INFORMATION COLLECTION REQUEST FOR NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP) FOR COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Part B of the Supporting Statement

1. Respondent Universe

In 2005, the number of coal- and oil-fired electric utility steam generating units (EGUs) at facilities owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies included approximately 1,332 units (boilers) that generated greater than 25 megawatts-electric (MWe), according to the U.S. Department of Energy/Energy Information Administration (DOE/EIA) Form EIA-767 database.[1] Currently, this database contains the most recent data available from DOE for coal- and oil-fired electric utility steam generating units but DOE/EIA states that (as of the writing of this supporting statement) the 2007 database is soon to be made publically available. The 2006 EIA-860 database covers some of the same units covered by EIA-767; however, this database also includes units owned and operated by non-utilities (including independent power producers and combined heat and power producers). EPA will query this database to determine if it includes any coal- or oil-fired EGUs that meet the CAA section 112(a)(8) definition of an EGU. Additionally, EPA/OAR/Office of Air Quality Planning and Standards will coordinate with EPA/OAR/Clean Air Markets Division (to obtain an industry configuration database output from their electric utility sulfur dioxide (SO_2) cap-and trade program) for help with the development of the final list of EGUs in this survey data collection effort. As facilities respond to Part I of the ICR data request, the Agency will modify this base list of units to represent all affected sources under this effort.

2. Selection of Units to Provide Source Information

All coal- and oil-fired EGUs identified by EPA as being potentially applicable sources under the definition in CAA section 112(a)(8) as well as all integrated gasification combined cycle (IGCC) EGUs and all EGUs fired by petroleum coke will be required to provide

[1] Note that units have been identified to the best of the Agency's ability for the purpose of this ICR action only. Identification of any unit for receipt of the CAA section 114 letter requiring information be submitted or testing be conducted does not constitute a final Agency applicability determination related to the rule under development. Similarly, units not receiving a CAA section 114 letter may ultimately be determined to be subject to the final rule. Specific applicability definitions will be developed during the rulemaking process and will be subject to notice and comment.

information on the current operational status of the unit, including applicable controls installed, along with emissions information. The coal-fired EGUs identified for this effort are shown in Attachment 4; the oil-fired EGUs identified are shown in Attachment 5; the IGCC EGUs identified are shown in Attachment 6; and the petroleum coke-fired EGUs identified are shown in Attachment 7.

3. Selection of Units to Conduct Stack Testing

Coal-fired units to be tested will be selected to cover four groups of hazardous air pollutants (HAP) that may potentially be regulated through the use of surrogate pollutant standards. At this time, we have made no final decision on the use of surrogate pollutants and any surrogate-based standard will be established only if consistent with the requirements of the CAA and applicable case law. The groups of HAP are acid-gas HAP (e.g., hydrogen chloride (HCl), hydrogen fluoride (HF)), dioxin/furan organic HAP, non-dioxin/furan organic HAP, and mercury and other non-mercury metallic HAP. Rationale for the selection of units for each possible surrogate group is discussed below. In the following stack testing, each facility is required to test after the last control device or at the stack if the last control device is not shared with one or more other units. In this way, the facility would test before any "dilution" by gases from a separately-controlled unit. Under certain circumstances, however, testing after a common control device or at the common stack will be allowed.

EPA has selected for testing the sources that the Agency believes, based on a variety of factors and information currently available to the Agency, are the best performing sources for the HAP groups for which they will be required to test. In targeting the best performing sources, EPA is proposing to require testing for approximately 15 percent of all coal-fired EGUs for 3 of the HAP groups – metal HAP and PM; non-dioxin/furan organic HAP, total hydrocarbon, CO, and VOC; and acid gas HAP and SO_2 – instead of only 12 percent of all sources. We will, of course, be obtaining emissions information from all sources in Parts I and II of the questionnaire. We are reasonably targeting the best performing coal-fired sources because the statute requires the Agency to set the MACT floor at the "average emission limitation achieved by the best performing 12 percent of the existing sources, (for which the Administrator has information)" in the category. By targeting the best performing 15 percent of coal-fired EGUs for testing, we believe this will ensure that we have emissions data on the best performing 12 percent of all existing coal-fired EGUs. For 3 of the HAP groups or individual HAP, to the extent the Agency can establish that it has in fact collected data from all of the existing sources that represent the best performing 12 percent of existing sources, we intend to use data from sources representing the best performing 12 percent of *all* sources in any category or subcategory to establish the CAA section 112(d) standards. For oil-fired units, the bases for any surrogacy argument(s) are less well developed and will require more extensive testing (EPA is proposing to require 100 of the oil-fired units to test).

<u>Coal-fired units, acid gas HAP</u>

The acid-gas HAP, HCl and HF, are water-soluble compounds and are more soluble in water than is SO_2. (Hydrogen cyanide, HCN, representing the "cyanide compounds," is also water-soluble and will be considered an "acid-gas HAP" in this document.) HCl also has a large acid dissociation constant (i.e., HCl is a strong acid) and it, thus, will react easily in an acid-base reaction with (i.e., be readily adsorbed on) caustic sorbents (e.g., lime, limestone). This indicates that both HCl and HF will be more rapidly and readily removed from a flue gas stream than will SO_2, even when only plain water is utilized. In the slurry streams, composed of water and sorbent (e.g., lime, limestone) utilized in both wet and dry flue gas desulfurization (FGD) systems, acid gases and SO_2 are absorbed by the slurry mixture and react to (usually) form solid salts. In fluidized bed combustion (FBC) systems, the acid gases and SO_2 are adsorbed by the sorbent (usually limestone) that is added to the coal and an inert material (e.g., sand, silica, alumina, or ash) as part of the FBC process. The adsorption process is temperature dependent and the cooler the flue gas, the more effectively the acid gases will react with the sorbents. One mole of calcium hydroxide ($Ca(OH)_2$) will neutralize one mole of SO_2, whereas one mole of $Ca(OH)_2$ will neutralize two moles of HCl. A similar reaction occurs with the neutralization of HF. These reactions demonstrate that when using a spray dryer, the HCl and HF are removed more readily than is the SO_2. Given that even more water is available in a wet-FGD system, the same condition would also hold in that situation (i.e., in a wet-FGD, HCl and HF would be removed more readily than SO_2). Thus, we are considering emissions of SO_2, a commonly measured pollutant, as a potential surrogate for emissions of the acid-gas HAP HCl and HF. Although this approach has not been used in any CAA section 112 rules by EPA, it has been used in a number of State permitting actions (e.g., Arkansas/Plum Point; Kentucky/Spurlock 3; Nebraska/Nebraska City 2; Wisconsin/Elm Road-Oak Creek, and Weston 4). However, should emissions of SO_2 be deemed inappropriate as a potential surrogate for emissions of the acid-gas

HAP, we are also gathering sufficient data on HCl, HF, and HCN to be able to establish individual emission limits.

EPA has identified the 175 units with the newest FGD controls installed. EPA believes that these units represent those units having to comply with the most recent, and, therefore, likely most stringent, emission limits for SO_2. Even though SO_2 may not be an adequate surrogate for the acid gas HAP, efforts by units to comply with stringent SO_2 limits will likely represent the top performers with regard to acid gas HAP emissions. The 170 units with the newest FGD controls installed would be selected from those identified in Attachment 8 and would be required to test the specified unit for HCl, HF, HCN, SO_2, O_2, CO_2, and moisture from the stack gases, and chlorine, fluorine, and sulfur content, HHV, and proximate/ultimate analyses of the coal being utilized during the test.

As units have been identified as meeting the criterion of being a "top performing" unit, substitution of units will not be permitted. However, for units selected for testing in this group that share an FGD system with another unit, testing after the FGD system will be allowed. Units not currently listed may be required to test if necessary to ensure that the approved number of units in the group actually test and provide the needed data to the Agency.

This would yield an additional 170 data sets to be added to the data set we currently have for these pollutants.

Coal-fired units, dioxin/furan organic HAP

Dioxin data were obtained in support of the 1998 Utility Report to Congress. However, approximately one-half of those data were listed as being below the minimum detection limit for the given test. Dioxin/furan emissions from coal-fired utility units are generally considered to be low, presumably because of the insufficient amounts of available chlorine. As a result of previous work conducted on municipal waste combustors (MWC), it has also been proposed that the formation of dioxins and furans in exhaust gases is inhibited by the presence of sulfur.[2] Further, it has been suggested that if the sulfur-to-chlorine ratio (S:Cl) is greater than 1.0, then formation of dioxins/furans is inhibited.[3,4] The vast majority of the coal analyses provided

[2] Gullett, B.K., et al. Effect of Cofiring Coal on Formation of Polychlorinated Dibenzo-*p*-Dioxins and Dibenzofurans during Waste Combustion. *Environmental Science and Technology*. Vol. 34, No. 2:282-290. 2000.
[3] Raghunathan, K., and B,K. Gullett. Role of Sulfur in Reducing PCDD and PCDF Formation. *Environmental Science and Technology*. Vol. 30, No. 6:1827-1834. 1996.
[4] Li., H., et al. Chlorinated Organic Compounds Evolved During the combustion of Blends of Refuse-derived Fuels and Coals. *Journal of Thermal Analysis*. Vol. 49:1417-1422. 1997.

through the 1999 ICR indicated S:Cl values greater than 1.0. As a result, EPA expects that additional data gathering efforts will continue the trend of data being at or below the minimum detection limit. However, EPA believes that some additional data are necessary upon which either to base a surrogate standard or to establish an emission limit for dioxin/furan. Therefore, 50 units have been selected at random from the entire coal-fired EGU population to conduct emission testing for dioxins/furans (Attachment 9). In addition, as a result of previous work done on MWC units, EPA identified activated carbon as a potential control technology for dioxin/furan control. Therefore, the above data set includes some units with activated carbon injection (ACI) systems installed. Each of these units would be required to test for dioxins/furans, O_2, CO_2, and moisture from the stack gases, and chlorine and sulfur content, HHV, and proximate/ultimate analyses of the coal being utilized during the test.

EPA would entertain requests to test sister units at the same facility. EPA would also entertain requests, within 3 weeks of receipt of the CAA section 114 letter, to test similar units at other facilities under the company's ownership or under an organizational umbrella (e.g., trade group) as long as the substituted unit was of similar size and type, utilized a similar coal, and had similar emission controls. The subject company would need EPA approval for any substitution. Units not currently listed may be required to test if necessary to ensure that the approved number of units in the group actually test and provide the needed data to the Agency.

This would yield an additional 50 data sets to be added to the data set we currently have for these pollutants.

Coal-fired units, non-dioxin/furan organic HAP

Emissions of carbon monoxide (CO), volatile organic compounds (VOC), and/or total hydrocarbons (THC) have in the past been used as surrogates for the non-dioxin/furan organic HAP based on the theory that efficient combustion leads to lower organic emissions.[5] However, although indications are that these emissions are low (and perhaps below the minimum detection level), there are very few emissions data available for these compounds from coal-fired utility boilers. EPA has identified the 175 newest units as being representative of the most modern, and, thus, presumed most efficient, units (Attachment 10). The 170 newest units would be selected from those identified in Attachment 10 and would be required to test for CO, VOC, and THC. From these 170 units, 50 units would be required to test for polycyclic organic matter

[5] U.S. Environmental Protection Agency. NESHAPS: Final Standards for Hazardous Air Pollutants for Hazardous Waste Combustors; Final Rule. 64 FR 52828. September 30, 1999.

(POM), NO_X, formaldehyde, methane, O_2, and CO_2, in addition to CO, VOC, and THC. All tested units would be required to test for moisture from the stack gases and HHV and proximate/ultimate analyses of the coal being utilized during the test.

As units have been identified as meeting the criterion of being a “top performing” unit, substitution of units will not be permitted. Companies with units sharing an FGD or PM control system will need to contact EPA with the individual boiler’s specifics. Units not currently listed may be required to test if necessary to ensure that the approved number of units in the group actually test and provide the needed data to the Agency.

This would yield an additional 170 data sets with data on the potential surrogates CO, VOC, and THC as well as 50 data sets on the potential surrogate relationships.

Coal-fired units, mercury and other non-mercury metallic HAP

Emissions of certain non-mercury metallic HAP (i.e., antimony (Sb), beryllium (Be), cadmium (Cd), cobalt (Co), lead (Pb), manganese (Mn), and nickel (Ni)) have been assumed to be well controlled by particulate matter (PM) control devices. However, mercury (Hg) and other non-mercury metallic HAP (i.e., arsenic (As), chromium (Cr), and selenium (Se)), because of their presence in both particulate and vapor phases, have been reported, in some instances, to be not well controlled by PM control devices. Also, it has been shown through recent stack testing that certain of these HAP (i.e., As, Cr, and Se) tend to condense on (or as) very fine particulate matter in the emissions from coal-fired units. There are very few recent emissions test data available showing the potential control of these metallic HAP from coal-fired utility boilers.

The capture of Hg is dependent on several factors including the chloride content of the coal, the amount of unburned carbon present in the fly ash, the flue gas temperature, and the speciation of the Hg. Based on available data, EPA believes that ACI may be an effective control technology for controlling Hg emissions in coal-fired plants. However, EPA has no direct stack test results showing how effectively these ACI-equipped plants reduce their Hg emissions.

EPA has identified the 175 units with the newest PM controls installed. EPA believes that these units represent those units having to comply with the most recent, and, therefore, likely most stringent, emission limits for PM (Attachment 11). Even though PM may not ultimately be an adequate surrogate for some of the non-mercury metallic HAP, efforts by units to comply with stringent PM limits will likely represent the top performers with regard to non-mercury metallic HAP emissions. The units selected also include a number with ACI installed. As units have been identified as meeting the criterion of being a "top performing" unit, substitution of units will not be permitted. However, units selected for testing in this group that share a PM control system with another unit, testing after the PM control system will be allowed.

The 170 units with the newest PM controls installed would be selected from those identified in Attachment 11 and would be required to test after that specific PM control (or at the stack if the PM control device is not shared with one or more other units). Each of these 170 units would be required to test the unit listed for Sb, As, Be, Cd, Cr, Co, Pb, Mn, Hg, Ni, Se, PM (total filterable, fine [dry], fine [wet]), O_2, CO_2, and moisture. All units would also be required to analyze their coal for the metals above (including Hg), chlorine, and provide the HHV and proximate/ultimate analyses of the coal being utilized during the test.

As units have been identified as meeting the criterion of being a "top performing" unit, substitution of units will not be permitted. However, units selected for testing in this group that share a PM control system with another unit, testing after the PM control system will be allowed. Units not currently listed may be required to test if necessary to ensure that the approved number of units in the group actually test and provide the needed data to the Agency.

This would yield an additional 170 data sets to be added to the data set we currently have for these pollutants.

<u>Coal-fired units, other</u>

To be able to assess the impact of the standards (e.g., reduction in HAP emissions over current conditions), EPA has selected at random 50 units (identified in Attachment 13) from the population of coal-fired units not selected in any of the above groups to test for HCl, HF, HCN, SO_2, O_2, CO_2, CO, VOC, THC, POM, NO_X, formaldehyde, methane, Sb, As, Be, Cd, Cr, Co, Pb, Mn, Hg, Ni, Se, PM (total filterable, fine [dry], fine [wet]), and moisture from the stack gases. All of these units would also be required to analyze their coal for the metals above (including Hg), chlorine, fluorine, and sulfur content, HHV, and proximate/ultimate analyses of the coal being utilized during the test. EPA does not believe that data available through other sources (e.g., National Emissions Inventory (NEI), Toxics Release Inventory (TRI), data gathered for the 1998 Utility Report to Congress) are of sufficient detail or completeness to be appropriate for this purpose. Utilities are not currently subject to a CAA section 112(d) standard and, therefore, they are not required to collect HAP data, nor report them to States which then report them to the

NEI. Further, the TRI data are based on "engineering judgment," emission factors, or other methods of estimation rather than emissions tests. In addition, none of the data sources currently contain detailed data for all of the necessary individual HAP. Thus, EPA believes that gathering these data is necessary to conduct a credible assessment of the emissions of this important source category.

EPA would entertain requests, within 3 weeks of receipt of the CAA section 114 letter, to test sister units at the same facility. EPA would also entertain requests, within 3 weeks of receipt of the CAA section 114 letter, to test similar units at other facilities under the company's ownership or under an organizational umbrella (e.g., trade group) as long as the substituted unit was of similar size and type, utilized a similar coal, and had similar emission controls. The subject company would need EPA approval for any substitution. Units not currently listed may be required to test if necessary to ensure that the approved number of units in the group actually test and provide the needed data to the Agency.

This would yield 50 data sets to be added to the data set we currently have for this analysis.

Coal-fired units, IGCC

All IGCC units identified in Attachment 6 will be required to test for HCl, HF, HCN, SO_2, O_2, CO_2, CO, VOC, THC, POM, NO_X, formaldehyde, methane, dioxins/furans, Sb, As, Be, Cd, Cr, Co, Pb, Mn, Hg, Ni, Se, PM (total filterable, fine [dry], fine [wet]), and moisture from the stack gases. All of these units would also be required to analyze their coal for the metals above (including Hg), chlorine, fluorine, and sulfur content, HHV, and proximate/ultimate analyses of the coal being utilized during the test.

Oil-fired units

The potential surrogacy arguments for coal-fired units are primarily based on compliance with recent, stringent emission limits that have generally resulted in the use of add-on control technologies, as in the case of the non-mercury metallic HAP (fabric filter or electrostatic precipitator) and the acid-gas HAP (FGD). For dioxin/furan organic HAP, the surrogacy argument may rely on the S:Cl value of the coal. However, the data obtained in support of the 1998 Utility Report to Congress and the 2000 Regulatory Determination do not indicate any correlation between PM control and emissions of non-mercury metallic HAP from oil-fired units. Further, no oil-fired unit has a FGD system installed, eliminating the potential basis for the use of compliance with an SO_2 emissions limit that resulted in the installation of an FGD system as a surrogate for emissions of the acid-gas HAP from such units. In addition, it is not known if the S:Cl value has the same relevance for oil-fired units as it does for coal-fired units. Thus, EPA has no basis for determining which oil-fired units may be the "best performers." Therefore, EPA is requiring that 100 units selected at random from the 180 known oil-fired units (Attachment 12) test their stack emissions for Sb, As, Be, Cd, Cr, Co, Pb, Mn, Hg, Ni, Se, PM (total filterable, fine [dry], fine [wet]), HCl, HF, HCN, SO_2, dioxins/furans, CO, VOC, THC, POM, NO_X, formaldehyde, methane, O_2, CO_2, and moisture. All units would be required to sample their oil for the metals (including Hg), chlorine, fluorine, sulfur, and provide HHV and proximate/ultimate analyses of the oil being utilized during the test.

EPA would entertain requests to test sister units at the same facility. EPA would also entertain requests, within 3 weeks of receipt of the CAA section 114 letter, to test similar units at other facilities under the company's ownership or under an organizational umbrella (e.g., trade group) as long as the substituted unit was of similar size and type, utilized a similar oil, and had similar emission controls. The subject company would need EPA approval for any substitution. Units not currently listed may be required to test if necessary to ensure that the approved number of units in the group actually test and provide the needed data to the Agency.

This would yield an additional 100 data sets to be added to the data set we currently have for this category of units.

Petroleum coke-fired units

All petroleum coke-fired units identified in Attachment 7 will be required to test for HCl, HF, HCN, SO_2, O_2, CO_2, CO, VOC, THC, POM, NO_X, formaldehyde, methane, dioxins/furans, Sb, As, Be, Cd, Cr, Co, Pb, Mn, Hg, Ni, Se, PM (total filterable, fine [dry], fine [wet]), and moisture from the stack gases. All of these units would also be required to analyze their petroleum coke for the metals above (including Hg), chlorine, fluorine, and sulfur content, HHV, and proximate/ultimate analyses of the petroleum coke being utilized during the test.

4. Response Rates

Since the information will be requested pursuant to the authority of CAA section 114, EPA expects that all respondents requested to submit information will do so within the time allotted for the information being requested.

Attachment 1.

Draft Questionnaire Content

Form Approved __/__/__
OMB Control No. ____-____
Approval Expires __/__/__

ELECTRIC UTILITY STEAM GENERATING UNIT
HAZARDOUS AIR POLLUTANT EMISSIONS INFORMATION COLLECTION EFFORT

BURDEN STATEMENT

Preliminary estimates of the public burden associated with this information collection effort indicate a total of 125,098 hours and $75,972,758. This is the estimated burden for 537 facilities to provide information on their boilers, fuel oil types and/or coal rank, 1,332 units to provide hazardous air pollutant (HAP) emissions data and 12 months of fuel analyses, and 512 units to conduct emissions testing.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information that is sent to ten or more persons unless it displays a currently valid Office of Management and Budget (OMB) control number.

GENERAL INSTRUCTIONS

[NOTE: It is EPA's intent for the final version of this questionnaire to be in electronic format. The final format will include all questions noted herein.]

Please provide the information requested in the following forms. If you are unable to respond to an item as it is stated, please provide any information you believe may be related. Use additional copies of the request forms for your response.

If you believe the disclosure of the information requested would compromise confidential business information (CBI) or a trade secret, clearly identify such information as discussed in the cover letter. Any information subsequently determined to constitute CBI or a trade secret under EPA's CBI regulations at 40 CFR part 2, subpart B, will be protected pursuant to those regulations and, for trade secrets, under 18 U.S.C. 1905. If no claim of confidentiality accompanies the information when it is received by EPA, it may be made available to the public by EPA without further notice pursuant to EPA regulations at 40 CFR 2.203. Because Clean Air Act (CAA) section 114(c) exempts emission data from claims of confidentiality, the emission data you provide may be made available to the public notwithstanding any claims of confidentiality. A definition of what the EPA considers emissions data is provided in 40 CFR 2.301(a)(2)(i).

The following section is to be completed by all facilities:

- Part I - General Facility Information: once for each facility. A copy of Part I should be completed and returned to the address noted below within 90 days of receipt.

The following section is to be completed by all facilities meeting the section 112(a)(8) definition of an electric utility steam generating unit:

- Part II - Fuel Analyses and Emission Data: Additional copies of certain pages may be necessary for a complete response. A copy of Part II responses should be completed and returned to the address noted below within 90 days of receipt.

The following section is to be completed by all facilities selected for stack testing:

- Part III – Emissions Test Data: One emissions test (consisting of three runs). A copy of the emissions test report should be completed and returned to the address noted below within 6 to 8 months of receipt. Note the discussion in Part III as to when in the 6 to 8 month period the tested facilities results must be submitted.

Detailed instructions for each part follow.

Questions regarding this information request should be directed to Mr. William Maxwell at (919) 541-5430.

Return this information request and any additional information to:

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Sector Policies and Programs Division
U.S. EPA Mailroom (D205-01)
Attention: Peter Tsirigotis, Director
109 T.W. Alexander Drive
Research Triangle Park, NC 27711

Form Approved __/__/__
OMB Control No. ____-____
Approval Expires __/__/__

PART I: GENERAL FACILITY INFORMATION

Process Information

NOTE: If any rank of coal or any grade of oil (including petroleum coke [pet coke]), in any amount, is fired, complete Parts I and II and return to the address noted earlier. If NO coal or oil is fired, complete only Part I and return to the address noted earlier.

1. Name of legal owner of facility: ____

____

____

2. Name of legal operator of facility, if different from legal owner: ____________________

____

____

3. Address of ____ legal owner or ____ operator: __________________________________

____

____

____

4a. Plant Name (as reported on U.S. DOE/EIA Form-860 (2007), "Annual Electric Generator Report," schedule 2, line 1, page 37, question 1) OR Plant Name (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 2, page 1, question 1):

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4b. EIA Plant Code (as reported on U.S. DOE/EIA Form-860 (2007), schedule 2, line 1, page 37, question 2) OR Plant ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), schedule 2, page 1, question 2): ____

5. Complete street address of facility (physical location): ____________________________

____

____

____

____

6. Provide mailing address if different: ____

____

____

7. Name and title of contact(s) able to answer technical questions about the completed survey: ____

____

8. Contact(s) telephone number(s): ____

and e-mail address(es): ____

9 Is this facility considered to be owned or operated by a small entity as defined by the Regulatory Flexibility Act? __ Yes __ No __ Don't know

10. Which of the following fossil fuels or other material(s) are fired in any steam generating unit at this facility?

_____ coal _____ oil (including pet coke) _____ natural gas

_____ other (specify in question 14 below)

11. Which of the following fossil fuels or other material(s) are permitted[6] to be fired in any steam generating unit at this facility?

_____ coal _____ oil (including pet coke) _____ natural gas

_____ other (specify in question 14 below)

12. If coal or solid fuel, as described below, derived from a fossil source is fired, indicate which rank of coal or solid fuel was utilized during the previous 12 months prior to the receipt of this ICR:[7,8]

__ lignite (% _____) __ subbituminous (% _____)

__ bituminous (% _____) __ anthracite (% _____)

__ coal refuse (including gob, culm, and subbituminous-derived coal refuse) (% _____)

__ synfuel (including, but not limited to, briquettes, pellets, or extrusions which are formed by binding materials, or processes that recycle materials) (% _____)

[6] "Permitted," in this context, refers to refers to the fuels that the permit anticipates will be combusted that the facility.

