U.S. Department of Energy Energy Information Administration Form EIA-860 (2007)	***ANNUAL ELECTRIC GENERATOR REPORT***	**Form Approved OMB No. 1905-0129 Approval Expires:**

PURPOSE	Form EIA-860 collects data on the status of existing electric generating plants and associated equipment (including generators, boilers, cooling systems and flue gas desulfurization systems) in the United States, and those scheduled for initial commercial operation within 5 years of the filing of this report. The data from this form appear in several EIA publications; including the *Electric Power Monthly, Electric Power Annual,* and the *Annual Energy Review.* The data collected on this form are used to monitor the current status and trends of the electric power industry and to evaluate the future of the industry.
REQUIRED RESPONDENTS	All existing plants and proposed (5-year plans) plants that: 1) have a total generator nameplate capacity (sum for generators at a single site) of 1 MW or greater; and 2) where the generator(s), or the facility in which the generator(s) resides, is connected to the local or regional electric power grid and has the ability to draw power from the grid or deliver power to the grid are reported on Form EIA-860. In the case of generators located in Alaska and Hawaii which are not a part of the North American interconnected grid, generators that are connected to a "public grid," meaning a local or regional transmission or distribution system that supplies power to the public, must be reported on Form EIA-860. The operator or planned operator of jointly-owned plants should be the only respondent for those plants.
RESPONSE DUE DATE	Submit the completed Form EIA-860 directly to the EIA annually on or before February 15.
METHODS OF FILING RESPONSE	Submit your data electronically using EIA's secure Internet Data Collection system (IDC). This system uses security protocols to protect information against unauthorized access during transmission. • If you have not registered with EIA's Single Sign-On system, send an e-mail requesting assistance to: EIA-860@eia.doe.gov • If you have registered with Single Sign-On, log on at https://signon.eia.doe.gov/ssoserver/login • If you are having a technical problem with logging into the IDC or using the IDC contact the IDC Help Center for further information. Contact the Help Desk at: E-mail: CNEAFhelpcenter@eia.doe.gov Phone: 202-586-9595 • If you need an alternate means of filing your response, contact the Help Desk. Retain a completed copy of this form for your files.
CONTACTS	**Internet System Questions**: For questions related to the Internet Data Collection system, see the help contact information immediately above. **Data Questions:** For questions about the data requested on Form EIA-860, contact either Survey Manager: Kenneth McClevey Telephone Number: (202) 586-4258 FAX Number: (202) 287-1960 E-mail: Kenneth.McClevey@eia.doe.gov Glenn McGrath Telephone Number: (202) 586-4325 FAX Number: (202) 287-1960 E-mail: Glenn.McGrath@eia.doe.gov

GENERAL INSTRUCTIONS

1. Verify all EIA provided information. If incorrect, revise the incorrect entry and provide the correct information. State codes are two-letter U.S. Postal Service abbreviation. Provide any missing information. If filing a paper copy of this form, typed or legible handwritten entries are acceptable. Allow the original entry to remain readable. See more specific instructions for correcting data in SCHEDULE 2, "Power Plant Data," and SCHEDULE 3. "Generator Information." If no corrections are needed to the pre-entered data and there are no missing data, check "No Change Needed" for plant, generator or boiler information, as applicable.

2. Check all data for consistency with the same or related data that appear in more than one schedule of this or other forms or reports submitted to EIA. Explain any inconsistencies under SCHEDULE 7,COMMENTS.

3. For planned power plants and/or planned equipment, use planning data to complete the form.

4. Report in whole numbers (i.e., no decimal points), except where explicitly instructed to report otherwise.

5. Indicate negative amounts by using a minus sign before the number.

6. Report date information as a two-digit month and four-digit year, e.g., "11 - 1980."

7. Furnish the requested information to reflect the status of your current or planned operations as of the beginning of the reporting calendar year. **If the 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 e-mail address, if known) in SCHEDULE 7, "COMMENTS." Do not complete the form for that power plant.**

8. To request additional blank schedules contact the Energy Information Administration using the contact information on page 1, or download the form from http://www.eia.doe.gov/cneaf/electricity/page/forms.html.

9. For definitions of terms, refer to the Energy Information Administration glossary at http://www.eia.doe.gov/glossary/index.html.

ITEM-BY-ITEM INSTRUCTIONS

SCHEDULE 1. IDENTIFICATION

1. **Survey Contact:** Verify contact name, title, address, telephone number, fax number, and e-mail address.
2. **Supervisor of Contact Person for Survey:** Verify the contact's supervisor's name, title, address, telephone number, Fax number and e-mail address.
3. **Report For:** Verify all information, including operator name, operator identification number, and year for which data are being reported. These fields cannot be revised online. Contact EIA if corrections are needed.

If any of the above information is incorrect, revise the incorrect entry and provide the correct information. Provide any missing information.

Operator and Preparer Information:

4. For **Legal Name of Operator**, verify the name. The operator of the power plant is the electric power producer owner/joint owner of the plant or a subsidiary of the electric power producer who has a working interest in the plant and who is responsible for making the strategic decisions related to the management and physical operation of the power plant. The operator entity may also be an electric power producer or a subsidiary of an electric power producer who operates a power plant that is wholly owned by another electric power producer. Operator **excludes** energy services companies under contract to operate the plant for the electric power producer;

in these cases, the electric power producer should be reported as the legal operator.

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

6. For **Preparer's Legal Name,** verify the name to which this form should be mailed if different from **Legal Name of Operator**.

7. For **Current Address of Preparer's Office**, verify the address to which this form should be mailed. Include an attention line, room number, building designation, etc., to facilitate the future handling and processing of this form, if preparer's address is different from the address of the **Legal Name of Operator** .

8. For **Is the Operator an Electric Utility**; check "Yes" if so. Otherwise check "No."

SCHEDULE 2. POWER PLANT DATA

Verify or complete one section for each existing power plant and each power plant planned for initial commercial operation within 5 years. To report a new plant or a plant that is not already identified, use a blank SCHEDULE 2.

1. For line 1**, Plant Name** and **EIA Plant Code,** enter the name of the power plant, and enter or verify the EIA Plant Code for the power plant. Each power plant must be uniquely identified. The type of plant does not need to be a part of the plant name, e.g., "Plant x Hydro" needs to be reported as "Plant x" only. The type of plant is recognized by the prime mover code(s) reported in SCHEDULE 3. Generator Information. There may be more than one prime mover type associated with a single plant name (single site). Enter "NA 1," "NA 2," etc., for planned facilities that have no name(s).

2. For line 2**, Street Address**, enter or verify the street address of the power plant.

3. For line 3, **County Name and City Name**, enter the county and city in which the plant is (will be) located. Enter "NA" for planned facilities that have not been sited. If a mobile power plant, indicate with a note in SCHEDULE 7, COMMENTS.

