Attachment 1.

Draft Questionnaire Content

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 86,881 hours and $96,541,879. This is the estimated burden for 531 facilities to provide information on their boilers, fuel oil types and/or coal rank, 1,334 units to provide hazardous air pollutant (HAP) emissions data and 12 months of fuel analyses, and 886 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 - 8 months of receipt.

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:

Sector Policies and Programs Division (Mail Code D205-01)
U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

Attention: Peter Tsirigotis, Director

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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):

____

____

____

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[1] 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:[2,3]

__ 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) (% _____)

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

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

[2] 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).

[3] In reference to footnote 1, 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").

__ 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:[4]

__ 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[5] 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: ____

____

[4] 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).

[5] 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").

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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[6]	**Original design fuel (i.e. coal rank or type of oil)**	**Design heat input, (MMBtu)**[7]	**Present maximum heat input, (MMBtu)**[8]	**MWe Gross capacity**	**MWe Net capacity**	**Original design gross efficiency (%, HHV)**	**Present operating gross efficiency (%, HHV)**	**Design steam pressure (psig)**	**Operating steam pressure (psig)**	**Design steam reheat temperature (°F)**[9]	**Operating steam temperature (°F)**	**Operating steam reheat temperature (°F)**[10]	**Fuel**[11]	**Hours/year operated**[12]	**Average annual capacity factor for the past 3 years**	**Applicable NSPS**	**Estimated year of retirement**[13]

[6] 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).
[7] Per fuel burned in the boiler
[8] Per fuel burned in the boiler
[9] Please indicate if more than one steam reheat cycle is utilized, and, if so, please provide information for both.
[10] Please indicate if more than one steam reheat cycle is utilized, and, if so, please provide information for both.
[11] Indicate the fuels utilized for the indicated boiler, and percentages, as indicated in questions 11 - 13.
[12] 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.
[13] 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.):

[14] 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).

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

[16] 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?

[17] 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.

[18] 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.

[19] 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[20] (e.g., U.S. Department of Energy program, consent decree, etc.).

Boiler ID[21]	**Company (vendor) name**	**Company (vendor) contact information**		
		Name	**Telephone**	**Address**

[20] 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.

[21] 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) 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[22]	**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**[23]**)**	**Desired HAP emission reduction (%) or emission rate**	**Coal rank(s) in use**

[22] 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).

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

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19. 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 providing a non-demonstration, full-scale operating system.

Boiler ID[24]	**Company (vendor) name**	**Company (vendor) contact information**		
		Name	**Telephone**	**Address**

24 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) 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[25]	**Actual start-up date**	**Expected or projected start-up date**	**Type of control (e.g., sorbent and type; chemical additive)[26]**	**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**

[25] 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).

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

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

Boiler ID[27]	**Permitted emission limit (indicate type of permit and format of emission limit)**										
	PM[28]	**PM_{10}**[(29)]	**$PM_{2.5}$**[(30)]	**SO_2**	**HCl and/or HF**	**HCN**	**Metal HAP**[31]	**Hg**	**CO**	**Other organics (specify)**	**Other pollutant (specify)**

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 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.

29 List the compliance test method utilized.

30 List the compliance test method utilized.

31 Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium; indicate permit level for all metal HAP for which a permit level has been developed.

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

Boiler ID[32]	Most recent guaranteed emission rate for each pollutant for which there is a permitted emission limit										
	PM[33]	PM_{10}	$PM_{2.5}$	SO_2	HCl and/or HF	HCN	Metal HAP[34]	Hg	CO	Other organics (specify)	Other pollutant (specify)

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

____

____

[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 guaranteed emission rate for filterable and condensable PM, respectively, please include those separate emission rates.

[34] Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium; indicate permit level for all metal HAP for which a permit level has been developed.

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

Boiler ID[35]	**Required monitoring, recordkeeping, and reporting requirements for each pollutant for which there is a permitted emission limit**									
	PM[36]	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**HCl and/or HF**	**HCN**	**Metal HAP**[37]	**Hg**	**CO**	**Other organics (specify)**

35 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).

36 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.

37 Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium; indicate permit level for all metal HAP for which a permit level has been developed.

25. For the control technologies identified in Part I, questions 17 and 19, provide the cost information requested.[38]

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

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

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. ____

____

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____

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PART II: FUEL ANALYSIS AND EMISSION DATA

Fuel Analysis

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: ________________________________

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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	**ID # of boiler(s) firing fuel**[39]	**Fuel source**			**Fuel shipment method**
		State/Country	**County**	**Coal seam**[40]	

[39] 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).
[40] If known.