[7] If the boiler is fired by a blend of coal ranks, please specify percentage (separately, on both a mass and on a Btu basis) of each coal rank (e.g., 85% subbituminous/15% bituminous).

[8] In reference to footnote Error: Reference source not found, if necessary, a notation can be added to a utilized fuel type that is not listed in the operating permit noting the reason the fuel type was combusted (e.g., "the permitting agency allowed this fuel to be combusted for special testing and research purposes").

(please specify the type or form of synfuel used ________________________________)

__ petroleum coke (% _____)

13. If oil is fired, indicate which type of oil was utilized during the previous 12 months prior to the receipt of this ICR:[9]

__ distillate (% _____) __ residual or bunker C (% _____)

__ other (specify ___________) (% _____)

14a. If "other" was checked in questions 10 or 11 above indicating that any non-fossil fuel or other material (including, but not limited to, plastics, treated wood, rubber belting or gaskets, whole tires, tire-derived fuel, boiler cleaning solutions, animal wastes, etc.) is either utilized or permitted to be used, please indicate below what materials are combusted in the boiler and in what quantities (specify whether this quantity is on a weight percentage or heat [Btu] basis). Also indicate (yes/no) whether you are permitted[10] to burn non-fossil fuel(s) or other material(s) even if you do not actually burn them.

Other Material	Permitted to burn	Actually burn	Quantity/year
________________	________________	________________	____________
________________	________________	________________	____________
________________	________________	________________	____________
________________	________________	________________	____________
________________	________________	________________	____________
________________	________________	________________	____________
________________	________________	________________	____________

14b. If "other" was checked in questions 10 or 11 above indicating that any non-fossil fuel or other material (including, but not limited to, plastics, treated wood, rubber belting or gaskets, whole tires, tire-derived fuel, boiler cleaning solutions, animal wastes, etc.) is either utilized or permitted to be used, were such material to be classified as "solid waste" under the Resource Conservation and Recovery Act and, thus, make the utilizing unit subject to CAA section 129, would you continue to utilize (i.e., use as a fuel) the material? __ Yes __ No

Explain: ____

[9] If the boiler is fired by a blend of fuel oil ranks, please specify percentage (separately, on both a volume and on a Btu basis) of each fuel oil rank (e.g., 85% residual oil/15% distillate).

[10] If necessary, a notation can be added to a utilized fuel type that is not listed in the operating permit noting the reason the fuel type was combusted (e.g., "the permitting agency allowed this fuel to be combusted for special testing and research purposes").

15. Identification (or designation) of all coal- and oil-fired steam generating units (boilers) (as defined by Clean Air Act section 112(a)(8)) located at this facility.

Boiler ID[11]	**Original design fuel (i.e. coal rank or type of oil)**	**Design heat input, (MMBtu/hr)**[12]	**Present maximum heat input, (MMBtu/hr)**[13]	**MWe Gross capacity summer**	**MWe Net capacity summer**	**Original design gross efficiency (%, HHV)**	**Present operating gross efficiency (%, HHV)**	**Design steam pressure (psig)**	**Operating steam pressure (psig)**	**Design steam temperature (°F)**	**Operating steam temperature (°F)**	**Design steam reheat temperature (°F)**[14]	**Operating steam reheat temperature (°F)**[15]	**Fuel**[16]	**Hours/year operated**[17]	**Average annual capacity factor for the past 3 years**	**Applicable NSPS**	**Estimated year of retirement**[18]

[11] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), "Annual Electric Generator Report," schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 5, part A, page 8).
[12] Per fuel burned in the boiler. Report this based on higher heating value (HHV).
[13] Per fuel burned in the boiler. Report this based on higher heating value (HHV).
[14] Please indicate if more than one steam reheat cycle is utilized, and, if so, please provide information for both.
[15] Please indicate if more than one steam reheat cycle is utilized, and, if so, please provide information for both.
[16] Indicate the fuels utilized for the indicated boiler, and percentages, as indicated in questions 11 - 13.
[17] The " hours/year operated" would be the average of the actual number of hours the unit operated in 1 year based on the last 3 years of operation.
[18] This can be treated as CBI and can be submitted through the proper CBI procedure if desired.

Emission Control Technology

16. For each boiler noted in Part I, question 15, provide the following information for each current emission control device installed and operating and/or planned (please designate the order of the emission controls – 1 for first control following the boiler, 2 for second control following the boiler, etc.):

[19] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), "Annual Electric Generator Report," schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 5, part A, page 8).

[20] Examples: tangential-fired; cyclone; wall-fired; circulating fluidized bed (CFB)

[21] Examples: low-NO_x burners; selective catalytic reduction (SCR); selective non-catalytic reduction (SNCR); over-fire air (OFA). Include specific date that control went online or planned operational date for new installation. If this boiler's control configuration utilizes a SCR, please include the type of material from which the catalyst is manufactured and the type of reductant used in with the SCR (e.g., anhydrous ammonia, aqueous ammonia, urea, other). Also, please note if the catalyst is specifically designed to reduce SO_3 formation?

[22] Examples: wet flue gas desulfurization (FGD; any type); dry scrubbing (any type); specify whether calcium- or sodium-based. Include specific date that control went online or planned operational date for new installation.

[23] Examples: fabric filter; cold-side electrostatic precipitator (ESP); hot-side ESP; cyclone or multiclone; venturi scrubber. Include specific date that control went online or planned operational date for new installation.

[24] Please indicate systems installed specifically to control any other pollutants (e.g., Hg, SO_3, etc.). Examples: activated carbon injection (ACI); Powerspan ECO®; dry sorbent injection or wet ESP for SO_3 control; flue gas conditioning to control opacity (e.g., SO_3 injection, ammonia, other); additive use for mercury control (e.g., bromine; scrubber additives). Include specific date that control went online or planned operational date for new installation. Also include any pollutants controlled by this other technology (e.g., control technology [pollutant controlled]).

17. For each boiler noted in Part I, question 15, provide the company (prime vendor) name and company contact information for each HAP-specific (e.g., mercury, hydrogen chloride) control technology that you have either contracted for, are installing, or have installed for the purpose of participating in a control technology demonstration project[25] (e.g., U.S. Department of Energy program, consent decree, etc.).

Boiler ID[26]	**Company (vendor) name**	**Company (vendor) contact information**		
		Name	**Telephone**	**Address**

[25] A control technology demonstration project is defined as a U.S. Government (e.g., U.S. Department of Energy program) sponsored (in whole or in part) project or mandate (e.g., as a result of a consent decree) that adds a HAP control technology to a facility's unit to demonstrate the technology's HAP removal performance.

[26] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), "Annual Electric Generator Report," schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 5, part A, page 8).

18. For the control technologies identified in Part I, question 17, provide the date of actual start-up of the demonstration (if the control is currently operating), the date of expected or projected start-up, the date the demonstration was completed, the type of HAP control installed (e.g., sorbent and type; pre-combustion boiler chemical additive; combustion boiler chemical additive), the desired HAP emission reduction or rate (if any), and the coal rank(s) in use or fuel type upon which the demonstration was conducted. Please specify the format of the target HAP emission reduction or rate (e.g., lb/MWh, lb/TBtu, percent reduction, etc.). If the format of the target end-point is percent reduction, provide (1) an estimate of what an equivalent emission rate would be (and specify the format of the equivalent emission rate), and (2) the basis for calculating the percent reduction (i.e., where the "inlet" and "outlet" are).

Boiler ID[27]	**Demonstration activity actual start-up date**	**Demonstration activity projected start-up date**	**Demonstration activity end-date or projected end-date**	**Type of control (e.g., sorbent and type; chemical additive[28])**	**Desired HAP emission reduction (%) or emission rate**	**Coal rank(s) in use**

[27] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), "Annual Electric Generator Report," schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 5, part A, page 8).
[28] If additive is used, please indicate injection point.

19. For each boiler noted in Part I, question 15, provide the company (prime vendor) name and company contact information for each HAP (e.g., mercury, hydrogen chloride, etc.) control technology that you have either contracted for, are installing, or have installed for the purpose of providing a non-demonstration, full-scale operating system.

Boiler ID[29]	Company (vendor) name	Company (vendor) contact information		
		Name	Telephone	Address

[29] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), “Annual Electric Generator Report,” schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), “Power Plant Operations Report,” schedule 5, part A, page 8).

20. For the control technologies identified in Part I, question 19, provide the date of actual start-up (if the control is currently operating), the date of expected or projected start-up, the type of HAP control installed (e.g., sorbent and type; pre-combustion boiler chemical additive; combustion boiler chemical additive), the guaranteed HAP emission reduction or emission rate, the sorbent feed rate upon which the guarantee is based, and the coal rank(s) or fuel type upon which the guarantee is based. Please specify the format of the guarantee (e.g., lb/MWh, lb/TBtu, percent reduction, etc.). If the format of the guarantee is percent reduction, provide (1) an estimate of what an equivalent emission rate would be (and specify the format of the equivalent emission rate), and (2) the basis for calculating the percent reduction (i.e., where the "inlet" and "outlet" are).

Boiler ID[30]	**Actual start-up date**	**Expected or projected start-up date**	**Type of control (e.g., sorbent and type; chemical additive)**[31]	**Guaranteed HAP emission reduction (%) or emission rate**	**Sorbent or additive feed rate on which guarantee is based**	**Coal rank(s) upon which guarantee is based**

[30] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), "Annual Electric Generator Report," schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 5, part A, page 8).

[31] If additive is used, please indicate injection point.

21. For each boiler noted in Part I, question 15, provide the following information:

Boiler ID[32]	**Permitted emission limit (indicate type of permit and format of emission limit and averaging period)**										
	PM[33]	**PM_{10}**[(34)]	**$PM_{2.5}$**[(35)]	**SO_2**	**HCl and/or HF**	**HCN**	**Metal HAP**[36]	**Hg**	**CO**	**Other organics (specify)**	**Other pollutant (specify)**

[32] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), "Annual Electric Generator Report," schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 5, part A, page 8).

[33] If the boiler has separate permitted emission limits for filterable and condensable PM, respectively, please include those separate limits. Also include the compliance test method utilized.

[34] List the compliance test method utilized.

[35] List the compliance test method utilized.

[36] Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel and selenium; indicate permit level for all metal HAP for which a permit limit is in place.

22. For each boiler noted in Part I, question 15, provide the following information:

Boiler ID[37]	Most recent guaranteed emission rate for each pollutant for which there is a permitted emission limit										
	PM[38]	PM_{10}	$PM_{2.5}$	SO_2	HCl and/or HF	HCN	Metal HAP[39]	Hg	CO	Other organics (specify)	Other pollutant (specify)

23. Was any other guarantee level sought or offered? Yes _____ No _____ Please elaborate. ________________________

____

____

[37] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), "Annual Electric Generator Report," schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 5, part A, page 8).

[38] If the boiler has separate guaranteed emission rate for filterable and condensable PM, respectively, please include those separate emission rates.

[39] Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel and selenium; indicate permit level for all metal HAP for which a permit limit is in place.

24. For each boiler noted in Part I, question 15, provide the following information:

Boiler ID[40]	**Required monitoring, recordkeeping, and reporting requirements for each pollutant for which there is a permitted emission limit**									
	PM[41]	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**HCl and/or HF**	**HCN**	**Metal HAP**[42]	**Hg**	**CO**	**Other organics (specify)**

[40] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), "Annual Electric Generator Report," schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 5, part A, page 8).

[41] If the boiler's monitoring, recordkeeping, and reporting requirements require your company to monitoring, keep records, and report filterable and condensable PM separately, please describe the separate actions required.

[42] Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel and selenium; indicate permit level for all metal HAP for which a permit limit is in place.

25. For the control technologies identified in Part I, questions 17 and 19, provide the cost information requested.[43]

Facility Name / Unit No.: _________	**Retrofit to existing boiler?** ____ **Installation on new boiler?** ____
Total Capital Investment:	$: ______________
Total Annual Operating and Maintenance Costs:	$: ______________ (Include base year for operating costs [e.g., 2006])

26. Are any other means of emission control (for any pollutant) employed on any boiler noted in Part I, question 15 (e.g., low-ash coal, coal or oil with low trace constituents, etc.)? Please specify.

____

____

____

____

[43] This can be treated as CBI and can be submitted through the proper CBI procedure if desired.

PART II: FUEL ANALYSIS AND EMISSION DATA

Fuel Analysis[44]

Each facility should provide the following information for each coal and oil shipment received during the preceding 12 calendar months.

1a. Plant or facility name from Part I, question 4a: ________________________________

____

1b. Plant or facility code from Part I, question 4b: ________________________________

[44] The respondent should reply to this ICR with separate pages 18 through 24 (Part II) for each of their facilities.

2. For each individual coal and oil shipment received during the preceding 12 calendar months, provide the following information, as available (indicate N/A if not available; use additional pages, as necessary):

Amount received, dry basis, short tons[45]	**ID # of boiler(s) firing fuel**[46]	**Fuel source**			**Fuel shipment method**
		State/Country	**County**[47]	**Coal seam**[48]	

[45] EPA recognizes that facilities have (sometimes) several months inventory and that the amount received is not necessarily the same as the amount fired.

[46] Boiler ID (as reported on U.S. DOE/EIA Form EIA-860 (2007), "Annual Electric Generator Report," schedule 6, part A, line 1, page 53, [for plants equal to or greater than 10 MW but less than 100 MW] or on schedule 6, part B, line 1, page 54, [for plants greater than 100 MW]) OR Generator ID (as reported on U.S. DOE/EIA Form EIA-923 (2008), "Power Plant Operations Report," schedule 5, part A, page 8).

[47] If known.

[48] If known.

3. For each individual coal and oil shipment received during the preceding 12 calendar months, provide the following information[49], as available (dry basis) (indicate N/A if not available):

Sample ID #	Total amount of fuel represented by sample, tons or gallons	Total sulfur, %	Ash content, %	Higher heating value, Btu/lb	Mercury, ppm	Chlorine, ppm	Fluorine, ppm	Nickel, ppm	Other trace metal HAP, ppm[50]

[49] To the extent that a vendor provides these data or that a facility is required by State or local agency to analyze its fuel for HAP constituents (e.g., Cl, F), and any metallic HAP (e.g., Hg, Pb, As, Se, etc.), EPA wishes the responding facility to provide those fuel analyses results. Otherwise, this 12-month fuel analysis requirement can be bypassed by the respondent.

[50] Metal HAP includes compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel and selenium.

4. Were the data provided in Part II, question 3 above, acquired pursuant to:

__ permit requirements

__ contractual obligations

__ standard operational procedures

__ other (please specify ____________________)

5. Analyses provided in Part II, question 3 above, supplied by

__ Fuel supplier (name and address) ____

____

__ Other (name and address) ____

____

6. Name and address of laboratory performing analyses: ___________________________

____

____

7. In addition to the analyses required in Part II, question 3 above, for samples for which analyses of chlorine and/or any of the HAP metals were conducted, please provide copies of any analyses conducted over the preceding 12 calendar months for (a) complete proximate and ultimate analyses, (b) additional trace metals, and (c) the mineralogy of the ash that are readily available for the oil(s) or coal(s) listed in Part II, question 2 above. The Agency is requesting these data only as they may already be available; no additional sampling or analyses are required to provide these data.

Emission Data

8a. What emission test report(s), parametric monitoring data, and other data or monitoring are available for the boilers noted in Part I, question 15, for tests conducted since January 1, 2005. Please consider reports prepared for all testing and monitoring programs, for all pollutants, including (but not limited to) those required under Title V, compliance with State or local requirements, fulfillment of contractual obligations, U.S. Department of Energy (DOE) programs, etc. (NOTE: EPA is not requesting copies of the test reports or data at this time; however we may request actual copies in the future.) Use additional pages as necessary.

____

____

____

____

8b. Please indicate the date(s) and types (e.g., stack, fuel, parametric, etc.) of the test(s) and the constituents (including criteria and hazardous air pollutants) sampled for.

Date: _____ Type: _____ Constituents: ____________________________________

Date: _____ Type: _____ Constituents: ____________________________________

Date: _____ Type: _____ Constituents: ____________________________________

Date: _____ Type: _____ Constituents: ____________________________________

Date: _____ Type: _____ Constituents: ____________________________________

Date: _____ Type: _____ Constituents: ____________________________________

Date: _____ Type: _____ Constituents: ____________________________________

Date: _____ Type: _____ Constituents: ____________________________________

Date: _____ Type: _____ Constituents: ____________________________________

8c. Do any of these test reports reflect testing at a location upstream of any emission control devices?

Yes _____ No _____ If yes, please note which reports and provide a detailed description of the location of the emissions sampling point(s). ____________________________________

8d. Were any of these test reports conducted when use of other material(s) or non-fossil fuels were fired in the boiler? Yes _____ No _____ If yes, please note which reports and identify the other material(s) or non-fossil fuels used.. ________________________________

____

8e. Do any of these test reports reflect testing during periods of startup, shutdown, and malfunction? Yes _____ No _____ If yes, please note which reports. ________________

8f. Did the unit's control configuration differ from that shown in Part I, question 16, at the time of these test results? Yes _____ No _____ If yes, please list the unit's complete control configuration at time of testing in a similar format to Part I, question 16. _____________

8g. Do any of these test reports reflect testing at a location upstream of a post combustion SO_2 emission control device (e.g., FGD, SDA, Dry Scrubber)? Yes _____ No _____ If yes, please note which reports and, in addition to the detailed description of the location of the sampling point(s) (question 8c above), include detail about how much, if any, bypass of unscrubbed flue gas was utilized at the time of testing (including percentage of total scrubber exhaust gas flow). Note by diagram where sampling ports were located in relation to the bypass ductwork. ___________

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9. What type of deviation reporting is required for violations of permit requirements?

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10. Are deviation reports available for malfunctions or other periods of noncompliance with permit terms and conditions? Yes _____ No _____ If yes, please note which reports.

---

11. Are continuous emissions monitoring system (CEMS) data available (e.g., mercury, continuous opacity monitoring systems) that are not already being provided to the U.S. EPA or permit authority, even if from short-term testing? Yes _____ No _____ If yes[51], please

[51] Where units are monitored by CEMS (either following CAMR, State, or NIST QA/QC procedures), and where data are available, EPA requests that these CEMS data be submitted by the respondent. The respondent should also mark the periods of start up, shut down and malfunction events (SSM) in the data sets.

note for which pollutants CEMS data are available and the period of time (both total period and calendar period) for which data are available. If CEMS data are being provided to EPA, please note to which Office the data are being provided. ____________________________________

____

12. For each boiler noted in Part I, question 15, provide the following information:

Boiler ID	Emissions test results (indicate format of emission data)[52,53]							
	Date of test	PM[54]	SO_2	HCl/HF/HCN	Metal HAP[55]	Hg[56]	CO	Other organics (specify)

52 Provide emission test data for all tests conducted since January 1, 2005. Please include test data acquired both before and after any control device. Use additional pages as necessary. EPA may, at some future date, request a copy of one or more emission test reports. Data generated to fulfill both Federal and State requirements must be provided. Note that data generated pursuant to CAA Title V must be maintained and available for 5 years. Also include averaging times and measurement units for all pollutants.

53 For each emissions test run the respondent should provide the following process information: Unit Load (MW), Net generation during run (MWh net), Flue gas moisture content (%), Flue gas flow rate (dscfm or Nm^3/hr), Flue gas oxygen content (%, dry), Flue gas carbon dioxide content (%, dry), Flue gas temperature at sampling point (°F), Flue gas pressure at sampling point (atm), Standard temperature (°F), Standard pressure (atm).

54 If emission testing recorded the emissions of filterable and condensable PM, separately, please include those separate emission results. Also, please include separate emission results for total PM, PM_{10}, and $PM_{2.5}$.

55 Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel and selenium; indicate emission level for all metal HAP for which an emission test has been conducted.

56 Please provide separate results for total Hg, elemental Hg, oxidized Hg, and particulate Hg, as available. If the emissions testing recorded the amount of unburned carbon in fly ash (as reflected by the "Loss on Ignition" [L.O.I.]) at the time of any Hg testing, please include these data.

PART III: EMISSIONS TESTING

For units identified in Part B of the Supporting Statement, testing is to be performed for the identified HAP on a one-time basis after the last control device (i.e., after the last control device or at the stack if the last control device is not shared with one or more other units). Facilities are to use the test procedures noted in Enclosure 1 ("Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Procedures, Methods, and Reporting Requirements") for both the stack and fuel sampling. Each test is to consist of at least three separate runs for each pollutant at the sampling location.

Companies with multiple units identified on the Attachments to Part B of the Supporting Statement will be required to notify EPA within 3 weeks of receipt of the CAA section 114 letter which units representing 60 percent of their required data will be submitted within 6 months of receipt of the letter and which units representing an additional 20 percent of their required data (i.e., a total of 80 percent of their required data) will be submitted within 7 months of receipt of the letter. Companies will also be notified of this requirement in the cover letter specifying the test requirements.

Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Procedures, Methods, and Reporting Requirements

This document provides an overview of approved methods, target pollutant units of measure, and reporting requirements for the coal- and oil-fired electric utility steam generating unit test plan. The document is organized as follows:

1.0 Stack Testing Procedures and Methods

The EPA coal- and oil-fired electric utility steam generating unit test program includes stack test data requests for several pollutants, including specific hazardous air pollutants (HAP) and potential surrogate groups. If you operate a coal- or oil-fired electric utility steam generating unit, you were selected to perform a stack test for some combination of the following pollutants or potential surrogate groups (i.e., simultaneous or overlapping measurements per group):

- Non-dioxin/furan organic HAP: Carbon monoxide (CO), total hydrocarbons (THC), methane (CH_4), formaldehyde, oxygen (O_2), carbon dioxide (CO_2), volatile and semi-volatile organic HAP
- Dioxin/furan: dioxins/furans (D/F), O_2, CO_2
- Acid gas HAP: hydrogen chloride (HCl), hydrogen fluoride (HF), hydrogen cyanide (HCN), oxides of nitrogen (NO_X), sulfur dioxide (SO_2), O_2, CO_2
- Mercury and non-mercury metallic HAP: mercury (Hg), non-Hg HAP metals (including antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), cobalt (Co), lead (Pb), manganese (Mn), nickel (Ni), and selenium (Se)), particulate matter ($PM_{2.5}$ (filterable and condensable); total solids; O_2, CO_2

Refer to Table 2 of the section 114 letter you received for the specific combustion unit and pollutants on which we are requesting that you perform emission tests. You may have submitted test data for some of these pollutants already.

1.1 How to Select Sample Location and Gas Composition Analysis Methods

U.S. EPA Method 1 of Appendix A of Part 60 must be used to select the locations and number of traverse points for sampling. See http://www.epa.gov/ttn/emc/methods/method1.html for a copy of the method and guidance information.

Analysis of flue gas composition, including oxygen concentration, must be performed using U.S. EPA Methods 3A or 3B of Appendix A of Part 60. See http://www.epa.gov/ttn/emc/methods/method3a.html for Method 3A or http://www.epa.gov/ttn/emc/methods/method3b.html for Method 3B information.

1.2 Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Reporting

Table 1.2 presents a summary of the recommended test methods for each pollutant and possible alternative methods. If you would like to use a method not on this list, and the list does not meet the definition of "equivalent" provided in the definitions section of this document, please contact EPA for approval of an alternative method.

For copies of the recommended U.S. EPA methods and additional information, please refer to EPA's Emission Measurement Center website: http://www.epa.gov/ttn/emc/. For copies of the US EPA's SW-846 sampling and analysis methods (such as EPA Method 0010 and EPA Method 8270D), please refer to EPA's SW-846 Online website, which is available at the following internet address: http://www.epa.gov/waste/hazard/testmethods/sw846/online/index.htm.

Report pollutant emission data as specified in Tables 1.2a through 1.2 d below. Each test should be comprised of at least three valid test runs. All pollutant concentrations should be corrected to 7 percent oxygen (or as otherwise directed by a specific method) and should be reported on the same moisture basis (dry). Report the results of the stack tests according to the instructions in Section 3.0 of this enclosure. During a 30 day period that includes emissions testing and fuel analysis reporting, you should collect the following process information: Total heat input; feed rate; steam output; gross electric output; net electric output; emissions control devices in use during the test; control device operating or monitoring parameters (including, as appropriate to the control device, flue gas flow rate, pressure drop, scrubber liquor pH, scrubber liquor flow rate, sorbent type and sorbent injection rate), and process parameters (such as oxygen). In addition to the emission test data, you should report the above process information as daily averages.

The owner/operator of the EGU must certify that the fuel that was fired during testing is representative of the fuel that is burned routinely at the EGU. The owner/operator of the EGU must also certify that it operated all of the pollution control equipment in accordance with manufacturers' specifications and requirements for proper operation during the emissions testing. Finally, the owner/operator of the EGU must certify that it operated its pollution control equipment to optimize reduction of the pollutants for which the equipment is designed.

