percent when SO_3 FGC was idled.

One possible solution to the SO_3 issue is dual injection of Hg sorbents and alkaline materials. This approach was explored during a Phase III field test at Public Service of New Hampshire Company's Merrimack Station Unit 2, which utilizes a cyclone-fired boiler to burn a blend of bituminous coals (~1 percent sulfur) and is equipped with a selective catalytic reduction (SCR) system followed by two ESPs in series.[17] During parametric testing, several Hg sorbents were evaluated both with and without the injection of magnesium oxide (MgO) or sodium sesquicarbonate (trona) – two potential SO_3 mitigation additives. Results indicate that trona injection enhanced ACI performance to a greater degree than MgO; however, the sodium content of trona may limit fly ash recycling opportunities. Without SO_3 mitigation, Hg removal was limited to about 22 percent with brominated DARCO® Hg-LH injection between the two ESPs at 8 lb/MMacf. Untreated DARCO® Hg injection at 8 lb/MMacf, coupled with trona injection, resulted in about 65 percent Hg removal. During a continuous injection test completed in March 2008, 50 percent Hg removal was achieved with trona injection upstream of the APH at 500 lb/hr and DARCO® Hg-LH injection between the two ESPs at about 4 lb/MMacf.

Figure 3: Impact of Flue Gas SO_3 on ACI Performance



Enhancing FGD Hg Capture

Oxidation of flue gas Hg^0 followed by absorption of Hg^{2+} across a wet FGD system has the potential to be a reliable and cost-effective Hg control strategy for some coal-fired power plants. To optimize Hg capture across FGD systems, NETL is funding the development of technologies that promote Hg^0 oxidation in coal combustion flue gas: chemical additives and Hg^0 oxidation catalysts. The impact of combustion modifications, such as coal reburn, on flue gas Hg^0 oxidation has also been examined under the IEP Program.[18] In addition, DOE/NETL field tested FGD additives designed to suppress Hg^0 re-emissions across the scrubber.

Chemical Additives

The ability of chemical additives, sprayed onto the coal as an aqueous salt solution, to promote flue gas Hg^0 oxidation and enhance FGD Hg capture has been evaluated during NETL full-scale field tests completed at Minnkota Power Cooperative's Milton R. Young (MRY) Unit 2 and Luminant Power's Monticello Station Unit 3.[19] MRY Unit 2 fires ND lignite coal in a cyclone boiler and is equipped with an ESP and wet FGD. During the 30-day long-term test at MRY Unit 2, total Hg capture across the ESP/FGD configuration ranged from 50 to 65 percent with dual injection of the proprietary SEA2 additive at 60-100 parts per million (ppm), on a dry coal basis, and the untreated DARCO® Hg sorbent at 0.15 lb/MMacf.

During a two-week trial conducted at Monticello Station, which burns a 50:50 blend of PRB and Texas lignite coals, total Hg capture across the ESP/FGD configuration averaged 86 percent with a $CaBr_2$ injection rate equivalent to 113 ppm Br in the coal. Greater than 90 percent total Hg capture was observed during a short-term test with a $CaBr_2$ injection rate equivalent to 330 ppm Br in the coal.

Hg^0 Oxidation Catalysts

The ability of fixed-bed catalysts to promote flue gas Hg^0 oxidation has been evaluated at pilot-scale, and a two-year, full-scale field test of a gold-based catalyst began in May 2008 at Lower Colorado River Authority's Fayette Unit 3.[20] The catalysts are designed for installation downstream of an ESP or FF, to: (1) minimize fly ash deposition on the catalysts; (2) prevent or minimize catalyst erosion; and (3) ensure a low flue gas temperature and flow rate, which reduces the catalyst space velocity and minimizes the volume of catalyst required.

During pilot-scale testing at Great River Energy's North Dakota (ND) lignite-fired Coal Creek Station, about 67 percent Hg^0 oxidation was measured across a palladium-based (Pd#1) catalyst, after 20 months of operation. Following thermal regeneration, Hg^0 oxidation across the Pd#1 catalyst increased from 67 to 88 percent (near the 95 percent activity of the fresh catalyst). Meanwhile, nearly 80 percent total Hg capture was observed across the pilot-scale wet FGD, with 84 percent Hg^{2+} at the FGD inlet.

At Luminant Power's Monticello Station, severe fly ash buildup was observed on the catalyst surfaces, likely caused by frequent pilot unit outages during the test campaign. Following catalyst cleaning, Hg^0 oxidation was approximately 72 percent across the regenerated Pd#1 catalyst (transferred from Coal Creek) and 66 percent across a gold-based catalyst, after about 20 months of pilot-scale operation. Total Hg capture across a pilot-scale wet FGD ranged from 76 to 87 percent, compared to only 36 percent removal under baseline conditions. This equates to about 70 percent incremental Hg capture due to the catalysts.

Addressing Hg^0 Re-emissions across FGD Systems

NETL has also conducted pilot- and full-scale field tests of wet FGD additives designed to limit Hg^0 re-emissions through the formation of insoluble salts with Hg^{2+}.[21] Originally thought to be a sampling artifact, Hg^0 re-emissions have been observed at several coal-fired units and occur when Hg^{2+} captured by a wet FGD is chemically-reduced within the vessel and re-emitted as Hg^0.

The effectiveness of Degussa Corporation's TMT-15 additive in suppressing Hg^0 re-emissions was inconclusive at pilot-scale due to: (1) the absence of re-emissions, even without chemical addition, at Monticello Station; and (2) Hg measurement issues at Southern Company's bituminous-fired Plant Yates. However, TMT-15 had the anticipated impact on FGD by-products as the FGD liquor Hg concentrations were significantly reduced during both tests. During a full-scale field test at Indianapolis Power & Light's Petersburg Station, which burns high-sulfur bituminous coal, a modest decline in Hg^0 emissions was observed during an eight-day TMT-15 injection test, but the additive did not impact the partitioning of Hg in FGD by-products at this site. Meanwhile, full-scale results obtained during a 30-day evaluation of Nalco Company's 8034 additive at Plant Yates were confounded by low baseline Hg^0 re-emission levels.

