Independent Statistics & Analysis
U.S. Energy Information Administration

FORM EIA-860 INSTRUCTIONS ANNUAL ELECTRIC GENERATOR REPORT

Approval: OMB No. 1905-0129
Approval Expires: 05/31/2017
Burden: 9.29 Hours

PURPOSE

Form EIA-860 collects data on the status of existing electric generating plants and associated equipment (including generators, boilers, cooling systems and air emission control systems) in the United States, and those scheduled for initial commercial operation within 5 or 10 years, as applicable. The data from this form appear in EIA publications and public databases. 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

Existing plants are required to respond to the EIA-860 if:

- The plant's total generator nameplate capacity is 1 Megawatt (MW) or greater **and**
- The plant's generator(s), or the facility in which the generator(s) resides, are connected to the local or regional electric power grid and have the ability to draw power from or deliver power to the grid

If the existing plant is jointly-owned, only the operator of that plant should respond to the EIA-860

Proposed plants are required to respond to the EIA-860 if:

- The plant's proposed total generator(s) nameplate capacity will be 1 MW or greater; **and**
- The plant's proposed generator(s), or the facility in which the proposed generator(s) resides, will be connected to the local or regional electric power grid and will be able to draw power from or deliver power to the grid; **and**
- The plant meets one of these two conditions
    - The plant will be primarily fueled by coal or nuclear energy and is expected to begin commercial operation within 10 years; or
    - The plant will be primarily fueled by energy sources other than coal or nuclear energy and is expected to begin commercial operation within 5 years

  The five and ten year reporting horizons are calculated from January 1 of the reporting year. For example, reports made in 2014 should reflect plans through December 31, 2018 (five year horizon) and December 31, 2023 (ten year horizon).

If the proposed plant is jointly-owned, only the planned operator of that plant should respond to the EIA-860

Generators located in Alaska and Hawaii are required to respond to the EIA-860 if:

- The generators are connected to a local or regional transmission or distribution system that supplies power to the public.

For all plants:

The total generator nameplate capacity is the sum of the maximum ratings in MW on the nameplates of all applicable generators at a specific site. For photovoltaic solar, the total generator nameplate capacity is the sum of the AC ratings of the array.

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RESPONSE DUE DATE

1) Submit the completed Form EIA-860 directly to EIA annually between the first business day of January and the last business day of February. For existing equipment the filing should reflect the status of that equipment as of December 31 of the reporting year. For proposed actions (e.g. planned retirements, planned additions, or planned modifications) the filing should reflect the most up to date information available to the respondent at the time the filing is made. Note: if EIA is late in opening its Internet Data Collection system the filing deadline will be extended day for day (respondents will be notified by email).

2) If subsequent to the submission date for the annual filing a respondent either (a) takes an action, not previously reported to EIA, to add, retire, or uprate/derate generating units or environmental control equipment; or (b) makes a decision, not previously reported to EIA, to add, retire, or uprate/derate generating units or environmental control equipment; then the respondent should notify EIA as soon as practical by an email to EIA-860@eia.gov. EIA staff will then assist the respondent in amending its filing or making a first-time filing.

METHODS OF FILING RESPONSE

If this is your first time submitting a Form EIA-860, fill out all applicable portions of this form and submit it to: EIA-860@eia.gov. All subsequent filings can be done electronically using EIA's secure e-filing system. This system uses security protocols to protect information against unauthorized access during transmission.

If you have any questions on filling out this form or have not registered with the e-file Single Sign-On (SSO) system, send an email requesting assistance to: EIA-860@eia.gov.

If you have registered with SSO, log on at https://signon.eia.gov/ssoserver/login.

Please retain a completed copy of this form for your files.

CONTACTS

If you have a question about the data requested on this form, email EIA-860@eia.gov (preferred) or contact one of the survey managers listed below.

Jonathan DeVilbiss	Suparna Ray	Tosha Richardson
Jonathan.DeVilbiss@eia.gov	Suparna.Ray@eia.gov	Tosha.Richardson@eia.gov
(202) 586-2992	(202) 586-5077	(202) 287-6597

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GENERAL INSTRUCTIONS

1. Verify all EIA-provided information. If incorrect, revise the incorrect entry and provide the correct information. Provide any missing information. If filing a paper copy of this form, typed or legible handwritten entries are acceptable.
2. Check all data for consistency with the same or related data that appear in more than one schedule of this form or in other forms or reports submitted to EIA. Use SCHEDULE 7 to explain inconsistencies or anomalies with data or to provide any further details that are pertinent to the data.
3. For planned power plants and/or planned equipment, use planning data to complete the form.
4. Number formats:
   a. Report in whole numbers (i.e., no decimal points), except where explicitly instructed to report otherwise.
   b. Indicate negative amounts by using a minus sign before the number.
   c. Report date information as a two-digit month and four-digit year, e.g., “11 - 1980.”
5. The reporting year is the calendar year that you are filing the survey for. For example, if you are **reporting** data as of December 31, 2013, then the reporting year is 2013.
6. Furnish the requested information to reflect the status of your current or planned operations as of the end of the reporting year. If your company no longer operated a specific power plant as of December 31, report the name of the operator as of December 31 along with related contact information (including contact person’s name, telephone number, and email address, if known) in SCHEDULE 7. Do not complete the form for that power plant.
7. The blank hardcopy form can be downloaded from www.eia.gov/cneaf/electricity/page/forms.html.
8. For definitions of terms, refer to the U.S. Energy Information Administration glossary at www.eia.gov/glossary/index.html.

ITEM-BY-ITEM INSTRUCTIONS

SCHEDULE 1. IDENTIFICATION

1. **Survey Contact:** Provide the name, title, address, telephone number, cell phone number, and email address for the person that will be the primary contact for this form.
2. **Supervisor of Survey Contact:** Provide the name, title, address, telephone number, cell phone number and email address of the primary contact's supervisor.
3. **Entity Name and Address:** Provide the name and address of the entity that is reporting for the plants reported on this form.
4. **Entity Relationship:** Indicate the relationship between the reporting entity and the power plants reported on this form. Select all that apply: owner, operator, asset manager or other. If you select "Other," provide details in SCHEDULE 7.
5. **Entity Type:** Select the category that best describes the entity that owns and/or operates the plants reported on this form from the list below:

   - Cooperative
   - Federally-Owned Utility
   - Investor-Owned Utility (IOU)
   - Independent Power Producer (IPP)
   - Municipally-Owned Utility
   - Political Subdivision
   - State-Owned Utility
   - Industrial
   - Commercial

SCHEDULE 2. POWER PLANT DATA

Complete one section for each power plant. A plant can consist of a single generator or of multiple generators at a single location. For the purpose of wind plants and solar plants, a plant can be defined based on phased expansions or other grouping methodologies used by the reporting entity. Include all plants that are (1) in commercial operation, (2) capable of commercial operation but currently inactive or on standby, or (3) expected to be in commercial operation within 10 years in the case of coal and nuclear units, or within 5 years for all other units.

1. For line 1**, What are the plant name and EIA Plant Code for this plant?** Enter the name of the power plant. When assigning a name to a plant, use its full name (i.e. do not shorten Alpha Generating Station to Alpha) and include as much detail as possible (e.g. Beta Paper Mill, Gamma Landfill Gas Plant, Delta Dam). The plant name may include additional details like owner name and business structure but "Corporation" should be shorted to "Corp" and "Incorporated" should be shortened to "Inc." Enter "NA 1," "NA 2," etc., for unnamed planned facilities.

   The EIA Plant Code is generated and provided by EIA upon the initial submission of the Form EIA-860.
2. For line 2, **What is this plant's physical address?** Enter the physical address where the plant is located or will be located. Do not enter the plant's mailing address. Do not enter the address of the plant's operator, holding company or other corporate entity. If the plant does not have a single, permanent address, indicate it with a note in SCHEDULE 7.
3. For line 3, **What is this plant's latitude and longitude?** Enter the latitude and longitude of the plant in decimal format. The coordinates should relate to a central point within the plant's property such as a generator. Do not enter the coordinates of the plant's

operator, holding company or other corporate entity.

4. For line 4, **Which North American Electric Reliability Corporation region does this plant operate in?** Select the North American Electric Reliability Corporation (NERC) region in which the plant operates.
5. For line 5, **What is this plant's balancing authority?** Select the plant's Balancing Authority. A balancing authority manages supply, demand, and interchanges within an electrically defined area. It may or may not be the same as the Owner of Transmission/Distribution Facilities, requested below. If you believe the plant is connected to more than one balancing authority, explain in SCHEDULE 7.
6. For line 6, **What is the name of the principle water source used by this plant for cooling or hydroelectric generation?** Enter the name of the principal source from which cooling water or water for generating power for hydroelectric plants is obtained. If water is from an underground aquifer, provide name of aquifer, if known. If name of aquifer is not known, enter "Wells." Enter "Municipality" if the water is from a municipality. Enter "UNK" for planned facilities for which the water source is not known. Enter "NA" for plants that do not use a water source for cooling or hydroelectric generation.
7. The response for line 7, **What is this plant's steam plant type?** is entered by EIA staff for all plants. If you are filling out this form on EIA's Internet Data Collection System and believe that the designation is not accurate, please contact the survey manager.
8. For line 8a, **Which North American Industry Classification System (NAICS) Code that best describes this plant's primary purpose?** Enter the North American Industry Classification System (NAICS) code found in Table 29 at the end of these instructions that best describes the primary purpose of the plant. Electric utility plants and independent power producers whose primary purpose is generating electricity for sale will generally use code 22. For generators whose primary business is an industrial or commercial process (e.g., paper mills, refineries, chemical plants, etc.) and for which generating electricity is a secondary purpose, use a code other than 22. For plants with multiple purposes, select the NAICS code corresponding to the line of business that generates - or where the chartered intent of the line of business is intended to generate - the highest value for the company.

   For line 8b **Did this plant have a net metering agreement in effect during the reporting year?** If any primary purpose other than 22 is selected on line 8a above, indicate whether the facility is net metered.

   Net metering is defined as a tariff arrangement in which a qualifying customer, typically generating electricity from a renewable resource, sells excess power it generates over its load requirement back to a utility, typically at a rate equivalent to the retail price of electricity.
9. For lines 9a and 9b, **Does this plant have Federal Energy Regulatory Commission Qualifying Facility (QF) Cogenerator status?** Check "Yes" or "No"; if "Yes" provide all QF docket numbers granted to the facility. Please do not include the prefix (e.g. QF, EWG, etc.) when entering the docket numbers. Only include the numerical portion of the docket number, including dashes.
10. For lines 10a and 10b, **Does this plant have Federal Energy Regulatory Commission Qualifying Facility (QF) Small Power Producer status**? Check "Yes" or "No"; if "Yes" provide all QF docket numbers granted to the facility. Please do not include the prefix

(e.g. QF, EWG, etc.) when entering the docket numbers. Only include the numerical portion of the docket number, including dashes.

11. For lines 11a and 11b, **Does this plant have Federal Energy Regulatory Commission Qualifying Facility (QF) Exempt Wholesale Generator status**? Check "Yes" or "No"; if "Yes," provide all QF docket numbers granted to the facility. Please do not include the prefix (e.g. QF, EWG, etc.) when entering the docket numbers. Only include the numerical portion of the docket number, including dashes.
12. For line 12a, **Is there an ash impoundment (e.g. pond, reservoir) at the plant?** Indicate whether there is an impoundment (e.g. pond, reservoir) at the plant where fly ash, bottom ash or other ash byproducts can be stored.

    If you entered "yes" to Question 12a, for Question 12b, **Is this ash impoundment lined?** Indicate whether the impoundment is lined and, in Question 12c, **What was this ash impoundment's status as of December 31 of the reporting year?** select the impoundment's status from the list of codes in Table 1 below.

Table 1. Ash Impoundment Status Codes and Descriptions

Ash Impoundment Status Code	Ash Impoundment Status Code Description
OP	Operating - in service (commercial operation)
SB	Standby/Backup - available for service but not normally used for this reporting period
OA	Out of service – was not used for some or all of the reporting period but is expected to be returned to service in the next calendar year
OS	Out of service – was not used for some or all of the reporting period and is NOT expected to be returned to service in the next calendar year

13. For line 13, **Who is the current owner of the transmission lines and/ or distribution facilities that this plant is interconnected to?** Enter the name of the current owner of the transmission or distribution facilities to which the plant is interconnected and which receives or may receive the plant's output. If the plant is interconnected to multiple owners, enter the name of the principal owner and list the other owners and their roles in SCHEDULE 7.
14. For line 14, **What is this plant's grid voltage at the point(s) of interconnection to transmission or distribution facilities?** Enter up to three grid voltages, in kilovolts, at the points of interconnection to the transmission/distribution facilities. If the plant is interconnected to more than three transmission/distribution facilities, enter the three highest grid voltages.
15. Line 15 is reserved for future use.
16. For line 16, **What is the name of the natural gas pipeline(s) that is connected to your facility?** Enter the name(s) of the natural gas pipeline(s) that provide natural gas to the plant.