4. For line 4, **State**, enter the two-letter U.S. Postal Service abbreviation for the State in which the plant is located. Enter "NA" for planned facilities for which the State has not been determined. If the State is "NA," the county name must be "NA."

5. For line 5, **Zip Code**, enter the zip code of the plant. Provide, at a minimum, the five-digit zip code; however, the nine-digit code is preferred.

6. For line 6, **Latitude and Longitude**, enter the latitude and longitude of the plant in degrees, minutes, and seconds.

7. For line 7, **Enter Datum for Latitude and Longitude, if Known; Otherwise Enter "UNK":**

   The longitude and latitude measurement for a location depends in part on the coordinate system (or "datum") the measurement is keyed to. "Datum systems" used in the United States, include the North American Datum 1927 (NAD27), North American Datum 1983 (NAD83) and World Geodetic Survey 1984 (WGS84).

   If you know the datum system for the plant longitude and latitude, enter the system name (e.g., NAD83) on line 7. If you do not know the datum system used, enter UNK.
   (For background information on datum and their uses, see: http://biology.usgs.gov/index.html).

8. For line 8, **NERC Region**, enter the NERC region in which the plant is located.

9. For line 9, **Name of Water Source**, enter the name of the principal source from which cooling water for thermal-electric plants and water for generating power for hydroelectric plants is directly obtained. If more than one water source is (will be) used, enter the name(s) of the other sources of water in SCHEDULE 7, COMMENTS. Enter "Municipality" if the water is from a municipality. Enter "wells" if water is from wells. Enter "NA" for planned facilities for which the water source is not known.

10. For line 10, **Steam Plant Status**, and line 11, **Steam Plant Type, verify** the appropriate status and type for completing Schedule 6, Boiler information. If either is incorrect, contact EIA.

11. For line 12, **Primary Purpose of the Plant**, enter the North American Industry Classification System (NAICS) code that best describes the primary purpose of the reporting plant. Electric utility plants will generally use code 22. Independent power producers whose sole or primary business is the sale of electricity will also generally use code 22. For industrial and commercial generators whose primary business is an industrial or commercial process (e.g., paper mills, refineries, chemical plants, etc.), use Table 2 in these instructions to determine the code.

12. Line 13, **Does this plant have Federal Energy Regulatory Commission (FERC) Qualifying Facility (QF) Cogenerator Status**? Check "Yes" or "No"; if "Yes" provide all QF docket numbers granted to the facility.

13. Line 14, **Does this plant have Federal Energy Regulatory Commission (FERC) Qualifying Facility (QF) Small Power Producer Status**? Check "Yes" or "No"; if "Yes" provide all QF docket numbers granted to the facility.

14. Line 15, **Does this plant have Federal Energy Regulatory Commission (FERC) Qualifying Facility (QF) Exempt Wholesale Generator Status**? Check "Yes" or "No"; if "Yes" provide all QF docket numbers granted to the facility.

15. For line 16, **Owner of Transmission/Distribution Facilities**, enter the name of the owner of the transmission or distribution facilities to which the plant is interconnected and the grid voltage at the point of interconnection.

SCHEDULE 3. GENERATOR INFORMATION

1. Verify or complete for each existing or planned generator. Complete one column for each generator (up to three generators can be reported on one page) for all generators that are: (1) in commercial operation (whether active or inactive), or (2) expected to be in commercial operation within 5 years and are either planned, under construction, or in testing stage. Do not report auxiliary generators.

2. To report a new generator, use a separate (blank) section of SCHEDULE 3. 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 (blank) section of SCHEDULE 3 to report all of the applicable data about the new generator. 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, **Plant Name**, enter the official or legal name of the power plant as reported on SCHEDULE 2.

2. For line 2, **EIA Plant Code**, enter the EIA plant code as reported on SCHEDULE 2.

3. For line 3, **Operator's Generator Identification**, enter the unique generator identification commonly used by plant management. Generator identification can have a maximum of four characters, and should be the same identification as reported on other EIA forms to be uniquely defined within a plant.

4. For line 4, for organic-fueled steam generators, including heat recovery steam generators, enter the identification (ID) code for each boiler that provides steam to the generator. The ID should match those provided in SCHEDULE 6. The applicable parts of SCHEDULE 6 must be completed for each boiler. Organic-fueled steam-electric generators include fossil-fueled and combustible renewable-fueled generators.

5. For line 5**, Prime Mover**, enter one of the prime mover codes below. For combined cycle units, a prime mover code must be entered for each generator.

Prime Mover Code	Prime Mover Description
ST	Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle).
GT	Combustion (Gas) Turbine – Simple Cycle (includes jet engine design)
IC	Internal Combustion Engine (diesel, piston, reciprocating)
CA	Combined Cycle Steam Part
CT	Combined Cycle Combustion Turbine Part (type of coal or solid must be reported as energy source for integrated coal gasification).
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).
HY	Hydraulic Turbine (includes turbines associated with delivery of water by pipeline)
PS	Hydraulic Turbine – Reversible (pumped storage)
BT	Turbines Used in a Binary Cycle (such as used for geothermal applications)
PV	Photovoltaic
WT	Wind Turbine
CE	Compressed Air Energy Storage
FC	Fuel Cell
OT	Other (Describe in SCHEDULE 7, COMMENTS)

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.

6. For line 6, **Unit Code** (Multi-generator code), identify all generators that are operated with other generators as a single unit. Generators operating as a single unit should have the same unit (multi-generator code) code or four-character identifier. Identify combined cycle generators that operate as a unit with a unique four-character identifier. All generators that operate as a unit in combined cycle must have the same unique identifier. If generators do not operate as a single unit, this space should be left blank.

7. For line 7, **Ownership Code**, identify the ownership for each generator using the following codes: "S" for single ownership by respondent, "J" for jointly owned with another entity or "W" for wholly owned by an entity other than respondent.

8. For line 8, **Is this generator an electric utility or non-utility generator?** For each generator, check "electric utility" or non-utility. (See EIA Glossary for definition of electric utility generator.)

9. For line 9, **Date of Sale, If Sold**, enter the month and year of the sale of the generator (e.g., 12-2007), if the generator has been sold in its entirety. For changes in shares of ownership only, with no change in operator, report in Schedule 4, OWNERSHIP OF GENERATORS OWNED JOINTLY OR BY OTHERS. . In SCHEDULE 7, provide the legal name, business address, contact person, phone number and e-mail address of the entity to which this generator was sold.

10. For line 10, **Can This Generator Deliver Power to the Transmission Grid**?, indicate if the generator can or cannot deliver power to the transmission grid.

11. For line 11, **if the prime mover is "CA,"** (combined-cycle steam), "CS" or "CC" check "Yes" if the unit has duct-burners for supplementary firing of the turbine exhaust gas. Otherwise, check "No." If "Yes" SCHEDULE 6 must be completed, as applicable.