A third wet FGD additive, Babcock & Wilcox's Absorption Plus(Hg)™, was evaluated at E.ON America's high-sulfur bituminous-fired Mill Creek Station after parametric trials revealed that untreated ACI had little, if any, impact on Hg removal.[22] During long-term testing, total Hg removal averaged about 92 percent with the addition of Absorption Plus(Hg)™. Note that over 80 percent total Hg removal was observed under baseline conditions.

Novel Hg Control Concepts

Innovative techniques for Hg control that could eventually replace and/or augment the more mature technologies previously discussed are also being explored under the IEP Program. The following is a brief discussion of these NETL-funded efforts.

MerCAP™

The Hg control via adsorption process (MerCAP™) relies on fixed structure sorbents positioned in the flue gas stream to adsorb Hg and then, as the sorbent becomes saturated, regenerate the sorbent and recover the Hg. An initial retrofit application of the MerCAP™ technology is for "polishing" control of Hg^0 downstream of FGD systems. During two six-month extended pilot-scale tests, the performance of gold-coated MerCAP™ plates was evaluated downstream of a: (1) spray dryer adsorber and fabric filter (SDA/FF) configuration at Great River Energy's Stanton Station Unit 10; and (2) wet FGD system at Plant Yates Unit 1.[23]

After more than 6,000 hours of continuous operation at Stanton Station, Hg removal averaged 30 to 35 percent across the acid-treated MerCAP™ plates and 10 to 30 percent across the untreated plates. Testing also revealed that regeneration via acid treatment and tighter plate spacing (½-inch vs. 1-inch) improved the Hg capture efficiency of the MerCAP™ technology. At Plant Yates, Hg removal decreased from 15 to 3 percent during the first three days of pilot-scale MerCAP™ operation. It was believed that limestone slurry carryover from the FGD system was inhibiting Hg reactions. Subsequent use of a water wash system for the plates was able to restore Hg removal to 15 percent.

Low Temperature Mercury Capture Process

Full-scale testing of the Low Temperature Mercury Capture (LTMC) process will be conducted at a bituminous coal-fired power plant that is equipped with a CS-ESP. LTMC has the ability to reduce Hg emissions by over 90 percent, as was recently shown on a slip-stream pilot plant at Allegheny Power's Mitchell Station. The LTMC process controls Hg by cooling the flue gas temperature to about 220°F, which promotes Hg adsorption on the unburned carbon inherent in fly ash. To avoid corrosion at the low-temperature conditions, the SO_3 concentration will be controlled through magnesium hydroxide slurry injection. The project will also demonstrate that water spray humidification can maintain ESP performance under low-SO_3 conditions. A two-month test will be conducted to evaluate long-term performance and any potential balance-of-plant impacts.

Sorbents Produced On-Site

A new Hg control technology that relies on sorbents produced from coal in a gasification process in-situ at the power plant is also being explored.[24] Pilot-scale testing will attempt to optimize the gasification process to maximize sorbent reactivity while minimizing the cost of sorbent production. Optimization will be conducted with respect to (1) coal type, (2) parameters of the gasification process, and (3) sorbent injection rate required to achieve at least 70 percent Hg removal. Among parameters of the gasification process to be optimized are: composition of solid fuel/air mixture in the gasifier; gasifier temperature; and mixture residence time in the gasifier. Work will also evaluate the stability of Hg captured by the sorbent and effect of the sorbent on fly ash salability.

Preliminary results indicate that surface area of the partially gasified coal is affected by conditions in the gasification zone, optimal conditions in the gasification zone are dependent on coal properties. The highest sorbent surface area produced to date was 383 m^2/g. Further, analysis of sorbent samples kept in storage for up to 40 days suggests that sorbent surface area is not affected by shelf life. Final optimization of Hg removal will be conducted in 2008.

Pre-combustion Thermal Treatment

A novel process to achieve pre-combustion Hg removal from raw coal via dual stage thermal treatment is also being evaluated.[25] In the first stage, the moisture in the fuel is driven-off; in the second stage, coal is heated by nearly inert gas resulting in significant removal of coal-bound Hg. Bench-scale testing has revealed the percentage of Hg released from the coals varied from 50 to 87 percent, depending on residence time. In addition, initial results from a fixed-bed test unit indicate that high temperature sorbents will be available to remove Hg from the process recycle sweep gas in the temperature range of 550 to 600°F. Pilot-scale testing (100 lb/hr) is currently being conducted to assess and scale-up results from the bench-scale tests. The pilot unit will examine two different Hg removal configurations: a vibratory fluid bed, and a proprietary vertical reactor.

NETL In-house Development of Novel Control Technologies

After studying numerous sorbents for Hg capture in simulated coal-derived gases, scientists at NETL discovered and patented three trace metal capture technologies that are now licensed and in commercial demonstration. The Thief process, licensed to Nalco-Mobotec USA, is a cost-effective method to produce sorbent *in situ* by extracting partially combusted coal from the furnace, which is subsequently injected downstream into the flue gas as an alternative to conventional ACI. The cost for producing Thief carbon sorbents ranges from $90 to $200 per ton. The Photochemical Oxidation (PCO) process, licensed to Powerspan Corporation, introduces a 254-nm ultraviolet light into the flue gas, leading to enhanced Hg oxidation and capture. NETL researchers received the 2005 Award for Excellence in Technology Transfer from the Federal Laboratory Consortium (FLC) for the PCO method.

Recognizing the need for a low-cost technique to remove Hg from coal-based Integrated Gasification Combined Cycle power plants, NETL researchers have invented a new palladium (Pd) based sorbent that works on fuel gas at elevated temperatures. Unlike conventional sorbents such as activated carbon, which operate at lower temperature, high temperature Pd sorbents remove Hg and arsenic at temperatures above 500°F, and have more than twice the capacity of previously existing sorbents, resulting in a major improvement in overall energy efficiency of the power combustion process. NETL researchers received the 2008 Award for Excellence in Technology Transfer from the FLC for developing the Pd-based Hg sorbents licensed to Johnson Matthey.