Table 1.2a: Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Alternative Methods for Non-dioxin / furan organic HAP

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
CO	U.S. EPA Method 10, 10A, or 10B. Collect a minimum volume of 1.7 cubic meters and have a minimum sample time of 2 hours per run.	None	lb/MMBtu and ppmvd @ 7% O_2
Formaldehyde	U.S. EPA Method 320. Use a minimum test run time of 2 hours.	RCRA Method 0011. Collect a minimum volume of 1.7 cubic meters and have a minimum sample time of 2 hours per run.	lb/MMBtu and ppmvd @ 7% O_2
THC	U.S. EPA Method 25A. Use a minimum sampling time of 2 hours per run. Calibrate the measuring instrument with a mixture of the organic compounds being emitted or with propane, and report as propane.	None	lb/MMBtu and ppmvd @ 7% O2
CH_4	U.S. EPA Method 18. Use a minimum sample time of 2 hours per run.	U.S. EPA Method 320.	lb/MMBtu and ppmvd @ 7% O2
Speciated Volatile Organic HAP	U.S. EPA Method 0031with SW-846 Method 8260B. Collect a minimum of 4 sets of sorbent traps for analysis per each 2 hour run. Each set of sorbent traps should be run for 20 minutes at an approximate flow rate of one liter per minute.	None	lb/MMBtu and µg/dscm @ 7% O2
Speciated Semi-volatile Organic HAP	U.S. EPA Method 0010 with SW-846 Method 8270D. Collect a minimum volume of 1.7 cubic meters and have a minimum sample time of 2 hours per run. Use high resolution GCMS for the analytical finish.	None	lb/MMBtu and µg/dscm @ 7% O2
SO_2***	U.S. EPA Method 6C	U.S. EPA Method 6	lb/MMBtu and ppmvd @ 7% O_2
O_2/CO_2***	U.S. EPA Method 3A	U.S. EPA Method 3B	%
Moisture	U.S. EPA Method 4	None	%

*** If a combustion unit has CEMS installed for CO, NO_X, and/or SO_2, the unit can report daily averages from 30 days of CEMS data in lieu of conducting a CO, NO_X, and/or SO_2 stack test. In order to correlate these emissions with other stack test emissions, a portion of the CEMS data should contain emissions data collected during performance of the other requested stack tests. The CEMS must meet the requirements of the applicable Performance Specification: CO – Performance Specification 4; NO_X and SO_2 – Performance Specification 2 and 40 CFR 60.13 or the CEMS accuracy and ongoing QA/QC requirements of 40 CFR Part 75.

Table 1.2b: Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Alternative Methods for Dioxin / furan HAP

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
D/F, PCB**	U.S. EPA Method 23. Collect a minimum volume of 8.5 cubic meters and have a minimum sample time of 8 hours per run. Use high resolution GCMS for the analytical finish.	None	lb/MMBtu and ng/dscm @ 7% O2
O_2/CO_2***	U.S. EPA Method 3A	U.S. EPA Method 3B	%
Moisture	U.S. EPA Method 4	None	%

** Just the 12 "dioxin-like" PCB congeners (IUPAC Numbers PCB-77, -81, -105, -114, -118, -123, -126, -156, -157, -167, -169, and -189)

*** If a combustion unit has CEMS installed for CO, NO_X, and/or SO_2, the unit can report daily averages from 30 days of CEMS data in lieu of conducting a CO, NO_X, and/or SO_2 stack test. In order to correlate these emissions with other stack test emissions, a portion of the CEMS data should contain emissions data collected during performance of the other requested stack tests. The CEMS must meet the requirements of the applicable Performance Specification: CO – Performance Specification 4; NO_X and SO_2 – Performance Specification 2 and 40 CFR 60.13 or the CEMS accuracy and ongoing QA/QC requirements of 40 CFR Part 75.

Table 1.2c: Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Alternative Methods for Acid gas HAP

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
HCl and HF	U.S. EPA Method 26A. Collect a minimum volume of 2.5 cubic meters and have a minimum sample time of 3 hours per run.	U.S. EPA Method 26 or U.S . EPA Method 320 if there are no entrained water droplets in the sample.	lb/MMBtu
HCN	U.S. EPA Conditional Test Method 033 (CTM-033)	U.S. EPA Method 26A combined with the analysis procedures from CTM-033, or U.S. EPA Method 26 combined with the analysis procedures from CTM-033 or U.S. EPA Method 320 if there are no entrained water droplets in the sample.	lb/MMBtu
NO_X***	U.S. EPA Method 7E	U.S. EPA Method 7, 7A, 7B, 7C, or 7D	lb/MMBtu and ppmvd @ 7% O_2
SO_2***	U.S. EPA Method 6C	U.S. EPA Method 6	lb/MMBtu and ppmvd @ 7% O_2
O_2/CO_2***	U.S. EPA Method 3A	U.S. EPA Method 3B	%
Moisture	U.S. EPA Method 4	None	%

*** If a combustion unit has CEMS installed for CO, NO_X, and/or SO_2, the unit can report daily averages from 30 days of CEMS data in lieu of conducting a CO, NO_X, and/or SO_2 stack test. In order to correlate these emissions with other stack test emissions, a portion of the CEMS data should contain emissions data collected during performance of the other requested stack tests. The CEMS must meet the requirements of the applicable

Performance Specification: CO – Performance Specification 4; NO_X and SO_2 – Performance Specification 2 and 40 CFR 60.13 or the CEMS accuracy and ongoing QA/QC requirements of 40 CFR Part 75.

Table 1.2d: Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Alternative Methods for Mercury and Non-mercury metallic HAP

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
Hg	U.S. EPA Method 30B. Use a minimum sample time of 2 hours per run.	None	lb/MMBtu
Metals	U.S. EPA Method 29. Collect a minimum volume of 3.4 cubic meters and have a minimum sample time of 4 hours per run. Determine total filterable PM emissions according to §8.3.1.1. Use ICAP/MS for the analytical finish.	None	lb/MMBtu
$PM_{2.5}$ (filterable) from stacks without entrained water droplets (e.g., not from units with wet scrubbers)	U.S. EPA Other Test Method 27 (OTM 27). Include cyclone catch as filterable PM. Collect a minimum volume of 3.4 cubic meters and have a minimum sample time of 4 hours per run.	None	lb/MMBtu
$PM_{2.5}$ (filterable) from stacks with entrained water droplets AND Total Dissolved Solids (TDS) and Total Suspended Solids (TSS) from wet scrubber recirculation liquid	U.S. EPA Method 5 with a filter temperature of 320°F +/- 25°F. Collect a minimum volume of 3.4 cubic meters and have a minimum sample time of 4 hours per run. AND ASTM D5907	For TDS and TSS, Standard Methods of the Examination of Water and Wastewater Method 2540B for solids in scrubber recirculation liquid	lb/MMBtu for PM; AND mg solids liter of scrubber recirculation liquid*
$PM_{2.5}$ (condensable)	U.S. EPA Other Test Method 28 (OTM 28). Collect a minimum volume of 3.4 cubic meters and have a minimum sample time of 4 hours per run.	None	lb/MMBtu
D/F, PCB**	U.S. EPA Method 23. Collect a minimum volume of 8.5 cubic meters and have a minimum sample time of 8 hours per run. Use high resolution GCMS for the analytical finish.	None	lb/MMBtu and ng/dscm @ 7% O2
O_2/CO_2***	U.S. EPA Method 3A	U.S. EPA Method 3B	%
Moisture	U.S. EPA Method 4	None	%

* Also report scrubber recirculation liquid flow rate in liters/min and fuel feed rate in MMBTU/hr.

** Just the 12 "dioxin-like" PCB congeners (IUPAC Numbers PCB-77, -81, -105, -114, -118, -123, -126, -156, -157, -167, -169, and -189)

*** If a combustion unit has CEMS installed for CO, NO_X, and/or SO_2, the unit can report daily averages from 30 days of CEMS data in lieu of conducting a CO, NO_X, and/or SO_2 stack test. In order to correlate these emissions with other stack test emissions, a portion of the CEMS data should contain emissions data collected during performance of the other requested stack tests. The CEMS must meet the requirements of the applicable Performance Specification: CO – Performance Specification 4; NO_X and SO_2 – Performance Specification 2 and 40 CFR 60.13 or the CEMS accuracy and ongoing QA/QC requirements of 40 CFR Part 75.

2.0 Fuel Analysis Procedures and Methods

The EPA coal- and oil-fired electric utility steam generating unit test program is requesting fuel variability data for fuel-based HAP. The fuel analyses requested include: mercury, chlorine, fluorine, and metals (e.g., antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, and selenium) for any coal- and oil-fired electric utility steam generating unit that is selected to conduct a stack test.

You will need to collect at least three samples of the fuel combusted during each metals, mercury, particulate matter, acid gas, and dioxin / furan emissions test run; composite these samples; and then analyze and report each composited sample. Only chlorine and fluorine analyses are required during acid gas emissions testing. Should you have an oil-fired unit that is subject to emissions testing and that is fed from just one fuel tank whose content is uniform and is sufficient to complete the emissions testing campaign, you may contact us with a request to reduce fuel sampling requirements. Your request should identify the characteristics of your site, your proposed alternative fuel sampling procedure, and anticipated impact on emissions of using your proposed approach.

Refer to page 1 of the Section 114 letter you received for the specific types of fuel analyses we are requesting from your facility. Directions for collecting, compositing, preparing, and analyzing fuel analysis data are outlined in Sections 2.1 through 2.4.

2.1 How to Collect a Fuel Sample

Table 2.1 outlines a summary of how samples should be collected. Alternately, you may use the procedures in ASTM D2234–00 (for coal) to collect the sample.

Table 2.1: Summary of Sample Collection Procedures

Sampling Location	Sampling Procedures	Sample Collection Timing
	Solid Fuels	
Belt or Screw Feeder	Stop the belt and withdraw a 6- inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag for further processing as specified in Sections 2.2 through 2.5 of this document.	Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.
Fuel Pile or Truck	For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile. At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling. Transfer all samples to a clean plastic bag for further processing as specified in Sections 2.2 through 2.5 of this document.	
	Liquid Fuels	
Manual Sampling	Follow collection methods outlined in ASTM D 4057	
Automatic Sampling	Follow collection methods outlined in ASTM D4177	
	Fuel Supplier Analysis	
Fuel Supplier	If you will be using fuel analysis from a fuel supplier in lieu of site specific sampling and analysis, the fuel supplier must collect the sample as specified above and prepare the sample according to methods specified in Sections 2.2 through 2.5 of this document.	

2.2 Create a Composite Sample for Solid Fuels

Follow the seven steps listed below to composite each sample:

(1) Thoroughly mix and pour the entire composite sample over a clean plastic sheet.
(2) Break sample pieces larger than 3 inches into smaller sizes.
(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.
(4) Separate one of the quarter samples as the first subset.
(5) If this subset is too large for grinding, repeat step 3 with the quarter sample and obtain a one-quarter subset from this sample.
(6) Grind the sample in a mill according to ASTM E829-94, or for selenium sampling according to SW-846-7740.
(7) Use the procedure in step 3 of this section to obtain a one quarter subsample for analysis. If the quarter sample is too large, subdivide it further using step 3.

2.3 Prepare Sample for Analysis

Use the methods listed in Table 2.2 to prepare your composite samples for analysis.

Table 2.2: Methods for Preparing Composite Samples

Fuel Type	Method
Solid	SW-846-3050B or EPA 3050 for total selected metal preparation
Liquid	SW-846-3020A or any SW-846 sample digestion procedures giving measures of total metal
Coal	ASTM D2013-04
Biomass	ASTM D5198-92 (2003) or equivalent, EPA 3050, or TAPPI T266 for total selected metal preparation

2.4 Analyzing Fuel Sample

Table 2.3 outlines a list of approved methods for analyzing fuel samplings. If you would like to use a method not on this list, and the list does not meet the definition of "equivalent" provided in Section 5 of this document, please contact EPA for approval of an alternative method.

Table 2.3: List of Analytical Methods for Fuel Analysis

Analyte	Fuel Type	Method	Target Reported Units of Measure
Higher Heating Value	Coal	ASTM D5865–04, ASTM D240, ASTM E711-87 (1996)	
	Biomass	ASTM E711–87 (1996) or equivalent, ASTM D240, or ASTM D5865-04	
	Other Solids	ASTM-5865-03a, ASTM D240, ASTM E711-87 (1997)	
	Liquid	ASTM-5865-03a, ASTM D240, ASTM E711-87 (1996)	Btu/lb
Moisture	Coal, Biomass, Other Solids	ASTM-D3 173-03, ASTM E871-82 (1998) or equivalent, EPA 160.3 Mod., or ASTM D2691-95 for coal.	%
Mercury Concentration	Coal	ASTM D6722-01, EPA Method 1631E, SW-846-1631, EPA 821-R-01-013, or equivalent	
	Biomass	SW-846-7471A, EPA Method 1631E, SW-846-1631, ASTM D6722-01, EPA 821-R-01-013, or equivalent	
	Other Solids	SW-846-7471A, EPA Method 1631E, SW-846-1631, EPA 821-R-01-013, or equivalent	ppm
	Liquid	SW-846-7470A, EPA Method 1631E, SW-846-1631E, SW-846-1631, EPA 821-R-01-013, or equivalent	

Analyte	Fuel Type	Method	Target Reported Units of Measure
Total Selected Metals Concentration	Coal	SW-846-6010B, ASTM D3683-94 (2000), SW-846-6020, -6020A or ASTM D6357-04 (for arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel in coal) ASTM D4606-03 or SW-846-7740 (for Se) SW-846-7060 or 7060A (for As)	ppm
	Biomass	SW-846-6010B, ASTM D6357-04, SW-846-6020, -6020A, EPA 200.8, or ASTM E885-88 (1996) or equivalent, SW-846-7740 (for Se) SW-846-7060 or -7060A (for As)	
	Other Solids	SW-846-6010B, EPA 200.8 SW-846-7060 or 7060A for As	
	Liquid	SW-846-6020, -6020A, , SW-846-6010B, SW-846-7740 for Se, SW-846-7060 or -7060A for As	
Chlorine Concentration	Coal	SW-846-9250 or ASTM D6721-01 or equivalent, SW-846-5050, -9056, -9076, or -9250, ASTM E776-87 (1996)	
	Biomass, Other Solids, Liquids	ASTM E776-87 (1996), SW-846-9250, SW-846-5050, -9056, -9076, or -9250	ppm
Fluorine Concentration	Coal	ASTM D3761-96(2002), D5987-96 (2002)	ppm

Report the results of your fuel analysis according to the directions provided in section 3.0 of this enclosure.

3.0 How to Report Data

The method for reporting the results of any testing and monitoring requests depend on the type of tests and the type of methods used to complete the test requirements. This section discusses the requirements for reporting the data.

3.1 Reporting stack test data

If you conducted a stack test using one of the methods listed in Table 3.1, shown below, you must report your data using the EPA Electronic Reporting Tool (ERT) Version 3. ERT is a Microsoft® Access database application. Two versions of the ERT application are available. If you are not a registered owner of Microsoft® Access, you can install the runtime version of the ERT Application. Both versions of the ERT are available at http://www.epa.gov/ttn/chief/ert/ert_tool.html. The ERT supports an Excel spreadsheet application (which is included in the files downloaded with the ERT) to document the collection of the field sampling data. After completing the ERT, you will also need to attach an electronic copy of the emission test report (PDF format preferred) to the Attachments module of the ERT.

Table 3.1: List of Test Methods Supported by ERT

Test Methods Supported by ERT
Methods 1 through 4
Method 7E
Method 6C
Method 5
Method 3A
Method 29
Method 26A
Method 25A
Method 23
Method 202
Method 201A
Method 17
Method 101A
Method 101
Method 10
CT Method 40
CT Method 39
OTM 27
OTM 28

If you conducted a stack test using a method not currently supported by the ERT, you must report the results of this test in a Microsoft® Excel Emission Test Template. The Excel templates are specific to each pollutant and type of unit and they can be downloaded from the Electric Utility MACT ICR 2009 website (http://utilitymacticr.rti.org). You must report the results of each test on the appropriately labeled worksheet corresponding to the specific tests requested at your combustion unit. If more than one unit at your facility conducted a stack test using methods not currently supported by the ERT, you must make a copy of the worksheet and update the combustor ID in order to distinguish between each separate test. After completing the worksheet, you must also submit an electronic copy of the emission test report (PDF format preferred).

If you have CO CEMS that meets performance specification-4 or a SO_2 and/or NO_X CEMS that meets performance specification-2 and 40 CFR 60.13 or the CEMS accuracy and ongoing QA/QC requirements of 40 CFR Part 75 installed at your combustion unit, and you used CEMS data to meet CO, SO_2 and/or NO_X test requirements at your facility, you must report daily averages from 30 days of CEMS data in a Microsoft® Excel CEMS Template. The Excel templates are specific to each pollutant and type of unit and they can be downloaded from the Electric Utility MACT ICR 2009 website (http://utilitymacticr.rti.org).

3.1.1 Reporting measured values below the detection level

Identify the status of measured values relative to detection levels on the spreadsheet or in the ERT using the following descriptions:

- **BDL** (below detection level) – all analytical values used to calculate and report an in-stack emissions value are less than the laboratory's reported detection level(s);
- **DLL** (detection level limited) – at least one but not all values used to calculate and report an in-stack emissions value are less than the laboratory's reported detection level(s); or
- **ADL** (above detection level) – all analytical values used to calculate and report an in-stack emissions value are greater than the laboratory's reported detection level(s).

For each reported emissions value, insert the appropriate flag (BDL, DLL, or ADL) in the ***Note*** line of Excel emission test spreadsheet template or in the ***Comments*** line of the Electronic Reporting Tool (ERT).

When reporting and calculating individual test run data:

- For analytical data reported from the lab as "nondetect" or "below detection level;"
    - Include a brief description of the procedures used to determine the analytical detection and in-stack detection levels:
        - In the ***Note*** line of Excel emission test spreadsheet template; or
        - In the ***Comments*** line of Lab Data tab in the Run Data Details in the **ERT**.
    - Describe these procedures completely in a separate attachment including the measurements made, the standards used, and the statistical procedures applied.
    - Calculate in-stack emissions rate for any analytical measurement below detection level using the relevant detection level as the "real" value.
    - Report the calculated emissions concentration or rate result:
        - As a bracketed "less than" detection level value (e.g., [<0.0105]) in the Excel emission test spreadsheet template and include the appropriate flag in the Note line; or
        - As a "real" value in the **ERT** with the appropriate flag in the Comments line.

- Report as “real” values (i.e., no brackets or < symbol) any analytical data measured above the detection level including any data between the analytical detection level and a laboratory-specific reporting or quantification level (i.e., flag as ADL).
- Apply these reporting and calculation procedures to measurements made with **Method 23**:
  - Report data in the Excel emission test spreadsheet template for each of the D/F congeners measured with Method 23 below the detection level as [< detection level]
  - Do **not report emissions as zero** as described in the method

- For pollutant measurements composed of multiple components or fractions (e.g., Hg and other metals sampling trains) when the result for the value for any component is measured below the analytical detection level;
  - Calculate in-stack emissions rate or concentrations as outlined above for each component or fraction;
  - Sum the measured and detection level values as outlined above using the in-stack emissions rate or concentrations for all of the components or fractions; and
  - Report the sum of all components or fractions:
    - As a bracketed “less than” detection level value (e.g., [<0.0105]) in the Excel emission test spreadsheet template and include the appropriate flag in the Note line; or
    - As a “real” value in the **ERT** with the appropriate flag in the Comments line.
  - Report also the individual component or fraction values for each run if the Excel emission test spreadsheet template or ERT format allows; if not (i.e., the format allows reporting only a single sum value):
    - For the Excel emission test spreadsheet template, next to the sum reported as above report in the ***Notes*** line the appropriate flag along with the values for the measured or detection level value for each component or fraction as used in the calculations (e.g., 0.036, [<0.069], 1.239, [<0.945] for a four fraction sample)
    - For the ERT, next to the sum reported as above, report on the ***Comments*** line the appropriate flag and the measured or detection level value for each component or fraction as used in the calculations (e.g., 0.036, [<0.069], 1.239, [<0.945] for a four fraction sample)
- For measurements conducted using instrumental test methods (e.g., Methods 3A, 6C, 7E, 10, 25A)
  - Record gaseous concentration values **as measured** including negative values and flag as ADL; do not report as BDL
  - Calculate and report in-stack emissions rates using these measured values
  - Include relevant information relative to calibration gas values or other technical qualifiers for measured values in ***Comments*** line in the **ERT**

- When reporting and calculating average emissions rate or concentration for a test when some results are reported as BDL

    - Sum all of the test run values including those indicated as BDL or DLL as "real" values
    - Calculate the average emissions rate or concentration (e.g., divide the sum by 3 for a three-run test)
    - Report the average emissions rate or concentration average:
        - As a bracketed "less than" detection level value (e.g., [<20.06]) in the Excel emission test spreadsheet template and include the appropriate flag in the Note line
        - As a "real" value in the **ERT** and include the appropriate flag in the Comments line.

3.2 Reporting Fuel Analysis Data

If you conducted a fuel analysis, you must report the analysis results separately for each of the composited samples in a Microsoft ® Excel Fuel Analysis Template. This Excel template can be downloaded from the Electric Utility MACT ICR 2009 website (http://utilitymacticr.rti.org). If you conducted fuel analysis on more than one type of fuel used during testing, or for more than one combustion unit, you must make a copy of the worksheet and update the combustor ID and fuel type in each worksheet order to distinguish between the separate fuel analyses.

3.3 Required Fields for ERT Reporting

This section outlines the required data entry fields for the ERT in order to satisfy the requirements of this ICR test program. The list of fields within the ERT with the notes whether or not the field is required or optional can be found at http://utilitymacticr.rti.org.

4.0 How to Submit Data

You may submit your data by using the Electric Utility MACT ICR 2009 website. To avoid duplicate data keep all data for a particular facility together, we request that you submit all of the data requested from your facility the same way. To submit your data:

- Use the Electric Utility MACT ICR 2009 website referenced below and follow the directions listed below.
- If you are submitting Confidential Business Information (CBI), you must mail a separate CD or DVD containing only the CBI portion of your data to the EPA address shown in your Section 114 letter.

Instructions for Uploading Part III

1. **Open the Web site**

   Open the Electrical Utility MACT ICR 2009 Web site, located at the following address: http://utilitymacticr.rti.org
2. **Log in, or register -** It is assumed that the respondent has registered and logged into the website previously for entry of Part I and II data.
3. **Go to the "Upload Part III" page**
   a. Click on the "Upload" menu item within the menu bar at the top of the screen to go to the "Upload" page.
   b. Click on the "Upload Part III" link.
4. **Upload your completed ERT Database and Excel Spreadsheets**
   a. Go to the tabbed section of the "Upload Part III" page.
   b. The first tab is the "Upload Checklist" tab.

      Answer all questions, then click on the "Continue" button. Your answers to the "Upload Checklist" questions will assist in guiding you correctly through the upload process.
   c. The next tab is the "Upload ERT Database" tab.
      i. Enter a description for the upload, or any comments. Note that the description and comments entered at this point are primarily for your own reference when referring back to the files you have uploaded (refer to 4.e).
      ii. Select the name(s) of the Facility(s) that the ERT Database applies to.
      iii. Select the name(s) of the Unit(s) that the ERT Database applies to.
      iv. Browse to the ERT Database file that you wish to upload.
      v. After selecting the file, click on the "Upload" link. The file's upload progress will be displayed. Uploading may take a few seconds or minutes depending on the size of the file you are attempting to upload, and your internet connection speed.

Please be aware that the only file types that will be accepted for the ERT Database upload are “.zip” and “.acddr” (the file type of the ERT Database originally supplied to you). It is recommended that you zip your completed ERT Database prior to uploading it, particularly if it is over 200MB in size.

d. After the ERT Database upload has completed, click on the “Continue” button.

e. If you answered “Yes” to the checklist question regarding Additional Excel data(Microsoft® Excel Emission Test Template and/or Microsoft ® Excel Fuel Analysis Template), the next tab will be the “Upload Additional Excel Data” tab.

   Follow the same process outlined in 4.c.

   Note that the only file types that will be accepted for the Excel data upload are “.xls” and “.xlsx”.

f. After the Excel data upload has completed, click on the “Continue” button.

g. The final tab is the “View uploaded files” tab. This will display a list of the files you have uploaded.

   i. Next to each file will be links to “Delete” and “Download” the file.

      1. You can click on the “Delete” link if you wish to remove the file in order to upload a new version.

      2. If you would like to check the file that is currently uploaded, click on the “Download” link to download a copy of it.

   ii. At the bottom of the “View uploaded files” tab, there is a “Finalize uploads” button.

      1. Click on this button when you are sure you have uploaded the final copy of your completed ERT Database.

      2. Once you have finalized uploads for Part III you will no longer be able to upload further files for that part of the ICR.

Also at the bottom of the “View uploaded files” tab, there is a button titled “Upload another file”.

Click on this button if you would like to start the upload process again, for another completed ERT Database

5.0 Definitions

The following definitions apply to the coal- and oil-fired electric utility steam generating unit test plan methods:

Equivalent means:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.
(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.
(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.
(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.
(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an ‘‘as received’’ basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.
(6) An equivalent pollutant (mercury, TSM, or total chlorine) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal to or lower than the methods listed in this test plan.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) developed or adopted by one or more voluntary consensus bodies. EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. States, such as California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, such as Department of Defense (DOD) and Department of Transportation (DOT).

