U.S. Department of Energy Energy Information Administration Form EIA-767 (2003)	*STEAM-ELECTRIC PLANT OPERATION AND DESIGN REPORT*	Form Approved OMB No. 1905-0129 Approval Expires 11/30/04

GENERAL INFORMATION

PURPOSE

Form EIA-767 collects information annually from all U.S. plants with a total existing or planned organic-fueled or combustible renewable steam-electric plant that has a generator nameplate rating of 10 megawatts or larger. This report is used for economic and regulatory analyses conducted by the Department of Energy. The data from this form appear in the *Electric Power Annual* and *Annual Energy Review*. The data collected on this form are used to monitor the current status and trends of the electric power industry and to evaluate the future of the industry.

REQUIRED RESPONDENTS

A separate Form EIA-767 must be completed and filed for each existing, under-construction, or planned U.S. organic-fueled or combustible renewable steam-electric generating plant with a nameplate capacity of 10 or more megawatts regardless of current ownership and/or operation. If plant has a nameplate capacity of 100 megawatts or greater, complete the entire Form EIA-767. If plant has a nameplate capacity of 10 megawatts but less than 100 megawatts, complete Schedules 1, 2, 4 (Part A, D, and E), 7 and 8 (Part A and B). Schedule 10, "Footnotes," is required if applicable.

SANCTIONS

The timely submission of Form EIA-767 by those required to report is mandatory under Section 13(b) of the Federal Energy Administration Act of 1974 (FEAA) (Public Law 93-275), as amended. Failure to respond may result in a penalty of not more than $2,750 per day for each civil violation, or a fine of not more than $5,000 per day for each criminal violation. The government may bring a civil action to prohibit reporting violations, which may result in a temporary restraining order or a preliminary or permanent injunction without bond. In such civil action, the court may also issue mandatory injunctions commanding any person to comply with these reporting requirements. **Title 18 U.S.C. 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

METHODS OF FILING RESPONSE

Submit your data electronically using EIA's Internet Data Collection system (IDC).

- If you have not registered with EIA's Single Sign-On system, send an e-mail requesting assistance to Natalie Ko at: EIA-767@eia.doe.gov.
  Important Note: Even if you used the IDC system in 2003, you will need to register with Single Sign-On for 2004. If you have not done so or are not sure, e-mail EIA as noted immediately above.
- If you have registered with Single Sign-On, log on at https://signon.eia.doe.gov/ssoserver/login
- If you are having a technical problem with logging into the IDC or using the IDC contact the IDC Help Desk for further information. Contact the Help Desk at:
  E-Mail: CNEAFhelpcenter@eia.doe.gov
  Phone: 202-287-1333
- If you need an alternate means of filing your response, contact the Help Desk.

Retain a completed copy of this form for your files.

CONTACT

Internet System Questions: For questions related to the Internet Data Collection system, see the help contact information immediately above:
Data Questions: For questions about the data requested on Form EIA767, contact:

Natalie Ko
Telephone Number: (202) 287-1957
FAX Number: (202) 287-1959
E-mail: eia-767@eia.doe.gov.

CONFIDENTIALITY

The information contained on Schedule 6, Part B and Schedule 9 relating to Latitude and Longitude will be kept confidential and not disclosed to the public to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. §552, the DOE regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905. The Energy Information Administration (EIA) will protect your information in accordance with its confidentiality and security policies and procedures.

The Federal Energy Administration Act requires the EIA to provide company-specific confidential data to other Federal agencies when requested for official use. The information reported on this form may also be made available, upon request, to another component of the Department of Energy (DOE); to any Committee of Congress, the General Accounting Office, or other Federal agencies authorized by law to receive such information. A court of competent jurisdiction may obtain this information in response to an order.

The information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes. Disclosure limitation procedures are applied to the statistical data published from EIA-767 confidential survey information to ensure that the risk of disclosure of identifiable information is very small.

All other Information reported on Form EIA-767 will not be treated as confidential and may be publicly released in identifiable form. In addition to the use of the information by EIA for statistical purposes, the information may be used for any nonstatistical purposes such as administrative, regulatory, law enforcement, or adjudicatory purposes.

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INSTRUCTIONS

Submit the completed form no later than April 30 following the close of the reporting year.

1. Operator of plant in the United States whether existing, under-construction, or planned should complete the parts of the form where applicable based on the following criteria:

PLANT TYPE	PLANT CAPACITY	REQUIRED SCHEDULES	BURDEN (HOURS)
Organic-fueled or combustible renewable steam-electric	100 megawatts or greater	All Schedules	78
Organic-fueled or combustible renewable steam-electric	10 to less than 100 megawatts	Schedules 1, 2, 4 (Part A, D, and E), 7, and 8 (Part A and B)	4

2. Verify all preprinted information. If incorrect, revise the incorrect entry and provide the correct information. Provide any missing information.

3. Combined plants complete applicable pages for organic, depending on capacity. For determining plant capacity, include waste-heat units with auxiliary firing. Do not include waste-heat units without auxiliary firing or auxiliary, house, or startup boilers. A separate Form EIA-767 must be submitted for each qualifying plant. Planned equipment is defined, for reporting purposes, as equipment that is on order and expected to go into commercial service within 5 years.

4. If a report is to be submitted for a plant that has not been assigned an EIA utility-plant code, call the EIA contact identified on page i of the instructions.

5. The form is designed for reporting at two levels: Schedules 2 and 3 request information at the plant level. Schedules 4 through 9 request information at the equipment level (i.e., generator, boiler, flue gas particulate collector, etc.).

6. Schedule 10 is for footnotes. Footnotes must be provided when requested in an instruction, or when additional explanation is requested. Information reported on this form that is inconsistent with other information filed with EIA should be explained in a footnote.

7. If the preprinted information is correct indicate in the box, “CHECK IF PRE-PRINTED DATA ARE CORRECT” at the bottom of the page. If the entire page is not applicable, then indicate in the box “CHECK IF PAGE NOT APPLICABLE” at the bottom of the page.

8. Information provided on this form should be for the calendar year indicated in the upper left-hand corner of each page of the form. Design information should be current as of December 31st of the year indicated.

9. Information provided should be actual data to the extent possible. If actual data are not available, enter estimated values. Do not put an “E” or any other annotation next to estimated values. If you cannot provide an estimate, enter “EN” for estimate not available.

10. Quantitative information should be reported in nearest whole numbers (no decimal points) unless otherwise indicated. Do not use commas in numerical entries.

11. If more than one sheet is required to complete a section, identify individual sheets as sheet “1 of 3,” “2 of 3,” etc.

12. All design data should reflect the current or planned configuration of equipment.

13. Enter the data in the unit of measurement requested. For example, if the actual cost is $14,586,625.43, and you are requested to report on the form in thousand dollars, then enter 14587.

14. If the plant or units are jointly owned, the plant operator (respondent) must submit the report for the entire plant, not just for the percent owned.

15. The data reported on this form must be consistent with the corresponding data reported on other Energy Information Administration forms, e.g., total annual steam-electric generation reported on Schedule 5 of this form should equal the annual steam-electric generation reported on the Form EIA-906, “Power Plant Report.” Maximum generator nameplate rating should be the same as the nameplate rating reported on Form EIA-860, “Annual Electric Generator Report.”

INSTRUCTIONS

Specific Instructions

Schedule 1. Identification

1. For line 1, **Company Name**, verify the name. The item represents the full legal name of the plant operator.

2. For line 2, **Current Address of Principal Business Office**, verify the principal name and address to which this form should be mailed. Include an attention line, room number, building designation, etc., to facilitate the future handling and processing of this form.

3. For line 5, **Plant Status**, and line 6, **Plant Type,** check the appropriate status and type.

Schedule 2. Plant Configuration

1. Identification information should be a code commonly used by plant management for that equipment (e.g., "2," "A101," "7B," etc.). Select a code for each piece of equipment and use it for that equipment throughout this form. The code should be a maximum of six characters long and should conform to codes reported for the same equipment (especially generators) on other EIA forms. Do not use blanks in the code. Do not enter "NA" for those lines that are not applicable. Organic plants under 100 MW should only complete lines 1, 2, 3, and if applicable, 5 and 6. Planned equipment that is on order and expected to go into commercial service within 5 years must be reported. If two or more pieces of equipment (e.g., two generators) are associated with a single boiler, report each identification code, separated by commas, under the appropriate boiler. Do not change preprinted equipment identification. Copy additional page(s) if necessary to report more boilers.

2. For line 1, using each boiler as a starting point, complete the entire column under the boiler identification with the requested information on each piece of associated existing or planned equipment (e.g., generators, cooling systems, etc.). Report waste-heat boilers with auxiliary firing. Do not report waste-heat boilers without auxiliary firing, or auxiliary house or startup boilers. A waste-heat boiler is a boiler that receives all or a substantial portion of its energy input from the noncombustible exhaust gases of a separate fuel-burning process.

3. For lines 2, 4, 5, 6, 7, and 8, if a piece of equipment (e.g., a generator or a cooling system) serves two or more boilers, repeat the identification information for that equipment under each appropriate boiler.

4. For line 2, **Associated Generator(s)**, do not report auxiliary, house, or emergency generators. Multiple generators operated as a single unit (e.g., cross compound and topping generators) should be identified as a group with one identification code.

5. For line 3, **Generator Associations with Boiler as Actual or Theoretical,** indicate "A" for actual association during year or "T" for theoretical associations.

6. For line 4, **Associated Cooling System(s)**, a cooling system is an equipment system that provides water to the condensers and includes water intakes and outlets, cooling towers and ponds, pumps, and pipes. Identify a single plant cooling system, not separate systems, unless systems are physically separated, e.g., two systems have separate water intake and outlet structures, and each system can be operated independently.

7. For line 5, **Associated Flue Gas Particulate Collector(s)**, if a combination particulate collector is associated with a single boiler, identify the collectors as a single group. If the particulate collector also removes sulfur dioxide, identify the unit in lines 4 and 5 using the same identification code.

8. For line 6, **Associated Flue Gas Desulfurization Units(s)**, for reporting purposes this unit, is considered to include all the trains (or modules) associated with a boiler. If the flue gas desulfurization unit also removes particulate matter, identify the unit in lines 4 and 5 using the same identification code.