SCHEDULE 3. PART B. GENERATOR INFORMATION – EXISTING GENERATORS

1. For line 1, **Generator Nameplate Capacity**, report the highest value on the nameplate in megawatts rounded to the nearest tenth. If the nameplate capacity is expressed in kilovolt amperes (kVA), convert to kilowatts by multiplying the corresponding power factor by the kVA, divide by 1,000 to express in megawatts to the nearest tenth. **If generator nameplate capacity is exceeded by net summer capacity, provide the reason(s) in SCHEDULE 7.**

2. For line 2, **Net Capacity**, enter the generator's (unit's) summer and winter net capacities for the primary energy sources. Report in megawatts, rounded to the nearest tenth. For generators that are out of service for an extended period or on standby or have no generation during the respective seasons, report the estimated capacities based on historical performance. For generators that are tested as a unit, a single aggregate net summer capacity and a single aggregate net winter capacity may be reported. For hydroelectric, report the instantaneous capacity at maximum waterflow.

3. For line 3a, **Reactive Power Output (MVAR) Corresponding to Net Summer Capacity for generators with nameplate capacity of 10 MW or greater**, based on the generator power capability curve for the generator**,** enter the lagging reactive power output and the leading reactive power output that correspond to the net summer capacity (line 2), adjusted for any impacts of exciter limiters. A MVAR is a Mega Voltampere Reactive.

4. For line 3b**, Reactive Power Output (MVAR) Corresponding to Net Winter Capacity for generators with nameplate capacity of 10 MW or greater,** based on the generator power capability curve for the generator, enter the lagging reactive power output and the leading reactive power output that correspond to the net winter capacity (line 2), adjusted for any impacts of exciter limiters. A MVAR is a Mega Voltampere Reactive.

5. For line 4, **Status Code**, enter one of the following status codes:

Status Code	Status 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.
OA	Out of service – was not used for some or all of the reporting period but was either returned to service on December 31 or will be returned to service in the next calendar year. Note: Units undergoing maintenance or repair of less than 12 months duration and are expected to be returned to service upon completion of maintenance or repair should be given an operating status.

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.
RE	Retired - no longer in service and not expected to be returned to service.

6. For line 5, **Synchronized to the Grid**, if the status code entered on line 4 is standby (SB) please note if the generator is currently equipped such that, when operating, it can be synchronized to the grid.
7. For line 6, **Initial Date of Operation**, enter the month and year of initial commercial operation.
8. For Line 7, **Retirement Date,** enter the date the generator was retired, in month and year format.
9. For line 8, **Is this generator associated with a Combined Heat and Power system (fuel input is used to produce both electricity and useful thermal output)?** check either "Yes" or "No". If the answer is "Yes", check either bottoming cycle or topping cycle, as applicable. In a topping cycle system, electricity is produced first and any waste heat from that production is used in a manufacturing process or for direct heating, and/or space heating/cooling. 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.
10. For line 9, **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. Select appropriate energy source codes from Table 1. in these instructions. 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).
11. For line 9a, if the predominant energy source for powering the generator is coal or petroleum coke, check all types of technology and steam conditions that apply.
12. For line 10, report the **Start-up and flame stabilization fuels** used by the combustion unit(s) associated with this generator.
13. For line 11, **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. Select appropriate energy source codes from Table 1 in these instructions. 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).
14. For line 12, **Other Energy Sources**, enter the codes for other energy sources: 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. Select appropriate energy source codes from Table 1 in these instructions. 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)
15. Line 13, **Is this generator part of a solid fuel gasification system,** check yes or no as appropriate.
16. For line 14, **If Energy Source is Wind**, enter the number of turbines.
17. For line 15, **Tested Heat Rate**, enter the tested heat rate under full load conditions for all generators that derive their energy from combustion or fission of fuel. Report the heat rate as the fuel consumed in British thermal units (Btus) necessary to generate one net kilowatthour of electric energy. Report the tested heat rate under full load, not 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, explain in SCHEDULE 7, COMMENTS.

18. For line 16, **Fuel Used for Heat Rate Test**, enter the fuel code or "M" for multiple fuels. Select appropriate energy source codes from Table 1in these instructions. 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).

Proposed Changes to Existing Generators (within the next 5 years)

19. For line 17a, indicate whether there are any planned capacity up-rates/de-rates, re-powering, other modifications, or generator retirements scheduled for the next 5 years.
20. For line 17b, enter the increase in capacity expected to be realized from the modification to the equipment. Enter the planned effective date (MM-YYYY) that the generator is scheduled to enter operation after the modification.
21. For line 17c, enter the decrease in capacity expected to be realized from the modification to the equipment. Enter the planned effective date (MM-YYYY) that the generator is scheduled to enter operation after the modification.
22. For line 17d, if a re-powering of the generator is planned, enter the new prime mover and new energy source, as well as the planned effective date (MM-YYYY) that the generator is scheduled to enter operation after the re-powering is complete.
23. For line 17e, enter the planned effective date (MM-YYYY) that the generator is scheduled to enter commercial operation after any other planned change is complete, that is not included in lines 17b through 17d. Please provide details of the planned change in SCHEDULE 7, COMMENTS. Other planned changes may include a second up-rate or de-rate to a unit or a reactivation of a previously retired generator,
24. For line 17f, if the generator is expected to be retired within the next 5 years, enter the planned effective date (MM-YYYY) of that scheduled retirement.
25. For line 18, **Ability to Use Multiple Fuels**, indicate if the combustion system that powers each generator has both:

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

    If the answer to this question is "No", go to SCHEDULE 3. PART C,.

    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 second fuel for start-up or flame stabilization***.

26. For line 19, **Ability to Co-Fire**, indicate whether or not the combustion system that powers the generator has, in working order, the equipment necessary to co-fire fuels and the regulatory permits to co-fire fuels.
27. For line 20, **Fuel Options for Co-Firing**, indicate up to six fuels that can be co-fired. Select appropriate energy source codes from Table 1in these instructions. (Note: fuel options listed for co-firing must also be included under either "Predominant Energy Source" (line 9), "Second Most Predominant Energy Source" (line 11), or "Other Energy Sources (line 12).
28. For line 21, **Ability to Co-Fire Oil and Natural Gas**, indicate if the combustion system that powers the generator can co-fire fuel oil with natural gas. If it cannot, skip to line 23.
29. For line 22, **Ability to Co-Fire Oil**, indicate whether or not the combustion system that powers

the generator can run on 100 percent oil. If the answer to this question is yes, skip to line 23. If no, indicate the maximum percentage of the heat input to the combustion system (percent of MMBtu) that can be supplied by oil when co-firing with natural gas. Also provide the maximum output (summer net MW) that the unit can achieve, taking into account all applicable technical limits, when making the maximum use of oil and co-firing natural gas.

30. For line 23, **Ability to Fuel Switch**, indicate whether or not the combustion system that powers the generator has, in working order, the equipment necessary to fuel switch and the regulatory permits to fuel switch.