SCHEDULE 3. GENERATOR INFORMATION

Complete SCHEDULE 3 for each generator at this plant that is:

- In commercial operation;
- Capable of commercial operation but currently inactive or on standby;
- Retired;
- Expected to be in commercial operation within 10 years in the case of coal and nuclear generators; or
- Expected to be in commercial operation within 5 years for all generators other than coal and nuclear generators.

1. Do **not** report auxiliary generators that are typically used solely for blackstart or maintenance purposes.
2. For generators associated with wind and solar plants, a generator can be any grouping of photovoltaic panels or wind turbines with similar characteristics (e.g. manufacturer, technical parameters, location, commercial operating date, etc.).
3. Treat energy storage facilities as generators and provide all necessary data requested below.
4. Include generators with maximum capability of less than 1 MW if located at a plant with a total nameplate capacity of 1 MW or greater.
5. To report a new generator, use a separate and blank section of SCHEDULE 3.
6. To report a new generator that has replaced one that is no longer in service, update the status of the generator that has been replaced along with other related information (e.g., retirement date), then use a separate and blank section of SCHEDULE 3 to report all of the applicable data about the new generator.
7. Each generator must be uniquely identified within a plant. The EIA cannot use the same generator ID for the new generator that was used for the generator that was replaced.

SCHEDULE 3. PART A. GENERATOR INFORMATION – GENERATORS

1. For line 1, **What is the generator ID for this generator?** Enter the unique generator identification commonly used by plant management. Generator identification should be the same identification as reported on other EIA forms to be uniquely defined within a plant. This identification code is restricted to five characters and cannot be changed once provided to EIA.

2. For line 2, **What is this generator's prime mover?** Enter one of the prime mover codes in Table 2. For combined cycle units, a prime mover code must be entered for each generator.

Table 2. Prime Mover Codes and Descriptions

Prime Mover Code	Prime Mover Description
BA	Energy Storage, Battery
CE	Energy Storage, Compressed Air
CP	Energy Storage, Concentrated Solar Power
FW	Energy Storage, Flywheel
PS	Energy Storage, Reversible Hydraulic Turbine (Pumped Storage)
ES	Energy Storage, Other (specify in SCHEDULE 7)
ST	Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)
GT	Combustion (Gas) Turbine (does not include the combustion turbine part of a combined cycle; see code CT, below)
IC	Internal Combustion Engine (diesel, piston, reciprocating)
CA	Combined Cycle Steam Part
CT	Combined Cycle Combustion Turbine Part
CS	Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator)
CC	Combined Cycle Total Unit (use only for plants/generators that are in planning stage, for which specific generator details cannot be provided)
HA	Hydrokinetic, Axial Flow Turbine
HB	Hydrokinetic, Wave Buoy
HK	Hydrokinetic, Other (specify in SCHEDULE 7)
HY	Hydroelectric Turbine (includes turbines associated with delivery of water by pipeline)
BT	Turbines Used in a Binary Cycle (including those used for geothermal applications)
PV	Photovoltaic
WT	Wind Turbine, Onshore
WS	Wind Turbine, Offshore
FC	Fuel Cell
OT	Other (specify in SCHEDULE 7)

Combined heat and power systems often generate steam with multiple sources and generate electric power with multiple prime movers. For reporting purposes, a simple cycle prime mover should be distinguished from a combined cycle prime mover by determining whether the power generation part of the steam system can operate independently of the rest of the steam system. If these system components cannot be operated independently, then the prime movers should be reported as combined cycle types.

3. For line 3, **What is this generator's unit or multi-generator code? I**f this generator operates as a single unit with another generator (including as a combined cycle unit), enter a unique 4-character code for the unit. All generators that operate as a unit must have the same unit code. Leave blank if this generator does not operate as a single unit with another generator.

4. For line 4, **What is this generator's ownership code?** Identify the ownership for each generator using the following codes:

Table 3: Generator Ownership Codes and Descriptions

Ownership Code	Ownership Code Description
S	Single ownership by respondent
J	Jointly owned with another entity
W	Wholly owned by an entity other than respondent

5. For line 5, **Does this generator have duct burners for the supplementary firing of the turbine exhaust gas?** Check "Yes" if 1) the generator has a combined cycle prime mover code of "Combined Cycle Steam Part (CA)" "Combined Cycle Single Shaft (CS)," or "Combined Cycle Total Unit (CC,)" and 2) if the unit has duct-burners for supplementary firing of the turbine exhaust gas. Otherwise, check "No."
6. For line 6, **Can this generator operate while bypassing the heat recovery steam generator?** Check "Yes" if 1) the generator has a combined cycle prime mover code of "Combined Cycle Combustion Turbine Part (CT)" or "Combined Cycle Total Unit (CC)" and 2) the combustion turbine can operate while bypassing the heat recovery steam generator. Otherwise, check "No."
7. For line 7a, **For this generator what is the RTO/ISO LMP price node designation?** If this generator operates in an electric system operated by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) and the RTO/ISO calculates a nodal Locational Marginal Price (LMP) at the generator location, then provide the nodal designation used to identify the price node in RTO/ISO LMP price reports.

   For line 7b, **For this generator what is the RTO/ISO location designation for reporting wholesale sales data to FERC?** If this generator operates in an electric system operated by a Regional Transmission Organization (RTO) or Independent System Operator (ISO) and the generator's wholesale sales transaction data is reported to FERC for the Electric Quarterly Report, then provide the designation used to report the specific location of the wholesale sales transactions to FERC. In many cases the RTO/ISO location designation may be the same as the RTO/ISO LMP price node designation submitted in line 7a. In these cases enter the same response in both line 7a and line 7b.

SCHEDULE 3, PART B. GENERATOR INFORMATION – EXISTING GENERATORS

Complete one SCHEDULE 3, Part B for each generator at this plant that is in commercial operation.

1. For line 1a, **What is the nameplate capacity for this generator?** Report the highest value on the generator nameplate in MW rounded to the nearest tenth, as measured in alternating current (AC). If the nameplate capacity is expressed in kilovolt amperes (kVA), first convert the nameplate capacity to kilowatts by multiplying the corresponding power factor by the kVA and then convert to megawatts by dividing by 1,000. Round this value to the nearest tenth. If generator nameplate capacity is less than net summer capacity, provide the reason(s) in SCHEDULE 7.

   For line 1b, **What is the nameplate power factor for this generator?** Enter the power

factor stamped on the generator nameplate. This should be the same power factor used to convert the generator's kilovolt-ampere rating (kVA) to megawatts (MW) as directed for line 1a above. Solar photovoltaic systems, wind turbines, batteries, fuel cells, and flywheels may skip this question.

2. For line 2, **What is this generator's net capacity?** Enter the generator's net summer and net winter capacities for the primary energy source. Report in MW rounded to the nearest tenth, as measured in alternating current (AC). For generators that are out of service for an extended period or on standby, report the estimated capacities based on historical performance. For generators that are tested as a unit, report a single aggregate net summer capacity and a single aggregate net winter capacity. For hydroelectric generators, report the instantaneous capacity at maximum water flow. For solar photovoltaic generators report the peak net capacity during the day for the generator assuming clear sky conditions on June 21 for summer capacity and on December 21 for winter capacity; assume average seasonal temperatures and average wind speeds for June 21 and December 21, respectively. If net capacity is only available as direct current (DC), estimate the effective AC output and explain in SCHEDULE 7.
3. For line 3, **What minimum load can this generator operate at continuously?** Enter the minimum load (MW) at which the unit can operate continuously. Solar-powered generators are not required to answer this question. For generators operating as a single unit that entered a Unit Code (Multi-Generator Code) on SCHEDULE 3, Part A, Line 3, provide the load when all generators are operating at their minimum load.
4. For line 4a, **Was an uprate or derate project completed on this generator during the reporting year?** Check "Yes" if an uprate or derate project was implemented during the reporting year. Check "No" if it was not. If both an uprate and derate were implemented during the reporting year, check "Yes" and explain in SCHEDULE 7.

   For line 4b, **When was this uprate or derate project completed?** Enter the date when the uprate or derate project identified in line 4a was completed.
5. For line 5a, **What was the status of this generator as of December 31 of the reporting year?** Enter one of the following status codes:

Table 4. Generator Status Codes and Descriptions

Ownership Code	Ownership Code Description
OP	Operating - in service (commercial operation) and producing some electricity. Includes peaking units that are run on an as needed (intermittent or seasonal) basis.
SB	Standby/Backup - available for service but not normally used (has little or no generation during the year) for this reporting period.
OS	Out of service – was not used for some or all of the reporting period and is NOT expected to be returned to service in the next calendar year.

OA	Out of service – was not used for some or all of the reporting period but is expected to be returned to service in the next calendar year.
RE	Retired - no longer in service and not expected to be returned to service.

For line 5b, **If Is this generator equipped to be synchronized to the grid?** If the status code entered on line 5a is standby (SB), check "Yes" if the generator is currently equipped to be synchronized to the grid when operating. Check "No" if it is not.

6. For line 6, **When did this generator begin commercial operation?** Enter the month and year of initial commercial operation in the format MM-YYYY.
7. For line 7, **When was this generator retired?** Enter the month and year that the generator was retired in the format (MM-YYYY).
8. For line 8, **If this generator will be retired in the next ten years, what is its estimated retirement date?** If you expect this generator to be retired in the next 10 years, enter your best estimate for this planned retirement date in the format MM-YYYY.
9. For line 9 **Is this generator associated with a combined heat and power system?** Check "Yes" if this generator is associated with a combined heat and power system. Check "No" if it is not.
10. For line 10, **Is this generator part of a topping or bottoming cycle?** If you checked "Yes" on line 9, check "Topping" if this generator is part of a topping cycle. In a topping cycle system, electricity is produced first and any waste heat from that production is used in a manufacturing or commercial application. Check "Bottoming" if this generator is part of a bottoming cycle. In a bottoming cycle system, thermal output is used in a process other than electricity production and any waste heat is then used to produce electricity.
11. For line 11, **What is this generator's predominant energy source?** Enter the energy source code for the fuel used in the largest quantity (Btus) during the reporting year to power the generator. For generators that are out of service for an extended period of time or on standby, report the energy sources based on the generator's latest operating experience. For generators driven by turbines using steam that is produced from waste heat or reject heat, report the original energy source used to produce the waste heat (reject heat). Do not include fuels expected to be used only for start-up or flame stabilization. Select the appropriate energy source code from Table 28 in these instructions.
12. For line 12, **What are the energy sources used by this generator's combustion units for start-up and flame stabilization?** If the prime mover is steam turbine (ST), report the energy sources used by the combustion unit(s) associated with this generator for start-up and flame stabilization; otherwise leave blank. Select the appropriate energy source code from Table 28 in these instructions.
13. For line 13, **What is this generator's second most predominant energy source?** Enter the energy source code for the energy source used in the second largest quantity (Btus) during the reporting year to power the generator. DO NOT include a fuel used only for start-up or flame stabilization. For generators driven by turbines using steam that is produced from waste heat or reject heat, report the original energy source used to produce the waste heat or reject heat. Select the appropriate energy source code from Table 28 in these instructions.

14. For line 14, **What other energy sources are used by the generator?** Enter the codes for other energy sources that can be used by the generator to generate electricity: first, list the energy sources actually used in order of predominance (based on quantity of Btus), then list ones that the generator was capable of using but was not used to generate electricity during the last 12 months. For generators that are out of service for an extended period of time or on standby, report the energy sources based on the generator's latest operating experience. For generators driven by turbines using steam that is produced from waste heat or reject heat, report the original energy source used to produce the waste heat or reject heat. Select the appropriate energy source codes from Table 28 in these instructions.
15. For line 15, **Is this generator part of a solid fuel gasification system?** Check "Yes" if this generator is part of a solid fuel gasification system. Check "No" if it is not.
16. For line 16, **What is the tested heat rate for this generator?** Enter the tested heat rate under full load conditions for all combustible-fueled generators and nuclear-fueled generators. The tested heat rate is the amount of fuel, measured in British thermal units (Btus) necessary to generate one net kilowatt-hour of electric energy. Do not report the actual heat rate, which is the quotient of the total Btu(s), consumed and total net generation. If generators are tested as a unit (not tested individually), report the same test result for each generator. For generators that are out of service for an extended period or on standby, report the heat rate based on the unit's latest test. If the generator is associated with a combined heat and power (CHP) system, and no tested heat rate data are available, report either the manufacturer's specification for heat rate or an estimated heat rate. DO NOT report a heat rate that includes the fuel used for the production of useful thermal output. For Internal Combustion units, a manufacturer's specification or estimated heat rate should be reported, if no tested heat rate is available. If the reported value is not a tested heat rate, specify in SCHEDULE 7.