9. For line 7, **Associated Stack(s)**, a stack is defined as a tall, vertical structure containing one or more flues used to discharge products of combustion to the atmosphere.

10. For line 8, **Associated Flue(s)**, a flue is defined as an enclosed passageway within a stack for directing products of combustion to the atmosphere. For stacks with multiple flues, report in one column all flues that serve the boiler identified in line 1. Separate multiple entries with commas. If the stack has a single flue, use the stack identification for the flue identification.

Schedule 3. Plant Information, Part A. Annual Byproduct Disposition and Useful Thermal Output

1. If no byproduct was produced, enter "NA" in column (f) for this item. If a byproduct is disposed of at no cost, enter the amount under the appropriate column and make a footnote entry on Schedule 10 of the form stating that no money was exchanged for the quantity indicated. If there was a cost for disposal, make sure there is a corresponding entry on Schedule 3, Part B, for collection and/or disposal costs. Costs for gypsum disposal (line 4) should be reported on Schedule 3, Part B, line 5, column b, with a footnote entry on Schedule 10. Entries on Schedule 3, Part A, "Byproducts Sold," column d, must be compatible with entries on Schedule 3, Section B, lines 11 through 16, "Byproduct Sales Revenue." If the byproduct was distributed in several different ways (for example, the byproduct was placed in a landfill and then later sold), report the end disposition of the byproduct and provide a footnote on Schedule 10 explaining all previous dispositions.

2. For line 6, check the appropriate box to indicate a topping cycle or a bottoming cycle system.

3. For line 7, enter for cogenerators, the total thermal energy (Million Btu) associated with the production of electricity. For a topping cycle, useful thermal output may be estimated by reporting the equivalent heat value (Million Btu) of any steam sent to either industrial or heating processes during the reporting period. For bottoming cycle, useful thermal output may be estimated by calculating the total plant energy consumption (Million Btu) and subtracting the equivalent heat value (Million Btu) of any steam or hot water supplied to the heat recovery boiler for electricity production.

4. For line 8, **How was the Useful Thermal Output used**, check the appropriate box(es).

INSTRUCTIONS

Specific Instructions

Schedule 3. Plant Information, Part B. Financial Information

1. All entries should be reported in thousand dollars to the nearest whole number.

2. For all **Operation and Maintenance (O&M) Expenditures During Year**, costs should be provided for both collection and disposal of the indicated byproducts. If the collection and disposal costs cannot be separated, place the total cost under collection (column a), place an “EN” (estimate not available) under disposal (column b), and a footnote on Schedule 10 indicating that the costs cannot be separated. All operation and maintenance expenditures should exclude depreciation expense, cost of electricity consumed, and fuel differential expense (i.e., extra costs of cleaner, thus more expensive fuel). Include all contract and self-service pollution abatement operation and maintenance expenditures for each line item.

3. For line 1, **Fly Ash**, and line 2**, Bottom Ash**, expenditures cover all material and labor costs including equipment operation and maintenance costs (such as particulate collectors, conveyers, hoppers, etc.) associated with the collection and disposal of ash byproducts.

4. For line 3, **Flue Gas Desulfurization**, expenditures cover all material and labor costs including equipment operation and maintenance costs associated with the collection and disposal of the byproduct. The total for line 3, columns a plus b (Flue Gas Desulfurization Collection and Disposal Costs) should be greater than or equal to the combination of all totals reported on Schedule 8, Part A, line 13 (Flue Gas Desulfurization Operation and Maintenance Expenditures During Year).

5. For line 4, **Water Pollution Abatement**, expenditures cover all operation and maintenance costs for material and/or supplies and labor costs including equipment operation and maintenance (pumps, pipes, settling ponds, monitoring equipment, etc.), chemicals, and contracted disposal costs. Collection costs include any expenditure incurred once the water used at the plant is drawn from its source. Begin calculating expenditures at the point of the water intake. Disposal costs include any expenditures incurred once the water that is used at the plant is discharged. Begin calculating disposal expenditures at the water outlet (i.e., cooling costs).

6. For line 5, **Other Pollution Abatement**, operation and maintenance expenditures are those not allocated to one particular expenditure (e.g., expenditures to operate an environmental protection office or lab). Include expenses for conducting environmental studies for expansion or reduction of operation. Exclude all expenses for health, safety, employee comfort (OSHA), environmental aesthetics, research and development, taxes, fines, permits, legal fees, Superfund taxes, and contributions. Define other pollution abatement(s) in a footnote(s) on Schedule 10.

7. For **Capital Expenditures for New Structures and Equipment During Year, Excluding Land and Interest Expense**, report all pollution abatement capital expenditures for new structures and/or equipment made during the reporting year regardless of the date they may become operational. Lines 7, 8, 9, and 10 should not be left blank. Enter “EN” if an estimate is not available, and “NA” if the item is not applicable. Specify expenditures for these items in a footnote(s) on Schedule 10.

8. For line 7, **Air Pollution Abatement**, report new structures and/or equipment purchased to reduce, monitor, or eliminate airborne pollutants, including particulate matter (dust, smoke, fly ash, dirt, etc.), sulfur dioxides, nitrogen oxides, carbon monoxide, hydrocarbons, odors, and other pollutants. Examples of air pollution abatement structures/equipment include flue gas particulate collectors, flue gas desulfurization units, continuous emissions monitoring equipment (CEMs), and nitrogen oxide control devices. Specify new structures/equipment in a footnote on Schedule 10.

9. For line 8, **Water Pollution Abatement**, report new structures and or equipment purchased to reduce, monitor, or eliminate waterborne pollutants, including chlorine, phosphates, acids, bases, hydrocarbons, sewage, and other pollutants. Examples include structures/equipment used to treat thermal pollution; cooling, boiler, and cooling tower blowdown water; coal pile runoff; and fly ash waste water. Water pollution abatement excludes expenditures for treatment of water prior to use at the plant. Specify new structures/equipment in a footnote on Schedule 10.

10. For line 9, **Solid/Contained Waste**, report new structures/equipment purchased to collect and dispose of objectionable solids or contained liquids. Examples include purchases of storage facilities, trucks, etc., to collect, store, and dispose of solid/contained waste. Include equipment used for handling solid/contained waste generated as a result of air and water pollution abatement. Specify new structures/equipment in a footnote on Schedule 10.

11. For line 10, **Other Pollution Abatement**, report amortizable expenses and purchases of new structures and or equipment when such purchases are not allocated to a particular unit or item. Examples include charges for the purchases of facilities to control hazardous waste, radiation, and noise pollution. Exclude all equipment purchased for aesthetics purposes. Specify new structures/equipment in a footnote on Schedule 10.

12. If **Byproduct Sales Revenue During Year** items are not applicable, place an “NA” in line 16 only. Report under **Byproduct Sales Revenue** the revenue, if any, for each listed byproduct. Specify “other” revenue in a footnote on Schedule 10. Entries must be compatible with the entries on Schedule 3, Part A, column (d), sold. If the revenue for a byproduct is less than $1,000, leave the item blank and make a footnote entry on Schedule 10. Revenue for gypsum should be reported on Schedule 3, Part B, line 14, with a footnote entry on Schedule 10. Report the total revenue for the sale of byproducts on line 16. If the revenue reported was for the sale of stockpiled byproducts from previous years, make a footnote entry on Schedule 10.

Schedule 4. Boiler Information, Part A. Fuel Consumption and Quality

1. For each **Boiler ID** fill in the information by fuel code. If necessary, copy and attach additional sheets. If a plant uses fuel for reheaters or other fuel combustion devices where the exhaust gases exit the same stack as a main boiler(s), then report this separate fuel consumption under a fictitious (proxy) boiler(s). Report a proxy boiler for each stack where exhaust gases exit. These boilers are to be identified as FB1, FB2, etc. Complete Schedule 4A for each proxy boiler and include an entry on Schedule 2 showing the boiler(s) and the stack(s) used.

2. If a common fuel feeder serves a group of boilers, so that individual boiler fuel consumption is not metered, estimate individual boiler fuel consumption.

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INSTRUCTIONS

Specific Instructions

Schedule 4. Boiler Information, Part A. Fuel Consumption and Quality (Continued)

3. For line 1, **Boiler Status**, select from the following equipment status codes:

CN	Cancelled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve, i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated. Usually requires 3 to 6 months to reactivate
TS	Operating under test conditions (not in commercial service)

4. For line 1, **Hours Under Load During Year**, enter hours the boiler has operated to drive the generator producing electricity.

5. For lines 2 through 29, columns a and f, **Fuel Code**, select a fuel code from the following list of energy sources:

Energy Source Code	Energy Source Description
BIT	Anthracite Coal, Bituminous Coal
LIG	Lignite
SUB	Subbituminous Coal
WC	Waste/Other Coal (Anthracite Culm, Bituminous Gob, Fine Coal, Lignite Waste, Waste Coal)
SC	Coal-based Synfuel (includes briquettes, pellets, or extrusions formed by binding materials and processes that recycle material)
DFO	Distillate Fuel Oil (includes all Diesel, and No. 1, No. 2, and No. 4 Fuel Oils)
JF	Jet Fuel
KER	Kerosene
RFO	Residual Fuel Oil (includes No. 5 and No. 6 Fuel Oils and Bunker C Fuel Oil)
WO	Other Oil and Waste Oil [Butane (Liquid), Crude Oil, Liquid Byproducts, Oil Waste, Propane (Liquid), Re-Refined Motor Oil, Sludge Oil, Tar Oil]
PC	Petroleum Coke
NG	Natural Gas
BFG	Blast-Furnace Gas
OG	Other Gas (Butane, Coal Process, Coke-Oven, Refinery, and other processes)
PG	Propane
AB	Agriculture Crop Byproducts/Straw/Energy Crops
BLQ	Black Liquor
LFG	Landfill Gas
MSW	Municipal Solid Waste
OBS	Other Biomass Solids (Animal Manure and Waste, Solid Byproducts, and other solid biomass not specified)
OBL	Other Biomass Liquids (Ethanol, Fish Oil, Liquid Acetonitrile Waste, Tall Oil, Waste Alcohol, and other biomass liquids not specified)
OBG	Other Biomass Gases (Digester Gas, Methane, and other biomass gases)
OTH	Other (Batteries, Chemicals, Coke Breeze, Hydrogen, Pitch, Sulfur, Tar Coal, and miscellaneous technologies)
PUR	Purchased Steam
SLW	Sludge Waste
TDF	Tires
WDS	Wood/Wood Waste Solids (Paper Pellets, Railroad Ties, Utility Poles, Wood Chips, and Other Wood Solids)
WDL	Wood Waste Liquids (Red Liquor, Sludge Wood, Spent Sulfite Liquor, and other wood-related liquids not specified)

To report more than four fuel types used during a calendar month, copy the page.