31. For line 24, **Oil – Natural Gas Fuel Switching**, (a) indicate whether or not the combustion system that powers the generator has, in working order, the equipment necessary to switch between oil and natural gas and the regulatory permits to switch between oil and natural gas are in effect. If no, go to line 26. If yes:

    a) Can the unit switch fuels while operating (i.e., without shutting down the unit)? Check "Yes" or "No".

    b) Enter the maximum output (summer net MW) that the unit can achieve, taking into account all applicable legal, regulatory, and technical limits, when running on natural gas.

    c) Enter the maximum output (summer net MW) that the unit can achieve, taking into account all applicable legal, regulatory, and technical limits, when running on oil.

    d) Enter how long it takes to switch the generator from using 100 percent natural gas to 100 percent oil.

32. For line 25, **Limits on Oil-fired Operation**, indicate whether or not there are factors that limit the operation of the generator (e.g., limits on maximum output, limits on annual operating hours), when running on 100 percent oil. Check all factors that limit the ability of this generator to switch from natural gas to oil.

33. For line 26, **Fuel Switching Options**, enter the codes for up to six fuels, including (if applicable) oil and natural gas, which can be used as a sole source of fuel to power the generator. Select appropriate energy source codes from the table in these instructions. (Note: fuel options listed for fuel switching must also be included under either "Predominant Energy Source" (line 9), "Second Most Predominant Energy Source" (line 11), or "Other Energy Sources (line 12).

SCHEDULE 3. PART C. GENERATOR INFORMATION – PROPOSED GENERATORS

1. For line 1, **Generator Nameplate Capacity**, enter the highest value on the nameplate in megawatts rounded to the nearest tenth. If the nameplate capacity is expressed in kilovolt amperes (kVA), convert to kilowatts by multiplying the corresponding power factor by the kVA, divide by 1,000 to express in megawatts to the nearest tenth. If the generator nameplate is not known at this time, estimate the nameplate rating for the generator and note this as an estimate in SCHEDULE 7. COMMENTS.

2. For line 2, **Net Capacity**, enter the net summer and net winter capacities in megawatts rounded to the nearest tenth that are expected when the generator goes into commercial operation.

3. For line 3a, **Reactive Power Output (MVAR) Corresponding to Net Summer Capacity for generators with nameplate capacity 10 MW or greater**, using **manufacturer provided design data ,** enter the lagging reactive power output and the leading reactive power output that correspond to the net summer capacity (line 2). A MVAR is a Mega Voltampere Reactive.

4. For line 3b, **Reactive Power Output (MVAR) Corresponding to Net Winter Capacity for generators with nameplate capacity 10 MW or greater**, using **manufacturer provided design data ,** enter the lagging reactive power output and the leading reactive power output that correspond to the net winter capacity (line 2). A MVAR is a Mega Voltampere Reactive.

5. For line 4, **Status Code**, enter one of the following status codes:

Status Code	Status Code Description
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 (describe in SCHEDULE 7, COMMENTS)

6. For line 5, **Planned Original Effective Date,** enter the month and year of the original effective date that: 1) the generator was scheduled to start operation after construction is completed. (Please note that this date does not change once it has been reported the first time.)
7. For line 6, **Planned Current Effective Date,** enter the month and year of the current effective date that the generator is scheduled to start operation.
8. For line 7, **Will this generator be associated with a Combined Heat and Power system (fuel input is used to produce both electricity and useful thermal output)?** Check either "Yes" or "No."
9. For line 8**, Will this generator be part of a solid fuel gasification system, check yes or no, as appropriate.**
10. For line 9, indicate **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.
11. For line 10, **Expected Predominant Energy Source**, enter the energy source code for the energy source expected to be used in the largest quantity (Btus) when the generator starts commercial operation. Select appropriate energy source codes from Table 1 in these instructions.
12. For line 11, if the expected predominant energy source for powering the generator is **coal or petroleum coke**, check all the types of technology and steam conditions that apply.
13. For line 12, **Expected Second Most Predominant Energy Source,** enter the energy source code for the energy sources expected to be used in the second largest quantity (Btus) when the generator starts commercial operation. Select appropriate energy source codes from Table 1 in these instructions. Do not include fuels expected to be used only for start-up or flame stabilization.
14. For line 13, **Other Energy Source Options**, enter the codes for other energy sources that will be used at the plant to power the generator. Enter up to four codes in order of their expected predominance of use, where predominance is based on quantity of Btu(s) to be consumed. Select appropriate energy source codes from Table 1 in these instructions.
15. For line 14, **If Energy Source is Wind**, enter the number of turbines.
16. For line 15, **Ability to Use Multiple Fuels**, indicate if the combustion system that will power each generator will have both:
    - The regulatory permits necessary to either co-fire fuels or fuel switch, **and**

- The equipment, including fuel storage facilities necessary to either co-fire fuels or fuel-switch.

If the answer is “No” or “Undetermined”, go to SCHEDULE 4.

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 second fuel for start-up or flame stabilization***.

17. For line 16, **Ability to Co-Fire**, indicate whether or not the combustion system that will power the generator will have the equipment necessary to co-fire fuels and the regulatory permits to co-fire fuels. If no, skip to line 20.

18. For line 17, **Fuel Options for Co-Firing**, indicate up to six fuels that the generator will be designed to co-fire. Select appropriate energy source codes from Table 1 in these instructions. Note: fuel options listed for co-firing must also be included under either “Predominant Energy Source” (line 9a), “Second Most Predominant Energy Source” (line 11), or “Other Energy Sources (line 13).

19. For line 18, **Ability to Co-Fire Oil and Natural Gas**, indicate if the combustion system that powers the generator will be able to co-fire fuel oil with natural gas. If it cannot, skip to line 20.

20. For line 19, **Ability to Co-Fire Oil**, indicate whether or not the combustion system that will power the generator can run on 100 percent oil. If yes, skip to line 20, if no, indicate the maximum percentage of the heat input to the combustion system (percent of MMBtu) that will be able to be supplied by oil when co-firing with natural gas. Also provide the maximum output (summer net MW) that the unit is expected to achieve, taking into account all applicable legal, regulatory, and technical limits, when making the maximum use of oil and co-firing natural gas.

21. For line 20, **Ability to Fuel Switch**, indicate whether or not the combustion system that will power the generator will have the equipment necessary to fuel switch and have the regulatory permits to fuel switch. If no, then skip to SCHEDULE 4.

22. For line 21, **Oil – Natural Gas Fuel Switching**, (a) indicate whether or not the combustion system that will power the generator will have the equipment necessary to switch between oil and natural gas and the regulatory permits in place to switch between oil and natural gas. If no, skip to line 23. If yes:
    a) Will the unit be able to switch fuels while operating (i.e., without shutting down the unit)?
    b) Enter the maximum output (summer net MW) that the unit can achieve, taking into account all applicable legal, regulatory, and technical limits, when running on natural gas.
    c) Enter the maximum output (summer net MW) that the unit can achieve, taking into account all applicable legal, regulatory, and technical limits, when running on oil.
    d) Enter how long it takes to switch the generator from using 100 percent natural gas to 100 percent oil.