SUMMARY

Insight into the factors that can influence Hg speciation and capture in coal combustion flue gas has allowed NETL to prioritize the search for reliable and cost-effective Hg control strategies. A determination that chlorine released during coal combustion promotes Hg^0 oxidation in flue gas led to field testing of technologies designed to provide a halogen "boost" for coals, such as subbituminous and lignite, that tend to contain low levels of chlorine. NETL has observed a step-change improvement in both the cost and performance of Hg control during full-scale field tests with chemically-treated ACI and $CaBr_2$ coal treatment. The improved Hg capture efficiency of these advanced control technologies has allowed NETL to satisfy the cost and performance goals set forth by the IEP Program.

Although the Federal regulatory structure for Hg emissions from coal-fired power plants is once again uncertain following the vacatur of EPA's Clean Air Mercury Rule on February 8, 2008,[26] NETL's field testing program has successfully brought Hg control technologies to the point of commercial-deployment readiness. As of April 2008, nearly 90 full-scale ACI systems, a signature technology of the IEP Program, have been ordered by U.S. coal-fired power generators.[27] These contracts represent over 44 gigawatts (GW) of coal-fired electric generating capacity. This includes approximately 33 GW of existing capacity (~10 percent of total U.S. coal-fired capacity). The ACI systems have the potential to remove more than 90 percent of the Hg in many applications based on results from NETL's field testing program, at a cost estimated to dip below $10,000/lb Hg removed. However, while the results achieved during NETL's field tests met or exceeded program goals, only through experience gained during long-term continuous operation of these advanced technologies in a range of full-scale commercial applications will their actual costs and performance be determined.

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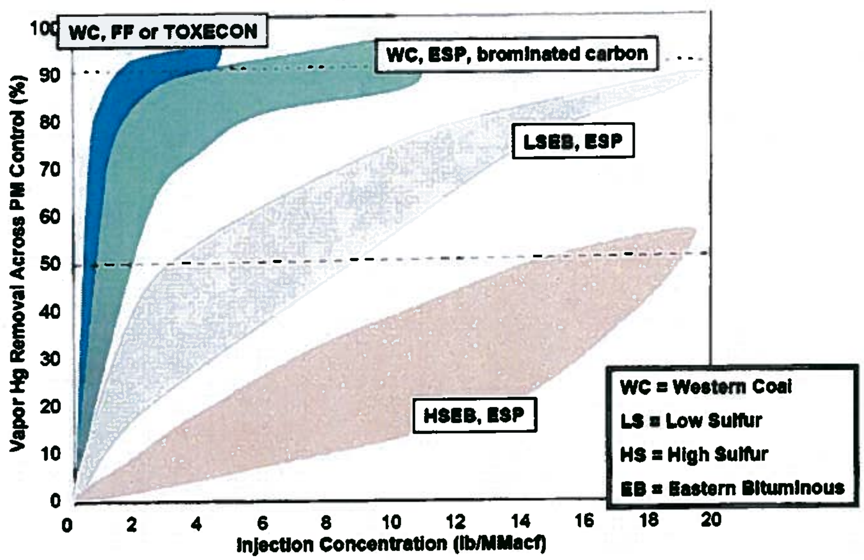
Exhibit 6

Sargent & Lundy, "Mercury Off-set for Baldwin Unit 3," Proj.No. 12111-003 Dynegy (November 26, 2008)

Mercury Off-set for Baldwin Unit 3

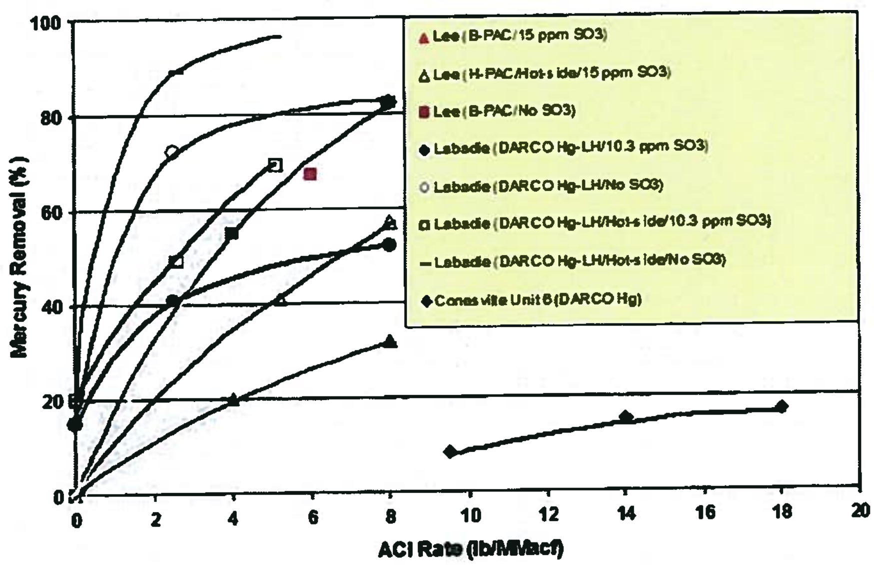
The attached calculations show the possibility of trade-off of Hg emission between Havana Unit 6/Hennepin Unit 2 and Baldwin Unit 3. To achieve such a trade off, Dynegy intends to operate Hg control with brominated activated carbon injection with baghouse. The technology is expected to achieve overall 90% Hg removal from coal to the stack. Attached is the graph showing mercury removal efficiency with ACI/baghouse.

Figure 1: Hg removal efficiencies with various technologies (MEGA Symposium 2008, Ramsay Chang)



According to Illinois Hg rule, Baldwin Unit 3 is required to operate with brominated carbon injection with existing ESP of at least 5 lb/mmacf carbon injection rate or achieve 90% Hg removal. However, if the injection of activated carbon causes non-compliance with either the opacity or particulate limits due to size of ESP, then the rate can be lowered. Currently, to achieve opacity limit of 30%, Baldwin Unit 3 has to use SO3 conditioning system. The injection of SO_3 has shown adverse effect on the Hg removal efficiency with activated carbon. The attached figure shows the impact of SO_3 conditioning system on Hg removal with ESP.

Figure 2: Impact of SO3 conditioning on Hg Removal (MEGA Symposium 2008, Feely et.al.)



Overall, a maximum of 70% Hg removal efficiency is expected with SO3 conditioning at Baldwin Unit 3.