This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

6.0 Contact Information for Questions on Test Plan and Reporting

For questions on how to report data using the ERT, contact:
Ron Myers
U.S. EPA
(919) 541-5407
myers.ron@epa.gov

or

Barrett Parker
U.S. EPA
(919) 541-5635
parker.barrett@epa.gov

For questions on the test methods contact:
Peter Westlin
U.S. EPA
(919) 541-1058
westlin.peter@epa.gov

OR

Gary McAlister
U.S. EPA
(919) 541-1062
mcalister.gary@epa.gov

For questions on the coal- and oil-fired electric utility steam generating unit test plan, including units selected to test and reporting mechanisms other than the ERT, contact:
William Maxwell
U.S. EPA
(919) 541-5430
maxwell.bill@epa.gov

For questions on uploading files to the HTTP site, Please visit http://utilitymacticr.rti.org and use the toll free technical support hotline or technical support email address.

Attachment 4. List of coal-fired electric utility steam generating units requiring Part I and II Information

State	Plant Name	Boiler ID
IN	A. B. Brown	1
IN	A. B. Brown	2
CA	ACE Cogeneration Facility	CFB
PA	AES Beaver Valley Partners Beaver Valley	2
PA	AES Beaver Valley Partners Beaver Valley	3
PA	AES Beaver Valley Partners Beaver Valley	4
PA	AES Beaver Valley Partners Beaver Valley	5
NY	AES Cayuga	1
NY	AES Cayuga	2
NY	AES Greenidge LLC	4
NY	AES Greenidge LLC	5
NY	AES Greenidge LLC	6
HI	AES Hawaii	BLRA
HI	AES Hawaii	BLRB
IN	AES Petersburg	1
IN	AES Petersburg	2
IN	AES Petersburg	3
IN	AES Petersburg	4
PR	AES Puerto Rico (Aurora)	1
PR	AES Puerto Rico (Aurora)	2
OK	AES Shady Point	1A
OK	AES Shady Point	1B
OK	AES Shady Point	2A
OK	AES Shady Point	2B
NY	AES Somerset LLC	1
CT	AES Thames	A
CT	AES Thames	B
MD	AES Warrior Run Cogeneration Facility	BLR1
NY	AES Westover	11
NY	AES Westover	12
NY	AES Westover	13
WV	Albright	1
WV	Albright	2
WV	Albright	3
MN	Allen S. King	1
TN	Allen Steam Plant	1
TN	Allen Steam Plant	2
TN	Allen Steam Plant	3
WI	Alma	B4
WI	Alma	B5
VA	Altavista Power Station	1
IA	Ames Electric Services Power Plant	7
IA	Ames Electric Services Power Plant	8
ND	Antelope Valley	B1
ND	Antelope Valley	B2
AZ	Apache Station	2
AZ	Apache Station	3
CO	Arapahoe	3
CO	Arapahoe	4
PA	Armstrong Power Station	1
PA	Armstrong Power Station	2
MO	Asbury	1
NC	Asheville	1
NC	Asheville	2
OH	Ashtabula	7
OH	Avon Lake	10
OH	Avon Lake	12
MI	B. C. Cobb	4
MI	B. C. Cobb	5
NJ	B. L. England	2
IN	Bailly	7
IN	Bailly	8
IL	Baldwin Energy Complex	1
IL	Baldwin Energy Complex	2
IL	Baldwin Energy Complex	3
AL	Barry	1
AL	Barry	2
AL	Barry	3
AL	Barry	4
AL	Barry	5
OH	Bay Shore	2
OH	Bay Shore	3
OH	Bay Shore	4
WI	Bay Front	5
NC	Belews Creek	1
NC	Belews Creek	2
MI	Belle River	1
MI	Belle River	2
FL	Big Bend	BB01
FL	Big Bend	BB02
FL	Big Bend	BB03
FL	Big Bend	BB04
TX	Big Brown	1
TX	Big Brown	2
LA	Big Cajun 2	2B1
LA	Big Cajun 2	2B2
LA	Big Cajun 2	2B3
KY	Big Sandy	BSU1
KY	Big Sandy	BSU2
SD	Big Stone	1
VA	Birchwood Power	1A
MN	Black Dog	3
MN	Black Dog	4
NY	Black River Generation	E0001
NY	Black River Generation	E0002
NY	Black River Generation	E0003
WI	Blount Street	7
WI	Blount Street	8
WI	Blount Street	9
MO	Blue Valley	1
MO	Blue Valley	2
MO	Blue Valley	3
OR	Boardman	1SG
UT	Bonanza	1-1
GA	Bowen	1BLR
GA	Bowen	2BLR
GA	Bowen	3BLR
GA	Bowen	4BLR
MD	Brandon Shores	1
MD	Brandon Shores	2
MA	Brayton Point	1
MA	Brayton Point	2
MA	Brayton Point	3
VA	Bremo Bluff	3
VA	Bremo Bluff	4
CT	Bridgeport Station	BHB3
PA	Bruce Mansfield	1
PA	Bruce Mansfield	2
PA	Bruce Mansfield	3
NC	Buck	5
NC	Buck	6
NC	Buck	7
NC	Buck	8
NC	Buck	9
TN	Bull Run	1
IA	Burlington	1
FL	C. D. McIntosh Jr	3
MD	C. P. Crane	1
MD	C. P. Crane	2
NY	C. R. Huntley Generating Station	65
NY	C. R. Huntley Generating Station	67
NY	C. R. Huntley Generating Station	68
PA	Cambria Cogen	B1
PA	Cambria Cogen	B2
SC	Canadys Steam	CAN1
SC	Canadys Steam	CAN2
SC	Canadys Steam	CAN3
KY	Cane Run	4
KY	Cane Run	5
KY	Cane Run	6
NC	Cape Fear	5
NC	Cape Fear	6
UT	Carbon	1
UT	Carbon	2
OH	Cardinal	1
OH	Cardinal	2
OH	Cardinal	3
IN	Cayuga	1
IN	Cayuga	2
FL	Cedar Bay Generating LP	CBA

Attachment 4. List of coal-fired electric utility steam generating units requiring Part I and II Information

State	Plant Name	Boiler ID
FL	Cedar Bay Generating LP	CBB
FL	Cedar Bay Generating LP	CBC
FL	Central Power & Lime	1
MD	Chalk Point LLC	1
MD	Chalk Point LLC	2
NJ	Chambers Cogeneration LP	BOIL1
NJ	Chambers Cogeneration LP	BOIL2
MO	Chamois	2
AL	Charles R Lowman	3
AL	Charles R. Lowman	1
AL	Charles R. Lowman	2
CO	Cherokee	1
CO	Cherokee	2
CO	Cherokee	3
CO	Cherokee	4
VA	Chesapeake	1
VA	Chesapeake	2
VA	Chesapeake	3
VA	Chesapeake	4
VA	Chesterfield	3
VA	Chesterfield	4
VA	Chesterfield	5
VA	Chesterfield	6
PA	Cheswick Power Plant	1
AZ	Cholla	1
AZ	Cholla	2
AZ	Cholla	3
AZ	Cholla	4
MN	Clay Boswell	1
MN	Clay Boswell	2
MN	Clay Boswell	3
MN	Clay Boswell	4
NC	Cliffside	1
NC	Cliffside	2
NC	Cliffside	3
NC	Cliffside	4
NC	Cliffside	5
IN	Clifty Creek	1
IN	Clifty Creek	2
IN	Clifty Creek	3
IN	Clifty Creek	4
IN	Clifty Creek	5
IN	Clifty Creek	6
VA	Clinch River	1
VA	Clinch River	2
VA	Clinch River	3
VA	Clover	1
VA	Clover	2
ND	Coal Creek	1
ND	Coal Creek	2
IL	Coffeen	01

State	Plant Name	Boiler ID
IL	Coffeen	02
NC	Cogentrix Dwayne Collier Battle Cogen	1A
NC	Cogentrix Dwayne Collier Battle Cogen	1B
NC	Cogentrix Dwayne Collier Battle Cogen	2A
NC	Cogentrix Dwayne Collier Battle Cogen	2B
VA	Cogentrix Hopewell	1A
VA	Cogentrix Hopewell	1B
VA	Cogentrix Hopewell	1C
VA	Cogentrix Hopewell	2A
VA	Cogentrix Hopewell	2B
VA	Cogentrix Hopewell	2C
VA	Cogentrix of Richmond	1A
VA	Cogentrix of Richmond	1B
VA	Cogentrix of Richmond	2A
VA	Cogentrix of Richmond	2B
VA	Cogentrix of Richmond	3A
VA	Cogentrix of Richmond	3B
VA	Cogentrix of Richmond	4A
VA	Cogentrix of Richmond	4B
VA	Cogentrix Virginia Leasing Corporation	1A
VA	Cogentrix Virginia Leasing Corporation	1B
VA	Cogentrix Virginia Leasing Corporation	1C
VA	Cogentrix Virginia Leasing Corporation	2A
VA	Cogentrix Virginia Leasing Corporation	2B
VA	Cogentrix Virginia Leasing Corporation	2C
AL	Colbert	1
AL	Colbert	2
AL	Colbert	3
AL	Colbert	4
AL	Colbert	5
TX	Coleto Creek	1
MT	Colstrip	1
MT	Colstrip	2
MT	Colstrip	3
MT	Colstrip	4
MT	Colstrip Energy LP	BLR1
WI	Columbia	1
WI	Columbia	2
PA	Colver Power Project	ABB01
CO	Comanche	1
CO	Comanche	2
CO	Comanche	3
PA	Conemaugh	1
PA	Conemaugh	2
OH	Conesville	1
OH	Conesville	2
OH	Conesville	3
OH	Conesville	4
OH	Conesville	5
OH	Conesville	6
KY	Cooper	1

State	Plant Name	Boiler ID
KY	Cooper	2
SC	Cope	COP1
AZ	Coronado	U1B
AZ	Coronado	U2B
IA	Council Bluffs	1
IA	Council Bluffs	2
IA	Council Bluffs	3
IA	Council Bluffs	4
ND	Coyote	B1
CO	Craig	C1
CO	Craig	C2
CO	Craig	C3
IL	Crawford	7
IL	Crawford	8
FL	Crist	4
FL	Crist	5
FL	Crist	6
FL	Crist	7
PA	Cromby Generating Station	1
SC	Cross	1
SC	Cross	2
SC	Cross	3
SC	Cross	4
FL	Crystal River	1
FL	Crystal River	2
FL	Crystal River	4
FL	Crystal River	5
TN	Cumberland	1
TN	Cumberland	2
KY	D. B. Wilson	W1
KY	Dale	1
KY	Dale	2
KY	Dale	3
KY	Dale	4
IL	Dallman	31
IL	Dallman	32
IL	Dallman	33
IL	Dallman	34
MI	Dan E. Karn	1
MI	Dan E. Karn	2
NC	Dan River	1
NC	Dan River	2
NC	Dan River	3
NY	Danskammer Generating Station	3
NY	Danskammer Generating Station	4
WY	Dave Johnston	BW41
WY	Dave Johnston	BW42
WY	Dave Johnston	BW43
WY	Dave Johnston	BW44
NJ	Deepwater	8
FL	Deerhaven Generating Station	B2

Attachment 4. List of coal-fired electric utility steam generating units requiring Part I and II Information

State	Plant Name	Boiler ID
MD	Dickerson	1
MD	Dickerson	2
MD	Dickerson	3
LA	Dolet Hills	1
SC	Dolphus M Grainger	1
SC	Dolphus M Grainger	2
IA	Dubuque	1
IA	Dubuque	5
IL	Duck Creek	1
NY	Dunkirk Generating Station	1
NY	Dunkirk Generating Station	2
NY	Dunkirk Generating Station	3
NY	Dunkirk Generating Station	4
AL	E. C. Gaston	1
AL	E. C. Gaston	2
AL	E. C. Gaston	3
AL	E. C. Gaston	4
AL	E. C. Gaston	5
IL	E. D. Edwards	1
IL	E. D. Edwards	2
IL	E. D. Edwards	3
KY	E. W. Brown	1
KY	E. W. Brown	2
KY	E. W. Brown	3
IN	Eagle Valley	3
IN	Eagle Valley	4
IN	Eagle Valley	5
IN	Eagle Valley	6
IA	Earl F. Wisdom	1
KY	East Bend	2
OH	Eastlake	1
OH	Eastlake	2
OH	Eastlake	3
OH	Eastlake	4
OH	Eastlake	5
PA	Ebensburg Power	031
MI	Eckert Station	1
MI	Eckert Station	2
MI	Eckert Station	3
MI	Eckert Station	4
MI	Eckert Station	5
MI	Eckert Station	6
PA	Eddystone Generating Station	1
PA	Eddystone Generating Station	2
DE	Edge Moor	3
DE	Edge Moor	4
WI	Edgewater	3
WI	Edgewater	4
WI	Edgewater	5
IN	Edwardsport	7-1
IN	Edwardsport	7-2
IN	Edwardsport	8-1
WI	Elm Road Generating Station	1
WI	Elm Road Generating Station	2
KY	Elmer Smith	1
KY	Elmer Smith	2
PA	Elrama Power Plant	1
PA	Elrama Power Plant	2
PA	Elrama Power Plant	3
PA	Elrama Power Plant	4
MI	Endicott Station	1
MI	Erickson Station	1
NM	Escalante	1
IN	F. B. Culley	1
IN	F. B. Culley	2
IN	F. B. Culley	3
IA	Fair Station	1
IA	Fair Station	2
TX	Fayette Power Project	1
TX	Fayette Power Project	2
TX	Fayette Power Project	3
IL	Fisk Street	19
AR	Flint Creek	1
WV	Fort Martin Power Station	1
WV	Fort Martin Power Station	2
PA	Foster Wheeler Mt Carmel Cogen	SG-101
NM	Four Corners	1
NM	Four Corners	2
NM	Four Corners	3
NM	Four Corners	4
NM	Four Corners	5
IN	Frank E. Ratts	1SG1
IN	Frank E. Ratts	2SG1
NC	G. G. Allen	1
NC	G. G. Allen	2
NC	G. G. Allen	3
NC	G. G. Allen	4
NC	G. G. Allen	5
AL	Gadsden	1
AL	Gadsden	2
TN	Gallatin	1
TN	Gallatin	2
TN	Gallatin	3
TN	Gallatin	4
OH	General James M Gavin	1
OH	General James M Gavin	2
WI	Genoa	1
IA	George Neal North	1
IA	George Neal North	2
IA	George Neal North	3
IA	George Neal South	4
NE	Gerald Gentleman	1
NE	Gerald Gentleman	2
KY	Ghent	1
KY	Ghent	2
KY	Ghent	3
KY	Ghent	4
TX	Gibbons Creek	1
IN	Gibson	1
IN	Gibson	2
IN	Gibson	3
IN	Gibson	4
IN	Gibson	5
VA	Glen Lyn	6
VA	Glen Lyn	51
VA	Glen Lyn	52
AL	Gorgas	6
AL	Gorgas	7
AL	Gorgas	8
AL	Gorgas	9
AL	Gorgas	10
WV	Grant Town Power Plant	BLR1A
WV	Grant Town Power Plant	BLR1B
OK	GRDA	1
OK	GRDA	2
KY	Green River	4
KY	Green River	5
AL	Greene County	1
AL	Greene County	2
SC	H. B. Robinson	1
KY	H. L. Spurlock	1
KY	H. L. Spurlock	2
KY	H. L. Spurlock	3
KY	H. L. Spurlock	4
OH	Hamilton	8
OH	Hamilton	9
GA	Hammond	1
GA	Hammond	2
GA	Hammond	3
GA	Hammond	4
MI	Harbor Beach	1
MT	Hardin Generator Project	PC1
IN	Harding Street	50
IN	Harding Street	60
IN	Harding Street	70
GA	Harllee Branch	1
GA	Harllee Branch	2
GA	Harllee Branch	3
GA	Harllee Branch	4
TX	Harrington	061B
TX	Harrington	062B
TX	Harrington	063B
WV	Harrison Power Station	1

Attachment 4. List of coal-fired electric utility steam generating units requiring Part I and II Information

State	Plant Name	Boiler ID
WV	Harrison Power Station	2
WV	Harrison Power Station	3
PA	Hatfields Ferry Power Station	1
PA	Hatfields Ferry Power Station	2
PA	Hatfields Ferry Power Station	3
IL	Havana	9
MO	Hawthorn	5A
CO	Hayden	H1
CO	Hayden	H2
AK	Healy	1
KY	Henderson I	6
IL	Hennepin Power Station	1
IL	Hennepin Power Station	2
MD	Herbert A. Wagner	2
MD	Herbert A. Wagner	3
KY	HMP&L Station Two Henderson	H1
KY	HMP&L Station Two Henderson	H2
KS	Holcomb	SGU1
PA	Homer City Station	1
PA	Homer City Station	2
PA	Homer City Station	3
MN	Hoot Lake	2
MN	Hoot Lake	3
OK	Hugo	1
UT	Hunter	1
UT	Hunter	2
UT	Hunter	3
UT	Huntington	1
UT	Huntington	2
IL	Hutsonville	05
IL	Hutsonville	06
MO	Iatan	1
AR	Independence	1
AR	Independence	2
DE	Indian River Generating Station	2
DE	Indian River Generating Station	3
DE	Indian River Generating Station	4
FL	Indiantown Cogeneration LP	AAB01
UT	Intermountain Power Project	1SGA
UT	Intermountain Power Project	2SGA
MI	J. B. Sims	3
MI	J. C. Weadock	7
MI	J. C. Weadock	8
MT	J. E. Corette Plant	2
MI	J. H. Campbell	1
MI	J. H. Campbell	2
MI	J. H. Campbell	3
KY	J. K. Smith	1
TX	J. K. Spruce	BLR1
TX	J. K. Spruce	BLR2
OH	J. M. Stuart	1
OH	J. M. Stuart	2
OH	J. M. Stuart	3
OH	J. M. Stuart	4
MI	J. R. Whiting	1
MI	J. R. Whiting	2
MI	J. R. Whiting	3
TX	J. T. Deely	1
TX	J. T. Deely	2
GA	Jack McDonough	MB1
GA	Jack McDonough	MB2
MS	Jack Watson	4
MS	Jack Watson	5
MI	James De Young	5
AL	James H. Miller Jr.	1
AL	James H. Miller Jr.	2
AL	James H. Miller Jr.	3
AL	James H. Miller Jr.	4
MO	James River Power Station	3
MO	James River Power Station	4
MO	James River Power Station	5
SC	Jefferies	3
SC	Jefferies	4
KS	Jeffrey Energy Center	1
KS	Jeffrey Energy Center	2
KS	Jeffrey Energy Center	3
WY	Jim Bridger	BW71
WY	Jim Bridger	BW72
WY	Jim Bridger	BW73
WY	Jim Bridger	BW74
PA	John B Rich Memorial Power Station	CFB1
PA	John B Rich Memorial Power Station	CFB2
WV	John E Amos	1
WV	John E Amos	2
WV	John E. Amos	3
WI	John P. Madgett	B1
TN	John Sevier	1
TN	John Sevier	2
TN	John Sevier	3
TN	John Sevier	4
TN	Johnsonville	1
TN	Johnsonville	2
TN	Johnsonville	3
TN	Johnsonville	4
TN	Johnsonville	5
TN	Johnsonville	6
TN	Johnsonville	7
TN	Johnsonville	8
TN	Johnsonville	9
TN	Johnsonville	10
IL	Joliet 29	71
IL	Joliet 29	72
IL	Joliet 29	81
IL	Joliet 29	82
IL	Joliet 9	5
IL	Joppa Steam	1
IL	Joppa Steam	2
IL	Joppa Steam	3
IL	Joppa Steam	4
IL	Joppa Steam	5
IL	Joppa Steam	6
WV	Kammer	1
WV	Kammer	2
WV	Kammer	3
WV	Kanawha River	1
WV	Kanawha River	2
KY	Kenneth C. Coleman	C1
KY	Kenneth C. Coleman	C2
KY	Kenneth C. Coleman	C3
PA	Keystone	1
PA	Keystone	2
OH	Killen Station	2
IL	Kincaid Generation LLC	1
IL	Kincaid Generation LLC	2
TN	Kingston	1
TN	Kingston	2
TN	Kingston	3
TN	Kingston	4
TN	Kingston	5
TN	Kingston	6
TN	Kingston	7
TN	Kingston	8
TN	Kingston	9
PA	Kline Township Cogen Facility	1
GA	Kraft	1
GA	Kraft	2
GA	Kraft	3
OH	Kyger Creek	1
OH	Kyger Creek	2
OH	Kyger Creek	3
OH	Kyger Creek	4
OH	Kyger Creek	5
NC	L. V. Sutton	1
NC	L. V. Sutton	2
NC	L. V. Sutton	3
KS	La Cygne	1
KS	La Cygne	2
MO	Labadie	1
MO	Labadie	2
MO	Labadie	3
MO	Labadie	4
MO	Lake Road	5
OH	Lake Shore	18

Attachment 4. List of coal-fired electric utility steam generating units requiring Part I and II Information

State	Plant Name	Boiler ID
IL	Lakeside	7
IL	Lakeside	8
CO	Lamar	4
IA	Lansing	3
IA	Lansing	4
FL	Lansing Smith	1
FL	Lansing Smith	2
WY	Laramie River Station	1
WY	Laramie River Station	2
WY	Laramie River Station	3
KS	Lawrence Energy Center	3
KS	Lawrence Energy Center	4
KS	Lawrence Energy Center	5
NC	Lee	1
NC	Lee	2
NC	Lee	3
ND	Leland Olds	1
ND	Leland Olds	2
MT	Lewis & Clark	B1
TX	Limestone	LIM1
TX	Limestone	LIM2
NJ	Logan Generating Plant	B01
NE	Lon Wright	8
IA	Louisa	101
WI	Manitowoc	6
WI	Manitowoc	7
WI	Manitowoc	8
IL	Marion	4
IL	Marion	123
NC	Marshall	1
NC	Marshall	2
NC	Marshall	3
NC	Marshall	4
CO	Martin Drake	5
CO	Martin Drake	6
CO	Martin Drake	7
TX	Martin Lake	1
TX	Martin Lake	2
TX	Martin Lake	3
NC	Mayo	1A
NC	Mayo	1B
GA	McIntosh	1
SC	McMeekin	MCM1
SC	McMeekin	MCM2
VA	Mecklenburg Power Station	BLR1
VA	Mecklenburg Power Station	BLR2
MO	Meramec	1
MO	Meramec	2
MO	Meramec	3
MO	Meramec	4
IL	Meredosia	01
IL	Meredosia	02
IL	Meredosia	03
IL	Meredosia	04
IL	Meredosia	05
IN	Merom	1SG1
IN	Merom	2SG1
NH	Merrimack	1
NH	Merrimack	2
OH	Miami Fort	6
OH	Miami Fort	7
OH	Miami Fort	8
OH	Miami Fort	5-1
OH	Miami Fort	5-2
IN	Michigan City	12
KY	Mill Creek	1
KY	Mill Creek	2
KY	Mill Creek	3
KY	Mill Creek	4
IA	Milton L. Kapp	2
ND	Milton R. Young	B1
ND	Milton R. Young	B2
GA	Mitchell	3
WV	Mitchell	1
WV	Mitchell	2
PA	Mitchell Power Station	33
MI	Monroe	1
MI	Monroe	2
MI	Monroe	3
MI	Monroe	4
TX	Monticello	1
TX	Monticello	2
TX	Monticello	3
MO	Montrose	1
MO	Montrose	2
MO	Montrose	3
WV	Morgantown Energy Facility	CFB1
WV	Morgantown Energy Facility	CFB2
MD	Morgantown Generating Plant	1
MD	Morgantown Generating Plant	2
MA	Mount Tom	1
WV	Mountaineer	1
WV	Mt Storm	3
CA	Mt. Poso Cogeneration	BL01
WV	Mt. Storm	1
WV	Mt. Storm	2
IA	Muscatine Plant #1	7
IA	Muscatine Plant #1	8
IA	Muscatine Plant #1	9
OH	Muskingum River	1
OH	Muskingum River	2
OH	Muskingum River	3
OH	Muskingum River	4
OH	Muskingum River	5
OK	Muskogee	4
OK	Muskogee	5
OK	Muskogee	6
WY	Naughton	1
WY	Naughton	2
WY	Naughton	3
AZ	Navajo	1
AZ	Navajo	2
AZ	Navajo	3
KS	Nearman Creek	N1
NE	Nebraska City	1
NE	Nebraska City	2
WY	Neil Simpson II	2
WI	Nelson Dewey	1
WI	Nelson Dewey	2
PA	New Castle Plant	3
PA	New Castle Plant	4
PA	New Castle Plant	5
MO	New Madrid	1
MO	New Madrid	2
IL	Newton	1
IL	Newton	2
OH	Niles	1
OH	Niles	2
WV	North Branch	1A
WV	North Branch	1B
NE	North Omaha	1
NE	North Omaha	2
NE	North Omaha	3
NE	North Omaha	4
NE	North Omaha	5
NV	North Valmy	1
NV	North Valmy	2
PA	Northampton Generating Company	BLR1
OK	Northeastern	3313
OK	Northeastern	3314
CO	Nucla	1
OH	O. H. Hutchings	H-1
OH	O. H. Hutchings	H-2
OH	O. H. Hutchings	H-3
OH	O. H. Hutchings	H-4
OH	O. H. Hutchings	H-5
OH	O. H. Hutchings	H-6
TX	Oak Grove	1
TX	Oak Grove	2
TX	Oklaunion	1
OH	Orrville	10
OH	Orrville	11
OH	Orrville	12