23. For line 22, **Limits on Oil-fired Operation**, indicate whether or not there will be factors that will limit the operation of the generator (e.g., limits on maximum output, limits on annual operating hours), when running on 100 percent oil. Check all factors that will limit the ability of this generator to switch from natural gas to oil.

24. For line 23, **Fuel Switching Options**, enter the codes for up to six fuels, including (if applicable) oil and natural gas, that can be used as a sole source of fuel to power each generator. Select appropriate energy source codes from Table 1 in these instructions. Note: fuel options listed for fuel switching must also be included under either “Predominant Energy Source” (line 10), “Second Most Predominant Energy Source” (line 12), or “Other Energy Sources (line 13).

SCHEDULE 4. OWNERSHIP OF GENERATORS OWNED JOINTLY OR BY OTHERS

1. Complete a separate SCHEDULE 4 for each existing and planned generator operated by the respondent that is, or will be, jointly owned; and each generator that the respondent operates but is 100 percent owned by another entity. Only the current or planned operator of jointly-owned generators should complete this schedule. The total percentage of ownership must equal 100 percent.

2. For each generator, specify the **Plant Name, EIA Plant Code, and Generator Identification**, as listed on SCHEDULE 3. PART A.

3. Enter the **Owner/Joint Owner Name and Address,** in order of percentage of ownership, of each generator. Enter the **EIA Code** for the owner, if known, otherwise leave blank. Enter the **Percent Owned** to two decimal places, i.e., 12.5 percent as "12.50." If a generator is 100 percent owned by an entity other than the operator, then enter the percentage ownership as "100.00."

4. Include any notes or comments in SCHEDULE 7, COMMENTS.

SCHEDULE 5. NEW GENERATOR INTERCONNECTION INFORMATION

1. Complete a separate SCHEDULE 5 for each generator that started commercial operation during the data year (calendar year for which this survey is being filed). For example, if Reporting is as of December 31, 2007, then data year is 2007.
2. For line 1, enter the **Name of the Power Plant** and the **EIA Power Plant Code**, as previously reported in SCHEDULE 3. PART A.
3. For line 2, enter the **Operator's Generator Identification**, as previously reported in SCHEDULE 3. PART A.
4. For Line 3**, Date of Actual Generator Interconnection,** report the month and year that the interconnection was put into place.
5. For line 4**, Date of the Initial Interconnection Request,** report the month and year that the first request for interconnection was filed with the grid operator.
6. For line 5**, Interconnection Site Location,** specify the nearest city or town, and the state, where the interconnection equipment is located.
7. **For line 6, Grid Voltage at the Point of Interconnection, specify the grid voltage, in kV, at the point of interconnection between the generator and the grid.**
8. For line 7, **Owner of the Transmission or Distribution Facilities to Which Generator is Interconnected,** provide the name of the owner of the transmission or distribution facilities to which the generator is interconnected. If the name of the owner of the facilities is unknown, provide the name of the contracting party.
9. For line 8, **Total Cost Incurred for the Direct, Physical Interconnection**, specify the total cost incurred, in thousands of dollars, to accomplish the physical interconnection.
10. For line 9, **Equipment Included in the Direct Interconnection Cost**, check each of the types of equipment that are included in the cost amount reported on line 8. If there are significant types of equipment that are not included in the list, please specify what additional equipment was needed for the interconnection in SCHEDULE 7, COMMENTS.
11. For line 10, (a)**Total Cost for Other Grid Enhancements/Reinforcements Needed to Accommodate Power Deliveries From the Generator**, specify the amount incurred, in thousands of dollars, for any other grid enhancements or reinforcements that were needed to accommodate power deliveries from the new generator. If these costs, or some portion of these costs, will be repaid to your company at some time in the future by the owner of the grid, or by the party with whom you contracted for the interconnection, please check "yes" in line 10b; otherwise, check "no" in 10b.
12. For line 11, **Were Specific Transmission Use Rights Secured As A Result Of The**

Interconnection Costs Incurred, check yes or no.

SCHEDULE 6. BOILER INFORMATION
(This information was formerly collected on Form EIA-767, Steam-Electric Plant Operation and Design Report)

This schedule is required to be completed for:

- All existing organic-fueled or combustible renewable-fueled steam-electric plants with a total generator nameplate capacity of at least 10 megawatts; and
- All planned (5-year plans) new organic-fueled or combustible renewable-fueled steam-electric plants with a total generator nameplate capacity of at least 10 megawatts.

Some parts of SCHEDULE 6 are not required to be completed for plants with a total generator nameplate capacity less than 100 megawatts. These parts are specifically noted in the form and/or the instructions.

SCHEDULE 6. PART A. PLANT CONFIGURATION

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

2. For line 1, using each boiler as a starting point, complete the entire column under the boiler identification with the requested information on each piece of associated existing or planned equipment (e.g., generators, cooling systems, etc.). Report waste-heat boilers with auxiliary firing. Do not report waste-heat boilers without auxiliary firing, or auxiliary house or start-up boilers. A waste-heat boiler is a boiler that receives all or a substantial portion of its energy input from the noncombustible exhaust gases of a separate fuel-burning process. Combined cycle units with auxiliary firing report the heat recovery steam generators (HRSGs) on line1.

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

4. For line 2, **Associated Generator(s)**, do not report auxiliary generators. Multiple generators operated as a single unit (e.g., cross compound and topping generators) should be identified as a group with one identification code. Combined cycle units with auxiliary firing report only the steam generators. Do not report the combustion turbine portion of the combined cycle unit.

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

6. For line 4, **Associated Cooling System(s)**, a cooling system is an equipment system that

provides water to the condensers and includes water intakes and outlets, cooling towers and ponds, pumps, and pipes. Identify a single plant cooling system, not separate systems, unless systems are physically separated, e.g., have separate water intake and outlet structures, where each system can be operated independently.

7. For line 4, **Associated Cooling System(s)**, a cooling system is an equipment system that provides water to the condensers and includes water intakes and outlets, cooling towers and ponds, pumps, and pipes. Identify a single plant cooling system, not separate systems, unless systems are physically separated, e.g., have separate water intake and outlet structures, where each system can be operated independently.
8. For line 5, **Associated Flue Gas Particulate Collector(s)**, if a combination particulate collector is associated with a single boiler, identify the collectors as a single group. If the particulate collector also removes sulfur dioxide, identify the unit in lines 5 and 6 using the same identification code.
9. For line 6, **Associated Flue Gas Desulfurization Units(s)**, for reporting purposes identify an associated flue gas desulfurization unit to include all the trains (or modules) associated with a single boiler. If the flue gas desulfurization unit also removes particulate matter, identify the unit in lines 5 and 6 using the same identification code
10. For line 7, **Associated Stack(s)**, a stack is defined as a tall, vertical structure containing one or more flues used to discharge products of combustion into the atmosphere.
11. For line 8, **Associated Flue(s)**, a flue is defined as an enclosed passageway within a stack for directing products of combustion to the atmosphere. For stacks with multiple flues, report in one column all flues that serve the boiler identified in line 1. Separate multiple entries with commas. If the stack has a single flue, use the stack identification for the flue identification.