Based on these efficiencies, it is estimated that for 6 months of operation, Hennepin 2 and Havana Unit 6 will be able to generate approximately 146 lbs of Hg due to early operation which would be used to off-set 127 lbs of Hg that could have been controlled with brominated carbon injection ahead of existing ESP on Baldwin Unit 3.

Proj.No.12111-003

Dynegy

Sargent & Lundy
Date 1/7/2009

Predictions of Mecury Emissions Off-sets for Baldwin Unit 3, 70% Removal

	Havana	Hennepin 2	Baldwin 3
Plant Net Generation, MW	424	221	600
Net Heat Rate, Btu/kW	11,600	10,300	10,100
PRB, Heating value, Btu/lb	8,600	8,600	8,600
Moisture in Fuel, %	30	30	30
Chlorine, ppmd	25	25	25
Hg, ppmd	0.08	0.08	0.08
Capacity Factor, %	85	85	90
Expected Removal Efficiency w/o control, %	5.0	10.0	10.0
Hg Control Technology	ACI/Baghouse	ACI/Baghouse	ACI/ESP
Expected total removal Efficiency, %	90	90	70
Start Date	07/01/09	07/01/09	07/01/09
End Date	12/31/09	12/31/09	03/06/10
Days of removal/non-operation	**183**	**183**	**248**
Hg, lb/TBtu	**6.5**	**6.5**	**6.5**
Outlet Emission after Hg control, lb/TBtu	**0.65**	**0.65**	**1.95**
Outlet Emission, lb/hr	**0.00320**	**0.00148**	**0.01184**
Hg Removal due to controls, lb/hr	**0.02722**	**0.01186**	**0.02368**
Havana, Hennepin removal, lbs	**101.63**	**44.27**	
Required Off-set for Baldwin Unit 3, lbs			**126.83**
Total Available Off-set, lbs	**145.90**		**-19.07**

Exhibit 7

Construction permit issued for Baldwin Unit 3, as stayed by the Board on May 15, 2008, in Docket 08-66

ILLINOIS POLLUTION CONTROL BOARD
May 15, 2008

DYNEGY MIDWEST GENERATION, INC. (BALDWIN ENERGY COMPLEX),	)	
Petitioner,	)	
v.	)	PCB 08-66 (Permit Appeal - Air)
ILLINOIS ENVIRONMENTAL PROTECTION AGENCY,	)	
Respondent.	)	

ORDER OF THE BOARD (by N.J. Melas):

By order of April 17, 2008, the Board accepted for hearing the April 9, 2008 petition for review (Pet.) of a March 3, 2008 construction permit issued to Dynegy Midwest Generation, Inc. (Dynegy) by the Illinois Environmental Protection Agency (Agency). *See* 415 ILCS 5/40(a)(1) (2006); 35 Ill. Adm. Code 105.206(a). The Agency granted Dynegy a construction permit for installation of a baghouse, scrubber, and sorbent injection control system for Unit 3 at the Baldwin Energy Complex located at 10901 Baldwin Road, Baldwin, Randolph County.

Dynegy appeals many permit conditions it alleges the Agency has inappropriately included, citing a variety of grounds:

> One category addresses inclusion of provisions for which the Agency has no underlying authority to require. A second category of issues concerns the Agency's treatment of the mercury rule adopted by the Board at 35 Ill. Adm. Code Part 225. Dynegy also appeals provisions that were appealed in the CAAPP [Clean Air Act Permit Program] appeal, PCB 06-063, or are otherwise CAAPP-related. Dynegy objects to certain testing, recordkeeping, and reporting provisions in the permit and has other general objections. Pet. at 5.

In the body of its petition, Dynegy includes a request for partial stay of the permit. (Pet. at 3-5, and Exh. 2. In its April 17, 2008 order accepting the petition for hearing, the Board reserved ruling on the requested stay pending any Agency response. To date, the Board has received no response from the Agency regarding Dynegy's request for a stay. Section 101.500(d) of the Board's procedural rules provides that, "[w]ithin 14 days after service of a motion, a party may file a response to the motion. If no response is filed, the party will be deemed to have waived objection to the granting of the motion, but the waiver of objection does not bind the Board or the hearing officer in its disposition of the motion." 35 Ill. Adm. Code 101.500(d).

In its request for a partial stay, Dynegy notes that, "[h]istorically, the Board has granted partial stays in permit appeals where a petitioner has so requested." Pet. at 3-4 (citations omitted). Stressing the risk that it will suffer irreparable harm and that the environment will not benefit from improved pollution control, Dynegy asks "that the Board exercise its inherent discretionary authority to grant a partial stay of the construction permit". *Id.* at 4. Specifically, Dynegy requests that the Board:

> grant a partial stay of the construction permit, staying only those conditions or portions of conditions indicated in Exhibit 2, i.e., Conditions 1.1(a), 1.2(b), 1.3, 1.4(a) Notes, 1.5, 1.6(a)(i), 1.6(a)(i) Note, 1.6(a)(ii), 1.6(a)(ii) Note, 1.6(a)(iv), 1.7(a)(i), 1.7(b)(ii)(B), 1.7(c) 1.7(e)(v), 1.7(e)(viii), 1.7(e) Note, 1.8(a), 1.8(c), 1.8 Note, 1.9-1, 1.9-2, 1.9-3, 1.9-4, 1.10-1, and 1.10-2. In the alternative, if the Board believes that it must stay the entirety of an appealed condition rather than only the portions of the condition where so indicated in Exhibit 2, Dynegy requests that the Board stay the entirety of each of the conditions identified in Exhibit 2. *Id.* at 3-4.