Attachment 4. List of coal-fired electric utility steam generating units requiring Part I and II Information

State	Plant Name	Boiler ID
OH	Orrville	13
IA	Ottumwa	1
OH	Painesville	3
OH	Painesville	4
OH	Painesville	5
PA	Panther Creek Energy Facility	BLR1
PA	Panther Creek Energy Facility	BLR2
KY	Paradise	1
KY	Paradise	2
KY	Paradise	3
CO	Pawnee	1
WV	Philip Sporn	11
WV	Philip Sporn	21
WV	Philip Sporn	31
WV	Philip Sporn	41
WV	Philip Sporn	51
OH	Picway	9
PA	Piney Creek Project	BRBR1
TX	Pirkey	1
WI	Pleasant Prairie	1
WI	Pleasant Prairie	2
WV	Pleasants Power Station	1
WV	Pleasants Power Station	2
AR	Plum Point Energy	STG1
CA	Port of Stockton District Energy Facility	N64514
CA	Port of Stockton District Energy Facility	N64516
PA	Portland	1
PA	Portland	2
VA	Potomac River	1
VA	Potomac River	2
VA	Potomac River	3
VA	Potomac River	4
VA	Potomac River	5
IL	Powerton	51
IL	Powerton	52
IL	Powerton	61
IL	Powerton	62
PA	PPL Brunner Island	1
PA	PPL Brunner Island	2
PA	PPL Brunner Island	3
PA	PPL Martins Creek	1
PA	PPL Martins Creek	2
PA	PPL Montour	1
PA	PPL Montour	2
IA	Prairie Creek	1
IA	Prairie Creek	2
IA	Prairie Creek	3
IA	Prairie Creek	4
MI	Presque Isle	5
MI	Presque Isle	6
MI	Presque Isle	7
MI	Presque Isle	8
MI	Presque Isle	9
NC	Primary Energy Roxboro	1A
NC	Primary Energy Roxboro	1B
NC	Primary Energy Roxboro	1C
NC	Primary Energy Southport	1A
NC	Primary Energy Southport	1B
NC	Primary Energy Southport	1C
NC	Primary Energy Southport	2A
NC	Primary Energy Southport	2B
NC	Primary Energy Southport	2C
NJ	PSEG Hudson Generating Station	2
NJ	PSEG Mercer Generating Station	1
NJ	PSEG Mercer Generating Station	2
WI	Pulliam	3
WI	Pulliam	4
WI	Pulliam	5
WI	Pulliam	6
WI	Pulliam	7
WI	Pulliam	8
KS	Quindaro	1
KS	Quindaro	2
KY	R D Green	G2
KY	R. D. Green	G1
MS	R. D. Morrow	1
MS	R. D. Morrow	2
OH	R. E. Burger	5
OH	R. E. Burger	6
OH	R. E. Burger	7
OH	R. E. Burger	8
IN	R. Gallagher	1
IN	R. Gallagher	2
IN	R. Gallagher	3
IN	R. Gallagher	4
ND	R. M. Heskett	B1
ND	R. M. Heskett	B2
IN	R. M. Schahfer	14
IN	R. M. Schahfer	15
IN	R. M. Schahfer	17
IN	R. M. Schahfer	18
MD	R. Paul Smith Power Station	9
MD	R. Paul Smith Power Station	11
LA	R. S. Nelson	6
CO	Rawhide	101
CO	Ray D. Nixon	1
MS	Red Hills Generating Facility	AA001
MS	Red Hills Generating Facility	AA002
NV	Reid Gardner	1
NV	Reid Gardner	2
NV	Reid Gardner	3
NV	Reid Gardner	4
OH	Richard Gorsuch	1
OH	Richard Gorsuch	2
OH	Richard Gorsuch	3
OH	Richard Gorsuch	4
MI	River Rouge	2
MI	River Rouge	3
NC	Riverbend	7
NC	Riverbend	8
NC	Riverbend	9
NC	Riverbend	10
IA	Riverside	9
KS	Riverton	39
KS	Riverton	40
WV	Rivesville	7
WV	Rivesville	8
NC	Roanoke Valley I	BLR1
NC	Roanoke Valley II	BLR2
KY	Robert A Reid	R1
NY	Rochester 7	1
NY	Rochester 7	2
NY	Rochester 7	3
NY	Rochester 7	4
IN	Rockport	MB1
IN	Rockport	MB2
LA	Rodemacher	2
NC	Roxboro	1
NC	Roxboro	2
NC	Roxboro	3A
NC	Roxboro	3B
NC	Roxboro	4A
NC	Roxboro	4B
MO	Rush Island	1
MO	Rush Island	2
MA	Salem Harbor	1
MA	Salem Harbor	2
MA	Salem Harbor	3
NM	San Juan	1
NM	San Juan	2
NM	San Juan	3
NM	San Juan	4
TX	San Miguel	SM-1
TX	Sandow Station	4
TX	Sandow Station	5A
TX	Sandow Station	5B
GA	Scherer	1
GA	Scherer	2
GA	Scherer	3
GA	Scherer	4
NH	Schiller	4
NH	Schiller	5
NH	Schiller	6

Attachment 4. List of coal-fired electric utility steam generating units requiring Part I and II Information

State	Plant Name	Boiler ID
FL	Scholz	1
FL	Scholz	2
PA	Scrubgrass Generating	UNIT 1
PA	Scrubgrass Generating	UNIT 2
FL	Seminole	1
FL	Seminole	2
PA	Seward	1
PA	Seward	2
KY	Shawnee	1
KY	Shawnee	2
KY	Shawnee	3
KY	Shawnee	4
KY	Shawnee	5
KY	Shawnee	6
KY	Shawnee	7
KY	Shawnee	8
KY	Shawnee	9
KY	Shawnee	10
PA	Shawville	1
PA	Shawville	2
PA	Shawville	3
PA	Shawville	4
NE	Sheldon	1
NE	Sheldon	2
MN	Sherburne County	1
MN	Sherburne County	2
MN	Sherburne County	3
MI	Shiras	3
MO	Sibley	1
MO	Sibley	2
MO	Sibley	3
MO	Sikeston Power Station	1
MN	Silver Bay Power	BLR1
MN	Silver Bay Power	BLR2
MN	Silver Lake	3
MN	Silver Lake	4
MO	Sioux	1
MO	Sioux	2
IA	Sixth Street	2
IA	Sixth Street	3
IA	Sixth Street	4
IA	Sixth Street	5
MA	Somerset Station	8
OK	Sooner	1
OK	Sooner	2
WI	South Oak Creek	5
WI	South Oak Creek	6
WI	South Oak Creek	7
WI	South Oak Creek	8
VA	Southampton Power Station	1
MO	Southwest Power Station	1
AZ	Springerville	1
AZ	Springerville	2
AZ	Springerville	3
AZ	Springerville	4
MI	St. Clair	1
MI	St. Clair	2
MI	St. Clair	3
MI	St. Clair	4
MI	St. Clair	6
MI	St. Clair	7
FL	St. Johns River Power Park	1
FL	St. Johns River Power Park	2
PA	St. Nicholas Cogen Project	1
ND	Stanton	1
ND	Stanton	10
FL	Stanton Energy Center	1
FL	Stanton Energy Center	2
IN	State Line Energy	3
IN	State Line Energy	4
IA	Streeter Station	7
UT	Sunnyside Cogen Associates	1
IA	Sutherland	1
IA	Sutherland	2
IA	Sutherland	3
MN	Syl Laskin	1
MN	Syl Laskin	2
IN	Tanners Creek	U1
IN	Tanners Creek	U2
IN	Tanners Creek	U3
IN	Tanners Creek	U4
KS	Tecumseh Energy Center	9
KS	Tecumseh Energy Center	10
MI	TES Filer City Station	1
MI	TES Filer City Station	2
MO	Thomas Hill	MB1
MO	Thomas Hill	MB2
MO	Thomas Hill	MB3
PA	Titus	1
PA	Titus	2
PA	Titus	3
TX	Tolk	171B
TX	Tolk	172B
WA	Transalta Centralia Generation	BW21
WA	Transalta Centralia Generation	BW22
MI	Trenton Channel	16
MI	Trenton Channel	17
MI	Trenton Channel	18
MI	Trenton Channel	19
MI	Trenton Channel	9A
CO	Trigen Colorado Energy	BLR3
CO	Trigen Colorado Energy	BLR4
CO	Trigen Colorado Energy	BLR5
NY	Trigen Syracuse Energy	1
NY	Trigen Syracuse Energy	2
NY	Trigen Syracuse Energy	3
NY	Trigen Syracuse Energy	4
NY	Trigen Syracuse Energy	5
KY	Trimble County	1
NV	TS Power Plant	BLR100
TX	Twin Oaks Power One	U1
TX	Twin Oaks Power One	U2
WY	Two Elk Generating Station	1
KY	Tyrone	5
SC	Urquhart	URQ3
WI	Valley	1
WI	Valley	2
WI	Valley	3
WI	Valley	4
CO	Valmont	5
IL	Vermilion	1
IL	Vermilion	2
MS	Victor J Daniel Jr	1
MS	Victor J Daniel Jr.	2
TX	W. A. Parish	WAP5
TX	W. A. Parish	WAP6
TX	W. A. Parish	WAP7
TX	W. A. Parish	WAP8
OH	W. H. Sammis	1
OH	W. H. Sammis	2
OH	W. H. Sammis	3
OH	W. H. Sammis	4
OH	W. H. Sammis	5
OH	W. H. Sammis	6
OH	W. H. Sammis	7
NC	W. H. Weatherspoon	1
NC	W. H. Weatherspoon	2
NC	W. H. Weatherspoon	3
OH	W. H. Zimmer	1
SC	W. S. Lee	1
SC	W. S. Lee	2
SC	W. S. Lee	3
IN	Wabash River	1
IN	Wabash River	2
IN	Wabash River	3
IN	Wabash River	4
IN	Wabash River	5
IN	Wabash River	6
OH	Walter C Beckjord	1
OH	Walter C Beckjord	2
OH	Walter C Beckjord	5
OH	Walter C. Beckjord	3
OH	Walter C. Beckjord	4

Attachment 4. List of coal-fired electric utility steam generating units requiring Part I and II Information

State	Plant Name	Boiler ID
OH	Walter C. Beckjord	6
GA	Wansley	1
GA	Wansley	2
IN	Warrick	1
IN	Warrick	2
IN	Warrick	3
IN	Warrick	4
SC	Wateree	WAT1
SC	Wateree	WAT2
IL	Waukegan	7
IL	Waukegan	8
IL	Waukegan	17
TX	Welsh	1
TX	Welsh	2
TX	Welsh	3
WI	Weston	1
WI	Weston	2
WI	Weston	3
WI	Weston	4
PA	Wheelabrator Frackville Energy	BLR1
NE	Whelan Energy Center	1
AR	White Bluff	1
AR	White Bluff	2
IN	Whitewater Valley	1
IN	Whitewater Valley	2
AL	Widows Creek	1
AL	Widows Creek	2
AL	Widows Creek	3
AL	Widows Creek	4
AL	Widows Creek	5
AL	Widows Creek	6
AL	Widows Creek	7
AL	Widows Creek	8
IL	Will County	1
IL	Will County	2
IL	Will County	3
IL	Will County	4
SC	Williams	WIL1
WV	Willow Island	1
WV	Willow Island	2
SC	Winyah	1
SC	Winyah	2
SC	Winyah	3
SC	Winyah	4
IL	Wood River	4
IL	Wood River	5
PA	WPS Energy Servs Sunbury Gen	3
PA	WPS Energy Servs Sunbury Gen	4
PA	WPS Energy Servs Sunbury Gen	1A
PA	WPS Energy Servs Sunbury Gen	1B
PA	WPS Energy Servs Sunbury Gen	2A
PA	WPS Energy Servs Sunbury Gen	2B
NY	WPS Power Niagara	1
PA	WPS Westwood Generation LLC	031
WY	Wygen I	3
WY	Wygen II	4
WY	Wyodak	BW91
GA	Yates	Y1BR
GA	Yates	Y2BR
GA	Yates	Y3BR
GA	Yates	Y4BR
GA	Yates	Y5BR
GA	Yates	Y6BR
GA	Yates	Y7BR
VA	Yorktown	1
VA	Yorktown	2

Attachment 5. List of oil-fired electric utility steam generating units requiring Part I and II Information

State	Plant Name	Boiler ID	State	Plant Name	Boiler ID	State	Plant Name	Boiler ID
PR	Aguirre	1	MA	Cleary Flood	8	HI	Kahe	1
PR	Aguirre	2	PR	Costa Sur	1	HI	Kahe	2
PR	Aguirre	3	PR	Costa Sur	2	HI	Kahe	3
PR	Aguirre	4	PR	Costa Sur	3	HI	Kahe	4
PR	Aguirre	5	PR	Costa Sur	4	HI	Kahe	5
PR	Aguirre	6	PR	Costa Sur	5	HI	Kahe	6
PR	Aguirre	7	PR	Costa Sur	6	FL	Manatee	PMT1
PR	Aguirre	8	PR	Costa Sur	7	FL	Manatee	PMT2
PR	Aguirre	9	PR	Costa Sur	8	FL	Martin	PMR1
PR	Aguirre	10	PR	Costa Sur	9	FL	Martin	PMR2
PR	Aguirre	11	PR	Costa Sur	10	DE	McKee Run	3
PR	Aguirre	12	PA	Cromby Generating Station	2	GA	McManus	1
FL	Anclote	1	MI	Dan E. Karn	3	GA	McManus	2
FL	Anclote	2	MI	Dan E. Karn	4	IL	Meredosia	06
PR	Arecibo	1	NY	Danskammer Generating Station	1	LA	Michoud	3
PR	Arecibo	2	NY	Danskammer Generating Station	2	CT	Middletown	2
PR	Arecibo	3	CT	Devon Station	7	CT	Middletown	4
NY	Astoria Generating Station	30	CT	Devon Station	8	MD	Mirant Chalk Point	3
NY	Astoria Generating Station	40	IN	Eagle Valley	1	MD	Mirant Chalk Point	4
NY	Astoria Generating Station	50	IN	Eagle Valley	2	PA	Mitchell Power Station	1
NJ	B. L. England	3	NY	East River	5	PA	Mitchell Power Station	2
MS	Baxter Wilson	1	NY	East River	6	PA	Mitchell Power Station	3
MS	Baxter Wilson	2	PA	Eddystone Generating Station	3	CT	Montville Station	5
DC	Benning	15	PA	Eddystone Generating Station	4	CT	Montville Station	6
DC	Benning	16	DE	Edge Moor	5	MA	Mystic Generating Station	7
NY	Bowline Point	1	IN	Edwardsport	6-1	CT	New Haven Harbor	NHB1
NY	Bowline Point	2	MS	Gerald Andrus	1	NH	Newington	1
MA	Brayton Point	4	IN	Harding Street	9	NY	Northport	1
CT	Bridgeport Station	BHB2	IN	Harding Street	10	NY	Northport	2
FL	C. D. McIntosh Jr	1	IL	Havana	1	NY	Northport	3
FL	C. D. McIntosh Jr	2	IL	Havana	2	NY	Northport	4
GU	Cabras	1	IL	Havana	3	FL	Northside Generating Station	3
GU	Cabras	2	IL	Havana	4	CT	NRG Norwalk Harbor	1
MA	Canal Station	1	IL	Havana	5	CT	NRG Norwalk Harbor	2
MA	Canal Station	2	IL	Havana	6	NY	Oswego Harbor Power	5
FL	Cape Canaveral	PCC1	IL	Havana	7	NY	Oswego Harbor Power	6
FL	Cape Canaveral	PCC2	IL	Havana	8	FL	P. L. Bartow	1
PR	Central Palo Seco	1	MD	Herbert A. Wagner	1	FL	P. L. Bartow	2
PR	Central Palo Seco	2	MD	Herbert A. Wagner	4	FL	P. L. Bartow	3
PR	Central Palo Seco	3	HI	Honolulu	16	FL	Port Everglades	PPE1
PR	Central Palo Seco	4	HI	Honolulu	17	FL	Port Everglades	PPE2
PR	Central Palo Seco	5	FL	Indian River	1	FL	Port Everglades	PPE3
PR	Central Palo Seco	6	FL	Indian River	2	FL	Port Everglades	PPE4
PR	Central Palo Seco	7	FL	Indian River	3	NY	Port Jefferson	3
PR	Central Palo Seco	8	SC	Jefferies	1	NY	Port Jefferson	4
NY	Charles Poletti	1	SC	Jefferies	2	VA	Possum Point	5

State	Plant Name	Boiler ID	State	Plant Name	Boiler ID	State	Plant Name	Boiler ID
PA	PPL Martins Creek	3	MA	Salem Harbor	4	HI	Waiau	3
PA	PPL Martins Creek	4	PR	San Juan Plant	1	HI	Waiau	4
NJ	PSEG Sewaren Generating Station	1	PR	San Juan Plant	2	HI	Waiau	5
NJ	PSEG Sewaren Generating Station	2	PR	San Juan Plant	3	HI	Waiau	6
NJ	PSEG Sewaren Generating Station	3	PR	San Juan Plant	4	HI	Waiau	7
NJ	PSEG Sewaren Generating Station	4	PR	San Juan Plant	5	HI	Waiau	8
VI	Randolph E. Harley	1	FL	Sanford	PSN3	MA	West Springfield	3
NY	Ravenswood Generating Station	1	PA	Schuylkill Generating Station	1	ME	William F. Wyman	1
NY	Ravenswood Generating Station	2	FL	Suwannee River	1	ME	William F. Wyman	2
NY	Ravenswood Generating Station	3	FL	Suwannee River	2	ME	William F. Wyman	3
VI	Richmond	1	FL	Suwannee River	3	ME	William F. Wyman	4
FL	Riviera	PRV3	GU	Tanguisson	1	VA	Yorktown	3
FL	Riviera	PRV4	FL	Turkey Point	PTP1			
NY	Roseton Generating Station	1	FL	Turkey Point	PTP2			
NY	Roseton Generating Station	2	MD	Vienna Operations	8			

Attachment 6. List of all IGCC units requiring Part I, II, and III Information and selected for HCl/HF/HCN acid gas HAP, dioxin/furan organic HAP, non-dioxin/furan organic HAP, and mercury and other non-mercury metallic HAP testing

State	Plant Name	Boiler ID
FL	Polk	1CA
FL	Polk	1CT
IN	Wabash River	1a

Attachment 7. List of all petroleum coke-fired units requiring Part I, II, and III Information and selected for HCl/HF/HCN acid gas HAP, dioxin/furan organic HAP, non-dioxin/furan organic HAP, and mercury and other non-mercury metallic HAP testing

State	Plant Name	Boiler ID	NO_X Control	PM Control	FGD Type
TX	AES Deepwater	AAB001	SCR	Electrostatic precipitator, hot side	Spray type
OH	Bay Shore	1		Baghouse, pulse	
PA	Chester Operations	10		Baghouse, pulse	
CA	Hanford	CB1302		Baghouse, pulse	Spray type
WI	Manitowoc	9	SNCR	Baghouse, pulse	
FL	Northside Generating Station	1		Baghouse, pulse	Spray type
FL	Northside Generating Station	2		Baghouse, pulse	Spray type
LA	R S Nelson	1A		Baghouse, reverse air	
LA	R S Nelson	2A		Baghouse, reverse air	
CA	Rio Bravo Jasmin	CFB	SNCR	Baghouse, pulse	
CA	Rio Bravo Poso	CFB	SNCR	Baghouse, pulse	
LA	Rodemacher	3a	SNCR	Baghouse, pulse	
LA	Rodemacher	3b	SNCR	Baghouse, pulse	
MT	Yellowstone Energy LP	BLR1		Baghouse, pulse	
MT	Yellowstone Energy LP	BLR2		Baghouse, pulse	

Attachment 8. List of coal-fired electric utility steam generating units selected for HCl/HF/HCN acid gas HAP testing

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Type	FGD Date
FL	Crystal River	5	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	12/31/2009
TX	Oak Grove	1	Lignite Coal		SCR	Baghouse, pulse		Spray dryer type	12/31/2009
AR	Plum Point Energy	STG1	Subbituminous Coal		SCR	Baghouse, pulse		Spray dryer type	12/31/2009
AZ	Springerville	4	Subbituminous Coal	Bituminous Coal	SCR	Baghouse, pulse		Spray dryer type	12/31/2009
WY	Two Elk Generating Station	1	Subbituminous Coal		SCR	Baghouse, pulse		Spray type	12/31/2009
AZ	Cholla	3	Subbituminous Coal			Baghouse, pulse		Spray dryer type	9/1/2008
AZ	Cholla	4	Subbituminous Coal			Baghouse, pulse		Spray dryer type	9/1/2008
TX	Sandow Station	5A	Lignite Coal		SCR	Baghouse, pulse		Spray type	8/31/2009
TX	Sandow Station	5B	Lignite Coal		SCR	Baghouse, pulse		Spray type	8/31/2009
WI	Elm Road Generating Station	1	Bituminous Coal		SCR	Baghouse, pulse		Spray type	6/1/2009
NC	G. G. Allen	1	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	5/1/2009
NE	Nebraska City	2	Subbituminous Coal			Baghouse, pulse		Spray type	5/1/2009
GA	Wansley	2	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Jet Bubbling Reactor	5/1/2009
GA	Bowen	2BLR	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Jet Bubbling Reactor	4/1/2009
OH	Conesville	4	Bituminous Coal			Electrostatic precipitator, cold side		Jet Bubbling Reactor	4/1/2009
SC	Cross	4	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	1/1/2009
IL	Dallman	34	Bituminous Coal		SCR	Baghouse, pulse		Packed type	1/1/2009
VA	Cogentrix Hopewell	1A	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2008
VA	Cogentrix Hopewell	1B	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2008
VA	Cogentrix Hopewell	1C	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2008
VA	Cogentrix Virginia Leasing Corporation	2A	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2008
VA	Cogentrix Virginia Leasing Corporation	2B	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2008
VA	Cogentrix Virginia Leasing Corporation	2C	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2008
GA	Bowen	4BLR	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Jet Bubbling Reactor	12/1/2008
WV	John E Amos	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Tray type	12/1/2008
WV	John E Amos	2	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Tray type	12/1/2008

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Type	FGD Date
GA	Wansley	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Jet Bubbling Reactor	12/1/2008
NV	TS Power Plant	BLR100	Subbituminous Coal		SCR	Baghouse, pulse		Spray dryer type	6/1/2008
WI	Weston	4	Bituminous Coal	Subbituminous Coal	SCR	Baghouse, pulse		Spray dryer type	6/1/2008
KY	Ghent	4	Bituminous Coal	Subbituminous Coal		Electrostatic precipitator, hot side		Spray type	5/1/2008
GA	Bowen	3BLR	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Jet Bubbling Reactor	4/1/2008
KY	H. L. Spurlock	4	Bituminous Coal		SNCR	Baghouse, pulse		CFB	4/1/2008
NC	Belews Creek	1	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	1/1/2008
GA	Hammond	1	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	1/1/2008
GA	Hammond	2	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	1/1/2008
GA	Hammond	3	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	1/1/2008
GA	Hammond	4	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	1/1/2008
VA	Cogentrix Hopewell	2A	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2007
VA	Cogentrix Hopewell	2B	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2007
VA	Cogentrix Hopewell	2C	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2007
VA	Cogentrix Virginia Leasing Corporation	1A	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2007
VA	Cogentrix Virginia Leasing Corporation	1B	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2007
VA	Cogentrix Virginia Leasing Corporation	1C	Bituminous Coal			Baghouse, pulse		Spray dryer type	12/31/2007
WY	Wygen II	4	Subbituminous Coal		SCR	Baghouse, pulse		Spray type	12/31/2007
OH	Cardinal	2	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Jet Bubbling Reactor	12/1/2007
WV	John E. Amos	3	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Tray type	12/1/2007
IA	Louisa	101	Subbituminous Coal			Baghouse, pulse	Electrostatic precipitator, hot side	Spray dryer type	12/1/2007
OH	Cardinal	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Jet Bubbling Reactor	11/1/2007
IA	Council Bluffs	4	Subbituminous Coal		SCR	Baghouse, pulse		Spray dryer type	6/1/2007
KY	Ghent	3	Bituminous Coal	Subbituminous Coal		Electrostatic precipitator, hot side		Spray type	5/1/2007
WV	Mitchell	1	Bituminous Coal			Electrostatic precipitator, cold side		Tray type	4/1/2007
SC	Cross	3	Bituminous Coal	Coal-based Synfuel	SCR	Electrostatic precipitator, cold side		Spray type	1/1/2007