6. For lines 2 though 25, columns b and g, **Quantity**, enter amount of fuel consumed for electric power generation and thermal energy associated with the production of electricity. Include all fuel used in a cogeneration system, such as used for processed steam, direct heating, space heating, or thermal output delivered to other end users. Report the fuel codes BIT, LIG, SUB, WC, and PC to the nearest thousand tons. Report the fuel codes DFO, JF, KER, RFO, and WO in thousand barrels. Report the fuel code NG in thousand cubic feet. For all other fuel codes report solids in thousand tons, liquids in thousand barrels, and gases in thousand cubic feet. If you cannot report your fuel using the above units of measure, specify in a footnote on Schedule 10.

7. For lines 2 though 25, columns c and h, **Heat Content**, report the heat content of the fuels burned in Btu. The heat content of the fuel should be reported as the gross or higher heating value (rather than the net or lower heating value). The higher heating value exceeds the lower heating value by the latent heat of vaporization of the water. The heating value of fuels generally used and reported in a fuel analysis, unless otherwise specified, is the higher heating value. If the fuel heat content cannot be reported, "as burned," data may be obtained from the fuel supplier on an "as received" basis. If this is the case, indicate in a footnote on Schedule 10 that the fuel heat content data are "as received." Report the value in the following units: solids in Btu per pound; liquids in Btu per gallon; and gases in Btu per cubic foot.

8. For lines 2 through 25, **Sulfur Content** and **Ash Content**, columns d and e, i and j, report content to nearest 0.01 percent for sulfur and the nearest 0.1 percent for ash.

INSTRUCTIONS

Specific Instructions

Schedule 4. Boiler Information, Part A. Fuel Consumption and Quality (Continued)

9. For lines 26 through 29, columns a and b, enter the fuel code and the summed quantity of fuel consumed in the year for each of the fuel codes reported in lines 2 through 25.

10. For line 30, **Sampling Procedure**, select one of these methods: proximate; ultimate; continuous drip method; gas chromatography; or other. If you select other please specify in a footnote on Section 10.

11. For line 31, **Method of Analysis**, indicate the predominant method for determining the properties reported for the boiler. Report ASTM codes for the boiler method of analysis.

12. For line 32, **Laboratory Performing Analysis**, identify the laboratory most frequently used to analyze the primary fuel for the boiler. If the plant's operating company performed the analysis, indicate "internal."

Schedule 4. Boiler Information, Part B. Air Emissions Standards

1. Complete a separate page for each existing or planned boiler.

2. For line 2, **Type of Boiler Standards Under Which The Boiler Is Operating,** indicate the standards as described in the U.S. Environmental Protection Agency regulation under 40 CFR. Select from the following codes of the New Source Performance Standards (NSPS):
   - D — Subpart D are Standards of Performance for fossil-fuel fired steam boilers for which construction began after August 17, 1971.
   - Da — Subpart Da are Standards of Performance for fossil-fuel fired steam boilers for which construction began after September 18, 1978.
   - Db — Subpart Db are Standards of Performance for fossil-fuel fired steam boilers for which construction began after June 19, 1984.
   - Dc — Subpart Dc are Standards of Performance for small industrial-commercial-institutional steam generating units.
   - N — Not covered under New Source Performance Standards.

3. For line 3, **Type of Statute or Regulation,** select from the following the most stringent type of statute or regulation code:
   - FD — Federal
   - ST — State
   - LO — Local

4. If there is no standard for nitrogen oxide emissions, report "NA" for line 3, column c, and skip the remaining column c items.

5. Line 4, **Emission Standard Specified**, refers to the numeric value for the unit of measurement in line 5. If no numeric value is specified, report "NA." For Sulfur Dioxide (column b), if the standard requires both an emission rate and a percent scrubbed, report both standards separated by a slash (e.g., 1.2/90 for emission standards specified in line 4, column b, and DP/SR for units of measurement in line 5, column b), and indicate in a footnote on Schedule 10.

6. For line 5, **Unit of Measurement Specified**, column a, Particulate Matter, select from the following unit of measurement codes (PB* is the preferred measurement):
   - OP — Percent of opacity
   - PB* — Pounds of particulate matter per million Btu in fuel
   - PC — Grains of particulate matter per standard cubic foot of stack gas
   - PG — Pounds of particulate matter per thousand pounds of stack gas
   - PH — Pounds of particulate matter emitted per hour
   - UG — Micrograms of particulate matter per cubic meter
   - OT — Other (specify in a footnote on Schedule 10)

7. For line 5, **Unit of Measurement Specified**, column b, Sulfur Dioxide, select from the following unit of measurement codes (DP* is the preferred measurement):
   - DC — Ambient air quality concentration of sulfur dioxide (parts per million)
   - DH — Pounds of sulfur dioxide emitted per hour
   - DL — Annual sulfur dioxide emission level less than a level in a previous year
   - DM — Parts per million of sulfur dioxide in stack gas
   - DP* — Pounds of sulfur dioxide per million Btu in fuel
   - SB — Pounds of sulfur per million Btu in fuel
   - SR — Percent sulfur removal efficiency (by weight)
   - SU — Percent sulfur content of fuel (by weight)
   - OT — Other (specify in a footnote on Schedule 10)

8. For line 5, **Unit of Measurement Specified**, column c, Nitrogen Oxides, select from the following unit of measurement codes (NP* is the preferred measurement):
   - NH — Pounds of nitrogen oxides emitted per hour
   - NL — Annual nitrogen oxides emission level less than a level in a previous year
   - NM — Parts per million of nitrogen oxides in stack gas
   - NO — Ambient air quality concentration of nitrogen oxides (parts per million)
   - NP* — Pounds of nitrogen oxides per million Btu in fuel
   - OT — Other (specify in a footnote on Schedule 10)

INSTRUCTIONS

Specific Instructions

Schedule 4. Boiler Information, Part B. Air Emissions Standards (Continued)

9. For line 6, **Time Period Specified**, select from the following codes to indicate the period over which measurements were averaged:

NV	Never to exceed
FM	5 minutes
SM	6 minutes
FT	15 minutes
OH	l hour
WO	2 hours
TH	3 hours
EH	8 hours
DA	24 hours
WA	Weekly average
MO	30 days
ND	90 days
YR	Annual
PS	Periodic stack testing
DT	Defined by testing
NS	Not specified
OT	Other (specify in a footnote on Schedule 10)

10. For line 7, **Year Boiler Was or Is Expected to Be in Compliance**, if the boiler is currently in compliance, enter the year the boiler came into compliance or the year of the regulation, whichever came last. Report “9999” only if a revision of a governing regulation is being sought or no plans have been approved to bring the boiler into compliance.

11. For line 8, **If Not in Compliance, Strategy for Compliance**, column c, select from the following strategy for compliance codes (separate multiple entries (up to three) with commas):

BO	Burner out of service
FR	Flue gas recirculation
LA	Low excess air
LN	Low nitrogen oxide burner
MS	Currently meeting standard
NC	No plans to control
OV	Over-fire air
SE	Seeking revision of governing regulation
OT	Other (specify in a footnote on Schedule 10)

12. For line 9, **Existing,** and line 10, **Planned, Strategies to Meet the Sulfur Dioxide Requirements of Title IV of the Clean Air Act Amendment of 1990**, column b, select from the following strategy for compliance codes (separate multiple entries (up to three) with commas):

CU	Control unit under Phase I extension plan
IF	Install flue gas desulfurization unit (other than Phase I extension plan)
NC	No change in historic operation of unit anticipated
ND	Not determined at this time
RP	Re-power Unit
SS	Switch to lower sulfur fuel
SU	Designate Phase II unit(s) as substitution unit(s)
TU	Transfer unit under Phase I extension plan
UC	Decrease utilization - designate Phase II unit(s) as compensating unit(s)
UE	Decrease utilization - rely on energy conservation and/or improved efficiency
US	Decrease utilization - designate sulfur-free generators to compensate
UP	Decrease utilization - purchase power
WA	Allocated allowances and/or purchase allowances
OT	Other (specify in a footnote on Schedule 10)

INSTRUCTIONS

Specific Instructions

Schedule 4. Boiler Information, Part C. Design Parameters

1. Complete a separate page for each existing or planned boiler. If a procurement contract has been signed for an upgrade or retrofit of a boiler: 1) complete a separate page for the existing boiler; 2) explain on Schedule 10 (footnotes) how long the existing equipment will be out of service; and 3) using the same boiler identification, complete a separate Schedule 4 Part C for the planned upgrade or retrofit.

2. For line 2, **Boiler Actual or Projected Inservice Date**, and line 3, **Boiler Actual or Projected Retirement Date**, the month-year date should be entered as follows: August 1959 as 8-1959. If the month is unknown, enter a 6 before the year (representing June).