The Board clearly has the authority to grant discretionary stays of the type requested here. In Community Landfill Co. and City of Morris v. IEPA, PCB 01-48, 01-49, slip op. at 4 (Oct. 19, 2000), the Board found "that it has the authority to grant discretionary stays from permit conditions." The Board noted it "has previously granted or denied discretionary stays in permit appeals, both when the Agency did and did not consent to such stays." *Id.* (citations omitted). The Board elaborated that "[t]he permit appeal system would be rendered meaningless in many cases, if the Board did not have the authority to stay permit conditions." *Id.*

The Board has reviewed the allegations in Dynegy's stay request, as well as the specific language requested-to-be-stayed, as detailed in Exhibit 2 to Dynegy's petition. On the basis of that review, and in the absence of any response to the request from the Agency, the Board grants Dynegy's request for partial stay of the contested conditions in the construction permit for the Baldwin Energy Complex. The Board stays those contested conditions and portions of conditions as reflected in the edited permit filed as Exhibit 2 to Dynegy's April 9, 2008 petition for review and request for stay. Exhibit 2 is incorporated herein by reference as if fully set forth. The partial stay remains in effect until the Board takes final action on the construction permit appeal, or until the Board orders otherwise.

IT IS SO ORDERED.

I, John T. Therriault, Assistant Clerk of the Illinois Pollution Control Board, certify that the Board adopted the above order on May 15, 2008, by a vote of 4-0.

John T. Therriault

John T. Therriault, Assistant Clerk
Illinois Pollution Control Board

Exhibit 2

Redlined Construction Permit Illustrating Those Portions of the Permit That Dynegy Requests Be Stayed

EXHIBIT 2

217/782-2113

CONSTRUCTION PERMIT

PERMITTEE

Dynegy Midwest Generation, Inc.
Attn: Rick Diericx
2828 North Monroe Street
Decatur, Illinois 62526

Application No.: 07110065 I.D. No.: 125804AAB
Applicant's Designation: Date Received: November 30, 2007
Subject: Baghouse, Scrubber and Sorbent Injection Systems for Unit 3
Date Issued: March 3, 2008
Location: Baldwin Energy Complex, 10901 Baldwin Road, Baldwin, Randolph County

Permit is hereby granted to the above-designated Permittee to CONSTRUCT equipment consisting of a baghouse, scrubber, and sorbent injection system for the Unit 3 Boiler and associated installation of booster fans, as described in the above referenced application. This Permit is subject to standard conditions attached hereto and the following special condition(s):

1.1 Introduction

a. This Permit authorizes construction of a baghouse system (Baghouses A and B), scrubber system (Scrubbers A and B), and sorbent injection system to supplement the existing emission control systems on the existing Unit 3 boiler. The new baghouse system, scrubber system, and sorbent injection system would further process the flue gas from this existing coal-fired boiler, which is equipped with an electrostatic precipitator (ESP). This permit also authorizes installation of booster fans to compensate for the additional pressure drop from these new control systems.

b. i. This permit is issued based on this project being an emissions control project, whose purpose and effect will be to reduce emissions of sulfur dioxide (SO_2), particulate matter (PM), and mercury from the existing boiler and which will not increase emissions of other PSD pollutants. ~~Accordingly, this permit does not address applicable requirements for emissions of nitrogen oxides (NO_x), as the current project does not include any changes to control measures for NO_x emissions.~~

ii. This permit is issued based on the receiving, storage and handling of limestone and activated carbon for the new control systems each qualifying as insignificant activities, with annual emissions of PM in the absence of control equipment that would be no more than 0.44 tons, so that these activities need not be addressed by this permit. This does not affect the Permittee's obligation to comply with all applicable requirements that apply to the receiving, storage and handling of these materials.

EXHIBIT 2

c. This permit does not authorize any modifications to the existing boiler or generating unit, which would increase their capacity or potential emissions.

d. This permit does not affect the terms and conditions of the existing permits for the boiler or generating unit.

Note: These existing permits do not necessarily provide a comprehensive list of the emission standards and other regulatory requirements that currently apply to the Unit 3 boiler.

e. This permit does not affect requirements for the affected boiler established by the Consent Decree in *United States of America and the State of Illinois, American Bottom Conservancy, Health and Environmental Justice-St. Louis, Inc., Illinois Stewardship Alliance, and Prairie Rivers Network, v. Illinois Power Company and Dynegy Midwest Generation Inc.*, Civil Action No. 99-833-MJR, U.S. District Court, Southern District of Illinois (Decree), which is incorporated by reference into this permit. (Refer to Attachment 1.)

1.2 Applicability Provisions

a. The "affected boiler" for the purpose of these unit-specific conditions is the existing Unit 3 boiler after the initial startup of the new emissions control systems, as described in Condition 1.1.

b. For purposes of certain conditions related to the Decree, the affected boiler is also part of a "Unit" as defined by Paragraph 50 of the Decree.

1.3 Applicable Emission Standards and Limits for the Affected Boiler

a. The affected boiler shall comply with applicable emission standards under Title 35, Subtitle B, Chapter I, Subchapter c of the Illinois Administrative Code.

1.4 Future Applicable Emission Standards and Limits

~~a. The Permittee shall comply with applicable emission standards and requirements related to mercury emissions for the affected boiler pursuant to 35 IAC Part 225, Subpart B, by the applicable dates specified by these rules~~.

b. The SO_2 emission rate of affected boiler shall be no greater than the limit specified in Paragraph 66 of the Decree, i.e., 0.100 lb/mmBtu, 30-day rolling average, by the date specified in Paragraph 66, i.e., no later than December 31, 2010. Compliance with this limit shall be determined in accordance with the provisions in Paragraphs 4 and 82 of the Decree.

Note: The SO_2 emission rate for the affected boiler pursuant to the Decree, when it takes effect, will be more stringent than the current applicable site specific federal standard of 6.0 lb/mmBtu. [Refer to 40 CFR 52.720(c)(71), which incorporates by

EXHIBIT 2

reference the SO_2 emission limits within Paragraph 1 of Illinois Pollution Control Board Final Order PCB 79-7, which was adopted September 8, 1983.]

c. The PM emission rate of the affected boiler shall be no greater than the limit specified in Paragraph 85 of the Decree, i.e., 0.015 lb/mmBtu, by the date specified in Paragraph 85, i.e., no later than December 31, 2010. Compliance with this limit shall be determined in accordance with the provisions in Paragraphs 90 and 97 of the Decree.

Note: The PM emission rate for the affected boiler pursuant to the Decree, when it takes effect, will be more stringent than the current applicable state rule limit of 0.1 lb/mmBtu pursuant to 35 IAC 212.203(a).