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Type	FGD Date
WI	Pleasant Prairie	2	Subbituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	3/31/2007
WV	Mountaineer	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	1/1/2007
AZ	Springerville	3	Subbituminous Coal		SCR	Baghouse, pulse		Spray dryer type	12/31/2006
WV	Mitchell	2	Bituminous Coal			Electrostatic precipitator, cold side		Tray type	12/1/2006
WI	Pleasant Prairie	1	Subbituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	11/31/2006
NC	Marshall	1	Bituminous Coal			Multiple cyclone	Electrostatic precipitator, cold side	Spray type	11/1/2006
MT	Hardin Generator Project	PC1	Subbituminous Coal		SCR	Baghouse, pulse		Spray dryer type	2/1/2006
NC	Asheville	1	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	11/1/2005
KY	H. L. Spurlock	3	Bituminous Coal		SNCR	Baghouse, pulse		CFB	4/1/2005
PA	Seward	1	Waste Coal	Bituminous Coal	SNCR	Baghouse, pulse		Spray dryer type	3/1/2004
PA	Seward	2	Waste Coal	Bituminous Coal	SNCR	Baghouse, pulse		Spray dryer type	3/1/2004
IL	Marion	123	Waste Coal	Bituminous Coal		Baghouse, pulse		CFB	5/1/2003
WY	Wygen I	3	Subbituminous Coal		SCR	Baghouse, pulse		Spray type	5/1/2003
CO	Arapahoe	3	Subbituminous Coal	Natural Gas		Baghouse, reverse air		Dry Sorbent Injection System	1/1/2003
CO	Cherokee	2	Bituminous Coal	Natural Gas		Baghouse, reverse air		Dry sodium injection	1/1/2003
CO	Cherokee	4	Bituminous Coal	Natural Gas		Baghouse, reverse air		Spray dryer type	1/1/2003
PR	AES Puerto Rico (Aurora)	1	Bituminous Coal		SNCR	Baghouse, pulse		CFB	12/31/2002
PR	AES Puerto Rico (Aurora)	2	Bituminous Coal		SNCR	Baghouse, pulse		CFB	12/31/2002
CO	Valmont	5	Subbituminous Coal	Bituminous Coal		Baghouse, reverse air		Spray dryer type	8/1/2002
CO	Cherokee	3	Bituminous Coal	Natural Gas		Baghouse, reverse air		Spray dryer type	7/1/2002
WA	Transalta Centralia Generation	BW21	Subbituminous Coal			Wet scrubber	Electrostatic precipitator, cold side	Spray type	6/1/2002
MS	Red Hills Generating Facility	AA001	Lignite Coal			Baghouse, reverse air		CFB	3/1/2002
MS	Red Hills Generating Facility	AA002	Lignite Coal			Baghouse, reverse air		CFB	3/1/2002
WV	Mt. Storm	1	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	2/1/2002
WV	Mt. Storm	2	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	2/1/2002
WA	Transalta Centralia Generation	BW22	Subbituminous Coal			Wet scrubber	Electrostatic precipitator, cold side	Spray type	10/1/2001

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Type	FGD Date
PA	Homer City Station	3	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	9/1/2001
IL	Dallman	31	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Packed type	6/1/2001
IL	Dallman	32	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Packed type	6/1/2001
MO	Hawthorn	5A	Subbituminous Coal	Natural Gas	SCR	Baghouse, pulse		Spray dryer type	6/1/2001
AK	Healy	1	Subbituminous Coal			Baghouse, reverse air		Spray dryer type	9/1/2000
MD	AES Warrior Run Cogeneration Facility	BLR1	Bituminous Coal		SNCR and SCR	Baghouse, reverse air		CFB	2/1/2000
FL	Big Bend	BB01	Bituminous Coal	Subbituminous Coal		Electrostatic precipitator, cold side		Spray type	12/1/1999
FL	Big Bend	BB02	Bituminous Coal	Subbituminous Coal		Electrostatic precipitator, cold side		Spray type	12/1/1999
AZ	Navajo	1	Bituminous Coal			Electrostatic precipitator, hot side		Spray type	8/1/1999
CO	Hayden	H2	Bituminous Coal	Distillate Fuel Oil		Baghouse, reverse air		Spray dryer type	6/1/1999
OH	Hamilton	9	Bituminous Coal	Natural Gas		Electrostatic precipitator, hot side	Baghouse, pulse	Dry gas absorption	4/1/1999
CO	Hayden	H1	Bituminous Coal	Natural Gas		Baghouse, reverse air		Spray dryer type	12/1/1998
AZ	Navajo	2	Bituminous Coal			Electrostatic precipitator, hot side		Spray type	11/1/1998
NM	San Juan	1	Subbituminous Coal			Electrostatic precipitator, hot side		Spray type	10/1/1998
NM	San Juan	2	Subbituminous Coal			Electrostatic precipitator, hot side		Spray type	10/1/1998
NM	San Juan	3	Subbituminous Coal			Electrostatic precipitator, hot side		Spray type	10/1/1998
NM	San Juan	4	Subbituminous Coal			Electrostatic precipitator, hot side		Spray type	10/1/1998
CO	Cherokee	1	Bituminous Coal	Natural Gas		Baghouse, reverse air		Dry sodium injection	2/1/1998
AZ	Navajo	3	Bituminous Coal			Electrostatic precipitator, hot side		Spray type	11/1/1997
VA	Birchwood Power	1A	Bituminous Coal		SCR	Baghouse, reverse air		Spray dryer type	12/1/1996
FL	Stanton Energy Center	2	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	6/1/1996
IN	AES Petersburg	1	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	5/1/1996
IN	AES Petersburg	2	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	5/1/1996
VA	Clover	2	Bituminous Coal			Baghouse, reverse air		Spray type	3/1/1996
FL	Indiantown Cogeneration LP	AAB01	Bituminous Coal		SCR	Baghouse, reverse air		Spray dryer type	12/1/1995
PA	Conemaugh	2	Bituminous Coal			Electrostatic precipitator, cold side	Wet scrubber	Spray type	11/1/1995
SC	Cope	COP1	Bituminous Coal	Natural Gas		Baghouse, reverse air		Spray dryer type	11/1/1995

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Type	FGD Date
WY	Neil Simpson II	2	Subbituminous Coal			Electrostatic precipitator, cold side		Circulating Dry Scrubber	11/1/1995
VA	Clover	1	Bituminous Coal			Baghouse, reverse air		Spray type	10/1/1995
PA	Northampton Generating Company	BLR1	Waste Coal	Petroleum Coke	SNCR	Baghouse, pulse		CFB	8/1/1995
NY	AES Cayuga	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	6/1/1995
NY	AES Cayuga	2	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	6/1/1995
KY	HMP&L Station Two Henderson	H1	Bituminous Coal			Electrostatic precipitator, cold side		Tray type	6/1/1995
KY	HMP&L Station Two Henderson	H2	Bituminous Coal			Electrostatic precipitator, cold side		Tray type	6/1/1995
NC	Roanoke Valley II	BLR2	Bituminous Coal			Baghouse, pulse		Circulating Dry Scrubber	6/1/1995
PA	Colver Power Project	ABB01	Waste Coal			Baghouse, pulse		CFB	5/1/1995
SC	Cross	1	Bituminous Coal	Coal-based Synfuel	SCR	Electrostatic precipitator, cold side		Spray type	5/1/1995
OH	General James M Gavin	2	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	3/1/1995
NJ	B. L. England	2	Bituminous Coal		SNCR	Electrostatic precipitator, cold side		Spray type	1/1/1995
TN	Cumberland	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	1/1/1995
TN	Cumberland	2	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	1/1/1995
IN	F. B. Culley	2	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	1/1/1995
IN	F. B. Culley	3	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	1/1/1995
IN	Gibson	4	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	1/1/1995
WV	Mt Storm	3	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	1/1/1995
PA	Conemaugh	1	Bituminous Coal			Electrostatic precipitator, cold side	Wet scrubber	Spray type	12/1/1994
OH	General James M Gavin	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	12/1/1994
KY	Ghent	1	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	12/1/1994
KY	Elmer Smith	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	11/1/1994
KY	Elmer Smith	2	Bituminous Coal		SNCR	Electrostatic precipitator, cold side		Spray type	11/1/1994
WV	Harrison Power Station	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side	Wet scrubber	Spray type	11/1/1994
WV	Harrison Power Station	2	Bituminous Coal		SCR	Electrostatic precipitator, cold side	Wet scrubber	Spray type	11/1/1994
WV	Harrison Power Station	3	Bituminous Coal		SCR	Electrostatic precipitator, cold side	Wet scrubber	Spray type	11/1/1994

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Type	FGD Date
IN	Whitewater Valley	2	Bituminous Coal			Electrostatic precipitator, cold side		Spray dryer type	10/1/1994
NJ	Logan Generating Plant	B01	Bituminous Coal		SCR	Baghouse, reverse air		Spray dryer type	9/1/1994
NC	Roanoke Valley I	BLR1	Bituminous Coal	Distillate Fuel Oil		Baghouse, reverse air		Circulating Dry Scrubber	5/1/1994
NJ	Chambers Cogeneration LP	BOIL1	Bituminous Coal		SCR	Baghouse, reverse air		Spray dryer type	3/1/1994
NJ	Chambers Cogeneration LP	BOIL2	Bituminous Coal		SCR	Baghouse, reverse air		Spray dryer type	3/1/1994
FL	Cedar Bay Generating LP	CBA	Bituminous Coal		SNCR	Baghouse, reverse air		Circulating Dry Scrubber	2/1/1994
FL	Cedar Bay Generating LP	CBB	Bituminous Coal		SNCR	Baghouse, reverse air		Circulating Dry Scrubber	2/1/1994
FL	Cedar Bay Generating LP	CBC	Bituminous Coal		SNCR	Baghouse, reverse air		Circulating Dry Scrubber	2/1/1994
CO	Arapahoe	4	Subbituminous Coal	Natural Gas		Baghouse, reverse air		Dry Sorbent Injection System	6/1/1993
PA	Scrubgrass Generating	UNIT 1	Waste Coal		SNCR	Baghouse, pulse		CFB	6/1/1993
PA	Scrubgrass Generating	UNIT 2	Waste Coal		SNCR	Baghouse, pulse		CFB	6/1/1993
UT	Sunnyside Cogen Associates	1	Waste Coal			Baghouse, pulse		CFB	2/1/1993
WV	North Branch	1A	Bituminous Coal	Waste Oil		Baghouse, pulse		CFB	12/31/1992
WV	North Branch	1B	Bituminous Coal	Waste Oil		Baghouse, pulse		CFB	12/31/1992
TX	J. K. Spruce	BLR1	Subbituminous Coal			Baghouse, reverse air		Spray type	12/1/1992
VA	Mecklenburg Power Station	BLR1	Bituminous Coal			Baghouse, pulse		Circulating Dry Scrubber	11/1/1992
VA	Mecklenburg Power Station	BLR2	Bituminous Coal			Baghouse, pulse		Circulating Dry Scrubber	11/1/1992
PA	Piney Creek Project	BRBR1	Waste Coal		SNCR	Baghouse, pulse		Circulating Dry Scrubber	11/1/1992
GA	Yates	Y1BR	Bituminous Coal	Natural Gas		Electrostatic precipitator, cold side	Wet scrubber	Jet Bubbling Reactor	10/1/1992
HI	AES Hawaii	BLRA	Subbituminous Coal	Tire-derived Fuels	SNCR	Baghouse, reverse air		CFB	9/1/1992
HI	AES Hawaii	BLRB	Subbituminous Coal	Waste Oil	SNCR	Baghouse, reverse air		CFB	9/1/1992
VA	Cogentrix of Richmond	3A	Bituminous Coal			Baghouse, pulse		Spray dryer type	8/1/1992
VA	Cogentrix of Richmond	3B	Bituminous Coal			Baghouse, pulse		Spray dryer type	8/1/1992
VA	Cogentrix of Richmond	4A	Bituminous Coal			Baghouse, pulse		Spray dryer type	8/1/1992
VA	Cogentrix of Richmond	4B	Bituminous Coal			Baghouse, pulse		Spray dryer type	8/1/1992
WV	Grant Town Power Plant	BLR1A	Waste Coal			Baghouse, pulse		CFB	8/1/1992
WV	Grant Town Power Plant	BLR1B	Waste Coal			Baghouse, pulse		CFB	8/1/1992
IN	Bailly	7	Bituminous Coal	Natural Gas		Electrostatic precipitator, cold side		Packed type	6/1/1992

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Type	FGD Date
IN	Bailly	8	Bituminous Coal	Natural Gas	SCR	Electrostatic precipitator, cold side		Packed type	6/1/1992
PA	Panther Creek Energy Facility	BLR1	Waste Coal		SNCR	Baghouse, pulse		Circulating Dry Scrubber	6/1/1992
PA	Panther Creek Energy Facility	BLR2	Waste Coal		SNCR	Baghouse, pulse		Circulating Dry Scrubber	6/1/1992
VA	Cogentrix of Richmond	1A	Bituminous Coal			Baghouse, pulse		Spray dryer type	5/1/1992
VA	Cogentrix of Richmond	1B	Bituminous Coal			Baghouse, pulse		Spray dryer type	5/1/1992
VA	Cogentrix of Richmond	2A	Bituminous Coal			Baghouse, pulse		Spray dryer type	5/1/1992
VA	Cogentrix of Richmond	2B	Bituminous Coal			Baghouse, pulse		Spray dryer type	5/1/1992
VA	Altavista Power Station	1	Bituminous Coal		SNCR	Baghouse, pulse		Spray dryer type	2/1/1992
WV	Morgantown Energy Facility	CFB1	Waste Coal			Baghouse, pulse		CFB	1/1/1992
WV	Morgantown Energy Facility	CFB2	Waste Coal			Baghouse, pulse		CFB	1/1/1992
TX	Twin Oaks Power One	U2	Lignite Coal			Baghouse, shake and deflate		CFB	10/1/1991
VA	Southampton Power Station	1	Bituminous Coal			Baghouse, pulse		Spray dryer type	6/1/1991
PA	Ebensburg Power	031	Waste Coal			Baghouse, pulse		CFB	5/1/1991
PA	Cambria Cogen	B1	Waste Coal		SNCR	Baghouse, shake and deflate		CFB	3/1/1991
PA	Cambria Cogen	B2	Waste Coal		SNCR	Baghouse, shake and deflate		CFB	3/1/1991
OH	W. H. Zimmer	1	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	3/1/1991

Attachment 9. List of coal-fired electric utility steam generating units selected for dioxin/furan organic HAP testing

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_x Control	PM Control 1	PM Control 2	FGD_Type01	ACI
CA	ACE Cogeneration Facility	CFB	Bituminous Coal	Petroleum Coke		Baghouse, reverse air		CFB	
CT	AES Thames	A	Bituminous Coal			Baghouse, reverse air		Circulating Dry Scrubber	
CT	AES Thames	B	Bituminous Coal			Baghouse, reverse air		Circulating Dry Scrubber	
VA	Altavista Power Station	1	Bituminous Coal		SNCR	Baghouse, pulse		Spray dryer type	
NY	Black River Generation	E0003	Bituminous Coal			Baghouse, pulse	Multiple cyclone	Jet Bubbling Reactor	
VA	Chesterfield	6	Bituminous Coal			Electrostatic precipitator, cold side			
NC	Cogentrix Dwayne Collier Battle Cogen	1A	Bituminous Coal			Baghouse, pulse		Spray dryer type	
VA	Cogentrix of Richmond	4A	Bituminous Coal			Baghouse, pulse		Spray dryer type	
IA	Council Bluffs	4	Subbituminous Coal		SCR	Baghouse, pulse		Spray dryer type	Y
CO	Craig	C2	Subbituminous Coal			Baghouse, pulse		Spray type	
TN	Cumberland	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		Spray type	
WY	Dave Johnston	BW41	Subbituminous Coal			Electrostatic precipitator, cold side			
DE	Edge Moor	4	Bituminous Coal	Residual Fuel Oil		Electrostatic precipitator, cold side			Y
KY	Green River	5	Bituminous Coal			Electrostatic precipitator, hot side			
KY	H. L. Spurlock	2	Bituminous Coal		SCR	Electrostatic precipitator, hot side		Spray dryer type	
IL	Havana	9	Subbituminous Coal		SCR	Electrostatic precipitator, hot side	Baghouse, pulse		Y
IL	Hennepin Power Station	2	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side			
MN	Hoot Lake	3	Subbituminous Coal			Electrostatic precipitator, cold side			
TX	J. K. Spruce	BLR1	Subbituminous Coal			Baghouse, reverse air		Spray type	
WV	Kammer	1	Bituminous Coal			Electrostatic precipitator, cold side			
WV	Kammer	2	Bituminous Coal			Electrostatic precipitator, cold side			
IL	Marion	4	Bituminous Coal	Waste Coal	SCR	Electrostatic precipitator, cold side		Venturi type	
ND	Milton R Young	B1	Lignite Coal			Electrostatic precipitator, cold side			
MI	Monroe	3	Subbituminous Coal	Bituminous Coal	SCR	Electrostatic precipitator, cold side			
OK	Northeastern	3314	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side			
IA	Prairie Creek	4	Subbituminous Coal	Landfill Gas		Electrostatic precipitator, cold side			
NC	Primary Energy Southport	1C	Bituminous Coal			Baghouse, pulse		N/A	

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_x Control	PM Control 1	PM Control 2	FGD_Type01	ACI
CO	Ray D. Nixon	1	Subbituminous Coal			Baghouse, reverse air			
NC	Roanoke Valley I	BLR1	Bituminous Coal	Distillate Fuel Oil		Baghouse, reverse air		Circulating Dry Scrubber	
GA	Scherer	1	Subbituminous Coal			Electrostatic precipitator, hot side			Y
GA	Scherer	3	Subbituminous Coal			Electrostatic precipitator, cold side		Spray type	Y
PA	Shawville	3	Bituminous Coal			Electrostatic precipitator, cold side			
MN	Silver Bay Power	BLR2	Subbituminous Coal	Natural Gas		Baghouse, reverse air			
ND	Stanton	1	Subbituminous Coal			Electrostatic precipitator, cold side			
IN	State Line Energy	3	Subbituminous Coal			Baghouse, pulse			
IA	Streeter Station	7	Bituminous Coal	Subbituminous Coal		Electrostatic precipitator, hot side			
KS	Tecumseh Energy Center	9	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side			
MI	TES Filer City Station	2	Bituminous Coal			Baghouse, pulse		Spray dryer type	
WA	Transalta Centralia Generation	BW21	Subbituminous Coal			Wet scrubber	Electrostatic precipitator, cold side	Spray type	
NY	Trigen Syracuse Energy	2	Bituminous Coal			Baghouse, reverse air		N/A	
TX	Twin Oaks Power One	U2	Lignite Coal			Baghouse, shake and deflate		CFB	
WY	Two Elk Generating Station	1	Subbituminous Coal		SCR	Baghouse, pulse		Spray type	
IL	Vermilion	1	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side	Baghouse, pulse		Y
OH	Walter C Beckjord	5	Bituminous Coal			Electrostatic precipitator, cold side			
IL	Waukegan	8	Subbituminous Coal			Electrostatic precipitator, cold side			
AL	Widows Creek	2	Bituminous Coal			Electrostatic precipitator, cold side			
AL	Widows Creek	7	Bituminous Coal			Electrostatic precipitator, cold side	Wet scrubber	Spray type	
AL	Widows Creek	8	Bituminous Coal			Wet scrubber		Tray type	
SC	Winyah	1	Bituminous Coal	Coal-based Synfuel		Electrostatic precipitator, cold side	Wet scrubber	Venturi type	
SC	Winyah	2	Bituminous Coal	Coal-based Synfuel		Electrostatic precipitator, cold side			

Attachment 10. List of coal-fired electric utility steam generating units selected for non-dioxin/furan organic HAP testing

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	Boiler Date	NO_X Control	PM Control 1	PM Control 2	FGD Type
TX	Oak Grove	1	Lignite Coal		12/31/2009	SCR	Baghouse, pulse		Spray dryer type
AR	Plum Point Energy	STG1	Subbituminous Coal		12/31/2009	SCR	Baghouse, pulse		Spray dryer type
AZ	Springerville	4	Subbituminous Coal	Bituminous Coal	12/31/2009	SCR	Baghouse, pulse		Spray dryer type
WY	Two Elk Generating Station	1	Subbituminous Coal		12/31/2009	SCR	Baghouse, pulse		Spray type
TX	Sandow Station	5A	Lignite Coal		8/31/2009	SCR	Baghouse, pulse		Spray type
TX	Sandow Station	5B	Lignite Coal		8/31/2009	SCR	Baghouse, pulse		Spray type
WI	Elm Road Generating Station	1	Bituminous Coal		6/1/2009	SCR	Baghouse, pulse		Spray type
NE	Nebraska City	2	Subbituminous Coal		5/1/2009		Baghouse, pulse		Spray type
SC	Cross	4	Bituminous Coal		1/1/2009	SCR	Electrostatic precipitator, cold side		Spray type
IL	Dallman	34	Bituminous Coal		1/1/2009	SCR	Baghouse, pulse		Packed type
NV	TS Power Plant	BLR100	Subbituminous Coal		6/1/2008	SCR	Baghouse, pulse		Spray dryer type
WI	Weston	4	Bituminous Coal	Subbituminous Coal	6/1/2008	SCR	Baghouse, pulse		Spray dryer type
KY	H. L. Spurlock	4	Bituminous Coal		4/1/2008	SNCR	Baghouse, pulse		CFB
WY	Wygen II	4	Subbituminous Coal		12/31/2007	SCR	Baghouse, pulse		Spray type
IA	Council Bluffs	4	Subbituminous Coal		6/1/2007	SCR	Baghouse, pulse		Spray dryer type
SC	Cross	3	Bituminous Coal	Coal-based Synfuel	1/1/2007	SCR	Electrostatic precipitator, cold side		Spray type
AZ	Springerville	3	Subbituminous Coal		12/31/2006	SCR	Baghouse, pulse		Spray dryer type
MT	Hardin Generator Project	PC1	Subbituminous Coal		4/1/2006	SCR	Baghouse, pulse		Spray dryer type
KY	H. L. Spurlock	3	Bituminous Coal		4/1/2005	SNCR	Baghouse, pulse		CFB
PA	Seward	1	Waste Coal	Bituminous Coal	3/1/2004	SNCR	Baghouse, pulse		Spray dryer type
PA	Seward	2	Waste Coal	Bituminous Coal	3/1/2004	SNCR	Baghouse, pulse		Spray dryer type
IL	Marion	123	Waste Coal	Bituminous Coal	5/1/2003		Baghouse, pulse		CFB
WY	Wygen I	3	Subbituminous Coal		5/1/2003	SCR	Baghouse, pulse		Spray type
PR	AES Puerto Rico (Aurora)	1	Bituminous Coal		12/31/2002	SNCR	Baghouse, pulse		CFB
PR	AES Puerto Rico (Aurora)	2	Bituminous Coal		12/31/2002	SNCR	Baghouse, pulse		CFB
MS	Red Hills Generating Facility	AA001	Lignite Coal		3/1/2002		Baghouse, reverse air		CFB

Shaded units are required to do all organic testing.

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	Boiler Date	NO_X Control	PM Control 1	PM Control 2	FGD Type
MS	Red Hills Generating Facility	AA002	Lignite Coal		3/1/2002		Baghouse, reverse air		CFB
MO	Hawthorn	5A	Subbituminous Coal	Natural Gas	6/1/2001	SCR	Baghouse, pulse		Spray dryer type
MD	AES Warrior Run Cogeneration Facility	BLR1	Bituminous Coal		2/1/2000	SCR and SNCR	Baghouse, reverse air		CFB
VA	Birchwood Power	1A	Bituminous Coal		12/1/1996	SCR	Baghouse, reverse air		Spray dryer type
FL	Stanton Energy Center	2	Bituminous Coal		6/1/1996	SCR	Electrostatic precipitator, cold side		Spray type
VA	Clover	2	Bituminous Coal		3/1/1996		Baghouse, reverse air		Spray type
FL	Indiantown Cogeneration LP	AAB01	Bituminous Coal		12/1/1995	SCR	Baghouse, reverse air		Spray dryer type
SC	Cope	COP1	Bituminous Coal	Natural Gas	11/1/1995		Baghouse, reverse air		Spray dryer type
WY	Neil Simpson II	2	Subbituminous Coal		11/1/1995		Electrostatic precipitator, cold side		Circulating Dry Scrubber
VA	Clover	1	Bituminous Coal		10/1/1995		Baghouse, reverse air		Spray type
PA	Northampton Generating Company	BLR1	Waste Coal	Petroleum Coke	8/1/1995	SNCR	Baghouse, pulse		CFB
NC	Roanoke Valley II	BLR2	Bituminous Coal		6/1/1995		Baghouse, pulse		Circulating Dry Scrubber
PA	Colver Power Project	ABB01	Waste Coal		5/1/1995		Baghouse, pulse		CFB
SC	Cross	1	Bituminous Coal	Coal-based Synfuel	5/1/1995	SCR	Electrostatic precipitator, cold side		Spray type
NJ	Logan Generating Plant	B01	Bituminous Coal		9/1/1994	SCR	Baghouse, reverse air		Spray dryer type
NC	Roanoke Valley I	BLR1	Bituminous Coal	Distillate Fuel Oil	5/1/1994		Baghouse, reverse air		Circulating Dry Scrubber
NJ	Chambers Cogeneration LP	BOIL1	Bituminous Coal		3/1/1994	SCR	Baghouse, reverse air		Spray dryer type
NJ	Chambers Cogeneration LP	BOIL2	Bituminous Coal		3/1/1994	SCR	Baghouse, reverse air		Spray dryer type
FL	Cedar Bay Generating LP	CBA	Bituminous Coal		1/1/1994	SNCR	Baghouse, reverse air		Circulating Dry Scrubber
FL	Cedar Bay Generating LP	CBB	Bituminous Coal		1/1/1994	SNCR	Baghouse, reverse air		Circulating Dry Scrubber
FL	Cedar Bay Generating LP	CBC	Bituminous Coal		1/1/1994	SNCR	Baghouse, reverse air		Circulating Dry Scrubber
PA	Scrubgrass Generating	UNIT 1	Waste Coal		6/1/1993	SNCR	Baghouse, pulse		CFB

Shaded units are required to do all organic testing.