SCHEDULE 6. PART B. BOILER INFORMATION – AIR EMISSION STANDARDS (DATA NOT REQUIRED FOR PLANTS LESS THAN 100 MW)

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

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 following codes of the New Source Performance Standards (NSPS):

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

For line 2b, **Is Boiler Operating Under a New Source Review (NSR) Permit?,** check "Yes" or "No"; if Yes, enter date and identification number of the issued permit.

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

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

5. Line 4, **Emission Standard Specified**, refers to the numeric value for the unit of measurement in line 5. If no numeric value is specified, report "NA." For Sulfur Dioxide (column (b)), if the standard requires both an emission rate and a percent scrubbed, report both standards separated by a slash (e.g., 1.2/90 for emission standards specified in line 4, column (b), and pounds of sulfur dioxide per million Btu in fuel/percent sulfur removal efficiency (by weight) for units of measurement in line 5, column (b), and indicate in a footnote on SCHEDULE 7.

6. For line 5, **Unit of Measurement Specified**, column (a), Particulate Matter, select from the following unit of measurement codes (PB* is the preferred measurement):

Code	Unit of Measurement
OP	Percent of opacity
PB*	Pounds of Particulate matter per million Btu in fuel
PC	Grains of particulate matter per standard cubic foot of stack gas
PG	Pounds of particulate matter per thousand pounds of stack gas
PH	Pounds of particulate matter emitted per hour
UG	Micrograms of particulate matter per cubic meter
OT	Other (specify in SCHEDULE 7, COMMENTS)

7. For line 5, **Unit of Measurement Specified**, column (b), Sulfur Dioxide, select from the following unit of measurement codes (DP* is the preferred measurement):

Code	Unit of Measurement
DC	Ambient air quality concentration of sulfur dioxide (parts per million)
DH	Pounds of sulfur dioxide emitted per hour
DL	Annual sulfur dioxide emission level less than a level in a previous year
DM	Parts per million of sulfur dioxide in stack gas
DP*	Pounds of sulfur dioxide per million Btu in fuel
SB	Pounds of sulfur per million Btu in fuel
SR	Percent sulfur removal efficiency (by weight)
SU	Percent sulfur content of fuel (by weight)
OT	Other (specify in SCHEDULE 7, COMMENTS)

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

Code	Time Period
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	Weekly average
MO	30 days
ND	90 days
YR	Annual
PS	Periodic stack testing
DT	Defined by testing
NS	Not specified
OT	Other (specify in SCHEDULE 7, COMMENTS)

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

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

Code	Strategy for Compliance
BO	Burner out of service
FR	Flue gas recirculation
LA	Low excess air
LN	Low nitrogen oxide burner
MS	Currently meeting standard
NC	No plans to control
OV	Overfire air
SE	Seeking revision of governing regulation
OT	Other (specify in SCHEDULE 7, COMMENTS)

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

Code	Strategy for Compliance (Sulfur Dioxide)
CF	Fluidized Bed Combustor
CU	Control unit under Phase I extension plan
IF	Install flue gas desulfurization unit (other than Phase I extension plan)
NC	No change in historic operation of unit anticipated
ND	Not determined at this time
RP	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
OT	Other (specify in SCHEDULE 7, COMMENTS)

Code	Strategy for Compliance (Nitrogen Oxides)
AA	Advanced Overfire Air
BF	Biased Firing (alternative burners)
CF	Fluidized Bed Combustor
FR	Flue Gas Recirculation
FU	Fuel Reburning
LA	Low Excess Air
LN	Low NOx Burner
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
UE	Decrease utilization - rely on energy conservation and/or improved efficiency
OT	Other (specify in SCHEDULE 7, COMMENTS)

SCHEDULE 6. PART C. BOILER INFORMATION – DESIGN PARAMETERS (DATA NOT REQUIRED FOR PLANTS LESS THAN 100 MW)

1. Complete for each existing or planned boiler. If a procurement contract has been signed for an upgrade or retrofit of a boiler: 1) complete a separate page for the existing boiler; 2) explain In SCHEDULE 7. COMMENTS how long the existing equipment will be out of service; and 3) using the same boiler identification, complete a separate SCHEDULE 6. PART C for the planned upgrade or retrofit.
   For line 2, verify boiler status. Select from the following codes.

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

2. For line 3, **Boiler Actual or Projected In-service Date**, and line 4, **Boiler Actual or Projected Retirement Date**, the month-year date should be entered as follows: August 1959 as 8-1959. If the month is unknown, use the month of June as a default and enter a 6 before the year.

3. For line 5, **Boiler Manufacturer**, select one code from the following boiler manufacturers' codes:

Code	Boiler Manufacturer
AI	Aalborg Industries
AL	Alstrom
AS	American Shack
AT	Applied Thermal Systems
BR	BROS
BW	Babcock and Wilcox
DJ	De John Coen bv
CE	Combustion Engineering
CH	Cohn
DL	Deltak
DS	Doosan
EC	Econotherm
ER	Erie City Iron Works
FW	Foster Wheeler
GE	General Electric
GT	Gotaverken
HT	Hitachi
ID	Indeck
IN	Innovative Steam Technology

KL	Keeler Dorr Oliver
KP	Kvaerner Pulping
KW	Kawasaki Heavy Industries
ME	Mitchell Engineering
NM	NEM
NT	Nooter/Erickson
PB	Peabody
PR	Pyro Power
RS	Riley Stoker
ST	Sterling
TM	Tampell
TS	Toshiba
VO	Vogt Machine Company/Vogt Power
WE	Westinghouse
WG	Wiegl Engineering
WI	Wickes
ZN	Zurn
OT	Other (specify in SCHEDULE 7, COMMENTS)

4. For line 6, **Type of Firing Used with Primary Fuels**, select from the following firing codes (separate multiple entries (up to three) with commas):

Firing Code	**Firing Type Description**
AF	Arch firing
CF	Concentric Firing
CY	Cyclone firing
DB	Duct burner
FB	Fluidized bed firing
FF	Front firing
OF	Opposed firing
RF	Rear firing
SF	Side firing
SS	Spreader stoker
TF	Tangential firing
VF	Vertical firing (burners mounted on furnace ceiling)
OT	Other (specify in SCHEDULE 7, COMMENTS)

5. For lines 8 through 11, enter firing rate data for primary fuels as entered in line 13. Do not enter firing rate for startup or flame stabilization fuels. For waste-heat boilers with auxiliary firing, enter the firing rate for auxiliary firing and complete line 12 for waste heat.
6. For line 12, a waste-heat boiler is a boiler that receives all or a substantial portion of its energy input from the noncombustible exhaust gases of a separate fuel-burning process.
7. For line 13, **Primary Fuels Used**, see table of energy source (fuel) codes. Show design firing rates for each fuel in the associated lines 8, 9, 10, and 11. Do not include startup fuels. Predominance is based on Btu.
8. For line 16, **Total Air Flow**, report at standard temperature and pressure, i.e., 68 degrees Fahrenheit and one atmosphere pressure.
9. For line 17, **Wet or Dry Bottom**, enter “W” for Wet or “D” for Dry. **Wet Bottom** is defined as slag tanks that are installed at furnace throat to contain and remove molten ash from the furnace. **Dry Bottom** is defined as having no slag tanks at furnace throat area; throat area is clear; bottom ash drops through throat to bottom ash water hoppers. This design is used where the ash melting temperature is greater than the temperature on the furnace wall, allowing for relatively dry furnace wall conditions.