    This information will be protected and not disclosed to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. §552, the Department of Energy (DOE) regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905
17. For line 17, **What fuel was used to determine this generator's tested heat rate?** Enter the fuel code for the fuel used to determine the heat rate reported in line 16. Enter "M" if multiple fuels were used to calculate the heat rate reported in line 16. For generators driven by turbines using steam that is produced from waste heat or reject heat, report the original energy source used to produce the waste or reject heat). Select appropriate energy source codes from Table 28 in these instructions.
18. For line 18, **Is the generator associated with a carbon dioxide capture process?** Check "Yes" if this generator is associated with carbon dioxide capture. Check "No" if it is not.
19. For line 19, **How many wind turbines, inverters, or hydrokinetic buoys are there at this generator?** Wind generators should enter the number of wind turbines, solar photovoltaic generators should enter the number of inverters, and hydrokinetic generators should enter the number of hydrokinetic buoys. All other generators should enter 0.
20. Line 20 is reserved for future use.
21. For line 21, **What is the minimum amount of time required to bring this generator**

from cold shut down to full load? Select the minimum amount of time required to bring the unit to full load from cold shutdown. Wind and solar-powered generators should not answer this question.

22. For line 22, **What is the minimum amount of time required to bring this generator from a non-spinning reserve status to full load?** Select the minimum amount of time required to bring the unit to full load from a non-spinning reserve status. Wind and solar-powered generators should not answer this question.

Answer questions on lines 23 and 24 only if generator is fueled by coal or petroleum coke

23. For line 23, **What combustion technology applies to this generator?** Select the appropriate combustion technology that applies to the generator.
24. For line 24, **What steam conditions apply to this generator?** Select the appropriate steam conditions that apply to the unit.

Answer questions on lines 25 through 29 only if generator is wind-powered

25. For line 25, **What is the predominant manufacturer of the turbines at this generator?** Enter the predominant manufacturer of the turbines at the generator. If the predominant manufacturer is not known, enter "UNKNOWN."
26. For line 26, **What is the predominant turbine model number at this generator?** Enter the predominant model number. If the predominant model number is not known, enter "UNKNOWN."
27. On line 27a, **What is the design average annual wind speed at this generator?** Enter the design average annual wind speed in miles per hour for the turbines included in the generator. If more than one value exists, select the one that best represents the turbines.

    On line 27b, **What is the wind quality class for turbines included in this generator?** Select the wind quality class for the turbines included in the generator, as defined by the International Electrotechnical Commission (IEC 61400-1 ed. 2) and Table 5 below. If more than one wind class exists, select the one that best represents the turbines.

Table 5. Wind Quality Class and Descriptions

Class	Annual Average Wind Speed	Extreme 50-Year Gust	Turbulence Intensity
Class 1 – High Wind	10 m/s	70 m/s	A: 0.210 B: 0.180
Class 2 – Medium Wind	8.5 m/s	59.6 m/s	A: 0.226 B: 0.191
Class 3 – Low Wind	7.5 m/s	52.5 m/s	A: 0.240 B: 0.200
Class 4 – Very Low Wind	6 m/s	42 m/s	A: 0.270 B: 0.220

28. On line 28, **What is the hub height for the turbines in this generator?** Enter the hub height in feet for the turbines at the generator. If this generator consists of turbines with multiple hub heights, select the one that best represents all of the turbines.

29. On line 29, **What is the FAA Obstacle Number assigned to turbines at this generator?** Enter the Obstacle Number assigned by the Federal Aviation Administration. When the generator consists of turbines with multiple Obstacle Numbers, select the Obstacle Number that best represents the turbines.

Answer questions on lines 30 through 32 only if generator is powered by photovoltaic or concentrated solar thermal technology

30. On line 30, **What are the solar tracking, concentrating and collector technologies used at this generator?** Select all applicable solar tracking, concentrating or collector technologies used at the unit. If you select "Other," provide details in SCHEDULE 7.

31. On line 31, **What is the net capacity of this photovoltaic generator in direct current (DC) under standard test conditions (STC) of 1000 W/m^2 solar irradiance and 25 degrees Celsius PV module temperature?** Enter the sum of the DC capacity ratings of the photovoltaic modules associated with this generator.

32. On line 32, **What materials are the photovoltaic panels included in this generator made of?** Select the material of the Photovoltaic panels. If the panels included in the "generator" are made of different materials, select all materials used. If you select "Other," provide details on the material in SCHEDULE 7.

Lines 33-37 apply to proposed changes to existing generators

33. If a capacity uprate is planned within the next 10 years, answer Questions 33a – 33c.

    For line 33a, **What is the expected incremental increase in the net summer capacity?** If an uprate is planned within the next 10 years enter the incremental amount by which the net summer capacity is expected to increase. If no uprate is planned in the next ten years, leave this blank.

    For line 33b, **What is the expected incremental increase in the net winter capacity?** If an uprate is planned within the next 10 years, enter the incremental amount by which the net winter capacity is expected to increase. If no uprate is planned in the next ten years, leave this blank.

    For line 33c, **What is the planned effective date for this capacity uprate?** If an uprate is planned within the next 10 years, enter the date on which the generator is scheduled to re-enter commercial operation after the planned uprate. Enter the date in the format MM-YYYY. If no uprate is planned in the next 10 years, leave this blank.

34. If a capacity derate is planned within the next 10 years, answer Questions 34a – 34c.

    For line 34a, **What is the expected incremental decrease in the net summer capacity?** If a derate is planned within the next 10 years, enter the incremental amount by which the net summer capacity is expected to decrease. If no derate is planned in the next 10 years, leave this blank.

    For line 34b, **What is the expected incremental decrease in the net winter capacity?** If a derate is planned within the next 10 years, enter the incremental amount by which the net winter capacity is expected to decrease. If no derate is planned in the next ten years, leave this blank.

    For line 34c, **What is the planned effective date for this capacity derate?** If a derate is planned in the next 10 years, enter the date on which the generator is scheduled to re-enter commercial operation after the planned derate. Enter the date in the format MM-YYYY. If no derate is planned in the next 10 years, leave this blank.

35. For line 35a, **What is the expected new prime mover for this generator?** If a repowering is planned within the next 10 years, enter the new prime mover for this generator. Select the prime mover code from those listed in the instructions for SCHEDULE 3 Part A, Table 2. If no repowering is planned within the next 10 years, leave this blank.

    For line 35b, **What is the expected new energy source for this generator?** If a repowering is planned within the next 10 years, enter the new energy source for this generator. Select the energy source code from Table 28 in these instructions. If no repowering is planned in the next ten years, leave this blank.

    For line 35c, **What is the expected new nameplate capacity for this generator?** If a repowering is planned for within the next 10 years, enter the new nameplate capacity for this generator.

    For line 35d, **What is the planned effective date for this repowering?** Enter the date on which this generator is scheduled to re-enter operation after the repowering. Enter the date in the format MM-YYYY. If no repowering is planned, leave this blank.

36. On line 36a, **Are any other modifications planned within the next 10 years?** Check "Yes" if any other significant modifications are planned for this generator in the next 10 years. Explain these modifications on SCHEDULE 7 of this form. Check "No" If no other significant modifications are planned within the next 10 years.

    On line 36b, **What is the planned date of these other modifications?** If you checked "Yes" on line 36a, enter the date on which this generator will reenter service after the modification. Enter the date in the format MM-YYYY. If you selected "No," leave this blank.

37. On line 37a, **Can this generator co-fire fuels?** Indicate yes if the combustion system that powers each generator has both:

    - The regulatory permits necessary to co-fire fuels, and
    - The equipment, including fuel storage facilities in working order, necessary to either co-fire fuels or fuel switch.

    Note: ***Co-firing*** means the simultaneous use of two or more fuels by a single combustion system to meet load. Co-firing excludes the limited use of a secondary fuel for start-up or flame stabilization.

    Line37b applies only if the generator can co-fire fuels

    For line 37b, **What are the fuel options for co-firing**? Indicate up to six fuels that can be co-fired. Select appropriate energy source codes from Table 28 in these instructions.

    Note: fuel options listed for co-firing must also be included under either "Predominant Energy Source," Second Most Predominant Energy Source," or "Other Energy Sources."

38. For line 38a, **Can this generator switch between oil and natural gas?** Check "Yes" if:

    - the primary energy source of the unit is oil or natural gas;
    - the combustion system that powers the generator has, in working order, the equipment (including fuel oil storage tanks) necessary to switch between natural gas and oil; and
    - this combustion system has the regulatory permits necessary to switch between

natural gas and oil.

Note: ***Fuel switching*** means the ability of a combustion system running on one fuel to replace that fuel in its entirety with a substitute fuel. Fuel switching excludes the limited use of a secondary fuel for start-up or flame stabilization.

Answer questions on lines 38b through 42 only if generator can fuel switch between oil and natural gas

For line 38b, **Can this generator switch between oil and natural gas while operating?** Check "Yes," if 1) you checked "Yes" for line 38a, and 2) if the combustion system that powers this generator is able to switch between natural gas and oil while operating.

39. For line 39a, **What is the maximum net summer output achievable when running on natural gas?** Enter the maximum net summer output in MW that the unit can achieve when running on natural gas, taking into account all applicable legal, regulatory, and technical limits.

    For line 39b, **What is the maximum net winter output achievable when running on natural gas?** Enter the maximum net winter output in MW that the unit can achieve when running on natural gas, taking into account all applicable legal, regulatory, and technical limits.

40. For line 40a, **What is the maximum net summer output achievable when running on oil?** Enter the maximum net summer output in MW that the unit can achieve when running on fuel oil, taking into account all applicable legal, regulatory, and technical limits.

    For line 40b, **What is the maximum net winter output achievable when running on oil?** Enter the maximum net winter output in MW that the unit can achieve when running on fuel oil, taking into account all applicable legal, regulatory, and technical limits.

41. For lines 41a, **How much time is required to switch the generator from using 100 percent natural gas to 100 percent oil?** Enter the amount of time that it takes to switch the generator from using 100 percent natural gas to 100 percent oil.

    For line 41b, **How much time is required to switch this generator from using 100 percent oil to using 100 percent natural gas?** Enter the amount of time that it takes to switch the generator from using 100 percent oil to 100 percent natural gas.

42. For line 42a, **Are there factors that limit this generator's ability to switch between natural gas and oil?** These factors may include limits on maximum output, limits on annual operating hours, or other limitations.

    For line 42b, **Which factors limit this generator's ability to switch between natural gas and oil?** If you selected "Yes" on line 42a, select all of the factors that limit the ability to switch fuels. If you select "Other" provide explanation in SCHEDULE 7.

SCHEDULE 3, PART C. GENERATOR INFORMATION – PROPOSED GENERATORS

Complete this Schedule for all generators at this plant that are:

- Expected to be in commercial operation within 10 years in the case of coal and nuclear generators; or
- Expected to be in commercial operation within 5 years for all generators other than coal and nuclear generators.

1. For line 1a, **What is the expected nameplate capacity for this generator?** Enter the expected nameplate capacity in MW rounded to the nearest tenth, as measured in alternating current (AC). If the expected nameplate capacity is expressed in kilovolt amperes (kVA), first convert the expected nameplate capacity to kilowatts by multiplying the corresponding power factor by the kVA and then convert to megawatts by dividing by 1,000. Round this value to the nearest tenth.

   For line 1b, **What is the expected nameplate power factor for this generator?** Enter the expected power factor. This should be the same power factor used to convert the generator's kilovolt-ampere rating (kVA) to megawatts (MW) as directed for line 1a above.

2. For line 2, **What is the expected net capacity for this generator?** Enter the generator's net summer and net winter capacities for the primary energy source that are expected when the generator goes into commercial operation. Report these values in MW rounded to the nearest tenth, as measured in alternating current (AC).