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	Boiler Date	NO_X Control	PM Control 1	PM Control 2	FGD Type
PA	Scrubgrass Generating	UNIT 2	Waste Coal		6/1/1993	SNCR	Baghouse, pulse		CFB
UT	Sunnyside Cogen Associates	1	Waste Coal		2/1/1993		Baghouse, pulse		CFB
WV	North Branch	1A	Bituminous Coal	Waste Oil	12/31/1992		Baghouse, pulse		CFB
WV	North Branch	1B	Bituminous Coal	Waste Oil	12/31/1992		Baghouse, pulse		CFB
TX	J. K. Spruce	BLR1	Subbituminous Coal		12/1/1992		Baghouse, reverse air		Spray type
PA	Piney Creek Project	BRBR1	Waste Coal		12/1/1992	SNCR	Baghouse, pulse		Circulating Dry Scrubber
VA	Mecklenburg Power Station	BLR1	Bituminous Coal		11/1/1992		Baghouse, pulse		Circulating Dry Scrubber
VA	Mecklenburg Power Station	BLR2	Bituminous Coal		11/1/1992		Baghouse, pulse		Circulating Dry Scrubber
HI	AES Hawaii	BLRA	Subbituminous Coal	Tire-derived Fuels	9/1/1992	SNCR	Baghouse, reverse air		CFB
HI	AES Hawaii	BLRB	Subbituminous Coal	Waste Oil	9/1/1992	SNCR	Baghouse, reverse air		CFB
VA	Cogentrix of Richmond	3A	Bituminous Coal		8/1/1992		Baghouse, pulse		Spray dryer type
VA	Cogentrix of Richmond	3B	Bituminous Coal		8/1/1992		Baghouse, pulse		Spray dryer type
VA	Cogentrix of Richmond	4A	Bituminous Coal		8/1/1992		Baghouse, pulse		Spray dryer type
VA	Cogentrix of Richmond	4B	Bituminous Coal		8/1/1992		Baghouse, pulse		Spray dryer type
WV	Grant Town Power Plant	BLR1A	Waste Coal		8/1/1992		Baghouse, pulse		CFB
WV	Grant Town Power Plant	BLR1B	Waste Coal		8/1/1992		Baghouse, pulse		CFB
PA	Panther Creek Energy Facility	BLR1	Waste Coal		6/1/1992	SNCR	Baghouse, pulse		Circulating Dry Scrubber
PA	Panther Creek Energy Facility	BLR2	Waste Coal		6/1/1992	SNCR	Baghouse, pulse		Circulating Dry Scrubber
VA	Cogentrix of Richmond	1A	Bituminous Coal		5/1/1992		Baghouse, pulse		Spray dryer type
VA	Cogentrix of Richmond	1B	Bituminous Coal		5/1/1992		Baghouse, pulse		Spray dryer type
VA	Cogentrix of Richmond	2A	Bituminous Coal		5/1/1992		Baghouse, pulse		Spray dryer type
VA	Cogentrix of Richmond	2B	Bituminous Coal		5/1/1992		Baghouse, pulse		Spray dryer type
VA	Altavista Power Station	1	Bituminous Coal		2/1/1992	SNCR	Baghouse, pulse		Spray dryer type
WV	Morgantown Energy Facility	CFB1	Waste Coal		1/1/1992		Baghouse, pulse		CFB
WV	Morgantown Energy Facility	CFB2	Waste Coal		1/1/1992		Baghouse, pulse		CFB

Shaded units are required to do all organic testing.

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	Boiler Date	NO_X Control	PM Control 1	PM Control 2	FGD Type
TX	Twin Oaks Power One	U2	Lignite Coal		10/1/1991		Baghouse, shake and deflate		CFB
VA	Southampton Power Station	1	Bituminous Coal		6/1/1991		Baghouse, pulse		Spray dryer type
MD	Brandon Shores	2	Bituminous Coal		5/1/1991	SCR	Electrostatic precipitator, hot side		Spray type
PA	Ebensburg Power	031	Waste Coal		5/1/1991		Baghouse, pulse		CFB
PA	Cambria Cogen	B1	Waste Coal		3/1/1991	SNCR	Baghouse, shake and deflate		CFB
PA	Cambria Cogen	B2	Waste Coal		3/1/1991	SNCR	Baghouse, shake and deflate		CFB
AL	James H Miller Jr.	4	Subbituminous Coal		3/1/1991	SCR	Electrostatic precipitator, cold side		Spray type
OH	W. H. Zimmer	1	Bituminous Coal		3/1/1991		Electrostatic precipitator, cold side		Spray type
OK	AES Shady Point	1A	Bituminous Coal		1/1/1991		Baghouse, pulse		CFB
OK	AES Shady Point	1B	Bituminous Coal		1/1/1991		Baghouse, pulse		CFB
OK	AES Shady Point	2A	Bituminous Coal		1/1/1991		Baghouse, pulse		CFB
OK	AES Shady Point	2B	Bituminous Coal		1/1/1991		Baghouse, pulse		CFB
CO	Nucla	1	Bituminous Coal		1/1/1991		Baghouse, shake and deflate		CFB
NY	Trigen Syracuse Energy	1	Bituminous Coal		1/1/1991		Baghouse, reverse air		N/A
NY	Trigen Syracuse Energy	2	Bituminous Coal		1/1/1991		Baghouse, reverse air		N/A
NY	Trigen Syracuse Energy	3	Bituminous Coal		1/1/1991		Baghouse, reverse air		N/A
NY	Trigen Syracuse Energy	4	Bituminous Coal		1/1/1991		Baghouse, reverse air		N/A
NY	Trigen Syracuse Energy	5	Bituminous Coal		1/1/1991		Baghouse, reverse air		N/A
KY	Shawnee	10	Bituminous Coal		12/1/1990		Baghouse, reverse air		CFB
KY	Trimble County	1	Bituminous Coal		12/1/1990	SCR	Electrostatic precipitator, cold side		Spray type
NC	Cogentrix Dwayne Collier Battle Cogen	1A	Bituminous Coal		10/1/1990		Baghouse, pulse		Spray dryer type
NC	Cogentrix Dwayne Collier Battle Cogen	1B	Bituminous Coal		10/1/1990		Baghouse, pulse		Spray dryer type

Shaded units are required to do all organic testing.

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	Boiler Date	NO_X Control	PM Control 1	PM Control 2	FGD Type
NC	Cogentrix Dwayne Collier Battle Cogen	2A	Bituminous Coal		10/1/1990		Baghouse, pulse		Spray dryer type
NC	Cogentrix Dwayne Collier Battle Cogen	2B	Bituminous Coal		10/1/1990		Baghouse, pulse		Spray dryer type
PA	Foster Wheeler Mt Carmel Cogen	SG-101	Waste Coal		9/1/1990		Baghouse, pulse		Circulating Dry Scrubber
TX	Twin Oaks Power One	U1	Lignite Coal		9/1/1990		Baghouse, shake and deflate		CFB
CA	ACE Cogeneration Facility	CFB	Bituminous Coal	Petroleum Coke	6/1/1990		Baghouse, reverse air		CFB
WI	Manitowoc	8	Bituminous Coal	Petroleum Coke	6/1/1990		Single cyclone	Baghouse, pulse	CFB
AZ	Springerville	2	Subbituminous Coal		6/1/1990		Baghouse, reverse air		Spray dryer type
MI	TES Filer City Station	1	Bituminous Coal		6/1/1990		Baghouse, pulse		Spray dryer type
MI	TES Filer City Station	2	Bituminous Coal		6/1/1990		Baghouse, pulse		Spray dryer type
NY	WPS Power Niagara	1	Bituminous Coal		4/1/1990	SNCR	Baghouse, pulse		CFB
CT	AES Thames	A	Bituminous Coal		3/1/1990		Baghouse, reverse air		Circulating Dry Scrubber
CT	AES Thames	B	Bituminous Coal		3/1/1990		Baghouse, reverse air		Circulating Dry Scrubber
MT	Colstrip Energy LP	BLR1	Waste Coal		2/1/1990		Baghouse, pulse		CFB
IN	Rockport	MB2	Subbituminous Coal		12/1/1989		Electrostatic precipitator, cold side		N/A
PA	St. Nicholas Cogen Project	1	Waste Coal		12/1/1989		Baghouse, pulse		CFB
PA	Kline Township Cogen Facility	1	Waste Coal		11/1/1989		Single cyclone	Baghouse, pulse	CFB
AL	James H Miller Jr.	3	Subbituminous Coal		5/1/1989	SCR	Electrostatic precipitator, cold side		Spray type
GA	Scherer	4	Subbituminous Coal		2/1/1989		Electrostatic precipitator, cold side		Spray type
PA	Wheelabrator Frackville Energy	BLR1	Waste Coal		9/1/1988		Baghouse, pulse		CFB
NY	Black River Generation	E0001	Bituminous Coal		6/1/1988		Baghouse, pulse	Multiple cyclone	Jet Bubbling Reactor
NY	Black River Generation	E0002	Bituminous Coal		6/1/1988		Baghouse, pulse	Multiple cyclone	Jet Bubbling Reactor
NY	Black River Generation	E0003	Bituminous Coal		6/1/1988		Baghouse, pulse	Multiple cyclone	Jet Bubbling Reactor

Shaded units are required to do all organic testing.

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	Boiler Date	NO_X Control	PM Control 1	PM Control 2	FGD Type
FL	Central Power & Lime	1	Bituminous Coal		6/1/1988		Baghouse, reverse air		N/A
VA	Cogentrix Virginia Leasing Corporation	1A	Bituminous Coal		6/1/1988		Baghouse, pulse		Spray dryer type
VA	Cogentrix Virginia Leasing Corporation	1B	Bituminous Coal		6/1/1988		Baghouse, pulse		Spray dryer type
VA	Cogentrix Virginia Leasing Corporation	1C	Bituminous Coal		6/1/1988		Baghouse, pulse		Spray dryer type
VA	Cogentrix Virginia Leasing Corporation	2A	Bituminous Coal		6/1/1988		Baghouse, pulse		Spray dryer type
VA	Cogentrix Virginia Leasing Corporation	2B	Bituminous Coal		6/1/1988		Baghouse, pulse		Spray dryer type
VA	Cogentrix Virginia Leasing Corporation	2C	Bituminous Coal		6/1/1988		Baghouse, pulse		Spray dryer type
CA	Mt. Poso Cogeneration	BL01	Bituminous Coal		6/1/1988	SNCR	Baghouse, reverse air		CFB
PA	WPS Westwood Generation LLC	031	Waste Coal		6/1/1988		Baghouse, reverse air		N/A
FL	St Johns River Power Park	2	Bituminous Coal	Coal-based Synfuel	5/1/1988		Electrostatic precipitator, cold side		Spray type
TX	Fayette Power Project	3	Subbituminous Coal		4/1/1988		Electrostatic precipitator, cold side		Spray type
PA	John B Rich Memorial Power Station	CFB1	Waste Coal		2/1/1988		Baghouse, pulse		CFB
PA	John B Rich Memorial Power Station	CFB2	Waste Coal		2/1/1988		Baghouse, pulse		CFB
VA	Cogentrix Hopewell	1A	Bituminous Coal		12/1/1987		Baghouse, pulse		Spray dryer type
VA	Cogentrix Hopewell	1B	Bituminous Coal		12/1/1987		Baghouse, pulse		Spray dryer type
VA	Cogentrix Hopewell	1C	Bituminous Coal		12/1/1987		Baghouse, pulse		Spray dryer type
VA	Cogentrix Hopewell	2A	Bituminous Coal		12/1/1987		Baghouse, pulse		Spray dryer type

Shaded units are required to do all organic testing.

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	Boiler Date	NO_X Control	PM Control 1	PM Control 2	FGD Type
VA	Cogentrix Hopewell	2B	Bituminous Coal		12/1/1987		Baghouse, pulse		Spray dryer type
VA	Cogentrix Hopewell	2C	Bituminous Coal		12/1/1987		Baghouse, pulse		Spray dryer type
MN	Sherburne County	3	Subbituminous Coal		11/1/1987		Baghouse, reverse air		Spray dryer type
NY	Danskammer Generating Station	3	Bituminous Coal	Natural Gas	9/1/1987		Electrostatic precipitator, cold side		N/A
NC	Primary Energy Southport	1A	Bituminous Coal		9/1/1987		Baghouse, pulse		N/A
NC	Primary Energy Southport	1B	Bituminous Coal		9/1/1987		Baghouse, pulse		N/A
NC	Primary Energy Southport	1C	Bituminous Coal		9/1/1987		Baghouse, pulse		N/A
NC	Primary Energy Southport	2A	Bituminous Coal		9/1/1987		Baghouse, pulse		N/A
NC	Primary Energy Southport	2B	Bituminous Coal		9/1/1987		Baghouse, pulse		N/A
NC	Primary Energy Southport	2C	Bituminous Coal		9/1/1987		Baghouse, pulse		N/A
NC	Primary Energy Roxboro	1A	Bituminous Coal		8/1/1987		Baghouse, pulse		N/A
NC	Primary Energy Roxboro	1B	Bituminous Coal		8/1/1987		Baghouse, pulse		N/A
NC	Primary Energy Roxboro	1C	Bituminous Coal		8/1/1987		Baghouse, pulse		N/A
PA	AES Beaver Valley Partners Beaver Valley	2	Bituminous Coal	Petroleum Coke	7/1/1987		Electrostatic precipitator, cold side	Wet scrubber	Spray type
PA	AES Beaver Valley Partners Beaver Valley	3	Bituminous Coal	Petroleum Coke	7/1/1987		Electrostatic precipitator, cold side	Wet scrubber	Spray type
PA	AES Beaver Valley Partners Beaver Valley	4	Bituminous Coal	Petroleum Coke	7/1/1987		Electrostatic precipitator, cold side	Wet scrubber	Spray type
PA	AES Beaver Valley Partners Beaver Valley	5	Bituminous Coal	Petroleum Coke	7/1/1987		Electrostatic precipitator, cold side	Wet scrubber	Spray type
FL	Stanton Energy Center	1	Bituminous Coal		7/1/1987		Electrostatic precipitator, cold side		Spray type

Shaded units are required to do all organic testing.

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	Boiler Date	NO_X Control	PM Control 1	PM Control 2	FGD Type
UT	Intermountain Power Project	2SGA	Bituminous Coal	Subbituminous Coal	5/1/1987		Baghouse, reverse air		Spray type
NY	Danskammer Generating Station	4	Bituminous Coal	Natural Gas	3/1/1987		Electrostatic precipitator, cold side		N/A
FL	St. Johns River Power Park	1	Bituminous Coal	Coal-based Synfuel	3/1/1987		Electrostatic precipitator, cold side		Spray type
GA	Scherer	3	Subbituminous Coal		1/1/1987		Electrostatic precipitator, cold side		Spray type
TX	Oklaunion	1	Bituminous Coal		12/1/1986		Electrostatic precipitator, cold side		Spray type
KY	D. B. Wilson	W1	Bituminous Coal		11/1/1986		Electrostatic precipitator, cold side		Spray type
TX	Limestone	LIM2	Lignite Coal	Subbituminous Coal	10/1/1986		Electrostatic precipitator, cold side		Spray type
ND	Antelope Valley	B2	Lignite Coal		7/1/1986		Baghouse, reverse air		Spray dryer type
UT	Intermountain Power Project	1SGA	Bituminous Coal	Subbituminous Coal	6/1/1986		Baghouse, reverse air		Spray type
UT	Bonanza	1-1	Bituminous Coal		5/1/1986		Baghouse, reverse air		Spray type
IN	AES Petersburg	4	Bituminous Coal		4/1/1986		Electrostatic precipitator, cold side		Spray type
MT	Colstrip	4	Subbituminous Coal		4/1/1986		Wet scrubber		Venturi type
LA	Dolet Hills	1	Lignite Coal	Natural Gas	4/1/1986		Electrostatic precipitator, cold side	Wet scrubber	Spray type
OK	GRDA	2	Subbituminous Coal		4/1/1986		Electrostatic precipitator, cold side		Spray dryer type
IN	A. B. Brown	2	Bituminous Coal		2/1/1986	SCR	Electrostatic precipitator, cold side		Spray type
IN	R. M. Schahfer	18	Bituminous Coal		2/1/1986		Electrostatic precipitator, cold side		Spray type
TX	Limestone	LIM1	Lignite Coal	Subbituminous Coal	10/1/1985		Electrostatic precipitator, cold side		Spray type
MI	Belle River	2	Subbituminous Coal		7/1/1985		Electrostatic precipitator, cold side		N/A
NV	North Valmy	2	Bituminous Coal	Subbituminous Coal	7/1/1985		Baghouse, reverse air		Spray dryer type
WI	Pleasant Prairie	2	Subbituminous Coal		7/1/1985		Electrostatic precipitator, cold side		Spray type
TX	Tolk	172B	Subbituminous Coal		7/1/1985		Baghouse, reverse air		N/A
AZ	Springerville	1	Subbituminous Coal		6/1/1985		Baghouse, reverse air		Spray dryer type
AL	James H Miller Jr.	2	Subbituminous Coal		5/1/1985		Electrostatic precipitator, cold side		N/A

Shaded units are required to do all organic testing.

Attachment 11. List of coal-fired electric utility steam generating units selected for mercury and other non-mercury metallic HAP testing

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	PM Control Date	FGD Type
TX	Oak Grove	1	Lignite Coal		SCR	Baghouse, pulse		12/31/2009	Spray dryer type
AR	Plum Point Energy	STG1	Subbituminous Coal		SCR	Baghouse, pulse		12/31/2009	Spray dryer type
AZ	Springerville	4	Subbituminous Coal	Bituminous Coal	SCR	Baghouse, pulse		12/31/2009	Spray dryer type
WY	Two Elk Generating Station	1	Subbituminous Coal		SCR	Baghouse, pulse		12/31/2009	Spray type
AZ	Cholla	3	Subbituminous Coal			Baghouse, pulse		9/1/2008	Spray dryer type
AZ	Cholla	4	Subbituminous Coal			Baghouse, pulse		9/1/2008	Spray dryer type
TX	Sandow Station	5A	Lignite Coal		SCR	Baghouse, pulse		8/31/2009	Spray type
TX	Sandow Station	5B	Lignite Coal		SCR	Baghouse, pulse		8/31/2009	Spray type
WI	Elm Road Generating Station	1	Bituminous Coal		SCR	Baghouse, pulse		6/1/2009	Spray type
NE	Nebraska City	2	Subbituminous Coal			Baghouse, pulse		5/1/2009	Spray type
SC	Cross	4	Bituminous Coal		SCR	Electrostatic precipitator, cold side		1/1/2009	Spray type
IL	Dallman	34	Bituminous Coal		SCR	Baghouse, pulse		1/1/2009	Packed type
NM	San Juan	1	Subbituminous Coal			Baghouse, pulse		12/1/2008	Spray type
NM	San Juan	2	Subbituminous Coal			Baghouse, pulse		12/1/2008	Spray type
NM	San Juan	3	Subbituminous Coal			Baghouse, pulse		12/1/2008	Spray type
NM	San Juan	4	Subbituminous Coal			Baghouse, pulse		12/1/2008	Spray type
NV	TS Power Plant	BLR100	Subbituminous Coal		SCR	Baghouse, pulse		6/1/2008	Spray dryer type
WI	Weston	4	Bituminous Coal	Subbituminous Coal	SCR	Baghouse, pulse		6/1/2008	Spray dryer type
IL	Hennepin Power Station	2	Subbituminous Coal	Natural Gas		Baghouse, pulse		6/1/2008	
KY	H. L. Spurlock	4	Bituminous Coal		SNCR	Baghouse, pulse		4/1/2008	CFB
WY	Wygen II	4	Subbituminous Coal		SCR	Baghouse, pulse		12/31/2007	Spray type
IA	Louisa	101	Subbituminous Coal			Baghouse, pulse	Electrostatic precipitator, hot side	12/1/2007	Spray dryer type
IA	Council Bluffs	4	Subbituminous Coal		SCR	Baghouse, pulse		6/1/2007	Spray dryer type
SC	Cross	3	Bituminous Coal	Coal-based Synfuel	SCR	Electrostatic precipitator, cold side		1/1/2007	Spray type
AZ	Springerville	3	Subbituminous Coal		SCR	Baghouse, pulse		12/31/2006	Spray dryer type

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	PM Control Date	FGD Type
MT	Hardin Generator Project	PC1	Subbituminous Coal		SCR	Baghouse, pulse		4/1/2006	Spray dryer type
NC	Asheville	1	Bituminous Coal			Electrostatic precipitator, cold side		11/1/2005	Spray type
IN	A. B. Brown	1	Bituminous Coal		SCR	Baghouse, pulse	Electrostatic precipitator, cold side	6/1/2005	Spray type
KY	H. L. Spurlock	3	Bituminous Coal		SNCR	Baghouse, pulse		4/1/2005	CFB
KY	Cane Run	5	Bituminous Coal	Coal-based Synfuel		Electrostatic precipitator, cold side		6/1/2004	Spray type
CO	Craig	C2	Subbituminous Coal			Baghouse, pulse		5/1/2004	Spray type
FL	Crist	7	Bituminous Coal	Natural Gas	SCR	Electrostatic precipitator, cold side		4/1/2004	
PA	Seward	1	Waste Coal	Bituminous Coal	SNCR	Baghouse, pulse		3/1/2004	Spray dryer type
PA	Seward	2	Waste Coal	Bituminous Coal	SNCR	Baghouse, pulse		3/1/2004	Spray dryer type
CO	Craig	C1	Subbituminous Coal			Baghouse, pulse		11/1/2003	Spray type
IL	Marion	123	Waste Coal	Bituminous Coal		Baghouse, pulse		5/1/2003	CFB
KY	H. L. Spurlock	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		4/1/2003	
WY	Wygen I	3	Subbituminous Coal		SCR	Baghouse, pulse		1/1/2003	Spray type
PR	AES Puerto Rico (Aurora)	1	Bituminous Coal		SNCR	Baghouse, pulse		12/31/2002	CFB
PR	AES Puerto Rico (Aurora)	2	Bituminous Coal		SNCR	Baghouse, pulse		12/31/2002	CFB
SD	Big Stone	1	Subbituminous Coal			Baghouse, pulse		10/1/2002	
MD	Herbert A Wagner	2	Bituminous Coal			Electrostatic precipitator, cold side		8/1/2002	
WA	Transalta Centralia Generation	BW21	Subbituminous Coal			Wet scrubber	Electrostatic precipitator, cold side	6/1/2002	Spray type
MS	Red Hills Generating Facility	AA001	Lignite Coal			Baghouse, reverse air		3/1/2002	CFB
MS	Red Hills Generating Facility	AA002	Lignite Coal			Baghouse, reverse air		3/1/2002	CFB
WA	Transalta Centralia Generation	BW22	Subbituminous Coal			Wet scrubber	Electrostatic precipitator, cold side	10/1/2001	Spray type
MI	J. H. Campbell	1	Bituminous Coal	Subbituminous Coal		Electrostatic precipitator, cold side		6/1/2001	

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	PM Control Date	FGD Type
NE	Gerald Gentleman	2	Subbituminous Coal			Baghouse, reverse air		5/1/2001	
MO	Hawthorn	5A	Subbituminous Coal	Natural Gas	SCR	Baghouse, pulse		5/1/2001	Spray dryer type
WI	Weston	3	Subbituminous Coal			Baghouse, pulse		5/1/2001	
PA	PPL Montour	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		4/1/2001	
GA	Hammond	1	Bituminous Coal			Electrostatic precipitator, cold side		1/1/2001	
NE	Gerald Gentleman	1	Subbituminous Coal			Baghouse, reverse air		12/1/2000	
PA	PPL Montour	2	Bituminous Coal		SCR	Electrostatic precipitator, cold side		6/1/2000	
IL	Will County	4	Subbituminous Coal			Electrostatic precipitator, cold side		4/1/2000	
MD	AES Warrior Run Cogeneration Facility	BLR1	Bituminous Coal		SCR and SNCR	Baghouse, reverse air		2/1/2000	CFB
PA	PPL Brunner Island	2	Bituminous Coal			Electrostatic precipitator, cold side		2/1/2000	
NE	Sheldon	2	Subbituminous Coal	Natural Gas		Baghouse, pulse		2/1/2000	
NE	Sheldon	1	Subbituminous Coal	Natural Gas		Baghouse, pulse		12/1/1999	
NC	Cape Fear	5	Bituminous Coal			Electrostatic precipitator, cold side		11/1/1999	
NH	Merrimack	2	Bituminous Coal		SCR	Electrostatic precipitator, cold side		10/1/1999	
CO	Hayden	H2	Bituminous Coal	Distillate Fuel Oil		Baghouse, reverse air		6/1/1999	Spray dryer type
SC	Canadys Steam	CAN3	Bituminous Coal	Distillate Fuel Oil		Baghouse, reverse air		5/1/1999	
IA	Muscatine Plant #1	8	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side		4/1/1999	
IN	State Line Energy	3	Subbituminous Coal			Baghouse, pulse		1/1/1999	
CO	Hayden	H1	Bituminous Coal	Natural Gas		Baghouse, reverse air		12/1/1998	Spray dryer type
MI	Erickson Station	1	Subbituminous Coal			Electrostatic precipitator, cold side		11/1/1998	
NC	Asheville	2	Bituminous Coal			Electrostatic precipitator, cold side		5/1/1998	
CO	Martin Drake	5	Subbituminous Coal	Natural Gas		Baghouse, reverse air		5/1/1998	
SC	H. B. Robinson	1	Bituminous Coal			Electrostatic precipitator, cold side		5/1/1997	
GA	Hammond	2	Bituminous Coal			Electrostatic precipitator, cold side		5/1/1997	