3. For line 4, **Boiler Manufacturer**, select one code from the following boiler manufacturers' codes:

AI	Aalborg Industries
AL	Alstrom
AS	American Shack
AT	Applied Thermal Systems
BR	BROS
BW	Babcock and Wilcox
CE	Combustion Engineering
DJ	De Jong Coen b v
DL	Deltak
DS	Doosan
EC	Econotherm
ER	Erie City Iron Works
FW	Foster Wheeler
GE	General Electric
GT	Gotaverken
HT	Hitachi
ID	Indeck
IN	Innovative Steam Technology
KL	Keeler Dorr Oliver
KP	Kvaerner Pulping
KW	Kawaskit Heavy Industries
NT	Nooter/Erickson
PB	Peabody
PR	Pyro Power
RS	Riley Stoker
ST	Sterling
TM	Tampella
TS	Toshiba
VO	Vogt Machine Company
WE	Westinghouse
WG	Wiegl Engineering
WI	Wickes
ZN	Zurn
OT	Other (specify in a footnote on Schedule 10)

4. For line 5, **Type of Firing Used with Primary Fuels**, select from the following firing codes [separate multiple entries (up to three) with commas]:

Firing Code	**Firing Type Description**
Arch firing	AF
Concentric firing	CF
Cyclone firing	CY
Duct burner	DB
Fluidized bed firing	FB
Front firing	FF
Opposed firing	OF
Rear firing	RF
Side firing	SF
Spreader stoker	SS
Tangential firing	TF
Vertical firing (burners mounted on furnace ceiling)	VF
Other (specify in a footnote on Schedule 10)	OT

5. For lines 7 through 10, enter firing rate data for primary or alternate fuels as entered in lines 12 and 18. Do not enter firing rate for startup or flame stabilization fuels. For waste-heat boilers with auxiliary firing, enter the firing rate for auxiliary firing and complete line 11 for waste heat.

6. For line 11, a waste-heat boiler is a boiler that receives all or a substantial portion of its energy input from the noncombustible exhaust gases of a separate fuel-burning process.

INSTRUCTIONS

Specific Instructions

Schedule 4. Boiler Information, Part C. Design Parameters (Continued)

7. For line 12, **Primary Fuels Used**, see the instructions for Schedule 4, Part A, line 3, for a list of fuel codes. Show design firing rates for each fuel in the associated lines 7, 8, 9, and 10. Do not include startup fuels. Predominance is based on Btu.

8. For line 15, **Total Air Flow**, report at standard temperature and pressure, i.e., 68 degrees Fahrenheit and one atmosphere pressure.

9. For line 16, **Wet or Dry Bottom**, enter “W” for Wet or “D” for Dry. **Wet Bottom** is defined as slag tanks that are installed at furnace throat to contain and remove molten ash from the furnace. **Dry Bottom** is defined as no slag tanks at furnace throat area; throat area is clear; bottom ash drops through throat to bottom ash water hoppers. This design is used where the ash melting temperature is greater than the temperature on the furnace wall, allowing for relatively dry furnace wall conditions.

10. For line 18, **Alternate Fuels Boiler is Equipped to Burn**, see the instructions for Schedule 4, Part A, line 3, for a list of fuel codes.

11. For line 19, **Year Alternate Fuel Last Burned**, enter latest year in which any alternate fuel was burned.

12. For line 20, **Number of Days Required to Switch**, the number of days reported should be the number of days required to refurbish, repair, or replace equipment necessary to burn any alternate fuel. Assume no environmental restrictions.

Schedule 4. Boiler Information, Part D. Nitrogen Oxide Emission Controls

1. Complete a separate page for each existing or planned boiler.

2. For line 2, **Nitrogen Oxide Control Status**, select from the following status codes:

CN	Cancelled (previously reported as “planned”)
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
OZ	Operated during the ozone season (May through September)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve); i.e., not normally used, but available for service
SC	Cold Standby (Reserve); deactivated (usually requires 3 to 6 months to reactivate)
TS	Operating under test conditions (not in commercial service)

3. For line 4, **Low Nitrogen Oxide Control Process**, select from the following low nitrogen oxide control processes [separate multiple entries (up to three) with commas]:

AA	Advanced Overfire Air
BF	Biased Firing (alternate burners)
CF	Fluidized Bed Combustor
FR	Flue Gas Recirculation
FU	Fuel Reburning
LA	Low Excess Air
LN	Low NOx Burner
NA	Not Applicable
OV	Overfire Air
SC	Slagging
SN	Selective Noncatalytic Reduction
SR	Selective Catalytic Reduction
OT	Other (specify in a footnote on Schedule 10)

INSTRUCTIONS

Specific Instructions

4. For line 5, **Manufacturer of Low Nitrogen Oxide Control Burners**, select from the following low nitrogen oxide control burner manufacturers:

AB	Advanced Burner Technologies
AC	Advanced Combustion Technology
AL	Alstom
AT	Applied Thermal Systems
AU	Applied Utility Systems (AUS)
AZ	Alzeta
BC	Babcock Borsig Power
BM	Bloom
BW	Babcock and Wilcox
CE	Combustion Engineering
CM	Combustion Components Associates Inc
CN	Coen
DB	Deutsche-Babcock
DD	Damper Design Inc
DQ	Duquense Light Company & Energy Systems Associates
DV	Davis
EA	Eagle Air
EG	Energy and Environmental Research Corp (EER)
EL	Electric Power Technologies
EP	EPRI
ET	Entropy Technology and Environmental Construction Corp (ETEC)
FB	Faber
FN	Forney
FT	Fuel Tech Inc
FW	Foster Wheeler
GR	GE Energy and Environmental Research Corp (GEEER)
HL	Holman
IC	International Combustion Limited
ID	Indeck
IH	in house
JZ	John Zink Todd Combustion
KL	Keeler Dorr Oliver
MB	Mitsui-Babcock
MI	Mitsubishi Industries
MT	Mobotec
NA	Not Applicable
NB	Nebraska Boiler Company
NC	Natcom, Inc
NE	NEI
NL	Noell, Inc
PA	Procedair
PB	Peabody
PL	Pillard
PS	Peerless Manufacturing Company
PX	Phoenix Combustion
RD	Rodenhuis and Verloop
RJ	RJM
RR	Rolls Royce
RS	Riley Stoker
RV	RV Industries
SW	Siemens-Westinghouse
TM	Tampella
TS	Toshiba
WG	Weigel Engineering
ZC	Zeeco
OT	Other (specify in a footnote on Schedule 10)

5. For line 6, **For Entire Year**, enter the controlled nitrogen oxide emission rate, in pounds per million Btu of the fuel, based on data from continuous emission monitors (CEMs) where possible. Where CEMs data are not available, report controlled nitrogen oxide emission rate based on the method used to report emissions data to environmental authorities.

6. For line 7, **For May through September Only,** enter the controlled nitrogen oxide emission rate, in pounds per million Btu of the fuel, based on data from continuous emission monitors (CEMs) where possible. Where CEMs data are not available, report controlled nitrogen oxide rates based on the method used to report emissions data to environmental authorities. The summer emission rate may be assumed to be equivalent to the annual emission rate where identical nitrogen oxide controls are used year round.

INSTRUCTIONS

Specific Instructions

Schedule 4. Boiler Information, Part E. Mercury Emission Controls

1. For line 1, **Does Your Facility have Mercury Emission Controls,** check "Yes" or "No" to indicate whether your facility has mercury emission controls.

2. For line 2, **Describe the Type of Controls,** if "Yes" is checked on line 1, describe the type of controls.

Schedule 5. Generator Information

1. For line 1, **Generator ID**, complete a column for each existing, under construction, or planned generator. The identification must be the same as on Schedule 2, item 2.

2. For line 2**, Maximum Generator Nameplate Rating**, report the maximum generator nameplate rating in megawatts. If the nameplate rating is expressed in kilovoltamperes, convert to kilowatts by multiplying the power factor by the kilovoltamperes, then convert kilowatts to megawatts. If more than one rating appears on the nameplate, select the highest rating. Do not indicate the nameplate rating of the turbine.

3. For line 3**, Design Flow Rate**, and line 4, **Design Temperature Rise**, the data for both items should be under the same operating conditions.

4. For line 3**, Design Flow Rate**, if more than one condenser serves the generator, report the total flow rate for all the condensers.

5. For line 4, **Design Temperature Rise**, if more than one condenser serves the generator, report the weighted average (by flow rate) temperature rise for all the condensers.

6. For lines 5 through 16, **Monthly Net Electrical Generation,** is the total amount of electric energy generated, measured at the generator terminals, minus the total electric energy consumed at the generating station for the time period indicated. If the monthly service load exceeded monthly gross electrical generation, report negative electrical generation with a minus sign. Do not use parentheses. Report in megawatthours only. If no generation occurred, place a zero (0) in line 17 only.

Schedule 6. Cooling System Information, Part A. Annual Operations

1. If actual data are not available, provide an estimated value.

2. If the source of cooling water is a wells or municipal water systems, do not complete lines 7 through 10.

3. For line 2, **Cooling System Status**, select from the following equipment status codes:

CN	Cancelled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve); i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated (usually requires 3 to 6 months to reactivate)
TS	Operating under test conditions (not in commercial service)

4. For line 2, if the code selected is "OP," complete lines 3 through 10; otherwise do not complete these lines.

5. For line 3**, Annual Amount of Chlorine Added to Cooling Water**, pertains solely to elemental chlorine. If a compound is used, determine the amount of chlorine in the compound. If the amount of chlorine added to the cooling water is known for the entire plant but not for each cooling system, enter the information in column (a), enter "EN" in the rest of the columns as necessary, and indicate in a footnote on Schedule 10 that the information is for the entire plant. Report amount of chlorine to the nearest whole number.

6. For line 5, **Discharge**, if the system is a closed, zero discharge system, report "0," complete lines 6, 7, and 8, but skip lines 9 and 10.

7. For lines 4, 5, and 6, if the **Average Annual Rate of Cooling Water** is known for the entire plant but not for each cooling system, enter the information in line 6, column (a), enter "EN" in the rest of the columns as necessary, and indicate in a footnote on Schedule 10 that the information is for the entire plant.

8. For lines 7, 8, 9, and 10, the "Peak Load Month" refers to the month of greatest plant electrical generation during the winter heating season (October-March) and summer cooling season (April-September), respectively. Report temperature to the nearest whole number.

INSTRUCTIONS

Specific Instructions

Schedule 6. Cooling System Information, Part B. Design Parameters

1. If a procurement contract has been signed for an upgrade or retrofit of a cooling system: 1) complete a separate page for the existing cooling system; 2) explain on Schedule 10 (footnotes) how long the existing equipment will be out of service; and 3) using the same cooling system identification, complete a separate Schedule 6, Part B, for the planned upgrade or retrofit.