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3. For each individual coal and oil shipment received during the preceding 12 calendar months, provide the following information, 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, %**	**Heating value, Btu/lb**	**Mercury, ppm**	**Chlorine, ppm**	**Fluorine, ppm**	**Nickel, ppm**	**Other trace metal HAP, ppm[41]**

[41] Metal HAP includes compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, 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 before 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 before 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 flue gas flow). Note by diagram where sampling ports were located in relation to the bypass ductwork. ___________

____

____

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

____

____

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 system monitoring (CEMS) data available (e.g., mercury, continuous opacity monitoring systems) that are not already being provided to the U.S. EPA,

even if from short-term testing? Yes _____ No _____ If yes[42], please 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 CEM 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)[43]							
	Date of test	PM[44]	SO_2	HCl/HF/HCN	Metal HAP[45]	Hg[46]	CO	Other organics (specify)

[42] Where units are monitored by CEMs (either following CAMR, State, or NIST QA/QC procedures), and where data are available, EPA requests that this CEM data by submitted by the respondent.
[43] 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.
[44] 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 $PM_{2.5}$.
[45] Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium; indicate emission level for all metal HAP for which an emission test has been conducted.
[46] 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 of Ignition” [L.O.I.]) at the time of any Hg testing, please include these data.

PART III: EMISSION 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 three separate runs for each pollutant at the sampling location. EPA requires that the facility conduct testing with paired trains for fine particulate matter (which is included in the testing of units for mercury and other non-mercury metallic HAP) and with duplicate (simultaneous but not necessarily collocated) trains for the other HAP being tested. Emission measurements frequently consist of a sequential set (typically three) of singular method tests over the course of several hours or days. In contrast, a sequential set of duplicate or paired method tests provides the only measure of test method precision, thereby facilitating identification of test data "outliers" occasionally generated through improper test method execution, versus true source emission variability. Indeed, paired method data provides a quantifiable way to identify and distinguish between erratic test data and actual emission variations.

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
2.0 Fuel Analysis Procedures and Methods
3.0 How to Report Data
4.0 How to Submit Data
5.0 Definitions
6.0 Contact Information for Questions on Test Plan and Reporting

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), volatile organic compounds (VOC), polycyclic organic matter (POM), methane, formaldehyde, oxygen (O_2), carbon dioxide (CO_2), oxides of nitrogen (NO_X), 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), sulfur dioxide (SO_2), O_2, CO_2
- Mercury and non-mercury metallic HAP: mercury (Hg), HAP metals (including antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), Cr^{+6}, cobalt (Co), lead (Pb), manganese (Mn), nickel (Ni), phosphorus (P) and selenium (Se)), particulate matter (PM – total filterable, $PM_{2.5}$ (wet and dry), and condensable); total solids; O_2, CO_2

Refer to Table _ on page _ of the section 114 letter you received for the specific combustion unit and pollutants 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/. A copy of RCRA Method 0011 for aldehydes may be obtained here: http://www.epa.gov/epawaste/hazard/testmethods/sw846/pdfs/0011.pdf.

Report pollutant emission data as specified in Table 1.2 below. Each test should be comprised of three test runs. All pollutant concentrations should be corrected to 7 percent oxygen 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. In addition to the emission test data, you should also report the following process information taken during the 30 day period before, at the time of, and following, the emissions test: 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).

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 1.2: Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Alternative Methods

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
CO	U.S. EPA Method 10, 10A, or 10B	None	lb/MMBtu and ppmvd @ 7% O_2
Formaldehyde	U.S. EPA Method 320 with a test run time of 1 hour.	RCRA Method 0011. Collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 2 hours per run.	lb/MMBtu and ppmvd @ 7% O_2

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
HCl and HF	U.S. EPA Method 26A	U.S. EPA Method 26 if there are no entrained water droplets in the sample or U.S. EPA Method 320.	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
Hg	ASTM-D6784-02 (Ontario Hydro Method). Collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 2 hours per run.	U.S. EPA Method 29** or U.S. EPA Method 30B.	lb/MMBtu
Cr^{+6}	U.S. EPA SW-846 Method 0061	U.S. EPA Method 29*. Report all Cr as Cr^{+6}.	lb/MMBtu
Metals	U.S. EPA Method 29** No permanganate solution needed, if Hg will not be measured. Collect a minimum volume of 4.0 cubic meters or have a minimum sample time of 4 hours per run. Determine total filterable PM emissions according to §8.3.1.1. Use IC(A)P/MS for the analytical finish. Report all metals results, and report all Cr as Cr^{+6}.	None	lb/MMBtu
$PM_{2.5}$ 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***)	None	lb/MMBtu
$PM_{2.5}$ 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 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****