3. For line 3, **What was the status of this proposed generator as of December 31 of the reporting year?** Enter one of the following status codes:

Table 6. Proposed Generator Status Codes and Descriptions

Proposed Generator Status Code	Proposed Generator Status Code Descriptions
IP	Planned new generator canceled, indefinitely postponed, or no longer in resource plan
TS	Construction complete, but not yet in commercial operation (including low power testing of nuclear units)
P	Planned for installation but regulatory approvals not initiated; Not under construction
L	Regulatory approvals pending. Not under construction but site preparation could be underway
T	Regulatory approvals received. Not under construction but site preparation could be underway
U	Under construction, less than or equal to 50 percent complete (based on construction time to date of operation)
V	Under construction, more than 50 percent complete (based on construction time to date of operation)
OT	Other (specify in SCHEDULE 7)

4. For line 4, **What is the planned original effective date for this generator?** Enter the date on which the generator is scheduled to start commercial operation. Enter the date in the format MM-YYYY. This date will not change after it has been reported the first time.
5. For line 5, **What is the planned current effective date for this generator?** If a Planned Original Effective Date was submitted an earlier filing and is no longer accurate, enter the updated date on which the generator is scheduled to start commercial operation. Enter the date in the format MM-YYYY. Leave blank if this is your first time filling out this form.
6. For line 6, **Will this generator be associated with a combined heat and power system?** Check "Yes" if this generator will be associated with combined heat and power system. If it will not, check "No."
7. For line 7, **Is this generator part of a site that was previously reported as indefinitely postponed or cancelled?** Check "Yes" if this generator is part of a site that was previously reported by either your company or a previous owner as an indefinitely postponed or cancelled plant. Check "No" if it is not. Check "Unknown" if this history is not known.
8. For line 8, **What is the predominant expected energy source for this generator?** Enter the energy source code for the energy source expected to be used in the largest quantity, as measured in Btus, when the generator starts commercial operation. Select appropriate energy source codes from Table 28 in these instructions.
9. For line 9, **What is the second most predominant expected energy source for this generator?** Enter the energy source code for the energy sources expected to be used in the second largest quantity, as measured in Btus, when the generator starts commercial operation. Do not include fuels expected to be used only for start-up or flame stabilization. Select the appropriate energy source code from Table 28 in these instructions.
10. For line 10, **What other energy sources do you expect to use for this generator?** Enter the codes for other energy sources that will be used at the plant to power the generator. Enter up to four codes. Enter these codes in order of their expected predominance as measured in Btus. Select appropriate energy source codes from Table 28 in these instructions.
11. For line 11, **How many turbines, inverters, or buoys is this generator expected to have?** Wind generators should enter the number of turbines, solar generators should enter the number of inverters, and hydroelectric generators should enter the number of buoys.
12. For line 12, **What combustion technology will apply to this generator?** If the generator will be fired by coal or petroleum coke, select the appropriate combustion technology. If you select "Other" provide explanation in SCHEDULE 7.
13. For line 13 **What steam conditions will apply to this generator?** If the generator will be fired by coal or petroleum coke, select the appropriate steam conditions.
14. For line 14, **Will this generator be part of a solid fuel gasification system?** Check "Yes" if this generator will be part of a solid fuel gasification system. Check "No" if it will not be.
15. For line 15, **Will this generator be associated with a carbon dioxide capture process?** Check "Yes" if this generator will be associated with a carbon capture process. Check "No" if it will not be associated with carbon capture.

Line 16 applies only if the generator will be able to fuel switch.

Lines 17a and 17b apply only if the generator will be able to co-fire fuels.

Note: ***Co-firing*** means the simultaneous use of two or more fuels by a single combustion system to meet load. ***Fuel switching*** means the ability of a combustion system running on one fuel to replace that fuel in its entirety with a substitute fuel. Co-firing and fuel switching exclude the limited use of a secondary fuel for start-up or flame stabilization

16. For line 16, **Will the combustion system that powers this generator be able to switch between natural gas and oil?** Check "Yes" if 1) the primary energy source of the generator will be natural gas or oil and 2) the combustion system that will power the generator will have the ability and equipment necessary (including fuel oil storage tanks) to switch between natural gas and oil. Check "No" if it will not. Check "Undetermined" if a determination on switching between natural gas and oil has not yet been made.

17. For line 17a, **Will the combustion system that powers this generator be able to co-fire fuels?** Indicate whether or not the combustion system that will power the generator will have the necessary equipment and regulatory permits to co-fire fuels.

    For line 17b, **What are the fuel options for co-firing?** Indicate up to six fuels that the generator will be designed to co-fire. Select the energy source codes from Table 28 in these instructions. Note: fuel options listed for co-firing must also be included under "Predominant Energy Source," Second Most Predominant Energy Source," and/or "Other Energy Sources."

SCHEDULE 4. OWNERSHIP OF GENERATORS OWNED JOINTLY OR BY OTHERS

1. Complete SCHEDULE 4 for each operable or planned generator that is or will be either jointly owned with another entity or wholly owned by an entity other than the reporting entity as entered on SCHEDULE 1, Line 3.
2. For each generator that is either jointly owned with another entity or wholly owned by another specify the Plant Name, EIA Plant Code, and Generator Identification Code, as listed on SCHEDULE 3, PART A.
3. For each owner of either a jointly owned generator or wholly owned by an entity other than the reporting entity generator, enter the name, address and percentage owned. The total percentage of reported ownership must equal 100 percent.
4. If known, enter the **EIA Owner Code** for the owner, otherwise leave blank. The EIA Owner Code is the same as the EIA Utility Identification Code and EIA Entity Identification Code.
5. Enter the **Percent Owned** to two decimal places, i.e., 12.5 percent as "12.50." Include any notes or comments in SCHEDULE 7.

SCHEDULE 5. GENERATOR CONSTRUCTION COST INFORMATION

1. The reporting year is the calendar year that you are filing the survey for. For example, if you are **reporting** data as of December 31, 2013, then the reporting year is 2013.
2. Include all construction costs in SCHEDULE 5 regardless of which party is ultimately responsible for those costs. All disputed costs must be included in the reported estimated or final project costs. If disputed costs are included in the reported estimated or final project costs, you can note this in SCHEDULE 7.

SCHEDULE 5, PART A. GENERATOR CONSTRUCTION COST INFORMATION - COAL AND NUCLEAR GENERATORS

Complete a separate SCHEDULE 5, PART A for each coal or nuclear generator that, during the reporting year:

- Began commercial operation; **or**
- Was under construction, in final testing or in the process of receiving permits and regulatory approvals; **or**
- Was a nuclear generator that has applied for a combined operating license (COL) from the Nuclear Regulatory Commission.

Enter the **Plant Name**, **EIA Plant Code**, and **Generator ID** as previously reported in SCHEDULE 3, PART A.

1. For line 1, **What is the total construction cost for this generator (in thousands of dollars)?** If the generator did not enter commercial operation during the reporting year, provide the best available projection of the total construction cost to completion. If the project entered commercial operation during the reporting year, provide the best available estimate of total construction costs. Total Construction Costs should be provided in nominal dollars (do not discount future costs to reflect the time value of money and do not adjust past costs to reflect inflation) and typically include the following items:

   - **Civil and structural costs** - allowance for site preparation, drainage, installation of underground utilities, structural steel supply, and construction of buildings on the site. Exclude land acquisition or leasing costs.
   - **Mechanical equipment supply and installation** - major equipment, including but not limited to, boilers, flue gas desulfurization scrubbers, cooling towers, steam turbine generators, condensers, and other auxiliary equipment.
   - **Electrical and instrumentation control –** electrical transformers, switchgear, motor control centers, switchyards, distributed control systems, and other electrical commodities.
   - **Project indirect costs –** engineering, distributable labor and materials, craft labor overtime and incentives, scaffolding costs, construction management start up and commissioning, and fees for contingency (including contractor overhead costs, fees,

profits, and construction).

- **Owner Costs –** development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a tie-in to a nearby electrical transmission system.

Exclude financing, government grants, tax benefits, or other incentives from this number.

2. For line 2, **What are the total financing costs for construction of this generator (in thousands of dollars)?** Enter the total financing costs including (1) the interest cost of debt financing, (2) any imputed cost of equity financing, and (3) funds recovered to maintain a debt service coverage ratio for the project. In the cast of investor-owned utilities, financing costs include any allowance for funds used during construction (AFUDC). For example, the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used.
3. For line 3, **What is the total cost to construct this generator including financing costs (in thousands of dollars)?** Enter the total cost to construct the generator including both construction costs and financing. This value should be the sum of the answers to the two previous questions.

SCHEDULE 5, PART B. GENERATOR CONSTRUCTION COST INFORMATION - OTHER THAN COAL AND NUCLEAR GENERATORS

Complete a separate SCHEDULE 5, PART B for each generator other than coal or nuclear generators that, during the reporting year:

- Began commercial operation

Do **not** report for any units reported on SCHEDULE 5, PART A.

Enter the **Plant Name**, **EIA Plant Code**, and **Generator ID** as previously reported in SCHEDULE 3, PART A.

1. For line 1, **What is the total construction cost for this generator (in thousands of dollars)?** Enter the total construction cost to completion. Total Construction Costs should be provided in nominal dollars (do not discount future costs to reflect the time value of money and do not adjust past costs to reflect inflation) and typically include the following items:

- **Civil and structural costs** - allowance for site preparation, drainage, installation of underground utilities, structural steel supply, and construction of buildings on the site. Exclude land acquisition or leasing costs.

- **Mechanical equipment supply and installation** - major equipment, including but not limited to, boilers, flue gas desulfurization scrubbers, cooling towers, steam turbine generators, condensers, photovoltaic modules, combustion turbines, and other auxiliary equipment.

- **Electrical and instrumentation control –** electrical transformers, switchgear, motor control centers, switchyards, distributed control systems, and other electrical commodities.

- **Project indirect costs –** engineering, distributable labor and materials, craft labor overtime and incentives, scaffolding costs, construction management start up and commissioning, and fees for contingency (including contractor overhead costs, fees, profits, and construction).

- **Owner Costs –** development costs, preliminary feasibility and engineering studies, environmental studies and permitting, legal fees, insurance costs, property taxes during construction, and the electrical interconnection costs, including a tie-in to a nearby electrical transmission system.

Exclude financing, government grants, tax benefits, or other incentives from this number.

2. For line 2, **What are the total financing costs for construction of this generator (in thousands of dollars)?** Enter the total financing costs including (1) the interest cost of debt financing, (2) any imputed cost of equity financing, and (3) funds recovered to maintain a debt service coverage ratio for the project. In the cast of investor-owned utilities, financing costs include any allowance for funds used during construction (AFUDC). For example, the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used.
3. For line 3, **What is the total cost to construct this generator including financing costs (in thousands of dollars)?** Enter the total cost to construct the generator including both construction costs and financing. This value should be the sum of the answers to the two previous questions.

SCHEDULE 6. INFORMATION ON BOILERS AND ASSOCIATED EQUIPMENT

SCHEDULE 6 collects information on existing and planned boilers and associated equipment serving steam electric generators, including units burning combustible fuels, nuclear units, and solar thermal units. Complete for EACH boiler.

Complete SCHEDULE 6 as follows:

Required Respondents	Schedule 6 Parts to be Completed
Plants where the sum of the nameplate capacity of the steam-electric generators, including duct fired steam components of combined cycle units, sum to 100 MW or more.	Parts A - G
All nuclear plants, solar thermal plants and steam components of combined cycle units without duct firing where the sum of the nameplate capacity of the steam-electric generators is 100 MW or more.	Part A Part D
Plants where the sum of the nameplate capacity of the steam-electric generators, including duct fired steam components of combined cycle units, sum to 10 MW or more, but less than 100 MW.	Part A Part B, Lines 6 to 8 and 11 to 14 *(NOx and Mercury questions)* Part C, Lines 1 to 3 Part E Part F

SCHEDULE 6, PART A. PLANT CONFIGURATION AND ENVIRONMENTAL EQUIPMENT INFORMATION

Complete SCHEDULE 6, Part A, if you are reporting for a plant where the sum of the nameplate capacity of the steam-electric generators, including duct-fired steam components of combined cycle units, sum to 10 MW or more.

1. For line 1, **What equipment is associated with each boiler at this plant?**

Enter the unique identification codes commonly used by plant management to identify the boiler and all associated equipment: generators, cooling systems, particulate matter control systems, sulfur dioxide control systems, NOx control, mercury control and stacks.

These identification codes are generally restricted to six characters and cannot be changed once provided to EIA. However, the identification codes for generators are restricted to five characters.