1.5 Nonapplicability Provisions

None

1.6 Work Practices and Operational Requirements for PM and SO_2 Control Devices

a. i. The Permittee shall operate and maintain the baghouse system authorized by this permit for the affected boiler in accordance with Paragraphs 83, 84 and 87 of the Decree.

~~ii. The Permittee shall operate and maintain the baghouse system for the affected boiler in accordance with a written Operation and Maintenance Plan for PM Control maintained by the Permittee pursuant to Condition 1.9-2(b)(i)(A).~~

b. i. Effective no later that December 31, 2010, the Permittee shall operate and maintain the scrubber authorized by this permit for the affected boiler in accordance with Paragraph 69 of the Decree.

ii. Effective no later than December 31, 2010, the Permittee shall not operate the affected boiler and Unit 3 unless the requirements of Paragraph 66 of the Decree with respect to addition of a flue gas desulfurization system (such as the scrubber authorized by this permit) or an equivalent SO_2 control technology to the affected boiler have been fulfilled.

~~iii. The Permittee shall operate and maintain the additional SO_2 control system on the affected boiler in accordance with a written Operation and Maintenance Plan for SO_2 Control maintained by the Permittee pursuant to Condition 1.9-2(c)(iii)(A).~~

EXHIBIT 2

1.7 Testing Requirements

a. i. The Permittee shall have testing conducted to measure the PM emissions from the affected boiler on a periodic basis consistent with the requirements of Paragraphs 89 and 119 of the Decree with respect to the timing of PM emission tests.

ii. The Permittee shall also have testing conducted to measure the PM emissions from the affected boiler within 90 days following receipt of a request by the Illinois EPA for such measurements or such later date set by the Illinois EPA.

b. i. These measurements shall be performed in the maximum operating range of the affected boiler and otherwise under representative operating conditions.

ii. The methods and procedures used for measurements to determine compliance with the applicable PM emission standards and limitations shall be in accordance with Paragraph 90 of the Decree.

c. Except for minor deviations in test methods, as defined by 35 IAC 283.130, emission testing shall be conducted in accordance with a test plan prepared by the testing service or the Permittee (which shall be submitted to the Illinois EPA for review at least 60 days prior to the actual date of testing) and the conditions, if any, imposed by the Illinois EPA as part of its review and approval of the test plan, pursuant to 35 IAC 283.220 and 283.230. Notwithstanding the above, a test plan need not be submitted to the Illinois EPA if emissions testing is conducted in accordance with the procedures used for previous testing accepted by the Illinois EPA or the previous test plan submitted to and approved by the Illinois EPA, provided, however, that the Permittee's notification for testing, as required below, contains the information specified by 35 IAC 283.220(d)(1)(A), (B) and (C).

d. The Permittee shall notify the Illinois EPA prior to conducting PM emission testing to enable the Illinois EPA to observe testing. Notification for the expected test date shall be submitted a minimum of 30 days prior to the expected date of testing. Notification of the actual date and expected time of testing shall be submitted a minimum of 5 working days prior to the actual test date. The Illinois EPA may on a case-by-case basis accept shorter advance notice if it would not interfere with the Illinois EPA's ability to observe testing.

e. The Permittee shall submit the Final Report(s) for this PM emission testing to the Illinois EPA within 45 days of completion of testing, which report(s) shall include the following information:

EXHIBIT 2

i. The name and identification of the affected unit and the results of the tests.

ii. The name of the company that performed the tests.

iii. The name of any relevant observers present including the testing company's representatives, any Illinois EPA or USEPA representatives, and the representatives of the Permittee.

iv. Description of test method(s), including description of sampling points, sampling train, analysis equipment, and test schedule, including a description of any minor deviations from the test plan, as provided by 35 IAC 283.230(a).

~~v. Detailed description of operating conditions during testing, including:~~

~~A. Operating information for the affected boiler, i.e., firing rate of the boiler (mmBtu/hour) and composition of fuel as burned (ash, sulfur and heat content).~~

~~B. Combustion system information, i.e., settings for distribution of primary and secondary combustion air, settings for O_2 concentration in the boiler, and levels of CO in the flue gas, if determined by any diagnostic measurements.~~

~~C. Control equipment information, i.e., equipment condition and operating parameters during testing, including any use of the flue gas conditioning system.~~

~~D. Load during testing (megawatt output).~~

vii. Data and calculations, including copies of all raw data sheets and records of laboratory analyses, sample calculations, and data on equipment calibration.

~~viii. The SO_2 and NO_x emissions (hourly averages), opacity data (6-minute averages), and O_2 or CO_2 concentrations (hourly averages) measured during testing.~~

~~ix. The emissions of condensable PM during testing, either as measured by USEPA Method 202 (40 CFR Part 51, Appendix M) or other established test method approved by the Illinois EPA during testing for PM or based on other representative emissions testing, with supporting data and explanation.~~

1.8 Monitoring Requirements

a. The Permittee shall operate and maintain continuous monitoring equipment to measure the following operating parameters of the baghouse system:

i. The temperature of the flue gas at the inlet of the system (hourly average).

ii. The pressure drop across the system (hourly average).

~~b. i. Beginning no later than the applicable dates specified by 35 IAC Part 225, the Permittee shall comply with all applicable requirements of 35 IAC Part 225, related to monitoring, including monitoring of mercury emissions from the affected boiler and operational monitoring for the sorbent injection system.~~

~~ii. If the sorbent injection system can be adjusted remotely by the personnel in the control room, the Permittee shall install, operate, and maintain instrumentation for measuring the rate of sorbent injection for the affected boiler and the operational status of the system.~~

~~1.9-1 Recordkeeping Requirements for the Coal Supply for the Affected Boiler~~

~~a. During the period before recordkeeping is required pursuant to 35 IAC Part 225, the Permittee shall keep records of the mercury and heat content of the coal supply to the affected boiler, with supporting data for the associated sampling and analysis methodology, so as to be able to have representative data for the coal supply to the boiler for periods during which mercury emission data is collected for the boiler. The analysis of the coal for mercury content shall be conducted using appropriate ASTM Methods as specified in 35 IAC Part 225.~~