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
PM (condensable)	U.S. EPA Other Test Method 28 (OTM 28)	None	lb/MMBtu
THC	U.S. EPA Method 25A with a minimum sampling time of 1 hour per run. Calibrate the measuring instrument with a mixture of the organic compounds being emitted or with propane.	None	lb/MMBtu and ppmvd @ 7% O2
CH_4	U.S. EPA Method 18. Have a minimum sample time of 1 hour per run.	U.S. EPA Method 320.	lb/MMBtu and ppmvd @ 7% O2
D/F, PCB*****	U.S. EPA Method 23. Collect a minimum volume of 10 cubic meters or 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
Speciated Volatile Organic HAP	U.S. EPA Method 0031with SW-846 Method 8260B. Collect a minimum volume of 60 liters or have a minimum sample time of 2 hours per run.	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 2 cubic meters or 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
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	%

*Method 29 in appendix A-8 to part 60 of this chapter can also be used for Hg, but follow the procedures for preparation of Hg standards and sample analysis in sections 13.4.1.1 through 13.4.1.3 of ASTM D6784-02 instead of the procedures in sections 7.5.33 and 11.1.3 of Method 29, and perform the QA/QC procedures in section 13.4.2 of ASTM D6784-02 instead of the procedures in section 9.2.3 of Method 29. The tester may also opt to use the sample recovery and preparation procedures in ASTM D6784-02 instead of the Method 29 procedures, as follows: sections 8.2.8 and 8.2.9.1 of Method 29 can be replaced with sections 13.2.9.1 through 13.2.9.3 of ASTM D6784-02; sections 8.2.9.2 and 8.2.9.3 of Method 29 can be replaced with sections 13.2.10.1 through 13.2.10.4 of ASTM D6784-02; section 8.3.4 of Method 29 can be replaced with section 13.3.4 or 13.3.6 of ASTM D6784-02 (as appropriate); and section 8.3.5 of Method 29 can be replaced with section 13.3.5 or 13.3.6 of ASTM D6784-02 (as appropriate).

**If both mercury and other metals will be testing using EPA Method 29, the stack test company must be particularly diligent in the set-up and handling of the impingers to avoid cross contamination of the manganese from the permanganate into the metals catch. Alternately, the contractor may want to collect mercury using a train separate from the train used to collect the other metals.

***PM filterable is determined by including the cyclone catch.

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

*****Just the 12 “dioxin-like” PCB congeners (see the WHO PCB Congener List)

******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 part 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 (antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, 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 conduct one fuel sample (comprised of three composite samples, each individually analyzed) of the fuel used during the stack test (one composite sample per test run).

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	

Sampling Location	Sampling Procedures	Sample Collection Timing
	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)	Btu/lb
	Liquid	ASTM-5865-03a, ASTM D240, ASTM E711-87 (1996)	
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	
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, (Method 6C, Method 7E, Method 10, Method 17, Method 25A, Method 26A, Method 29, Method 101, Method 101A, Method 201A, Method 202) you must report your data using the EPA Electronic Reporting Tool (ERT) Version 3. At present, only these methods are supported by the ERT. 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, 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 {*to be added later*}. You must report the results of each test on 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 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 {*to be added later*}.

3.2 Reporting Fuel Analysis Data

If you conducted a fuel analysis, you must report the analysis results separately for each of the 12 samples in a Microsoft ® Excel Fuel Analysis Template. The fuel samples collected in conjunction with the stack test are comprised of three composite samples, each of which is analyzed separately. The remaining nine additional fuel samples are also comprised of three composite samples, but only the combined composite samples are analyzed. The Excel template can be downloaded from {*to be added later*}. 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. Appendix A {*to be provided later*} lists each field within the ERT and notes whether or not the field is required or optional.

4.0 How to Submit Data

You may submit your data in one of three ways as listed below. However, in order to avoid duplicate data and keep all data for a particular facility together, we request that you submit all of the data requested from your facility in the same way. To submit your data:

- E-mail an electronic copy of all requested files to {*to be added later*}
- If the files are too large for your e-mail system, you may upload the electronic files to a FTP site (see directions for FTP site procedures below)
- Mail a CD or DVD containing an electronic copy of all requested files to the EPA address shown in your Section 114 letter. If no electronic copy is available, mail a hard copy of all requested files to the EPA address shown in your Section 114 letter.
- 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.

The steps below outline how to upload files to the FTP site by using "My Computer" as well as by using a FTP Client software.

<u>Directions for accessing the FTP site via "My Computer"…</u>

{*To be added later*}

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 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, 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 FTP site, contact:
{*To be provided later.*}