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	PM Control Date	FGD Type
NC	Roxboro	2	Bituminous Coal			Electrostatic precipitator, cold side		1/1/1997	
VA	Birchwood Power	1A	Bituminous Coal		SCR	Baghouse, reverse air		12/1/1996	Spray dryer type
FL	Stanton Energy Center	2	Bituminous Coal		SCR	Electrostatic precipitator, cold side		6/1/1996	Spray type
VA	Clover	2	Bituminous Coal			Baghouse, reverse air		3/1/1996	Spray type
IL	Waukegan	8	Subbituminous Coal			Electrostatic precipitator, cold side		1/1/1996	
FL	Indiantown Cogeneration LP	AAB01	Bituminous Coal		SCR	Baghouse, reverse air		12/1/1995	Spray dryer type
SC	Cope	COP1	Bituminous Coal	Natural Gas		Baghouse, reverse air		11/1/1995	Spray dryer type
WY	Neil Simpson II	2	Subbituminous Coal			Electrostatic precipitator, cold side		11/1/1995	Circulating Dry Scrubber
PA	Northampton Generating Company	BLR1	Waste Coal	Petroleum Coke	SNCR	Baghouse, pulse		8/1/1995	CFB
WI	Valley	3	Bituminous Coal			Baghouse, pulse		7/1/1995	
WI	Valley	4	Bituminous Coal			Baghouse, pulse		7/1/1995	
NC	Roanoke Valley II	BLR2	Bituminous Coal			Baghouse, pulse		6/1/1995	Circulating Dry Scrubber
NC	Roxboro	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		6/1/1995	
PA	Colver Power Project	ABB01	Waste Coal			Baghouse, pulse		5/1/1995	CFB
SC	Cross	1	Bituminous Coal	Coal-based Synfuel	SCR	Electrostatic precipitator, cold side		5/1/1995	Spray type
IN	Eagle Valley	6	Bituminous Coal			Electrostatic precipitator, cold side		2/1/1995	
IN	Harding Street	60	Bituminous Coal		SNCR	Multiple cyclone	Electrostatic precipitator, cold side	2/1/1995	
VA	Clover	1	Bituminous Coal			Baghouse, reverse air		1/1/1995	Spray type
WI	Manitowoc	6	Bituminous Coal			Multiple cyclone	Baghouse, pulse	1/1/1995	
WI	Manitowoc	7	Bituminous Coal			Multiple cyclone	Baghouse, pulse	1/1/1995	
NJ	Logan Generating Plant	B01	Bituminous Coal		SCR	Baghouse, reverse air		9/1/1994	Spray dryer type
WI	Valley	1	Bituminous Coal			Baghouse, pulse		7/1/1994	
WI	Valley	2	Bituminous Coal			Baghouse, pulse		7/1/1994	
FL	Crist	6	Bituminous Coal	Natural Gas		Electrostatic precipitator, cold side		6/1/1994	

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	PM Control Date	FGD Type
IN	Harding Street	70	Bituminous Coal		SCR	Electrostatic precipitator, cold side		6/1/1994	
NJ	PSEG Mercer Generating Station	1	Bituminous Coal	Natural Gas	SCR and SNCR	Electrostatic precipitator, cold side		6/1/1994	
GA	Hammond	4	Bituminous Coal		SCR	Electrostatic precipitator, cold side		5/1/1994	
NC	Roanoke Valley I	BLR1	Bituminous Coal	Distillate Fuel Oil		Baghouse, reverse air		5/1/1994	Circulating Dry Scrubber
MO	James River Power Station	5	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side		4/1/1994	
NJ	Chambers Cogeneration LP	BOIL1	Bituminous Coal		SCR	Baghouse, reverse air		3/1/1994	Spray dryer type
NJ	Chambers Cogeneration LP	BOIL2	Bituminous Coal		SCR	Baghouse, reverse air		3/1/1994	Spray dryer type
FL	Cedar Bay Generating LP	CBA	Bituminous Coal		SNCR	Baghouse, reverse air		2/1/1994	Circulating Dry Scrubber
FL	Cedar Bay Generating LP	CBB	Bituminous Coal		SNCR	Baghouse, reverse air		2/1/1994	Circulating Dry Scrubber
FL	Cedar Bay Generating LP	CBC	Bituminous Coal		SNCR	Baghouse, reverse air		2/1/1994	Circulating Dry Scrubber
KY	Elmer Smith	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		11/1/1993	Spray type
CO	Martin Drake	7	Subbituminous Coal	Natural Gas		Baghouse, reverse air		11/1/1993	
IN	Gibson	2	Bituminous Coal			Electrostatic precipitator, cold side		7/1/1993	
KY	Elmer Smith	2	Bituminous Coal		SNCR	Electrostatic precipitator, cold side		6/1/1993	Spray type
GA	Hammond	3	Bituminous Coal			Electrostatic precipitator, cold side		6/1/1993	
PA	Scrubgrass Generating	UNIT 1	Waste Coal		SNCR	Baghouse, pulse		6/1/1993	CFB
PA	Scrubgrass Generating	UNIT 2	Waste Coal		SNCR	Baghouse, pulse		6/1/1993	CFB
SC	McMeekin	MCM1	Coal-based Synfuel	Bituminous Coal		Baghouse, reverse air		5/1/1993	
MO	Sibley	1	Subbituminous Coal			Electrostatic precipitator, cold side		4/1/1993	
MO	Sibley	3	Subbituminous Coal			Electrostatic precipitator, cold side		4/1/1993	
KY	Cane Run	4	Bituminous Coal	Coal-based Synfuel		Electrostatic precipitator, cold side		3/1/1993	Spray type
UT	Sunnyside Cogen Associates	1	Waste Coal			Baghouse, pulse		2/1/1993	CFB

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	PM Control Date	FGD Type
WV	North Branch	1A	Bituminous Coal	Waste Oil		Baghouse, pulse		12/31/1992	CFB
WV	North Branch	1B	Bituminous Coal	Waste Oil		Baghouse, pulse		12/31/1992	CFB
TX	J. K. Spruce	BLR1	Subbituminous Coal			Baghouse, reverse air		12/1/1992	Spray type
PA	Piney Creek Project	BRBR1	Waste Coal		SNCR	Baghouse, pulse		12/1/1992	Circulating Dry Scrubber
VA	Mecklenburg Power Station	BLR1	Bituminous Coal			Baghouse, pulse		11/1/1992	Circulating Dry Scrubber
VA	Mecklenburg Power Station	BLR2	Bituminous Coal			Baghouse, pulse		11/1/1992	Circulating Dry Scrubber
IL	Meredosia	05	Subbituminous Coal	Bituminous Coal		Electrostatic precipitator, cold side		11/1/1992	
HI	AES Hawaii	BLRA	Subbituminous Coal	Tire-derived Fuels	SNCR	Baghouse, reverse air		8/1/1992	CFB
HI	AES Hawaii	BLRB	Subbituminous Coal	Waste Oil	SNCR	Baghouse, reverse air		8/1/1992	CFB
VA	Cogentrix of Richmond	3A	Bituminous Coal			Baghouse, pulse		8/1/1992	Spray dryer type
VA	Cogentrix of Richmond	3B	Bituminous Coal			Baghouse, pulse		8/1/1992	Spray dryer type
VA	Cogentrix of Richmond	4A	Bituminous Coal			Baghouse, pulse		8/1/1992	Spray dryer type
VA	Cogentrix of Richmond	4B	Bituminous Coal			Baghouse, pulse		8/1/1992	Spray dryer type
WV	Grant Town Power Plant	BLR1A	Waste Coal			Baghouse, pulse		8/1/1992	CFB
WV	Grant Town Power Plant	BLR1B	Waste Coal			Baghouse, pulse		8/1/1992	CFB
PA	Panther Creek Energy Facility	BLR1	Waste Coal		SNCR	Baghouse, pulse		6/1/1992	Circulating Dry Scrubber
PA	Panther Creek Energy Facility	BLR2	Waste Coal		SNCR	Baghouse, pulse		6/1/1992	Circulating Dry Scrubber
WI	South Oak Creek	7	Subbituminous Coal			Electrostatic precipitator, cold side		6/1/1992	
VA	Cogentrix of Richmond	1A	Bituminous Coal			Baghouse, pulse		5/1/1992	Spray dryer type
VA	Cogentrix of Richmond	1B	Bituminous Coal			Baghouse, pulse		5/1/1992	Spray dryer type
VA	Cogentrix of Richmond	2A	Bituminous Coal			Baghouse, pulse		5/1/1992	Spray dryer type
VA	Cogentrix of Richmond	2B	Bituminous Coal			Baghouse, pulse		5/1/1992	Spray dryer type
IN	Michigan City	12	Subbituminous Coal	Natural Gas	SCR	Electrostatic precipitator, cold side		5/1/1992	
KS	Quindaro	2	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side		5/1/1992	

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	PM Control Date	FGD Type
IN	Gibson	1	Bituminous Coal			Electrostatic precipitator, cold side		1/1/1992	
SC	McMeekin	MCM2	Coal-based Synfuel	Bituminous Coal		Baghouse, reverse air		1/1/1992	
WV	Morgantown Energy Facility	CFB1	Waste Coal			Baghouse, pulse		1/1/1992	CFB
WV	Morgantown Energy Facility	CFB2	Waste Coal			Baghouse, pulse		1/1/1992	CFB
NJ	PSEG Mercer Generating Station	2	Bituminous Coal	Natural Gas	SCR and SNCR	Electrostatic precipitator, cold side		1/1/1992	
MO	Sibley	2	Subbituminous Coal			Electrostatic precipitator, cold side		1/1/1992	
TX	Twin Oaks Power One	U2	Lignite Coal			Baghouse, shake and deflate		10/1/1991	CFB
VA	Altavista Power Station	1	Bituminous Coal		SNCR	Baghouse, pulse		6/1/1991	Spray dryer type
CO	Comanche	2	Subbituminous Coal	Natural Gas		Baghouse, reverse air		6/1/1991	
WI	South Oak Creek	8	Subbituminous Coal			Electrostatic precipitator, cold side		6/1/1991	
VA	Southampton Power Station	1	Bituminous Coal			Baghouse, pulse		6/1/1991	Spray dryer type
OH	W. H. Zimmer	1	Bituminous Coal			Electrostatic precipitator, cold side		6/1/1991	Spray type
MD	Brandon Shores	2	Bituminous Coal		SCR	Electrostatic precipitator, hot side		5/1/1991	Spray type
PA	Ebensburg Power	031	Waste Coal			Baghouse, pulse		5/1/1991	CFB
WI	Manitowoc	8	Bituminous Coal	Petroleum Coke		Single cyclone	Baghouse, pulse	4/1/1991	CFB
PA	Cambria Cogen	B1	Waste Coal		SNCR	Baghouse, shake and deflate		3/1/1991	CFB
PA	Cambria Cogen	B2	Waste Coal		SNCR	Baghouse, shake and deflate		3/1/1991	CFB
AL	James H Miller Jr.	4	Subbituminous Coal		SCR	Electrostatic precipitator, cold side		3/1/1991	Spray type
OK	AES Shady Point	1A	Bituminous Coal			Baghouse, pulse		1/1/1991	CFB
OK	AES Shady Point	1B	Bituminous Coal			Baghouse, pulse		1/1/1991	CFB
OK	AES Shady Point	2A	Bituminous Coal			Baghouse, pulse		1/1/1991	CFB
OK	AES Shady Point	2B	Bituminous Coal			Baghouse, pulse		1/1/1991	CFB
AL	Colbert	4	Bituminous Coal			Electrostatic precipitator, cold side		1/1/1991	
CO	Nucla	1	Bituminous Coal			Baghouse, shake and deflate		1/1/1991	CFB

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_x Control	PM Control 1	PM Control 2	PM Control Date	FGD Type
NY	Trigen Syracuse Energy	1	Bituminous Coal			Baghouse, reverse air		1/1/1991	N/A
NY	Trigen Syracuse Energy	2	Bituminous Coal			Baghouse, reverse air		1/1/1991	N/A
NY	Trigen Syracuse Energy	3	Bituminous Coal			Baghouse, reverse air		1/1/1991	N/A
NY	Trigen Syracuse Energy	4	Bituminous Coal			Baghouse, reverse air		1/1/1991	N/A
NY	Trigen Syracuse Energy	5	Bituminous Coal			Baghouse, reverse air		1/1/1991	N/A
KY	Trimble County	1	Bituminous Coal		SCR	Electrostatic precipitator, cold side		12/1/1990	Spray type
AL	Colbert	1	Bituminous Coal			Electrostatic precipitator, cold side		11/1/1990	
CO	Comanche	1	Subbituminous Coal	Natural Gas		Baghouse, reverse air		11/1/1990	
NC	Cogentrix Dwayne Collier Battle Cogen	1A	Bituminous Coal			Baghouse, pulse		10/1/1990	Spray dryer type
NC	Cogentrix Dwayne Collier Battle Cogen	1B	Bituminous Coal			Baghouse, pulse		10/1/1990	Spray dryer type

Attachment 12. List of all oil-fired electric utility steam generating units selected for HCl/HF/HCN acid gas HAP, dioxin/furan organic HAP, non-dioxin/furan organic HAP, and mercury and other non-mercury metallic HAP testing

State	Plant Name	Boiler ID	NO_X Control	PM Control 1	PM Control 2
PR	Aguirre	3			
PR	Aguirre	4			
PR	Aguirre	9			
PR	Aguirre	10			
FL	Anclote	1			
FL	Anclote	2			
PR	Arecibo	1			
NY	Astoria Generating Station	40			
NJ	B L England	3		Multiple cyclone	Electrostatic precipitator, cold side
DC	Benning	16			
MA	Brayton Point	4		Electrostatic precipitator, cold side	
CT	Bridgeport Station	BHB2		Electrostatic precipitator, cold side	
FL	C. D. McIntosh Jr	2		Electrostatic precipitator, cold side	
GU	Cabras	2			
FL	Turkey Point	PTP1		Multiple cyclone	
FL	Turkey Point	PTP2		Multiple cyclone	
PR	Central Palo Seco	2			
PR	Central Palo Seco	3			
PR	Central Palo Seco	4			
PR	Central Palo Seco	5			
PR	Central Palo Seco	6			
PR	Central Palo Seco	7			
PR	Central Palo Seco	8			
MA	Cleary Flood	8			
PR	Costa Sur	1			
PR	Costa Sur	2			
PR	Costa Sur	6			
PR	Costa Sur	7			
PR	Costa Sur	8			
PR	Costa Sur	9			

State	Plant Name	Boiler ID	NO_X Control	PM Control 1	PM Control 2
PR	Costa Sur	10			
CT	Devon Station	8		Electrostatic precipitator, cold side	
IN	Eagle Valley	1		Multiple cyclone	Electrostatic precipitator, cold side
IN	Eagle Valley	2		Multiple cyclone	Electrostatic precipitator, cold side
NY	East River	6			
PA	Eddystone Generating Station	4		Multiple cyclone	Electrostatic precipitator, cold side
DE	Edge Moor	5		Multiple cyclone	Electrostatic precipitator, cold side
IN	Harding Street	9		Multiple cyclone	Electrostatic precipitator, cold side
IN	Harding Street	10		Multiple cyclone	Electrostatic precipitator, cold side
IL	Havana	2		Electrostatic precipitator, hot side	
IL	Havana	4		Electrostatic precipitator, hot side	
IL	Havana	5		Electrostatic precipitator, hot side	
IL	Havana	6		Electrostatic precipitator, hot side	
IL	Havana	7		Electrostatic precipitator, hot side	
IL	Havana	8		Electrostatic precipitator, hot side	
HI	Honolulu	16			
FL	Indian River	1			
FL	Indian River	2			
FL	Indian River	3			
SC	Jefferies	2		Electrostatic precipitator, cold side	
HI	Kahe	3			
HI	Kahe	4			
FL	Manatee	PMT1		Multiple cyclone	
FL	Manatee	PMT2		Multiple cyclone	
FL	Martin	PMR1		Multiple cyclone	
DE	McKee Run	3		Multiple cyclone	
GA	McManus	2			
LA	Michoud	3			
MD	Mirant Chalk Point	3		Electrostatic precipitator, cold side	
PA	Mitchell Power Station	1		Electrostatic precipitator, cold side	
PA	Mitchell Power Station	2		Electrostatic precipitator, cold side	
PA	Mitchell Power Station	3		Electrostatic precipitator, cold side	
CT	Montville Station	5		Electrostatic precipitator, cold side	

State	Plant Name	Boiler ID	NO_X Control	PM Control 1	PM Control 2
CT	Montville Station	6		Electrostatic precipitator, cold side	
MA	Mystic Generating Station	7		Electrostatic precipitator, cold side	
NH	Newington	1		Electrostatic precipitator, hot side	
NY	Northport	2		Electrostatic precipitator, cold side	
NY	Northport	4		Electrostatic precipitator, cold side	
FL	Northside Generating Station	3		Baghouse, pulse	
NY	Oswego Harbor Power	5		Electrostatic precipitator, cold side	
FL	Port Everglades	PPE3		Multiple cyclone	
FL	Port Everglades	PPE4		Multiple cyclone	
NY	Port Jefferson	4		Electrostatic precipitator, cold side	
VA	Possum Point	5		Multiple cyclone	Electrostatic precipitator, cold side
PA	PPL Martins Creek	3			
PA	PPL Martins Creek	4			
NJ	PSEG Sewaren Generating Station	2			
NJ	PSEG Sewaren Generating Station	4			
VI	Randolph E. Harley	1			
NY	Ravenswood Generating Station	1		Electrostatic precipitator, cold side	
NY	Ravenswood Generating Station	2		Electrostatic precipitator, cold side	
VI	Richmond	1			
FL	Martin	PMR2		Multiple cyclone	
NY	Roseton Generating Station	2		Multiple cyclone	
PR	San Juan Plant	1			
PR	San Juan Plant	2			
PR	San Juan Plant	4			
PA	Schuylkill Generating Station	1		Multiple cyclone	
FL	Suwannee River	2			
FL	Suwannee River	3			
MD	Vienna Operations	8		Multiple cyclone	
HI	Waiau	3			
HI	Waiau	4			
HI	Waiau	5			
HI	Waiau	6			
HI	Waiau	7			

State	Plant Name	Boiler ID	NO_X Control	PM Control 1	PM Control 2
HI	Waiau	8			
MA	West Springfield	3		Electrostatic precipitator, cold side	
ME	William F Wyman	1		Multiple cyclone	Electrostatic precipitator, cold side
ME	William F Wyman	2		Multiple cyclone	Electrostatic precipitator, cold side

Attachment 13. List of 50 additional coal-fired electric utility steam generating units not chosen in Attachments 8 through 11 selected for HCl/HF/HCN acid gas HAP, non dioxin/furan organic HAP, and mercury and other non-mercury metallic HAP testing

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Control	ACI
WV	Albright	1	Bituminous Coal			Electrostatic precipitator, cold side			
WV	Albright	3	Bituminous Coal			Electrostatic precipitator, cold side			
CT	Bridgeport Station	BHB3	Subbituminous Coal	Residual Fuel Oil		Electrostatic precipitator, cold side			Y
OH	Cardinal	3	Bituminous Coal		SCR	Electrostatic precipitator, hot side			
VA	Clinch River	3	Bituminous Coal			Electrostatic precipitator, cold side			
AL	Colbert	3	Bituminous Coal			Electrostatic precipitator, cold side			
MT	Colstrip	3	Subbituminous Coal			Wet scrubber		Venturi type	
OH	Conesville	3	Bituminous Coal			Electrostatic precipitator, cold side			
FL	Crystal River	1	Bituminous Coal			Electrostatic precipitator, cold side			
KY	Dale	3	Bituminous Coal			Electrostatic precipitator, cold side			
NY	Dunkirk Generating Station	1	Bituminous Coal	Subbituminous Coal		Electrostatic precipitator, hot side			
NY	Dunkirk Generating Station	4	Bituminous Coal	Subbituminous Coal		Electrostatic precipitator, hot side			
PA	Eddystone Generating Station	2	Bituminous Coal		SNCR	Multiple cyclone	Electrostatic precipitator, cold side	Spray type	
PA	Elrama Power Plant	2	Bituminous Coal		SNCR	Multiple cyclone	Electrostatic precipitator, cold side	Venturi type	
NC	G. G. Allen	3	Bituminous Coal			Electrostatic precipitator, cold side			
TN	Gallatin	2	Subbituminous Coal			Electrostatic precipitator, cold side			
PA	Hatfields Ferry Power Station	3	Bituminous Coal			Electrostatic precipitator, cold side			

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Control	ACI
IL	Havana	9	Subbituminous Coal		SCR	Electrostatic precipitator, hot side	Baghouse, pulse		Y
MN	Hoot Lake	2	Subbituminous Coal			Electrostatic precipitator, cold side			
TX	J. T. Deely	1	Subbituminous Coal			Electrostatic precipitator, cold side			
MO	James River Power Station	4	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side			
IL	Joliet 9	5	Subbituminous Coal			Electrostatic precipitator, cold side			
KS	La Cygne	2	Subbituminous Coal			Electrostatic precipitator, cold side			
KS	Lawrence Energy Center	3	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side			
TX	Monticello	1	Lignite Coal	Subbituminous Coal		Electrostatic precipitator, cold side	Baghouse, shake and deflate		
IL	Newton	2	Subbituminous Coal			Electrostatic precipitator, cold side			
PA	PPL Martins Creek	2	Bituminous Coal			Electrostatic precipitator, cold side			
WI	Pulliam	8	Subbituminous Coal			Electrostatic precipitator, cold side			
KY	R D Green	G2	Bituminous Coal			Electrostatic precipitator, cold side		Spray type	
IN	R M Schahfer	14	Bituminous Coal	Subbituminous Coal		Electrostatic precipitator, cold side			
LA	R. S. Nelson	6	Subbituminous Coal			Electrostatic precipitator, hot side			
CO	Rawhide	101	Subbituminous Coal			Baghouse, reverse air		Spray dryer type	
NV	Reid Gardner	1	Bituminous Coal	Lignite Coal		Multiple cyclone		Spray type	
OH	Richard Gorsuch	3	Bituminous Coal	Natural Gas		Electrostatic precipitator, cold side			
NC	Riverbend	7	Bituminous Coal			Electrostatic precipitator, hot side			
NH	Schiller	5	Bituminous Coal	Residual Fuel Oil	SNCR	Electrostatic precipitator, cold side			
FL	Scholz	2	Bituminous Coal			Electrostatic precipitator, cold side			
PA	Shawville	2	Bituminous Coal			Electrostatic precipitator, cold side			

State	Plant Name	Boiler ID	Primary Fuel	Secondary Fuel	NO_X Control	PM Control 1	PM Control 2	FGD Control	ACI
MN	Silver Bay Power	BLR1	Subbituminous Coal	Natural Gas		Baghouse, reverse air			
MO	Sioux	2	Subbituminous Coal	Tire-derived Fuels		Electrostatic precipitator, cold side			
IN	Tanners Creek	U4	Subbituminous Coal			Electrostatic precipitator, cold side			
SC	Urquhart	URQ3	Bituminous Coal	Natural Gas		Electrostatic precipitator, cold side			
IL	Vermilion	1	Subbituminous Coal	Natural Gas		Electrostatic precipitator, cold side	Baghouse, pulse		Y
OH	W H Sammis	3	Bituminous Coal	Subbituminous Coal		Baghouse, reverse air			
OH	W H Sammis	4	Bituminous Coal	Subbituminous Coal		Baghouse, reverse air			
NC	W. H. Weatherspoon	1	Bituminous Coal			Electrostatic precipitator, cold side			
IN	Wabash River	2	Bituminous Coal			Electrostatic precipitator, cold side			
TX	Welsh	1	Subbituminous Coal			Electrostatic precipitator, hot side			
NE	Whelan Energy Center	1	Subbituminous Coal			Electrostatic precipitator, cold side			
PA	WPS Energy Servs Sunbury Gen	4	Bituminous Coal	Distillate Fuel Oil		Electrostatic precipitator, cold side	Electrostatic precipitator, cold side		