Include all equipment that:

- Was operable in the past calendar year; **or**

- Is expected to be in commercial operation within 10 years in the case of equipment associated with coal and nuclear generators; **or**
- Is expected to be in commercial operation within 5 in the case of equipment not associated with coal and nuclear generators

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.

If any equipment is associated with multiple boilers, repeat the equipment identification code under each boiler. Do not change prepopulated equipment identification codes.

Note equipment such as selective catalytic reduction, activated carbon injection, and dry sorbent injection into a fluidized bed boiler will require an identification code entry as these were not collected in past reporting years.

- Row 1 – Enter boiler ID
- Row 2 – Enter all generator ID(s) associated with the boiler (Generator ID must match those entered on SCHEDULE 3 PART A.
- Row 3 – Enter associated cooling system ID(s)
- Row 4 – Enter associated particulate matter control system ID(s)
- Row 5 – Enter associated sulfur dioxide control system ID(s) including dry sorbent injection (DSI) in a fluidized bed combustion boiler
- Row 6 – Enter associated nitrogen oxide (NOx) control equipment ID(s) (assign an ID to each selective catalytic reduction and selective noncatalytic reduction device).
- Row 7 – Enter associated mercury control ID(s), including activated carbon injection (assign an ID to each mercury control system).
- Row 8 – Enter associated stack (or flue) ID(s)

2. For Line 2, **What are the characteristics of each piece of emissions control equipment?**

   Enter in Column A, the Equipment Type code from Table 7.

Table 7. Equipment Type Code and Description

Equipment Type Code	Equipment Type Description
JB	Jet bubbling reactor (wet) scrubber
MA	Mechanically aided type (wet) scrubber
PA	Packed type (wet) scrubber
SP	Spray type (wet) scrubber
TR	Tray type (wet) scrubber

VE	Venturi type (wet) scrubber
BS	Baghouse (fabric filter), shake and deflate
BP	Baghouse (fabric filter), pulse
BR	Baghouse (fabric filter), 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
CD	Circulating dry scrubber
SD	Spray dryer type / dry FGD / semi-dry FGD
DSI	Dry sorbent (powder) injection type (DSI)
ACI	Activated carbon injection system
LIJ	Lime injection
SN	Selective noncatalytic reduction
SR	Selective catalytic reduction
OT	Other equipment (Specify in SCHEDULE 7)

For Columns B to I:

Enter the identification codes from the above table in the appropriate columns for emissions controls. If a piece of equipment controls multiple air emissions, enter the appropriate code in multiple columns (for example, if a wet scrubber controls for both sulfur dioxide, particulate matter and mercury, enter the associated identification code from the table above in Columns B, C and E).

- For Particulate Control (PM) equipment, enter identification code(s) in Column B
- For Sulfur Dioxide Control (SO2) equipment, enter the identification code(s) in Column C
- For Nitrogen Oxide Control (NOx) equipment, enter the identification code(s) in Column D
- For Mercury Control (Hg) equipment, enter the identification code(s) in Column E
- For HCl gas control, enter an X in Column F (no identification codes are required).
- For Column G, enter the status for the equipment as of December 31 of the reporting year from Table 8 in the instructions.

Table 8. Equipment Status Codes and Descriptions

Status Code	Status Description
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 only during the ozone season (May through September)
PL	Planned (expected to go into commercial service within 10 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)

In Column H**, In-service Date,** enter the date on which the equipment began commercial operation or the date on which it is expected to begin commercial operation (MM/YYYY).

In Column I, **Total Costs (Thousand Dollars),** enter the nominal installed cost for the existing system or the anticipated cost to bring a planned piece of equipment into commercial operation (in thousands of dollars). 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 emissions or pollutants or which results in a different pollutant being emitted. Costs should be provided in nominal dollars (do not discount future costs to reflect the time value of money and do not adjust past costs to reflect inflation)

SCHEDULE 6, PART B. BOILER INFORMATION – AIR EMISSION STANDARDS AND CONTROL STRATEGIES

For plants with a total steam-electric nameplate capacity of 10 MW or greater but less than 100 MW:

Complete ONLY questions 1, 6a to 6d, 7, 8a, 8b, 11,12, 13 and 14 (NOx and Mercury questions) SCHEDULE 6, Part B for each boiler and its associated equipment that serve or are expected to serve combustible-fueled steam electric generators or combined cycle steam generators with duct firing.

For plants with a total steam-electric nameplate capacity of 100 MW or greater:

Complete one SCHEDULE 6, Part B in its entirety for each boiler and its associated equipment that serve or are expected to serve combustible-fueled steam electric generators and combined cycle steam generators with duct firing.

Include all boilers that:

- Were operable in the past calendar year; or
- Are expected to be in commercial operation within 10 years in the case of coal plans;

or

- Are expected to be in commercial operation within 5 years in the case of non-coal plants

1. For line 1, **What is this boiler's identification code?** Enter the boiler identification number corresponding to each boiler listed on SCHEDULE 6, PART A.
2. For Line 2a, **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 codes in Table 9 of the New Source Performance Standards (NSPS):

Table 9. Boiler Standards Codes and Descriptions

D	Standards of Performance for fossil-fuel fired steam boilers for which construction began after August 17, 1971.
Da	Standards of Performance for fossil-fuel fired steam boilers for which construction began after September 18, 1978
Db	Standards of Performance for fossil-fuel fired steam boilers for which construction began after June 19, 1984.
Dc	Standards of Performance for small industrial-commercial-institutional steam generating units
N	Not covered under New Source Performance Standards.

For line 2b, **Is this boiler operating under a new Source Review (NSR) permit?**, indicate whether the boiler is operating under a new source review permit

For line 2c, if the boiler is operating under a NSR permit, provide the **NSR Permit List Date and NSR Permit identification** number.

Lines 3-5 apply to sulfur dioxide compliance

3. For line 3a, **What is the regulatory level of the most stringent regulation that this boiler is operating under to meet sulfur dioxide control standards?** Select the *most stringent* regulation that the boiler operates under to meet sulfur dioxide control standards.

   For line 3b, **What is the emission rate specified by the most stringent sulfur dioxide regulation?** Enter the emission rate corresponding to the most stringent sulfur dioxide regulation. Pounds of sulfur dioxide per million Btu in fuel is the preferred measurement or use Units of Measurement in Table 10.

   For line 3c, **What is the percent of sulfur to be scrubbed specified by the most stringent sulfur dioxide regulation?** If the most stringent regulation specifies a percent (by weight) of sulfur to be scrubbed enter the percent.

   For line 3d, **What is the unit of measurement specified by the most stringent sulfur**

dioxide regulation? Select the unit of measure corresponding to the emission rate entered in line 3b from the values in Table 10. Note that DP*, "Pounds of sulfur dioxide per million Btu in fuel" is the preferred measurement.

Table 10. Sulfur Dioxide Unit of Measurement Codes

Sulfur Dioxide Unit of Measurement Code	Sulfur Dioxide Unit of Measurement Code Description
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 SCHEDULE 7)

For line 3e, **What is the time period specified by the most stringent sulfur dioxide regulation?** Enter the time period corresponding to the emission rate entered in line 3b from the values in Table 11.

Table 11. Time Period Codes

Time Period Code	Time Period Code Description
NV	Never to exceed
FM	5 minutes
SM	6 minutes
FT	15 minutes
OH	1 hour
WO	2 hours
TH	3 hours
EH	8 hours
DA	24 hours
WA	1 week
MO	30 days
ND	90 days
YR	Annual
PS	Periodic stack testing
DT	Defined by testing
NS	Not specified
OT	Other (specify in SCHEDULE 7)

4. For line 4, **In what year did the boiler became compliant or is expected to become compliant with the most stringent sulfur dioxide regulation?** Indicate the year in which the boiler came into compliance or is expected to come into compliance with Federal, State and Local Regulations as they relate to sulfur dioxide control.

5. For line 5a, **What is your existing strategy for complying with the most stringent sulfur dioxide regulation?** If the boiler is already in compliance with Federal, State and local regulations as they relate to sulfur dioxide control, select up to three compliance strategies from table 12 below.

Table 12. Sulfur Dioxide Compliance Strategies

Sulfur Dioxide Compliance Codes	Sulfur Dioxide Compliance Code Descriptions
CF	Fluidized Bed Combustor
CU	Control unit under Phase I extension plan
IF	Install flue gas desulfurization unit or other SO2 control process (other than Phase I extension plan)
NC	No change in historic operation of unit anticipated
ND	Not determined at this time
RP	Repower 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 purchase allowances
OT	Other (specify in SCHEDULE 7)

For line 5b, **What is your proposed strategy for complying with the most stringent sulfur dioxide regulation?** If the boiler is not in compliance with Federal, State and local regulations as they relate to sulfur dioxide control, select up to three proposed compliance strategies from table 12 above.

Lines 6-8 apply to nitrogen oxide compliance

6. For line 6a, **What is the regulatory level of the most stringent regulation that this boiler is operating under to meet nitrogen oxide control standards?** Select the *most stringent* regulation that the boiler operates under to meet nitrogen oxide control standards.

   For line 6b, **What is the emission rate specified by the most stringent nitrogen oxide regulation?** Enter the emission rate corresponding to the most stringent nitrogen oxide regulation. Pounds of nitrogen oxides per million Btu in fuel is the preferred measurement or use Units of Measurement in Table 13.

For line 6c, **What is the unit of measurement specified by the most stringent nitrogen oxide regulation?** Select the unit of measure corresponding to the emission rate entered in line 6b from the values in Table 13. Note that "Pounds of nitrogen oxides per million Btu in fuel" is the preferred measurement.

Table 13. Nitrogen Oxide Unit of Measurement Codes

Nitrogen Oxide Unit of Measurement Code	Nitrogen Oxide Unit of Measurement Code Description
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 SCHEDULE 7)

For line 6d, **What is the time period specified by the most stringent nitrogen oxide regulation?** Enter the time period corresponding to the emission rate entered in line 6b from the values in Table 11.

7. For line 7, **In what year did the boiler became compliant or is expected to become compliant with the most stringent nitrogen oxide regulation?** Indicate the year in which the boiler came into compliance or is expected to come into compliance with Federal, State and Local Regulations as they relate to nitrogen oxide control.

8. For line 8a, **What is your existing strategy for complying with the most stringent nitrogen oxide regulation?** If the boiler is already in compliance with Federal, State and local regulations as they relate to nitrogen oxide control, select up to three compliance strategies from Table 14 below.

Table 14. Nitrogen Oxide Compliance Codes and Strategies

Nitrogen Oxide Compliance Codes	Nitrogen Oxide Compliance Strategies
AA	Advanced overfire air
BF	Biased firing (alternative burners)
CF	Fluidized bed combustor
FR	Flue gas recirculation
FU	Fuel reburning
H2O	Water injection
LA	Low excess air
LN	Low NOx burner
NH3	Ammonia injection
NC	No change in historic operation of unit anticipated
ND	Not determined at this time
OV	Overfire air
RP	Repower unit

SC	Slagging
SN	Selective noncatalytic reduction
SR	Selective catalytic reduction
STM	Steam injection
UE	Decrease utilization – rely on energy conservation and/or improved efficiency
NA	Not applicable
OT	Other (specify in SCHEDULE 7)
BO	Burner out of service
MS	Currently meeting standard
NP	No plans to control
SE	Seeking revision of government regulation

For line 8b, **What is your proposed strategy for complying with the most stringent nitrogen oxide regulation?** If the boiler is not in compliance with Federal, State and local regulations as they relate to nitrogen oxide control, select up to three proposed compliance strategies from Table 14 above.

Lines 9-10 apply to particulate matter compliance

9. For line 9a, **What is the regulatory level of the most stringent regulation that this boiler is operating under to meet particulate matter control standards?** Select the *most stringent* regulation that the boiler operates under to meet particulate matter control standards.

   For line 9b, **What is the emission rate specified by the most stringent particulate matter regulation?** Enter the emission rate corresponding to the most stringent particulate matter regulation. Pounds of particulate matter per million Btu in fuel is the preferred measurement or use Units of Measurement in Table 15.

   For line 9c, **What is the unit of measurement specified by the most stringent particulate matter regulation?** Select the unit of measure corresponding to the emission rate entered in line 9b from the values in Table 15. Note that "Pounds of Particulate matter per million Btu in fuel" is the preferred measurement.