SCHEDULE 6. PART D. BOILER INFORMATION – NITROGEN OXIDE EMISSION CONTROLS

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

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

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

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

Code	Control Process
AA	Advanced Overfire Air
BF	Biased Firing (alternative burners)
CF	Fluidized Bed Combustor
FR	Flue Gas Recirculation
FU	Fuel Reburning
LA	Low Excess Air
LN	Low NOx Burner
NA	Not Applicable
OV	Overfire Air
SC	Slagging
SN	Selective Noncatalytic Reduction
SR	Selective Catalytic Reduction
OT	Other (specify in SCHEDULE 7, COMMENTS)

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

Code	Manufacturer
AB	Advanced Burner Technologies
ABB	ABB
AC	Advanced Combustion Technology
AL	Alstom
AT	Applied Thermal Systems
AU	Applied Utility Systems (AUS)
AZ	Alzeta
BC	Babcock Borsig Power
BM	Bloom
BMD	Burns & McDonnell
BW	Babcock and Wilcox
CE	Combustion Engineering

CM	Combustion Components Associates Inc
CN	Coen
CT	Callidus Technologies
DB	Deutsche-Babcock
DD	Damper Design Inc
DQ	Duquesne Light Company & Energy Systems Associates
DV	Davis
EA	Eagle Air
EG	Energy and Environmental Research Corp (EER)
EL	Electric power Technologies
EP	EPRI
ET	Entropy Technology and Environmental Construction Corp (ETEC)
FB	Faber
FN	Forney
FT	Fuel Tech Inc
FW	Foster Wheeler
GE	General Electric
GR	GE Energy and Environmental Research Corp (GEEER)
HL	Holman
HT	Hitachi
IC	International Combustion Limited
ID	Indeck
IH	In house
JZ	John Zink Todd Combustion/Todd Combustion
KL	Keeler Dorr Oliver
MB	Mitsui-Babcock
MI	Mitsubishi Industries
MT	Mobotec
NA	Not Applicable
NB	Nebraska Boiler Company
NC	Natcom, Inc
NE	NEI
NL	Noell, Inc
PA	Procedair
PB	Peabody
PS	Peerless Manufacturing Company
PL	Pillard
PX	Phoenix Combustion
RD	Rodenhuis and Verloop
RI	Riley
RJ	RJM
RR	Rolls Royce
RS	Riley Stoker/Riley Power
RV	RV Industries
SC	Southern Company
SW	Siemans-Westinghouse
TC	Todd Combustion
TM	Tampella
TS	Toshiba
WG	Weigel Engineering
ZC	Zeeco
OT	Other (specify in a footnote in SCHEDULE 7)

SCHEDULE 6. PART E. BOILER INFORMATION – MERCURY EMISSION CONTROLS

1. For line 2, if “Yes” is checked on line 1, **Does This Boiler have Mercury Emission Controls**, mark all of the boxes that apply to the type of mercury emission controls used. If the type of control is “other”, please describe in SCHEDULE 7, COMMENTS.

SCHEDULE 6 PART F. COOLING SYSTEM INFORMATION – DESIGN PARAMETERS (DATA NOT REQUIRED FOR PLANTS LESS THAN 100 MW)

1. If a procurement contract has been signed for an upgrade or retrofit of a cooling system: 1) complete a separate page for the existing cooling system; 2) explain on SCHEDULE 7, COMMENTS how long the existing equipment will be out of service; and 3) using the same cooling system identification, complete a separate SCHEDULE 6. PART F, for the planned upgrade or retrofit.

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

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

3. For line 4, **Type of Cooling System**, select from the following cooling system codes (separate multiple entries (up to four) with commas):

Code	Cooling System Description
OC	Once through with cooling pond(s) or canal(s)
OF	Once through, fresh water
OS	Once through, saline water
RC	Recirculating with cooling pond(s) or canal(s)
RF	Recirculating with forced draft cooling tower(s)
RI	Recirculating with induced draft cooling tower(s)
RN	Recirculating with natural draft cooling tower(s)
OT	Other (specify in a footnote on SCHEDULE 7)

4. For line 5, **Source of Cooling Water**, provide name of river, lake, etc. For line 5 and line 6, **Design Cooling Water Flow Rate**, if more than one source of cooling water is used by a cooling system, enter other sources in a footnote in SCHEDULE 7. If water is purchased, report "municipal." If water is taken from wells, report "wells." If source of water is "municipal" or "wells," do not complete lines 19, 20, 21, and 22 and provide the total amount of water used at 100 percent load in line 5.

5. For lines 8, 9, and 10, a cooling pond is a natural or man-made body of water that is used for dissipating waste heat from power plants.

6. For line 12, **Type of Towers**, select from the following cooling tower codes (separate multiple entries (up to two) with commas):

Code	Type of Towers
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

7. For lines 15, 16, 17, and 18, enter the actual installed cost for the existing system or the anticipated cost to bring a planned system into commercial operation. Installed cost should include the cost of all major modifications. A major modification is any physical change which results in a change in the amount of air or water pollutants or which results in a different pollutant being emitted.

8. For line 15, **Total System**, the cost should include amounts for items such as pumps, piping, canals, ducts, intake and outlet structures, dams and dikes, reservoirs, cooling towers, and appurtenant equipment. The cost of condensers should not be included.

9. For lines 19 through 22, if the cooling system is a zero discharge type (RC, RF, RI, RN), do not complete column (b). The intake and the outlet are the points where the cooling system meets the source of cooling water found on line 5. For all longitude and latitude coordinates, provide degrees, minutes, and seconds.

10. For line 23, Enter Datum for the above Latitude and Longitude, if Known; Otherwise Enter “UNK”:

    The longitude and latitude measurement for a location depends in part on the coordinate system (or “datum”) the measurement is keyed to. “Datum systems” used in the United States include the North American Datum 1927 (NAD27), North American Datum 1983 (NAD83) and World Geodetic Survey 1984 (WGS84).