~~b. If the Permittee elects to comply with a limit for mercury emissions in 35 IAC Part 225 that is expressed in terms of a control efficiency, the Permittee shall comply with all applicable requirements of 35 IAC Part 225 related to sampling and analysis of the coal supply to the affected boiler for its mercury content beginning no later than the applicable date specified by 35 IAC Part 225.~~

1.9-2 Records for Control Devices and Control Equipment

The Permittee shall maintain the following records for the new baghouse, scrubber, and sorbent injection system on the affected boiler:

a. i. Records for the Baghouse System

A. Records for the operation of the baghouse system that, at a minimum: (1) Identify the trigger for bag cleaning, e.g., manual, timer, or pressure drop; (2) Identify each period when the Unit was in operation and the baghouse system was not being operated or was not operating effectively; (3) Identify each period

EXHIBIT 2

when any baghouse compartment(s) have been taken out of regular service, with the identity of the module(s) and explanation~~, and (4) Address the implementation of the operating procedures related to the baghouse system that are required to be or are otherwise implemented pursuant to Condition 1.6(a)~~.

B. Records for maintenance and repair for the baghouse system that, at a minimum: (1) List the activities performed, with date and description~~, and (2) Address the maintenance and repair activities related to the baghouse system that are required to be or are otherwise implemented pursuant to Condition 1.6(a)~~.

ii. Records for the Scrubber System

A. Records for the operation of the scrubber system that, at a minimum: (1) Identify each period when the affected Unit was in operation and associated scrubber system was not being operated or was not operating effectively~~, and (2) Address the implementation of the operating procedures related to the scrubber system that are required to be or are otherwise implemented pursuant to Condition 1.6(b)~~.

B. Records for maintenance and repair for the scrubber system that, at a minimum: (1) List the activities performed, with date and description~~, and (2) Address the maintenance and repair activities related to the scrubber system that are required to be or are otherwise implemented pursuant to Condition 1.6(b)~~.

iii. Records for the Sorbent Injection System

~~A. Records for the operation of the sorbent injection system that, at minimum, identify the sorbent that is being used, the sorbent injection rate or setting for sorbent injection rate, each period of time when the affected boiler was in operation without the system being operated with explanation.~~

B. Records for the maintenance and repair of the sorbent injection system that, at a minimum, list the activities performed, with date and description.

~~b. Operation and Maintenance Plan for PM Control~~

~~i. Beginning no later than December 31, 2010, the following records related to the procedures and practices for the baghouse system controlling PM emissions from the affected boiler:~~

~~A. A written Operation and Maintenance Plan for PM Control, which shall be kept up to date, that identifies the specific operating procedures and maintenance practices (including procedures and~~

EXHIBIT 2

~~practices specifically related to startups and malfunction/breakdown incidents) currently being implemented by the Permittee for the baghouse system to satisfy Condition 1.6(a)(ii).~~

~~B. Accompanying this record, the Permittee shall maintain a demonstration showing that the above Operation and Maintenance Plan for PM Control fulfills the requirements of Conditions 1.6(a)(i) and (ii).~~

~~ii. Copies of the records required by Condition 1.9-2(b)(i) shall be submitted to the Illinois EPA upon request.~~

~~iii. Accompanying the records required by Conditions 1.92(b)(i), a file containing a copy of all correspondence and other written material exchanged with USEPA that addresses the procedures and practices that must be implemented pursuant to Paragraphs 83, 84 and 87 of the Decree. This file shall be retained for at least three years after the permanent shutdown of the affected Unit.~~

~~c. Operation and Maintenance Plan for SO_2 Control~~

~~i. Beginning no later than December 31, 2010, the following records related to the procedures and practices for the scrubber system controlling SO_2 emissions from the affected boiler:~~

~~A. A written Operation and Maintenance Plan for SO_2 Control, which shall be kept up to date, that identifies the specific operating procedures and maintenance practices (including procedures and practices specifically related to startups and malfunction/breakdown incidents) currently being implemented by the Permittee for the scrubber to satisfy Conditions 1.6(b)(iii).~~

~~B. Accompanying this record, the Permittee shall maintain a demonstration showing that the above Operation and Maintenance Plan for SO_2 Control fulfills the requirements of Conditions 1.6(b)(i) and (ii).~~

~~ii. Copies of the records required by Conditions 1.9-2(c)(i) shall be submitted to the Illinois EPA upon request.~~

~~iii. Accompanying the records required by Condition 1.9-2(c)(i), a file containing a copy of all correspondence and other written material exchanged with USEPA that addresses the procedures and practices that must be implemented pursuant to Paragraph 69 of the Decree. This file shall be retained for at least three years after the permanent shutdown of the affected Unit.~~

~~d. Specific Records for the Sorbent Injection System~~

EXHIBIT 2

~~During the period before recordkeeping is required for usage of sorbent pursuant to 35 IAC Part 225, the usage of sorbent (lbs) and average sorbent injection rate (lbs/operating hour), on a monthly basis.~~

1.9-3 Other Recordkeeping Requirements

a. ~~Records for Lapses in the Implementation of the Operation and Maintenance Plan for PM Control~~

~~Beginning no later than December 31, 2010, the Permittee shall maintain the following records, as relevant, for all lapses, i.e., periods or incidents when applicable action(s) were not taken for the baghouse system that were specified in the current Operation and Maintenance Plan for PM Control, as prepared pursuant to Condition 1.9-2(b)(i)(A):~~

~~i. The date of the lapse.~~

~~ii. A description of the lapse, including the specified action(s) that were not taken; other actions or mitigation measures that were taken, if any; and the likely consequences of the lapse as related to emissions, if any.~~

~~iii. The time and means by which the lapse was identified.~~

~~iv. If relevant, the length of time after the lapse was identified and before specified action(s) were taken or were no longer applicable and an explanation why this time was not shorter, including a discussion of the timing of any mitigation measures that were taken.~~

~~v. If relevant, the estimated total duration of the lapse, i.e., the total length of time that the affected boiler ran without the specified action(s) being taken.~~

~~vi. A discussion of the probable cause of the lapse and any preventative measures taken.~~