Table 15. Particulate Matter Unit of Measurement Codes

Particulate Matter Unit of Measurement Code	Particulate Matter Unit of Measurement Code Description
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 SCHEDULE 7)

For line 9d, **What is the time period specified by the most stringent particulate matter regulation?** Enter the time period corresponding to the emission rate entered in line 9b from the values in Table 11.

10. For line 10, **In what year did the boiler became compliant or is expected to become compliant with the most stringent particulate matter regulation?** Indicate the year in which the boiler came into compliance or is expected to come into compliance with Federal, State and Local Regulations as they relate to particulate matter control.

Lines 11-14 apply to mercury and acid gas compliance

11. For line 11, **What is the regulatory level of the most stringent regulation that this boiler is operating under to meet mercury and acid gas standards?** Select the *most stringent* regulation that the boiler operates under to meet mercury and acid gas control standards.
12. For line 12, **In what year did the boiler became compliant or is expected to become compliant with the most stringent mercury and acid gas regulation?** Indicate the year in which the boiler came into compliance or is expected to come into compliance with Federal, State and Local Regulations as they relate to mercury and acid gas control.
13. For line 13, **What are the existing strategies to control mercury emissions?** If the boiler is already in compliance with Federal, State and local regulations as they relate to mercury control, select up to three compliance strategies from Table 16 below.

Table 16. Mercury Compliance Codes and Descriptions

Strategy Type Code	Strategy Type Description
BS	Baghouse (fabric filter), shake and deflate
BP	Baghouse (fabric filter), pulse
BR	Baghouse (fabric filter), reverse air
CD	Circulating dry scrubber
SD	Spray dryer type / dry FGD / semi-dry FGD
DSI	Dry sorbent (powder) injection type
ACI	Activated carbon injection system
LIJ	Lime injection
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
JB	Jet bubbling reactor (wet) scrubber
MA	Mechanically aided type (wet) scrubber
PA	Packed type (wet) scrubber
SP	Spray type (wet) scrubber
TR	Tray type (wet) scrubber
VE	Venturi type (wet) scrubber
OT	Other (specify in SCHEDULE 7)
ND	Not determined at this time
NA	Not applicable

14. For line 14**, What are the proposed strategies to control mercury emissions?** If the boiler is not in compliance with Federal, State and local regulations as they relate to mercury control, select up to three proposed compliance strategies from Table 16 above.

SCHEDULE 6, PART C. BOILER INFORMATION – DESIGN PARAMETERS

Complete SCHEDULE 6, Part C, ONLY Lines 1 through 3 if you are reporting for a plant where the sum of the nameplate capacity of the steam-electric generators, including duct fired steam components of combined cycle units, sum to at least 10 MW, but less than 100 MW.

Complete SCHEDULE 6, Part C in its entirety if you are reporting for a plant where the sum of the nameplate capacity of the steam-electric generators, including duct fired steam components of combined cycle units, sum to 100 MW or more.

Complete one SCHEDULE 6, Part C for each unique Boiler ID as reported on SCHEDULE 6 PART A, Line 1, Row 1

1. For line 1, **What was this boiler's status as of December 31 of the reporting year?** Select the boiler status from Table 17:

Table 17. Boiler Status Codes and Descriptions

Boiler Status Code	Boiler Status Description
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 (expected to go into commercial service within 10 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 2, **What is the actual or projected in-service date for this boiler?** Enter the month during which the boiler came into service or is expected to come into service. The month-year date should be entered as follows: August 1959 as 08-1959. If the month is unknown, use the month of June.

3. For line 3, **What is the actual or projected retirement date for this boiler?** Enter the month during whicht the boiler was retired or is expected to be retired. The month-year date should be entered as follows: August 1959 as 08-1959. If the month is unknown, use the month of June.

4. For line 4, **What type of boiler is this?** Enter up to three of the firing codes from Table 18.

Table 18. Boiler Firing Type Code and Description

Boiler Type Code	Boiler Type Description
CB	Cell Burner
CY	Cyclone Firing
DB	Duct Burner
FB	Fluidized Bed Firing (Circulating Fluidized Bed, Bubbling Fluidized Bed)
SS	Stoker (Spreader, Vibrating Gate, Slinger)
TF	Tangential Firing / Concentric Firing / Corner Firing
VF	Vertical Firing / Arch Firing
WF	Wall Fired (Opposed Wall, Rear Wall, Front Wall, Side Wall)
OT	Other (specify in SCHEDULE 7)

5. For lines 5, **What is the maximum continuous steam flow at 100 percent load for this boiler?** Enter the maxium, design steam flow for the boiler at 100 percent load in 1000 pounds per hour.

6. For line 6, **What is the design firing rate at the maximum continuous steam flow for coal and petroleum coke?** Enter the design firing rate data for burning coal and petroleum coke to the nearest 0.1 tons per hour. Do not enter firing rate data for startup or flame stabilization fuels. For waste-heat boilers with auxiliary firing, enter the firing rate for auxiliary firing.

7. For line 7, **What is the design firing rate at the maximum continuous steam flow for petroleum liquids?** Enter the design firing rate data for burning petroleum liquids to the nearest 0.1 barrels per hour. Do not enter firing rate data for startup or flame stabilization fuels. For waste-heat boilers with auxiliary firing, enter the firing rate for auxiliary firing.

8. For line 8, **What is the design firing rate at the maximum continuous steam flow for natural gas?** Enter the design firing rate data for burning natural gas to the nearest 0.1 thousand cubic feet per hour. Do not enter firing rate data for startup or flame stabilization fuels. For waste-heat boilers with auxiliary firing, enter the firing rate for auxiliary firing.

9. For line 9, **What is the design firing rate at the maximum continuous steam flow for energy sources other than coal, petroleum or natural gas?** Enter the design firing rate data for burning any other primary fuel other than coal, petroleum or natural gas. Do not enter firing rate data for startup or flame stabilization fuels. For waste-heat boilers with auxiliary firing, enter the firing rate for auxiliary firing. Specify the primary fuel (use codes from Table 28) for which value is provided along with related measurement unit in SCHEDULE 7.

10. For line 10, **What is the design waste-heat input rate at maximum continuous steam flow for this boiler?** If the boiler receives all or a substantial portion of its energy input from the noncombustible exhaust gases of a separate fuel-burning process, enter the design waste-heat input rate as measured in million Btu per hour at maximum continuous

steam flow.

11. For line 11, **What fuels are used by this boiler in order of predominance?** Enter the fuels used by this boiler in order of predominance. Select energy source codes from Table 28 in the instructions in order of predominance based on Btu.
12. For line 12, **What is the turndown ratio for this boiler?** Calculate (to nearest 0.1) the turndown ratio for the boiler as the ratio of the boiler's maximum output to its minimum output.
13. For line 13, **What is the efficiency of this boiler when it is burning the reported primary fuel at 100 percent load?** Enter the efficiency of the boiler when burning the reported primary fuel at 100 percent load.
14. For line 14, **What is the efficiency of this boiler when it is burning reported primary fuel at 50 percent load?** Enter the efficiency of the boiler when burning the reported primary fuel at 50 percent load.
15. For line 15, **What is the total air flow (including excess air) at 100 percent load?** Report the total air flow (including excess air) at 100 percent load. Report air flow at standard temperature and pressure (i.e., 68 degrees Fahrenheit and one atmosphere pressure).
16. For line 16, **Does the boiler have a wet bottom or a dry bottom?** Indicate whether the boiler has a wet bottom or dry bottom. Report only for coal-capable boilers. *Wet Bottom* is defined as having slag tanks installed at the furnace's throat to contain and remove molten ash from the furnace. *Dry Bottom* is defined as having no slag tanks installed at the furnace's throat so bottom ash drops through throat to bottom ash water hoppers.
17. For line 17, **Is the boiler capable of fly ash re-injection?** Indicate whether the boiler is capable of re-injecting fly ash.

SCHEDULE 6, PART D. COOLING SYSTEM INFORMATION – DESIGN PARAMETERS

Complete SCHEDULE 6, PART D for plants with a total steam-electric nameplate capacity of 100 MW or greater consisting of:

- Combustible fueled steam-electric generators, including combined cycle steam generators with duct firing;
- Combined cycle steam-electric generators without duct firing;
- Nuclear generators; or
- Solar thermal units using a steam cycle.

Complete one SCHEDULE 6 PART D for each unique Cooling system ID as reported on SCHEDULE 6 PART A, Line 1, Row 3.

1. For line 1, **What is this identification code of the cooling system?** Enter the cooling system's identification code commonly used by plant management to refer to this cooling system. Cooling system identification should be the same identification as entered on SCHEDULE 6, PART A, Line 1, Row 3 and as reported on other EIA forms. This identification code is restricted to six characters and cannot be changed once provided to

EIA.

2. For line 2, **What was the status of this cooling system as of December 31 of the reporting year?** Select from the cooling system's status codes in Table 19.

Table 19. Cooling System Status Codes and Descriptions

Cooling System Status Code	Cooling System Status Description
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 (expected to go into commercial service within 10 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 3, **What is the actual or projected in-service date of commercial operation for this cooling system?** Enter either the date on which the cooling system began commercial operation or the date on which the system is expected to begin commercial operation.

4. For line 4a, **What type of cooling system is this?** Select up to four types from the cooling system type codes in Table 20 that reflect that components of the cooling system. If the plant has a downstream helper tower that is associated with all boilers at a plant instead of any particular boiler or combination of boilers, treat it as a distinct cooling system and select "HT" from the list of codes.

Table 20. Cooling System Type Codes and Descriptions

Cooling System Type Code	Cooling System Type Description
DC	Dry (air) cooling system
HRC	Hybrid: cooling pond(s) or canal(s) with dry cooling
HRF	Hybrid: forced draft cooling tower(s) with dry cooling
HRI	Hybrid: induced draft cooling tower(s) with dry cooling
OC	Once through with cooling pond(s)
ON	Once through without cooling pond(s)
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)
HT	Helper Tower
OT	Other (specify in SCHEDULE 7)

For line 4b, **If this is a hybrid cooling system, what percent of the cooling load is**

served by dry cooling components? In the case of a hybrid cooling system, indicate the percent of total cooling load that is served by any dry cooling components.

5. For line 5, **What is the name of the water source for this cooling system?** Provide the name of the river, lake, or other water source for the cooling system if different than the water source listed on question 6 of SCHEDULE 2.
6. For line 6, **What is the name of the cooling system's discharge body of water?** If the discharge body of water is different than the source of the cooling water, enter the name of the water.
7. For line 7, **What is the cooling water source code for this system?** Select the appropriate cooling water source from Table 21:

Table 21. Cooling Water Source Code and Description

Cooling Water Source Code	Cooling Water Source Description
SW	Surface Water (ex: river, canal, bay)
GW	Ground Water (ex: aquifer, well)
PD	Plant Discharge Water (ex: wastewater treatment plant discharge)
OT	Other (specify in SCHEDULE 7)

8. For line 8, **What type of cooling water is used for this system?** Select the type of cooling water used by the cooling system from Table 22.

Table 22. Cooling Water Type Codes and Description

Type of Cooling Water Code	Type of Cooling Water Description
BR	Brackish Water
FR	Fresh Water
BE	Reclaimed Water (ex: treated wastewater effluent)
SA	Saline Water
OT	Other (specify in SCHEDULE 7)

9. For line 9, **What is the design maximum cooling water flow rate at 100 percent load at intake?** Enter the design maximum flow rate (gallons per minute) for the cooling system when operating at 100 percent load.
10. For line 10, **What is the actual or projected in-service date for the chlorine discharge control structures and equipment**? Enter either the date on which the chlorine discharge control structures and equipment began commercial operation or the date on which the chlorine discharge control structures and equipment are expected to begin commercial operation, if applicable.
11. For lines 11, **What is the actual or projected in-service date for the cooling pond(s)?** Enter either the date on which the cooling pond(s) began commercial operation or the date on which cooling pond(s) is expected to begin commercial operation, if applicable. A *cooling pond* is a natural or man-made body of water that is used for dissipating waste heat from power plants.
12. For line 12 **What is the total surface area for the cooling pond(s)?** Enter the total

surface area for the cooling pond(s), if applicable. A *cooling pond* is a natural or man-made body of water that is used for dissipating waste heat from power plants.

13. For line 13, **What is the total volume of the cooling ponds?** Enter the total volume of the cooling pond(s), if applicable. A *cooling pond* is a natural or man-made body of water that is used for dissipating waste heat from power plants.
14. For line 14, **What is the actual or projected in-service date for cooling towers?** Enter either the date on which the cooling tower(s) began commercial operation or the date on which the cooling tower(s) is expected to begin commercial operation, if applicable.
15. For line 15, **What types of cooling towers are at this plant or are planned to be at this plant?** Enter all tower types that apply from the cooling tower codes in Table 23.