2. For line 3, **Type of Cooling System**, select from the following cooling system codes [separate multiple entries (up to four) with commas]:

OC	Once through with cooling pond(s) or canal(s)
OF	Once through, fresh water
OS	Once through, saline water
RC	Recirculating with cooling pond(s) or canal(s)
RF	Recirculating with forced draft cooling tower(s)
RI	Recirculating with induced draft cooling tower(s)
RN	Recirculating with natural draft cooling tower(s)
OT	Other (specify in a footnote on Schedule 10)

3. For line 4, **Source of Cooling Water**, and line 5, **Design Cooling Water Flow Rate**, if more than one source of water is used by a cooling system, enter other sources in a footnote on Schedule 10. If water is purchased, report "municipal." If water is from wells, report "wells." If source of water is "municipal" or "wells," do not complete lines 18, 19, 20, and 21 and provide the total amount of water used at 100 percent load in line 5. Give the name of river, lake, etc.

4. For lines 7, 8, and 9, a cooling pond is a natural or man-made body of water that is used for dissipating waste heat from power plants.

5. For line 11, **Type of Towers**, select from the following cooling tower codes [separate multiple entries (up to two) with commas]:

MD	Mechanical draft, dry process
MW	Mechanical draft, wet process
ND	Natural draft, dry process
NW	Natural draft, wet process
WD	Combination wet and dry processes

6. For lines 14, 15, 16, and 17, enter the actual installed cost for the existing system or the anticipated cost to bring a planned system into commercial operation. Installed cost should include the cost of all major modifications. A major modification is any physical change which results in a change in the amount of air or water pollutants or which results in a different pollutant being emitted.

7. For line 14, **Total System**, the cost should include amounts for items such as pumps, piping, canals, ducts, intake and outlet structures, dams and dikes, reservoirs, cooling towers, and appurtenant equipment. The cost of condensers should not be included.

8. For lines 18 through 21, if the cooling system is a zero discharge type (RC, RF, RI, RN), do not complete column b. The intake and the outlet are the points where the cooling system meets the source of cooling water found on line 4.

Schedule 7. Flue Gas Particulate Collector Information

1. For line 3, **Flue Gas Particulate Collector Status**, select from the following equipment status codes:

CN	Cancelled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve); i.e., not normally used, but available for service
SC	Cold Standby (Reserve); deactivated (usually requires 3 to 6 months to reactivate)
TS	Operating under test conditions (not in commercial service)

2. For line 4, **Type of Flue Gas Particulate Collector**, select from the following flue gas particulate collector codes [for combination units, separate multiple entries (up to three) with commas]:

BS	Baghouse, shake and deflate
BP	Baghouse, pulse
BR	Baghouse, reverse air
EC	Electrostatic precipitator, cold side, with flue gas conditioning
EH	Electrostatic precipitator, hot side, with flue gas conditioning
EK	Electrostatic precipitator, cold side, without flue gas conditioning
EW	Electrostatic precipitator, hot side, without flue gas conditioning
MC	Multiple cyclone
SC	Single cyclone
WS	Wet scrubber
OT	Other (specify in a footnote on Schedule 10 of the form).

INSTRUCTIONS

Specific Instructions

Schedule 7. Flue Gas Particulate Collector Information (Continued)

3. For line 5, **Installed Cost of Flue Gas Particulate Collector Excluding Land**, enter the actual installed cost for the existing system or the anticipated cost to bring a planned system into commercial operation. Installed cost should include the cost of all major modifications. A major modification is any physical change which results in a change in the amount of air or water pollutants or which results in a different pollutant being emitted.

4. For line 7, **Typical Particulate Emissions Rate at Annual Operating Rate,** enter the particulate emission rate based on the annual operating factor (to nearest 0.01 pound per million Btu).

5. For lines 8 and 9, if the collector has a combination of components (i.e., a baghouse and an electrostatic precipitator) enter both components as one unit in one column. If the particulate collector also removes sulfur dioxide, enter the particulate scrubbing process in this section and the desulfurization process on Schedule 8, Part A.

6. For line 8, **At Annual Operating Factor**, enter removal efficiency based on the annual operating factor. Annual operating factor is defined as annual fuel consumption divided by the product of design firing rate and hours of operation per year. If actual data are unavailable, provide estimates based on equipment design performance specifications.

7. For line 9, **At 100 Percent Load or Tested Efficiency**, if the test was conducted, but not at 100 percent load, enter the efficiency on Schedule 7 and provide the load at which the test was conducted in a footnote on Schedule 10.

8. For lines 11,12, 13, and 14, enter value for fuel. Enter range of values, if applicable.

Schedule 8. Flue Gas Desulfurization Unit Information, Part A. Annual Operations

1. For line 2**, Flue Gas Desulfurization Unit Status**, select from the following equipment status codes:

CN	Cancelled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve); i.e., not normally used, but available for service
SC	Cold Standby (Reserve); deactivated (usually requires 3 to 6 months to reactivate)
TS	Operating under test conditions (not in commercial service)

   If the code selected is "OP" complete lines 3 through 13, otherwise do not complete these lines.

2. For line 3, **Hours In-Service During Year**, enter the total number of hours one or more trains were in operation; do not report for individual trains.

3. For lines 6 and 7, if the flue gas desulfurization unit also removes particulate matter, enter the desulfurization process in this section and the particulate scrubbing process on Schedule 7, **Flue Gas Particulate Collector Information**.

4. For line 6, **At Annual Operating Factor,** enter removal efficiency based on the annual operating factor. Annual operating factor is defined as annual fuel consumption divided by the product of design firing rate and hours of operation per year. If actual data are unavailable, provide estimates based on equipment design performance specifications.

5. For line 7, **At 100 Percent Load or Tested Efficiency,** if the test was conducted, but not at 100 percent load, enter the efficiency on Schedule 8, Part A, and provide the load at which the test was conducted in a footnote on Schedule 10.

6. For lines 9, 10, 11, 12, and 13 enter expenditures to the nearest whole number. **Flue Gas Desulfurization Operation and Maintenance Expenditures** should include the costs of continuous emissions monitoring, raw and byproduct material handling, limestone milling and storage, dewatering facilities, contracted labor, and all other auxiliary flue gas desulfurization support facilities excluding depreciation expense and cost of electricity. These costs should also be included in line 3, Schedule 3, Part B.

Schedule 8. Flue Gas Desulfurization Unit Information, Part B. Design Parameters

1. If a procurement contract has been signed for an upgrade or retrofit of a Flue Gas Desulfurization Unit: 1) complete a separate page for the existing unit; 2) explain on Schedule 10 (footnotes) how long the existing equipment will be out of service; and 3) using the same FGD identification, complete a separate Schedule 8B for the planned upgrade or retrofit.

2. For line 3, **Type of Flue Gas Desulfurization Unit**, select from the following FGD unit codes [for combination units, separate multiple entries (up to four) with commas]:

BR	Jet Bubbling Reactor
CD	Circulating Dry Scrubber
MA	Mechanically aided type
PA	Packed type
SD	Spray dryer type
SP	Spray type
TR	Tray type
VE	Venturi type

INSTRUCTIONS

Specific Instructions

Schedule 8. Flue Gas Desulfurization Unit Information, Part B. Design Parameters (Continued)

3. For line 4, **Type of Sorbent**, select from the following sorbent codes [separate multiple entries (up to four) with commas]:

AF	Alkaline fly ash
CC	Calcium carbide slurry
DB	Dibasic acid
DL	Dolomitic limestone
LA	Lime and alkaline fly ash
LF	Limestone and alkaline fly ash
LI	Lime
LS	Limestone
MO	Magnesium oxide
SA	Soda ash
SC	Sodium carbonate
SL	Soda liquor
SS	Sodium sulfite
OT	Other (specify in a footnote on Schedule 10)

4. For line 6, **Flue Gas Desulfurization Unit Manufacturer**, select one code from the following flue gas desulfurization unit manufacturer codes:

AM	American Air Filter
BW	Babcock and Wilcox
CC	Chemico
CE	Combustion Engineering
CO	Combustion Equipment
DM	Davey McKee
EE	Environmental Engineering
FL	Flakt Inc
FM	FMC
GE	General Electric
JO	Joy Manufacturing
KE	M W Kellogg
KR	Krebs Engineers
MI	Mitsubishi Industry
PB	Peabody
RC	Research Cottrell
RS	Riley Stoker
TH	Thyssen/CEA
UO	Universal Oil Products
OT	Other (specify in a footnote on Schedule 10)

5. For line 15, **Removal Efficiency for Sulfur Dioxide**, report the removal efficiency as the percent by weight of gases removed from the flue gas.

6. For lines 20, 21, 22, and 23, enter the actual installed costs for the existing systems or the anticipated costs to bring a planned system into commercial operation. Installed cost should include the cost of all major modifications. A major modification is any physical change which results in a change in the amount of air or water pollutants or which results in a different pollutant being emitted. The total will be the sum of lines 20, 21, and 22, which includes any other costs pertaining to the installation of the unit.

Schedule 9. Stack and Flue Information—Design Parameters

1. If a procurement contract has been signed for an upgrade or retrofit of a stack or flue: 1) complete a page for the existing stack or flue; 2) explain on Schedule 10 (footnotes) how long the existing structure will be out of service; and 3) using the same flue and stack identifications, complete a separate Schedule 9, Part B for the planned upgrade or retrofit.

2. For line 1, **Flue ID**, and line 2**, Stack ID**, there must be an entry. If there is only one flue, use the stack ID also as the flue ID. Identification codes must be the same as reported on Schedule 2.

3. For line 3, **Stack (or Flue) Actual or Projected In-Service Date of Commercial Operation**, the month-year should be entered as follows: August 1959 as 08-1959.

4. For line 4, **Status of Stack**, select one from the following equipment status codes:

CN	Cancelled (previously reported as “planned”)
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve, i.e., not normally used, but available for service)
SC	Cold standby (Reserve); deactivated. Usually requires 3 to 6 months to reactivate
TS	Operating under test conditions (not in commercial service)

INSTRUCTIONS

Specific Instructions

Schedule 9. Stack and Flue Information—Design Parameters (Continued)

5. For lines 7 and 8, rate should be approximately equal to cross-sectional area multiplied by the velocity, multiplied by 60.

6. For lines 13 and 14, seasonal average flue gas exit temperatures should be reported in degrees Fahrenheit, based on the arithmetic mean of measurements during operating hours. Summer season includes June, July, and August. Winter season includes January, February, and December.