~~vii. A discussion whether the applicable PM emission limit, as addressed by Condition 1.3(a) or 1.4(c), may have been violated, either during or as a result of the lapse, with supporting explanation.~~

~~b. Records Related to Mercury Emissions~~

~~i. The Permittee shall comply with all applicable recordkeeping requirements of 35 IAC Part 225 related to control of mercury emissions from the affected boiler.~~

~~ii. During the period before the Permittee is required to conduct monitoring for the mercury emissions of the affected boiler pursuant to 35 IAC Part 225, the Permittee shall maintain records of any emission data for mercury collected for the affected boiler by the Permittee, including emissions (micrograms per cubic meter, pounds per~~

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~~hour, or pounds per million Btu) and control efficiency, with identification and description of the mode of operation of the boiler and sorbent injection system.~~

~~e. Records for Lapses in the Implementation of the Operation and Maintenance Plan for~~ ~~SO_2~~ ~~Control~~

~~Beginning no later than December 31, 2010, the Permittee shall maintain the following records, as relevant, for all lapses, i.e., periods or incidents when applicable action(s) were not taken for the scrubber system that were specified by the current Operation and Maintenance Plan for~~ ~~SO_2~~ ~~Control, as prepared pursuant to Condition 1.9-2(c)(i)(A),:~~

~~i. The date of the lapse.~~

~~ii. A description of the lapse, including the specified action(s) that were not taken; other actions or mitigation measures that were taken, if any; and the likely consequences of the lapse as related to emissions, if any.~~

~~iii. The time and means by which the lapse was identified.~~

~~iv. If relevant, the length of time after the lapse was identified and before specified action(s) were taken or were no longer applicable and an explanation why this time was not shorter, including a discussion of the timing of any mitigation measures that were taken.~~

~~v. If relevant, the estimated total duration of the lapse, i.e., the total length of time that the affected boiler ran without the specified action(s) being taken.~~

~~vi. A discussion of the probable cause of the lapse and any preventative measures taken.~~

~~vii. A discussion whether the applicable~~ ~~SO_2~~ ~~emission limit of Condition 1.4(b) may have been violated, either during or as a result of the lapse, with supporting explanation.~~

~~1.10-1 Reporting Requirements - Reporting of Deviations~~

~~a. Prompt Reporting of Deviations~~

~~For the affected boiler, the Permittee shall promptly notify the Illinois EPA of deviations from the requirements of this permit as follows. At a minimum, these notifications shall include a description of such deviations, including whether they occurred during startup or malfunction/breakdown, and a discussion of the possible cause of such deviations, any corrective actions and any preventative measures taken.~~

~~i. Notification within 24 hours for a deviation from requirements related to PM emissions if the deviation is accompanied by the failure of six or more compartments in the baghouse system.~~

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~~ii. Notification with the semi-annual reports required by Condition 1.10-2(a) for deviations not addressed above, including deviations from other applicable requirements, e.g., work practice requirements, required operating procedures, required maintenance practices, and recordkeeping requirements.~~

~~b. Periodic Reporting of Deviations~~

~~The semi-annual reports required by Condition 1.10-2(a) shall include the following information for the affected boiler related to deviations from permit requirements during the quarter.~~

~~i. A listing of all instances of deviations that have been reported in writing to the Illinois EPA as provided by Condition 1.10-1(a)(i), including identification of each such written notification or report. For this purpose, the Permittee need not resubmit copies of these previous notifications or reports but may elect to supplement such material.~~

~~ii. Detailed information, as required by Condition 1.10-1(a)(ii), for all other deviations.~~

1.10-2 Reporting Requirements - Periodic Reporting

~~a. The Permittee shall submit semi-annual reports to the Illinois EPA.~~

~~i. These reports shall include a summary of information recorded during the reporting period pursuant to Condition 1.9-3(a).~~

~~ii. These reports shall include the information for the affected boiler related to deviations during the quarter specified by Condition 1.10-1(b).~~

~~iii. These reports shall be submitted within 30 days after the end of each calendar half. For example, the report for the first half, i.e., January through June, shall be submitted by July 30.~~

~~b. The Permittee shall comply with all applicable reporting requirements of 35 IAC Part 225 related to control of mercury emissions from the affected boiler.~~

1.11 Authorization for Operation

The Permittee may operate the affected boiler with the new baghouse, scrubber, and sorbent injection system under this construction permit until such time as final action is taken to address these systems in the CAAPP permit for the source provided that the Permittee submits an appropriate application for CAAPP permit, which incorporates new requirements established by this permit within one year (365 days) of beginning operations of the affected boiler with these systems.

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If you have any questions concerning this permit, please contact Kunj Patel or Christopher Romaine at 217/782-2113.

Edwin C. Bakowski, P.E.
Acting Manager, Permit Section
Division of Air Pollution Control

Date Signed: _______________

ECB:CPR:KMP:psj

cc: Region 3

EXHIBIT 2

Attachment 1:

Consent Decree:
United States of America and the State of Illinois, American Bottom Conservancy, Health and Environmental Justice-St. Louis, Inc., Illinois Stewardship Alliance, and Prairie Rivers Network, v. Illinois Power Company and Dynegy Midwest Generation Inc., Civil Action No. 99-833-MJR, U.S. District Court, Southern District of Illinois

1. Order, Modifying the Consent Decree, entered August 9, 2006

2. Original Consent Decree, entered May 27, 2005

KMP:psj

CERTIFICATE OF SERVICE

I, the undersigned, certify that on this 9th day of January, 2009, I have served electronically the attached **PETITION FOR VARIANCE, AFFIDAVIT OF ARIC D. DIERICX,** and **APPEARANCES OF KATHLEEN C. BASSI AND STEPHEN J. BONEBRAKE**, upon the following persons:

John Therriault, Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
Suite 11-500
100 West Randolph
Chicago, Illinois 60601

and by first class mail, postage affixed, upon:

Illinois Environmental Protection Agency
Division of Legal Counsel
1021 North Grand Avenue, East
P.O. Box 19276
Springfield, Illinois 62794-9276

Kathleen C. Bassi

Kathleen C. Bassi
Stephen J. Bonebrake
SCHIFF HARDIN, LLP
6600 Sears Tower
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Chicago, Illinois 60606
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