Table 23. Types of Towers

Tower Type Code	Tower Type Description
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
OT	Other (specify in SCHEDULE 7)

16. For line 16 **What is the design rate of water flow at 100 percent load for the cooling towers?** Enter the design flow rate (gallons per minute) for the cooling tower when operating at 100 percent generator load in gallons per minute.
17. For line 17, **What is the maximum power requirement for the cooling towers at 100 percent load?** Enter the maximum design power requirement for the cooling tower when operating at 100 percent generator load in megawatts.
18. For line 18, **What is the total installed cost for this cooling system?** Enter the total nominal installed cost for the existing system or the anticipated cost to bring a planned system into commercial operation in thousands of dollars. Installed cost should include the cost of all major modifications. The *Total System 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.
19. For line 19, **What is the installed cost for the cooling ponds?** Enter the nominal installed cost for the existing ponds or the anticipated cost to bring a planned pond into commercial operation in thousands of dollars. Installed cost should include the cost of all major modifications.
20. For line 20, **What is the installed cost for the cooling towers?** Enter the nominal installed cost for the existing towers or the anticipated cost to bring a planned tower into commercial operation in thousands of dollars. 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.

21. For line 21, **What is the installed cost for the chlorine discharge control structures and equipment?** Enter in thousands of dollars, the nominal installed cost for the existing chlorine discharge control structures and equipment or the anticipated cost to bring planned chlorine discharge control structures and equipment 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.

22. For line 22a, **What is the maximum distance of water intake from shore?** Enter the maximum distance of the water intake from the shore, in feet.

    For line 22b, **What is the maximum distance of the water outlet from shore?** Enter the maximum distance of the water outlet from the shore, in feet (not required for recirculating systems).

23. For lines 23a, **What is the average distance of the water intake point below the surface of the water?** Enter the average distance of the water intake point below the surface of the water, in feet.

    For line 23b, **What is the average distance of the water outlet point below the surface of the water?** Enter the average distance of the water outlet points below the surface of the water, in feet (not required for recirculating systems).

SCHEDULE 6, PART E. FLUE GAS PARTICULATE COLLECTOR INFORMATION

Complete SCHEDULE 6, Part E for plants where the sum of the nameplate capacity of the steam-electric generators, including duct fired steam components of combined cycle units, sum to 10 MW or more.

Complete one SCHEDULE 6 PART E for each unique Particulate Matter Control system ID as reported on SCHEDULE 6 PART A, Line 1, Row 4.

1. For line 1, **What is the identification code for the equipment controlling particulate matter?** Enter the particulate matter control identification code as it was reported on SCHEDULE 6, Part A, Line 1, Row 4 (Associated Particulate Matter Control Systems).

2. For line 2, **What type of flue gas particulate matter control is this?** Select the flue gas particulate matter control type from Table 24. These should be the same equipment type entered on SCHEDULE 6, PART A, Line 2, COLUMN A for Particulate Matter Control. Enter up to three codes. If more than three exist, enter others in SCHEDULE 7, COMMENTS.

Table 24. Flue Gas Particulate Matter Control

Flue Gas Particulate Matter Control	Flue Gas Particulate Matter Control Description
BS	Baghouse (fabric filter), shake and deflate
BP	Baghouse (fabric filter), pulse
BR	Baghouse (fabric filter), 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
JB	Jet bubbling reactor (wet) scrubber
MA	Mechanically aided type (wet) scrubber
PA	Packed type (wet) scrubber
SP	Spray type (wet) scrubber
TR	Tray type (wet) scrubber
VE	Venturi type (wet) scrubber
OT	Other (specify in SCHEDULE 7)

3. For line 3, **What is the design fuel specification for ash when burning coal or petroleum coke?** Enter the design fuel specification for ash (as burned) to the nearest 0.1 percent of weight, when burning coal or petroleum coke, if applicable.

4. For line 4, **What is the design fuel specification for ash when burning petroleum liquids?** Enter the design fuel specification for ash (as burned) to the nearest 0.1 percent of weight, when burning petroleum liquids, if applicable.

5. For line 5, **What is the design fuel specification for sulfur when burning coal or petroleum coke?** Enter the design fuel specification for sulfur (as burned) to the nearest 0.1 percent of weight, when burning coal or petroleum coke, if applicable.

6. For line 6, **What is the design fuel specification for sulfur when burning petroleum liquids?** Enter design fuel specification for sulfur (as burned) to the nearest 0.1 percent of weight, when burning petroleum liquids, if applicable.

7. For line 7, **What is the design collection efficiency for this flue gas particulate collector at 100 percent load?** Enter the design collection efficiency (to nearest 0.1 percent) of the equipment at 100 percent generator load.

8. For line 8, **What is the design particulate emission rate for this collector at 100 percent load?** Enter the design particulate emission rate in pounds per hour at 100 percent generator load.

9. For line 9, **What is the particulate collector gas exit rate at 100 percent load?** Enter equipment's gas exit rate in cubic feet per minute at 100 percent generator load.

10. For line 10, **What is the particulate collector gas exit temperature?** Enter the equipment's gas exit temperature in degrees Fahrenheit.

SCHEDULE 6, PART F. FLUE GAS DESULFURIZATION UNIT INFORMATION (INCLUDES COMBUSTION TECHNOLOGIES)

Complete SCHEDULE 6, Part F for plants where the sum of the nameplate capacity of the steam-electric generators, including duct fired steam components of combined cycle units, sum to 10 MW or more.

Complete one SCHEDULE 6 PART F for each unique Sulfur Dioxide Control System ID as reported on SCHEDULE 6 PART A, Line 1, Row 5.

1. For line 1, **What is the identification code for the equipment associated with this sulfur dioxide control?** Enter the sulfur dioxide control identification code as reported on SCHEDULE 6, PART A, Line 1, Row 5 (Associated Sulfur Dioxide Control Systems)
2. For line 2, **What type of sulfur dioxide control is this?** Select the sulfur dioxide control code from Table 25. Enter up to three for each Sulfur Dioxide Control Identification Code.

Table 25. Sulfur Dioxide Control Codes and Descriptions

Sulfur Dioxide Control Codes	Sulfur Dioxide Control Description
ACI	Activated carbon injection system
JB	Jet bubbling reactor (wet) scrubber
MA	Mechanically aided type (wet) scrubber
PA	Packed type (wet) scrubber
SP	Spray type (wet) scrubber
TR	Tray type (wet) scrubber
VE	Venturi type (wet) scrubber
CD	Circulating dry scrubber
SD	Spray dryer type / dry FGD / semi-dry FGD
DSI	Dry sorbent (powder) injection type
OT	Other (specify in SCHEDULE 7)

3. For line 3, **What type(s) of sorbent(s) is used by this unit?** Select up to four sorbent codes from Table 26.

Table 26. Sorbent Type Codes and Descriptions

Sorbent Type Code	Type of Sorbent
AF	Alkaline fly ash
AM	Ammonia
CSH	Caustic Sodium hydroxide
DB	Dibasic acid assisted
LI	Lime / slacked lime / hydrated lime
LS	Limestone / dolomitic limestone / calcium carbonate
MO	Magnesium oxide

SA	Soda ash / Sodium bicarbonate / Sodium carbonate / Sodium formate / Soda liquid
TR	Trona
WT	Water / Treated wastewater (select only if no other sorbent is used)
OT	Other (specify in SCHEDULE 7)

4. For line 4, **Is there any salable byproduct recovery?** Enter "Yes" if there is any salable byproduct recovery. Otherwise, enter "No."

5. For line 5, **What are the annual pond and land fill requirements?** Report the annual pond and land fill requirements in acre feet per year.

6. For line 6, **Is the sludge pond lined?** Indicate whether the sludge pond is lined.

7. For line 7, **Can flue gas bypass the flue gas desulfurization unit?** Indicate whether the flue gas can bypass the FGD unit.

8. For line 8, **What is the design specification for ash when burning coal or petroleum coke?** Enter the design fuel specifications for ash (as burned) to the nearest 0.1 percent of weight, when burning coal or petroleum coke, if applicable.

9. For line 9, **What is the design specification for sulfur when burning coal or petroleum coke?** Enter the design fuel specifications for sulfur (as burned) to the nearest 0.1 percent of weight, when burning coal or petroleum coke, if applicable.

10. For line 10, **What is the total number of flue gas desulfurization unit scrubber trains or modules?** Enter the total number of flue gas desulfurization unit scrubber trains or modules operated.

11. For line 11, **How many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load?** Enter how many flue gas desulfurization unit scrubber trains or modules are operated at 100 percent load.

12. For line 12, **What is this unit's design removal efficiency for sulfur dioxide when operating at 100 percent load?** Report the design removal efficiency to nearest 0.1 percent by weight of gases removed from the flue gas when operating at 100 percent generator load.

13. For line 13, **What is the design sulfur dioxide emission rate for this unit when operating at 100 percent load?** Report the design sulfur dioxide emission rate in pounds per hour when operating at 100 percent generator load.

14. For line 14, **What is the flue gas exit rate for this unit?** Report the flue gas exit rate in actual cubic feet per minute when operating at 100 percent generator load.

15. For line 15, **What is this unit's flue gas exit temperature?** Report the flue gas exit temperature in degrees Fahrenheit when operating at 100 percent generator load.

16. For line 16, **What percentage of flue gas enters the flue gas desulfurization unit when operating at 100 percent load?** Enter the percentage of flue gas entering this

FGD unit at a percent of total gas when operating at 100 percent generator load.

17. For line 17, **What are the installed or anticipated costs of all FGD structures and equipment, excluding land?** Enter the nominal installed costs for the existing flue gas desulfurization unit or the anticipated costs, in thousand dollars, to bring a planned flue gas desulfurization unit 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.
18. For line 18, **What are the installed costs of the sludge transport and disposal system?** Enter the nominal installed costs for the sludge transport and disposal system, or the anticipated costs, in thousand dollars, to bring a planned sludge transport and disposal 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.
19. For line 19, **What other installed costs are there pertaining to the installation of the FGD unit?** Enter any other nominal installed costs, in thousand dollars, pertaining to the installation of the flue gas desulfurization unit, or any other costs related to bringing a planned flue gas desulfurization unit 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.
20. For 20, **What are the total installed costs of the FGD unit?** Enter the total nominal installed cost, in thousand dollars, for the existing flue gas desulfurization unit or the total anticipated costs to bring a planned flue gas desulfurization unit 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. This total will be the sum of lines 17, 18, and 19.

SCHEDULE 6, PART G. STACK AND FLUE INFORMATION – DESIGN PARAMETERS

Complete SCHEDULE 6, Part G for plants where the sum of the nameplate capacity of the steam-electric generators, including duct fired steam components of combined cycle units, sum to 100 MW or more.

NOTE: A *stack* is defined as a vertical structure containing one or more flues used to discharge products of combustion into the atmosphere. A *flue* is defined as an enclosed passageway within a stack for directing products of combustion to the atmosphere. If the stack has a single flue, use the stack identification for the flue identification

Complete one SCHEDULE 6 PART G for each Stack ID or Flue ID reported on SCHEDULE 6 PART A, Line 1, Row 8.

1. For line 1, **What is this stack or flue equipment's identification code?** Enter the identification code for each stack or flue as entered on SCHEDULE 6 PART A, Line 1,

Row 8.

2. For line 2, **What is the actual or projected in-service date for this stack or flue?** Enter either the date on which the stack or flue began commercial operation or the date (MM/YYYY) on which the stack or flue are expected to begin commercial operation.
3. For line 3, **What was the status of this stack or flue as of December 31 of the reporting year?** Select one from the following equipment status codes from Table 27.

Table 27. Stack Status Codes and Description

Stack Status Code	Stack Status Code Description
CN	Cancelled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service within 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order or expected to go into commercial service within 10 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 4, **What is this stack's height at the top, as measured from the ground?** Enter the height of the stack in feet as measured from the ground by the plant.
5. For line 5, **What is the cross-sectional area at the top of this stack?** Enter the cross-sectional area at the top of the stack as measured in square feet.
6. For line 6, **What is the design flue gas exit rate at the top of the stack at 100 percent load?** Enter the design flue gas exit rate at the top of the stack when operating at 100 percent load as measured in actual cubic feet per minute. The rate should be approximately equal to the cross-sectional area of the flue multiplied by the velocity and then multiplied by 60.
7. For line 7, **What is the design flue gas exit rate at the top of the stack at 50 percent load?** Enter the design flue gas exit rate at the top of the stack when operating at 50 percent load as measured in actual cubic feet per minute. The rate should be approximately equal to the cross-sectional area of the flue multiplied by the velocity and then multiplied by 60.
8. For line 8, **What is the design flue gas exit temperature at the top of the stack at 100 percent load?** Enter the design flue gas exit temperature in degrees Fahrenheit at the top of the stack when operating at 100 percent load.
9. For line 9, **What is the design flue gas exit temperature at the top of the stack at 50 percent load?** Enter the design flue gas exit temperature in degrees Fahrenheit at the

top of the stack when operating at 50 percent load.