7. For line 15, **Source**, enter "M" for measured or "E" for estimated.

8. For lines 16 and 17, **Stack Location**, enter the latitude and longitude in degrees, minutes, and seconds.

Schedule 10. Footnotes

The footnote reference can only refer to one page, one schedule and part, one sheet, and one line number and column letter. If the footnote is the same for multiple references, indicate this in the comment section. If the comment exceeds one line, repeat the page, schedule, part, line, and column identification. If "OT" is used instead of a specific code, please explain what it represents. Note preprinted text in comment section. Do not white-out footnotes. Show any changes to footnotes by drawing a line through the preprinted information. Do not hand write a preprinted footnote again as this could result in a duplication.

REPORTING BURDEN

Public reporting burden for this collection of information is estimated to average 78.0 hours per response for plants greater than or equal to 100 megawatts and 4.0 hours for plants 10 megawatts or greater but less than 100 megawatts. These estimates include the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Energy Information Administration, Statistics and Methods Group, EI-70, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585-0670; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. A person is not required to respond to the collection of information unless the form displays a valid OMB number.

GLOSSARY

Air Pollution Abatement Equipment: Equipment used to reduce or eliminate airborne pollutants, including particulate matter (dust, smoke, fly, ash, dirt, etc.), sulfur oxides, nitrogen oxides (NOx), carbon monoxide, hydrocarbons, odors, and other pollutants. Examples of air pollution abatement structures and equipment include flue-gas particulate collectors, flue-gas desulfurization units and nitrogen oxide control devices.

Alternate Fuel: Those fuels, that the boiler is capable of burning, but are not normally used.

Annual Operating Factor: The annual fuel consumption divided by the product of design firing rate and hours of operation per year.

Bottom Ash: Residue mainly from the coal burning process that falls to the bottom of the boiler for removal and disposal.

Bottoming Cycle: A waste-heat recovery boiler recaptures the unused energy and uses it to produce steam to drive a steam turbine generator to produce electricity.

Coal: A readily combustible black or brownish-black rock whose composition, including inherent moisture, consists of more than 50 percent by weight and more than 70 percent by volume of carbonaceous material. It is formed from plant remains that have been compacted, hardened, chemically altered, and metamorphosed by heat and pressure over geologic time.

Cooling Pond: A natural or man made body of water that is used for dissipating waste heat from power plants.

Cooling System: An equipment system that provides water to the condensers and includes water intakes and outlets; cooling towers; and ponds, pumps, and pipes.

Dry Bottom Boiler: No slag tanks at furnace throat area. The throat area is clear. Bottom ash drops through the throat to the bottom ash water hoppers. This design is used where the ash melting temperature is greater than the temperature on the furnace wall, allowing for relatively dry furnace wall conditions.

FGD Sludge: Solid wastes from flue gas cleaning systems composed of sulfur salts of calcium together with varying amounts of calcium carbonate ($CaCO_3$) and unreacted lime (CaO).

Flue: An enclosed passageway for directing products of combustion to the atmosphere.

Flue Gas Desulfurization Unit (Scrubber): Equipment used to remove sulfur oxides from the combustion gases of a boiler plant before discharge to the atmosphere. Chemicals such as lime are used as the scrubbing media.

Flue Gas Particulate Collector: Equipment used to remove fly ash from the combustion gases of a boiler plant before discharge to the atmosphere. Particulate collectors include electrostatic precipitators, mechanical collectors (cyclones), fabric filters (baghouses), and wet scrubbers.

Fly Ash: Particulate matter mainly from coal ash in which the particle diameter is less than 1×10^{-4} meter. This ash is removed from the flue gas using flue gas particulate collectors such as fabric filters and electrostatic precipitators.

Gas: A non-solid, non-liquid combustible energy source that includes natural gas, coke-oven gas, blast-furnace gas, and refinery gas.

Gypsum: Calcium sulfate dihydrate ($CaSO_4 \bullet 2H_2O$), a sludge constituent from the conventional lime scrubber process, obtained as a byproduct of the dewatering operation and sold for commercial use.

Hours Under Load: The hours the boiler is operating to drive the generator producing electricity.

Latitude and Longitude: The distance on the earth's surface measured, respectively, north or south of the equator and east or west of the standard meridian, expressed in angular degrees, minutes, and seconds.

Load on Equipment: One hundred percent load is the maximum continuous net output of the unit at normal operating conditions during the annual peak load month. For example, if the equipment is capable of operating at 5% overpressure continuously, use this condition for 100% load.

Net Generation: The amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. Note: Electricity required for pumping at pumped-storage plants is regarded as electricity for station service and is deducted from gross generation.

Peak Load Month: The month of greatest plant electrical generation during the winter heating season (Oct-Mar) and summer cooling season (Apr-Sept), respectively.

Petroleum: A broadly defined class of liquid hydrocarbon mixtures. Included are crude oil, lease condensate, unfinished oils, refined products obtained from the processing of crude oil, and natural gas plant liquids. *Note:* Volumes of finished petroleum products include nonhydrocarbon compounds, such as additives and detergents, after they have been blended into the products.

Regulated Entity: For the purpose of EIA's data collection efforts, entities that either provide electricity within a designated franchised service area and/or file forms listed in the Code of Federal Regulations, Title 18, part 141 are considered regulated entities. This includes investor-owned electric utilities that are subject to rate regulation, municipal utilities, federal and state power authorities, and rural electric cooperatives. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Power Act (PURPA) are not considered regulated entities.

GLOSSARY

Stack: A tall, vertical structure containing one or more flues used to discharge products of combustion to the atmosphere.

Thermal: A term used to identify a type of electric generating station, capacity, capability, or output in which the source of energy for the prime mover is heat.

Topping Cycle: A boiler produces steam to power a turbine-generator to produce electricity. The steam leaving the turbine is used in thermal applications such as space hearting and/or cooling or delivered to other end user(s).

Unregulated Entity: For the purpose of EIA's data collection efforts, entities that do not have a designated franchised service area and that do not file forms listed in the Code of Federal Regulations, Title 18, Part 141, are considered unregulated entities. This includes qualifying cogenerators, qualifying small power producers, and other generators that are not subject to rate regulation, such as independent power producers.

Useful Thermal Output: The thermal energy made available for use in any industrial or commercial process or used in any heating or cooling application, i.e., total thermal energy made available for processes and applications other than electrical generation.

Waste Heat Boiler: A boiler that receives all or a substantial portion of its energy input from the combustible exhaust gases from a separate fuel-burning process.

Water Pollution Abatement Equipment: Equipment used to reduce or eliminate waterborne pollutants, including chlorine, phosphates, acids, bases, hydrocarbons, sewage, and other pollutants. Examples of water pollution abatement structures and equipment include those used to treat thermal pollution; cooling, boiler, and cooling tower blowdown water; coal pile runoff; and fly ash waste water. Water pollution abatement excludes expenditures for treatment of water prior to use at the plant.

Wet Bottom Boiler: Slag tanks are installed usually at the furnace throat to contain and remove molten ash.

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NOTICE: The timely submission of Form EIA-767 by those required to report is mandatory under Section 13(b) of the Federal Energy Administration Act of 1974 (FEAA) (Public Law 93-275), as amended. Failure to respond may result in a penalty of not more than $2,750 per day for each civil violation, or a fine of not more than $5,000 per day for each criminal violation. The government may bring a civil action to prohibit reporting violations, which may result in a temporary restraining order or a preliminary or permanent injunction without bond. In such civil action, the court may also issue mandatory injunctions commanding any person to comply with these reporting requirements. A person is not required to respond to collection of information unless the form displays a valid OMB number **Data reported on Schedule 6, Part B and Schedule 9 relating to Latitude and Longitude will be kept confidential. All other data are not confidential. Title 18 U.S.C. 1001 makes it a criminal offense for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.**

RESPONSE DUE DATE: April 30

REPORT FOR< respondent name >, <respondent id>, <plant name>, <plant code>

REPORTING PERIOD ENDING: 20xx

SURVEY CONTACTS: Persons to contact with questions about this form.

Contact

First Name: Last Name: Title:

Telephone: ( ) Ext: FAX ( ) E-mail:

Supervisor

First Name: Last Name: Title:

Telephone: ( ) Ext: FAX ( ) E-mail:

SCHEDULE 1. IDENTIFICATION

LINE NO.					
1	**Company Name (full legal name of operator)**				
2	**Current Address of Principal Business Office**				
3	**Plant Name**				
4	**Plant Code**				
5	**Plant Status (check one)**	**[ ] Existing**	**[ ] Planned**	**[ ] Retired**	**EIA Use Only Correct Frame [ ]**
6	**Plant Type (check one)**	**[ ] Organic 100 MW or More**	**[ ] Organic 10 MW or Greater to Under 100 MW**		
PLANT LOCATION					
7	**State (U.S. Postal Abbreviation)**				
8	**County (or Parish)**				
9	**Nearest Post Office Name**				
10	**Nearest Post Office Zip Code**				

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SCHEDULE 2. PLANT CONFIGURATION
(ORGANIC PLANTS 10 MW OR GREATER TO UNDER 100 MW COMPLETE ONLY LINES 1, 2, 3, AND IF APPLICABLE 5 AND 6)

LINE NO.	EQUIPMENT TYPE	EQUIPMENT IDENTIFICATION (a)	EQUIPMENT IDENTIFICATION (b)	EQUIPMENT IDENTIFICATION (c)	EQUIPMENT IDENTIFICATION (d)	EQUIPMENT IDENTIFICATION (e)
1	Boiler					
2	Associated Generator(s)					
3	Generator Associations with Boiler as Actual or Theoretical (indicate "A" for actual association or "T" for theoretical association)					
4	Associated Cooling System(s)					
5	Associated Flue Gas Particulate Collector(s) (include flue gas desulfurization units that also remove particulate matter)					
6	Associated Flue Gas Desulfurization Unit(s) (include flue gas particulate collectors that also remove sulfur dioxide)					
7	Associated Stack(s)					
8	Associated Flue(s)					

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SCHEDULE 3. PLANT INFORMATION, PART A. ANNUAL BYPRODUCT DISPOSITION AND USEFUL THERMAL OUTPUT (IF ACTUAL DATA ARE NOT AVAILABLE, PROVIDE AN ESTIMATED VALUE)