10. For line 10, **What is the design flue gas velocity at the top of the stack at 100 percent load?** Enter the design flue gas exit velocity in feet per second at the top of the stack when operating at 100 percent load.
11. For line 11, **What is the design flue gas velocity at the top of the stack at 50 percent load?** Enter the design flue gas exit velocity in feet per second at the top of the stack when operating at 50 percent load.
12. For line 12, **What is the average flue gas exit temperature for the summer season?** Enter the seasonal average flue gas exit temperature in degrees Fahrenheit, based on the arithmetic mean of measurements during operating hours. Summer season includes June, July, and August.
13. For line 13, **What is the average flue gas exit temperature for the winter season?** Enter the seasonal average flue gas exit temperature in degrees Fahrenheit, based on the arithmetic mean of measurements during operating hours. Winter season includes December, January, and February (for example, when reporting for year 2013, use December 2012, January 2013 and February 2013).
14. For line 14, **Were the average flue gas exit temperatures measures or estimated**? Indicate whether the flue gas exit temperatures used to calculate the mean values reported on Lines 13 and 14 were measured or estimated.

SCHEDULE 7. COMMENTS

This schedule provides additional space for comments. Please identify schedule, part, and question and include identifying information (e.g., plant code, boiler id, generator id) for each comment. Use additional pages, if necessary.

Table 28. Energy Source Codes and Heat Content

Fuel Type	Energy Source Code	Unit Label	Higher Heating Value Range		Energy Source Description
			MMBtu Lower	MMBtu Upper	
Fossil Fuels					
Coal	ANT	Tons	22	28	Anthracite Coal
	BIT	Tons	20	29	Bituminous Coal
	LIG	Tons	10	14.5	Lignite Coal
	SGC	Mcf	0.2	0.3	Coal-Derived Synthesis Gas
	SUB	Tons	15	20	Subbituminous Coal
	WC	tons	6.5	16	Waste/Other Coal (incl. anthracite culm, bituminous gob, fine coal, lignite waste, waste coal)
	RC	tons	20	29	Refined Coal
Petroleum Products	DFO	barrels	5.5	6.2	Distillate Fuel Oil (including diesel, No. 1, No. 2, and No. 4 fuel oils)
	JF	barrels	5	6	Jet Fuel
	KER	barrels	5.6	6.1	Kerosene
	PC	tons	24	30	Petroleum Coke
	PG	Mcf	2.5	2.75	Gaseous Propane
	RFO	barrels	5.8	6.8	Residual Fuel Oil (incl. Nos. 5 & 6 fuel oils, and bunker C fuel oil)
	SGP	Mcf	0.2	1.1	Synthesis Gas from Petroleum Coke
	WO	barrels	3.0	5.8	Waste/Other Oil (including crude oil, liquid butane, liquid propane, naphtha, oil waste, re-refined motor oil, sludge oil, tar oil, or other petroleum-based liquid wastes)
Natural Gas and Other Gases	BFG	Mcf	0.07	0.12	Blast Furnace Gas
	NG	Mcf	0.8	1.1	Natural Gas
	OG	Mcf	0.32	3.3	Other Gas (specify in SCHEDULE 7)
Renewable Fuels					
Solid Renewable Fuels	AB	tons	7	18	Agricultural By-Products
	MSW	tons	9	12	Municipal Solid Waste
	OBS	tons	8	25	Other Biomass Solids (specify in SCHEDULE 7)
	WDS	tons	7	18	Wood/Wood Waste Solids (incl. paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)

Fuel Type	Energy Source Code	Unit Label	Higher Heating Value Range		Energy Source Description
			MMBtu Lower	MMBtu Upper	
Renewable Fuels					
Liquid Renewable (Biomass) Fuels	OBL	barrels	3.5	4	Other Biomass Liquids (specify in SCHEDULE 7)
	SLW	tons	10	16	Sludge Waste
	BLQ	tons	10	14	Black Liquor
	WDL	barrels	8	14	Wood Waste Liquids excluding Black Liquor (including red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids)
Gaseous Renewable (Biomass) Fuels	LFG	Mcf	0.3	0.6	Landfill Gas
	OBG	Mcf	0.36	1.6	Other Biomass Gas (including digester gas, methane, and other biomass gases; specify in SCHEDULE 7)
All Other Renewable Fuels	SUN	N/A	N/A	N/A	Solar
	WND	N/A	N/A	N/A	Wind
	GEO	N/A	N/A	N/A	Geothermal
	WAT	N/A	N/A	N/A	Water at a Conventional Hydroelectric Turbine, and water used in Wave Buoy Hydrokinetic Technology, Current Hydrokinetic Technology, and Tidal Hydrokinetic Technology
All Other Fuels					
All Other Energy Sources	WAT	MWh	N/A	N/A	Pumping Energy for Reversible (Pumped Storage) Hydroelectric Turbine
	NUC	N/A	N/A	N/A	Nuclear (including Uranium, Plutonium, and Thorium)
	PUR	N/A	N/A	N/A	Purchased Steam
	WH	N/A	N/A	N/A	Waste heat not directly attributed to a fuel source (WH should only be reported when the fuel source is undetermined, and for combined cycle steam turbines that do not have supplemental firing.)
	TDF	Tons	16	32	Tire-derived Fuels
	MWH	MWh	N/A	N/A	Electricity used for energy storage
	OTH	N/A	N/A	N/A	Specify in SCHEDULE 7

Table 29. Commonly Used North American Industry Classification System (NAICS) Codes

	Agriculture, Forestry, Fishing and Hunting
111	Crop Production
112	Animal Production and Aquaculture
113	Forestry and Logging
114	Fishing, Hunting and Trapping
115	Support Activities for Agriculture and Forestry
	Mining, Quarrying, and Oil and Gas Extraction
211	Oil and Gas Extraction
2121	Coal Mining
2122	Metal Ore Mining
2123	Nonmetallic Mineral Mining and Quarrying
	Utilities
22	Electric Power Generation, Transmission and Distribution (other than 2212, 2213, 22131, 22132 or 22133)
2212	Natural Gas Distribution
22131	Water Supply and Irrigation Systems
22132	Sewage Treatment Facilities
22133	Steam and Air-Conditioning Supply
	Manufacturing
311	Food Manufacturing
312	Beverage and Tobacco Product Manufacturing
313	Textile Mills (Fiber, Yarn, Thread, Fabric, and Textiles)
314	Textile Product Mills
315	Apparel Manufacturing
316	Leather and Allied Product Manufacturing
321	Wood Product Manufacturing
322	Paper Manufacturing (other than 322122 or 32213)
322122	Newsprint Mills
32213	Paperboard Mills
323	Printing and Related Support Activities
324	Petroleum and Coal Products Manufacturing (other than 32411)
32411	Petroleum Refineries
325	Chemical Manufacturing (other than 32511, 32512, 325193, 3252 325211, 3253 or 325311)
32511	Petrochemical Manufacturing
32512	Industrial Gas Manufacturing
325193	Ethyl Alcohol Manufacturing (including Ethanol)
3252	Resin, Synthetic Rubber, and Artificial Synthetic Fibers and Filaments Manufacturing (other than 325211)

325211	Plastics Material and Resin Manufacturing
3253	Pesticide, Fertilizer, and Other Agricultural Chemical Manufacturing (other than 325311)
325311	Nitrogenous Fertilizer Manufacturing
326	Plastics and Rubber Products Manufacturing
327	Nonmetallic Mineral Product Manufacturing (other than 32731)
32731	Cement Manufacturing
331	Primary Metal Manufacturing (other than 3311 or 3313)
3311	Iron and Steel Mills and Ferroalloy Manufacturing
3313	Alumina and Aluminum Production and Processing
332	Fabricated Metal Product Manufacturing
333	Machinery Manufacturing
334	Computer and Electronic Product Manufacturing
335	Electrical Equipment, Appliance, and Component Manufacturing
336	Transportation Equipment Manufacturing
337	Furniture and Related Product Manufacturing
339	Miscellaneous Manufacturing
421	**Wholesale Trade**
441	**Retail Trade**
	Transportation and Warehousing
481	Air Transportation
482	Rail Transportation
483	Water Transportation
484	Truck Transportation
485	Transit and Ground Passenger Transportation
486	Pipeline Transportation
487	Scenic and Sightseeing Transportation
488	Support Activities for Transportation (other than 4881, 4882, 4883 or 4884)
4881	Support Activities for Air Transportation (including Airports)
4882	Support Activities for Rail Transportation (including Rail Stations)
4883	Support Activities for Water Transportation (including Marinas)
4884	Support Activities for Road Transportation
491	Postal Service
492	Couriers and Messengers
493	Warehousing and Storage
	Information
511	Publishing Industries (except Internet)
512	Motion Picture and Sound Recording Industries
515	Broadcasting (except Internet)
517	Telecommunications
518	Data Processing, Hosting, and Related Services
519	Other Information Services

521	**Finance and Insurance**
53	**Real Estate and Rental and Leasing (including Convention Centers and Office Buildings)**
541	**Professional, Scientific, and Technical Services**
55	**Management of Companies and Enterprises**
	Administrative and Support and Waste Management and Remediation Services
561	Administrative and Support Services
562	Waste Management and Remediation Services (other than 562212 or 562213)
562212	Solid Waste Landfill
562213	Solid Waste Combustors and Incinerators
611	**Educational Services**
	Health Care and Social Assistance
621	Ambulatory Health Care Services
622	Hospitals
623	Nursing and Residential Care Facilities
624	Social Assistance
	Arts, Entertainment, and Recreation
711	Performing Arts, Spectator Sports, and Related Industries
712	Museums, Historical Sites, and Similar Institutions
713	Amusement, Gambling, and Recreation Industries
	Accommodation and Food Services
721	Accommodation
722	Food Services and Drinking Places
	Other Services (except Public Administration)
811	Repair and Maintenance
812	Personal and Laundry Services
813	Religious, Grantmaking, Civic, Professional, and Similar Organizations
814	Private Households
92	**Public Administration (other than 921, 922, 92214 or 928)**
921	Executive, Legislative, and Other General Government Services
922	Justice, Public Order and Safety Activities (other than 92214)
92214	Correctional Facilities
928	National Security and International Affairs (including Military Bases)

GLOSSARY

The glossary for this form is available online at the following URL:
http://www.eia.gov/glossary/index.html

SANCTIONS

The timely submission of Form EIA 860 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.

REPORTING BURDEN

Public reporting burden for this collection of information is estimated to average 6.75 hours per response for respondents without environmental information and 12.5 hours per response for respondents with environmental information, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. The weighted average burden per form is 9.29 hours. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the U.S. Energy Information Administration, Office of Survey Development and Statistical Integration, EI-21 Forrestal Building, 1000 Independence Avenue SW, Washington, DC 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.

DISCLOSURE OF INFORMATION

The following information reported on this survey will be protected and not disclosed to the extent that it satisfies the criteria for exemption under the Freedom of Information Act (FOIA), 5 U.S.C. §552, the Department of Energy (DOE) regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905:

•All information associated with the "Survey Contact" and the "Supervisor of Contact Person for Survey" on SCHEDULE 1.

•Information reported for the data element "Tested Heat Rate" on SCHEDULE 3, PART B, GENERATOR INFORMATION – EXISTING GENERATORS

•All data reported on Parts A and B of SCHEDULE 5, GENERATOR COST INFORMATION

All other information reported on Form EIA-860 will be treated as non-sensitive and may be publicly released in identifiable form.

The Federal Energy Administration Act requires EIA to provide company-specific 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 Government Accountability 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.

With the exception of data on the costs of constructing power plants, disclosure limitation procedures are not applied to the aggregate statistical data published from this survey. There may be some statistics that are based on data from fewer than three respondents, or that are dominated by data from one or two large respondents. In these cases, it may be possible for a knowledgeable person to closely estimate the information reported by a specific respondent.