LINE NO.	BYPRODUCT	COMPANY LANDFILL (DRY) (a)	COMPANY DISPOSAL PONDS (WET) (b)	ONSITE USE AND STORAGE (c)	SOLD (d)	OFF SITE DISPOSAL (e)	TOTAL (f)
QUANTITY OF COMBUSTION BYPRODUCTS DURING YEAR BY TYPE OF DISPOSAL (TO NEAREST 0.1 THOUSAND TONS)							
1	Fly Ash (zero percent moisture)						
2	Bottom Ash (zero percent moisture)						
3	Flue Gas Desulfurization (FGD) Sludge Including Stabilizers if Added (zero percent moisture)						
4	Gypsum (salable)						
5	Other Byproducts (specify other byproducts in footnote on Schedule 10)						
6	Facilities Producing Electricity and Useful Thermal Output from Equipment Associated with the Production of Electricity (Cogenerators) Check Appropriate Box: Bottoming Cycle System [ ] Topping Cycle System [ ]						
7	Enter the Estimated Useful Thermal Output for the Reporting Year (in million Btu) for Facilities Producing Electricity and Useful Thermal Output from Equipment Associated with the Production of Electricity						
8	How was the Useful Thermal Output used (check all that apply) [ ] Direct Heating [ ] Space Heating and/or Cooling [ ] Process Steam [ ] Delivered to Other End User(s) [ ] Other, Specify:						

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SCHEDULE 3. PLANT INFORMATION, PART B. FINANCIAL INFORMATION
(IF ACTUAL DATA ARE NOT AVAILABLE, PROVIDE AN ESTIMATED VALUE)

LINE NO.	TYPE	COLLECTION (a)	DISPOSAL (b)	OTHER (c)
OPERATION AND MAINTENANCE (O&M) EXPENDITURES DURING YEAR (THOUSAND DOLLARS)				
1	Fly Ash			
2	Bottom Ash			
3	Flue Gas Desulfurization			
4	Water Pollution Abatement			
5	Other Pollution Abatement (specify in footnote on Schedule 10)			
6	Total (sum of lines 1, 2, 3, 4, 5)			

LINE NO.	TYPE	AMOUNT (a)
CAPITAL EXPENDITURES FOR NEW STRUCTURES AND EQUIPMENT DURING YEAR, EXCLUDING LAND AND INTEREST EXPENSE (THOUSAND DOLLARS)		
7	Air Pollution Abatement	
8	Water Pollution Abatement	
9	Solid/Contained Waste	
10	Other Pollution Abatement	
BYPRODUCT SALES REVENUE DURING YEAR (THOUSAND DOLLARS)		
11	Fly Ash	
12	Bottom Ash	
13	Fly and Bottom Ash Sold Intermingled	
14	Flue Gas Desulfurization Byproducts	
15	Other Byproduct Revenue (specify in a footnote on Schedule 10)	
16	Total (sum of lines 11, 12, 13, 14, 15)	

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SCHEDULE 4. BOILER INFORMATION, PART A. FUEL CONSUMPTION AND QUALITY (COMPLETE A SEPARATE PAGE FOR EACH BOILER)

1	Boiler ID (as reported on Schedule 2)		Boiler Status (use code)		Hours Under Load During Year (nearest hour)	

MONTHLY FUEL CONSUMPTION AND QUALITY DURING YEAR

LINE NO.	MONTH	FUEL CODE (a)	QUANTITY (b)	HEAT CONTENT (c)	SULFUR CONTENT (d)	ASH CONTENT (e)	MONTH	FUEL CODE (f)	QUANTITY (g)	HEAT CONTENT (h)	SULFUR CONTENT (i)	ASH CONTENT (j)
2	January						July					
3												
4												
5												
6	February						August					
7												
8												
9												
10	March						September					
11												
12												
13												
14	April						October					
15												
16												
17												
18	May						November					
19												
20												
21												
22	June						December					
23												
24												
25												
TOTAL SUM OF ALL MONTHS (January to December) BY FUEL CODE (Quantity)												
26	Total											
27	Total											
28	Total											
29	Total											

ANALYSIS METHOD FOR PRIMARY FUEL TYPE

30	Sampling Procedure		
31	Method Of Analysis		
32	Laboratory Performing Analysis		

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SCHEDULE 4. BOILER INFORMATION, PART B. AIR EMISSION STANDARDS
(COMPLETE A SEPARATE PAGE FOR EACH BOILER)

LINE NO.				
1	Boiler ID (as reported on Schedule 2)			
2	Type Of Boiler Standards Under Which The Boiler Is Operating (use codes)			
	CATEGORY	PARTICULATE MATTER (a)	SULFUR DIOXIDE (b)	NITROGEN OXIDES (c)
3	Type of Statute or Regulation (use codes)			
4	Emission Standard Specified			
5	Unit of Measurement Specified (use codes)			
6	Time Period Specified (use codes)			
7	Year Boiler Was or is Expected to Be in Compliance			
8	If Not in Compliance, Strategy for Compliance (use codes)			
9	Select Existing Strategies to meet the Sulfur Dioxide Requirements of Title IV of the Clean Air Act Amendment of 1990 (use codes)			
10	Select Planned Strategies to meet the Sulfur Dioxide Requirements of Title IV of the Clean Air Act Amendment of 1990 (use codes)			

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SCHEDULE 4. BOILER INFORMATION, PART C. DESIGN PARAMETERS (COMPLETE A SEPARATE PAGE FOR EACH BOILER)

LINE NO.		
1	Boiler ID (as reported on Schedule 2)	
2	Boiler Actual or Projected In-Service Date of Commercial Operation (e.g., 12-2001)	
3	Boiler Actual or Projected Retirement Date (e.g., 12-2001)	
4	Boiler Manufacturer (use code)	
5	Type of Firing Used with Primary Fuels (use codes)	
6	Maximum Continuous Steam Flow at 100 Percent Load (thousand pounds per hour)	
7	Design Firing Rate at Maximum Continuous Steam Flow for Coal (nearest 0 .1 ton per hour)	
8	Design Firing Rate at Maximum Continuous Steam Flow for Petroleum (nearest 0 .1 barrels per hour)	
9	Design Firing Rate at Maximum Continuous Steam Flow for Gas (nearest 0 .1 thousand cubic feet per hour)	
10	Design Firing Rate at Maximum Continuous Steam Flow for Other (specify fuel and unit on Schedule 10)	
11	Design Waste Heat Input Rate at Maximum Continuous Steam Flow (million Btu per hour)	
12	Primary Fuels Used in Order of Predominance (use codes)	
13	Boiler Efficiency When Burning Primary Fuel at 100 Percent Load (nearest 0.1 percent)	
14	Boiler Efficiency When Burning Primary Fuel at 50 Percent Load (nearest 0.1 percent)	
15	Total Air Flow Including Excess Air at 100 Percent Load (cubic feet per minute at standard conditions)	
16	Wet Or Dry Bottom (for coal-capable boilers), (enter "W" for Wet or "D" for Dry)	
17	Fly Ash Re-injection (enter "Y" for Yes or "N" for No)	
ALTERNATE FUELS CAPABILITY (FUELS OTHER THAN PRIMARY FUEL)		
18	Alternate Fuels Boiler Is Equipped to Burn (use codes)	
19	Year Alternate Fuel Last Burned	
20	Number of Days Required to Switch	
21	Can Alternate Fuels Be Burned Continuously for 30 Days or Longer (enter "Y" for Yes or "N" for No)	

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SCHEDULE 4. BOILER INFORMATION, PART D. NITROGEN OXIDE EMISSION CONTROLS (COMPLETE A SEPARATE PAGE FOR EACH BOILER)		
1	**Boiler ID (as reported on Schedule 2)**	
2	**Nitrogen Oxide Control Status (use codes)**	
3	**Total Hours Nitrogen Oxide Control was Inservice During the Year (nearest hour)**	
NITROGEN OXIDE CONTROL EQUIPMENT AND OR PROCESS		
4	**Low Nitrogen Oxide Control Process (use codes)**	
5	**Manufacturer of Low Nitrogen Oxide Control Burners (use code)**	
ESTIMATE NITROGEN OXIDE ACTUAL EMISSION RATE (pounds/million Btu)		
6	**For Entire Year**	
7	**May Through September Only**	
SCHEDULE 4. BOILER INFORMATION, PART E. MERCURY EMISSION CONTROLS		
1	**Does Your Facility Have Mercury Emission Controls (check yes or no)**	**Yes [ ]** **No [ ]**
2	**If "Yes," Describe the Type of Controls**	

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SCHEDULE 5. GENERATOR INFORMATION

LINE NO.	ITEM	GENERATOR (a)	GENERATOR (b)	GENERATOR (c)	GENERATOR (d)	GENERATOR (e)
1	Generator ID (as reported on Schedule 2)					
2	Maximum Generator Nameplate Rating (megawatts)					
ASSOCIATED CONDENSER'S COOLING WATER						
3	Design Flow Rate in Condenser at 100 Percent Load (cubic feet per second)					
4	Design Temperature Rise Across Condenser at 100 Percent Load (degrees Fahrenheit)					
MONTHLY NET ELECTRICAL GENERATION (MEGAWATTHOURS)						
5	January					
6	February					
7	March					
8	April					
9	May					
10	June					
11	July					
12	August					
13	September					
14	October					
15	November					
16	December					
17	Total					

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SCHEDULE 6. COOLING SYSTEM INFORMATION, PART A. ANNUAL OPERATIONS

LINE NO.	ITEM	COOLING SYSTEM (a)	COOLING SYSTEM (b)	COOLING SYSTEM (c)	COOLING SYSTEM (d)	COOLING SYSTEM (e)
1	Cooling System ID (as reported on Schedule 2)					
2	Cooling System Status (use code)					
3	Annual Amount of Chlorine Added to Cooling Water (thousand pounds)					
AVERAGE ANNUAL RATE OF COOLING WATER (NEAREST 0.1 CUBIC FOOT PER SECOND)						
4	Withdrawal					
5	Discharge					
6	Consumption (line 4 less line 5)					
MAXIMUM COOLING WATER TEMPERATURE AT INTAKE DURING (DEGREES FAHRENHEIT)						
7	Winter Peak Load Month					
8	Summer Peak Load Month					
MAXIMUM COOLING WATER TEMPERATURE AT DISCHARGE OUTLET DURING (DEGREES FAHRENHEIT)						
9	Winter Peak Load Month					
10	Summer Peak Load Month					

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SCHEDULE 6. COOLING SYSTEM INFORMATION, PART B. DESIGN PARAMETERS
(COMPLETE A SEPARATE PAGE FOR EACH COOLING SYSTEM)

LINE NO.		
1	Cooling System ID (as reported on Schedule 2)	
2	Cooling System Actual or Projected Inservice Date of Commercial Operation (e.g., 12-2001)	
3	Type of Cooling System (use codes)	
4	Source of Cooling Water Including Makeup Water (name) (if discharge is into different water body, footnote in Schedule10)	
5	Design Cooling Water Flow Rate at 100 percent Load at Intake (cubic feet per second)	
6	Actual or Projected In-Service Date for Chlorine Discharge Control Structures and Equipment (month and year of commercial operation, e.g., 12-1982)	
COOLING PONDS		
7	Actual or Projected In-Service Date (month and year of commercial operation, e.g. 12-1982)	
8	Total Surface Area (acres)	
9	Total Volume (acre-feet)	
COOLING TOWERS		
10	Actual or Projected Inservice Date (month and year of commercial operation, e.g., 12-1982)	
11	Type of Towers (use codes)	
12	Maximum Design Rate of Water Flow at 100 Percent Load (cubic feet per second)	
13	Maximum Power Requirement at 100 Percent Load (megawatts)	
INSTALLED COST OF COOLING SYSTEM EXCLUDING LAND AND CONDENSERS (thousand dollars)		
14	Total System	
15	Ponds (if applicable)	
16	Towers (if applicable)	
17	Chlorine Discharge Control Structures and Equipment (if applicable)	

COOLING WATER INTAKE AND OUTLET LOCATIONS

	ITEM	INTAKE (a)	OUTLET (b)
18	Latitude (degrees, minutes, seconds)		
19	Longitude (degrees, minutes, seconds)		
20	Maximum Distance from Shore (feet)		
21	Average Distance below Water Surface (feet)		

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SCHEDULE 7. FLUE GAS PARTICULATE COLLECTOR INFORMATION
(COMPLETE A SEPARATE PAGE FOR EACH FLUE GAS PARTICULATE COLLECTOR)

LINE NO.		
1	Flue Gas Particulate Collector ID (as reported on Schedule 2)	
2	Flue Gas Particulate Collector Actual or Projected In-Service Date of Commercial Operation (e.g., 12-2001)	
3	Flue Gas Particulate Collector Status (use code)	
4	Type of Flue Gas Particulate Collector (use codes)	
5	Installed Cost of Flue Gas Particulate Collector Excluding Land (thousand dollars)	
6	Hours In-Service During Year (to nearest hour)	
7	Typical Particulate Emission Rate at Annual Operating Rate (to nearest 0.01 pound per million Btu)	
ESTIMATE REMOVAL EFFICIENCY OF PARTICULATE MATTER (TO NEAREST 0.1 PERCENT REMOVED BY WEIGHT)		
8	At Annual Operating Factor	
9	At 100 Percent Load or Tested Efficiency (if test conducted was not at 100 percent load, footnote load on Schedule 10)	
10	Date of Most Recent Efficiency Test (e.g., 12-2001)	
DESIGN FUEL SPECIFICATIONS FOR ASH (AS BURNED, TO NEAREST 0.1 PERCENT BY WEIGHT)		
11	For Coal	
12	For Petroleum	
DESIGN FUEL SPECIFICATIONS FOR SULFUR (AS BURNED, TO NEAREST 0.1 PERCENT BY WEIGHT)		
13	For Coal	
14	For Petroleum	
DESIGN SPECIFICATIONS AT 100 PERCENT GENERATOR LOAD		
15	Collection Efficiency (to nearest 0.1 percent)	
16	Particulate Emission Rate (pounds per hour)	
17	Particulate Collector Gas Exit Rate (actual cubic feet per minute)	
18	Particulate Collector Gas Exit Temperature (degrees Fahrenheit)	

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SCHEDULE 8. FLUE GAS DESULFURIZATION UNIT INFORMATION, PART A. ANNUAL OPERATIONS

LINE NO.	ITEM	FLUE GAS DESULFURIZATION (a)	FLUE GAS DESULFURIZATION (b)	FLUE GAS DESULFURIZATION (c)	FLUE GAS DESULFURIZATION (d)	FLUE GAS DESULFURIZATION (e)
1	Flue Gas Desulfurization ID (as reported on Schedule 2)					
2	Flue Gas Desulfurization Unit Status (use code)					
3	Hours In-Service During Year (to nearest hour)					
4	Quantity of FGD Sorbent Used During Year (to nearest 0.1 thousand tons)					
5	Electrical Energy Consumption During Year (megwatthours)					
ESTIMATED REMOVAL EFFICIENCY FOR SULFUR DIOXIDE (TO NEAREST 0.1 PERCENT REMOVED BY WEIGHT)						
6	At Annual Operating Factor					
7	At 100 percent Load or Tested Efficiency (if test conducted was not at 100 percent, footnote load on Schedule 10)					
8	Date of Most Recent Efficiency Test (i.e., 12-2001)					
FLUE GAS DESULFURIZATION OPERATION AND MAINTENANCE EXPENDITURES DURING YEAR, EXCLUDING ELECTRICITY (THOUSAND DOLLARS)						
9	Feed Materials and Chemicals					
10	Labor and Supervision					
11	Waste Disposal					
12	Maintenance, Materials and All Other Costs					
13	Total (sum of lines 9, 10, 11, 12)					

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SCHEDULE 8. FLUE GAS DESULFURIZATION UNIT INFORMATION, PART B. DESIGN PARAMETERS
(COMPLETE A SEPARATE PAGE FOR EACH FLUE GAS DESULFURIZATION UNIT)

LINE NO.		
1	Flue Gas Desulfurization Unit ID (as reported on Schedule 2)	
2	Flue Gas Desulfurization Unit Actual or Projected Inservice Date of Commercial Operation (e.g., 12-2001)	
3	Type of Flue Gas Desulfurization Unit (use code)	
4	Type of Sorbent (use code)	
5	Salable Byproduct Recovery (enter "Y" for Yes or "N" for No)	
6	Flue Gas Desulfurization Unit Manufacturer (use code)	
7	Estimated Flue Gas Desulfurization Waste and Salable Byproducts Produced Annually (thousand tons at zero percent moisture)	
8	Annual Pond and Land Fill Requirements (nearest acre foot per year)	
9	Is Sludge Pond Lined (enter "Y" for Yes, "N" for No, or "NA" for Not Applicable)	
10	Can Flue Gas Bypass Flue Gas Desulfurization Unit (enter "Y" for Yes or "N" for No)	
DESIGN FUEL SPECIFICATIONS FOR COAL		
11	Ash (to nearest 0.1 percent by weight)	
12	Sulfur (to nearest 0.1 percent by weight)	
NUMBER OF FLUE GAS DESULFURIZATION UNIT SCRUBBER TRAINS (OR MODULES)		
13	Total	
14	Operated at 100 Percent Load	
DESIGN SPECIFICATIONS OF FLUE GAS DESULFURIZATION UNIT AT 100 PERCENT GENERATOR LOAD		
15	Removal Efficiency for Sulfur Dioxide (to nearest 0.1 percent by weight)	
16	Sulfur Dioxide Emission Rate (pounds per hour)	
17	Flue Gas Exit Rate (actual cubic feet per minute)	
18	Flue Gas Exit Temperature (degrees Fahrenheit)	
19	Flue Gas Entering Flue Gas Desulfurization Unit (percent of total)	
INSTALLED COST OF FLUE GAS DESULFURIZATION UNIT, EXCLUDING LAND (THOUSAND DOLLARS)		
20	Structures and Equipment	
21	Sludge Transport and Disposal System	
22	Other (installed cost of flue gas desulfurization unit)	
23	Total (sum of lines 20, 21, 22)	

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SCHEDULE 9. STACK AND FLUE INFORMATION - DESIGN PARAMETERS
(COMPLETE A SEPARATE PAGE FOR EACH STACK AND FLUE)

LINE NO.		
1	Flue ID (as reported on Schedule 2)	
2	Stack ID (as reported on Schedule 2)	
3	Stack (or Flue) Actual or Projected In-Service Date of Commercial Operation (e.g., 12-2001)	
4	Status of Stack (or Flue) (use code)	
5	Flue Height at Top from Ground Level (feet)	
6	Cross-Sectional Area at Top of Flue (nearest square foot)	
DESIGN FLUE GAS EXIT (AT TOP OF STACK)		
7	Rate at 100 Percent Load (actual cubic feet per minute)	
8	Rate at 50 Percent Load (actual cubic feet per minute)	
9	Temperature at 100 Percent Load (degrees Fahrenheit)	
10	Temperature at 50 Percent Load (degrees Fahrenheit)	
11	Velocity at 100 Percent Load (feet per second)	
12	Velocity at 50 Percent Load (feet per second)	
ACTUAL SEASONAL FLUE GAS EXIT TEMPERATURE (DEGREES FAHRENHEIT)		
13	Summer Season	
14	Winter Season	
15	Source (enter "M" for measured or "E" for estimated)	
STACK LOCATION		
16	Stack Location - Latitude (degrees, minutes, seconds)	
17	Stack Location - Longitude (degrees, minutes, seconds)	

CHECK IF PAGE IS NOT APPLICABLE	[ ]	CHECK IF PRE-PRINTED DATA ARE CORRECT	[ ]	Page		of	

U.S. Department of Energy Energy Information Administration Form EIA-767 (2003)	*STEAM-ELECTRIC PLANT OPERATION AND DESIGN REPORT*	Form Approved OMB No. 1905-0129 Approval Expires 11/30/04

REPORT FOR: < respondent name >, <respondent id>, <plant name>, <plant code>

REPORTING PERIOD: 20xx

SCHEDULE 10. FOOTNOTES

PAGE NO. (a)	SCHEDULE NO. (b)	PART NO. (c)	LINE NO. (d)	COLUMN (e)	NOTE (f)

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