    (For background information on datums and their uses, see: http://biology.usgs.gov/index.html).

SCHEDULE 6. PART G. FLUE GAS PARTICULATE COLLECTOR INFORMATION

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

Code	Status
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 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve, i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated. Usually requires 3 to 6 months to reactivate
TS	Operating under test conditions (not in commercial service).

2. For line 4, **Type of Flue Gas Particulate Collector**, select from the following flue gas particulate collector codes (for combination units, separate multiple entries (up to three) with commas):
3.

Code	Description
BS	Baghouse, shake and deflate
BP	Baghouse, pulse
BR	Baghouse, reverse air
EC	Electrostatic precipitator, cold side, with flue gas conditioning
EH	Electrostatic precipitator, hot side, with flue gas conditioning
EK	Electrostatic precipitator, cold side, without flue gas conditioning
EW	Electrostatic precipitator, hot side, without flue gas conditioning
MC	Multiple Cyclone
SC	Single Cyclone
WS	Wet Scrubber
OT	Other (specify in a footnote on SCHEDULE 7 of the form).

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

5. For lines 6, 7, 8 and 9 enter value for fuel. Enter range of values, if applicable.

SCHEDULE 6. PART H. FLUE GAS DESULFURIZATION UNIT INFORMATION – DESIGN PARAMETERS

1. If a procurement contract has been signed for an upgrade or retrofit of a Flue Gas Desulfurization Unit: 1) complete a separate page for the existing unit; 2) explain on SCHEDULE 7, COMMENTS, how long the existing equipment will be out of service; and 3) using the same FGD identification, complete a separate SCHEDULE 6. Part H for the planned upgrade or retrofit.

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

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

If the code selected is “OP” complete lines 4 through 14, otherwise do not complete these lines.

2. For line 4, **Type of Flue Gas Desulfurization Unit**, select from the following FGD unit codes (for combination units, separate multiple entries (up to four) with commas):

Code	Type of Unit
BR	Jet Bubbling Reactor
CD	Circulating Dry Scrubber
MA	Mechanically aided type
PA	Packed type

SD	Spray dryer type
SP	Spray type
TR	Tray type
VE	Venture type

3. For line 5, **Type of Sorbent**, select from the following sorbent codes (separate multiple entries (up to four) with commas):

Code	**Type of Sorbent**
AF	Alkaline fly ash
CC	Calcium carbide slurry
DB	Dibasic acid
DL	Dolomitic limestone
LA	Lime and alkaline fly ash
LF	Limestone and alkaline fly ash
LI	Lime
LS	Limestone
MO	Magnesium oxide
SA	Soda ash
SC	Sodium carbonate
SL	Soda liquid
SS	Sodium sulfite
OT	Other (specify in SCHEDULE 7)

4. For line 7, **Flue Gas Desulfurization Unit Manufacturer,** select one code from the following flue gas desulfurization unit manufacturer codes:

Code	Manufacturer
AA	Advanced Air Technologies
ABB	ABB Environmental Systems
AL	Alstom
AM	American Air Filter
AP	Airpol
API	Air Pollution Industries
AX	Amerex Industries
BE	Bact Engineering
BI	Bleco Industries
BL	Bechtel Corporation
BMC	Burns and McDonnell
BO	Bionomics
BPC	Belco Pollution Control
BPE	Babcock Power Environmental Inc (BPEI)
BT	Belco Technologies
BW	Babcock and Wilcox
CA	Chiyoda
CC	Chemico
CE	Combustion Engineering
CO	Combustion Equipment
DA	Delta Conveying Systems
DC	Ducon
DM	Davey McKee
EE	Environmental Engineering
EEC	Environmental Elements Corporation
EI	Entoleter Inc
FL	Flakt, Inc
FM	FMC
FW	Foster Wheeler
GE	General Electric
HA	Hamon
IH	In House Design
JO	Joy Manufacturing
KE	M.W. Kellogg
KR	Krebs Equipment
MC	Macrotek
MG	McGill Air Clean
MI	Mitsubishi Industry
MX	Marselex
NPA	Neptune Airpol
NSP	NSP
PA	Procedair
PB	Peabody
PR	Pyro Power
PU	Pure Air
RC	Research Cottrell
RS	Riley Stoker
SHU	Saarberg-Holter Umwelttechnick GmbH
SK	Schenck Weigh Feeders
TC	Turbosonic
TH	Thyssen/CEA

UE	Utility Engineering
UM	United McGill
UO	Universal Oil Products
WAPC	Wheelabrator Air Pollution Control
OT	Other (specify in a footnote in SCHEDULE 7)

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

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

SCHEDULE 6. PART I. STACK AND FLUE INFORMATION – DESIGN PARAMETERS (DATA NOT REQUIRED FOR PLANTS LESS THAN 100 MW)

1. If a procurement contract has been signed for an upgrade or retrofit of a stack or flue: 1) complete a page for the existing stack or flue; 2) explain on SCHEDULE 7, COMMENTS, how long the existing structure will be out of service; and 3) using the same flue and stack identifications, complete a separate SCHEDULE 6. Part I for the planned upgrade or retrofit.

2. For line 1, **Flue ID**, and line 2**, Stack ID**, there must be an entry. If there is only one flue, also use the stack ID as the flue ID. Identification codes must be the same as reported on SCHEDULE 6. PART A.

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

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

Status	Code
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 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve, i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated. Usually requires 3 to 6 months to reactivate
TS	Operating under test conditions (not in commercial service).

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

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

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

8. For line 18, Enter Datum for Latitude and Longitude, if Known; Otherwise Enter "UNK":

   The longitude and latitude measurement for a location depends in part on the coordinate system (or "datum") the measurement is keyed to. "Datum systems" used in the United States, include the North American Datum 1927 (NAD27), North American Datum 1983 (NAD83) and World Geodetic Survey 1984 (WGS84).

If you know the datum system for the plant longitude and latitude, enter the system name (e.g., NAD83) on line 7. If you do not know the datum system used, enter UNK.

SCHEDULE 7. COMMENTS

This schedule provides additional space for comments. Please identify schedule and line number and identifying information (e.g., plant code, boiler id, generator id) for each comment.

Table 1. Energy Source Codes and Heat Content

	Energy Source Code	Unit Label	Higher Heating Value" Range (Million Btu per Unit of Fuel MMBtu Lower	MMBtu Upper	Energy Source Description
Fossil Fuels					
Coal and Coal Synfuel	BIT	tons	20	29	Anthracite Coal and Bituminous Coal
	LIG	tons	10	14.5	Lignite Coal
	SC	tons	10	35	Coal Synfuel. Coal-based solid fuel that has been processed by a coal synfuel plant; and coal-based fuels such as briquettes, pellets, or extrusions, which are formed from fresh or recycled coal and binding materials.
	SUB	tons	15	20	Subbituminous Coal
	WC	tons	6.5	16	Waste/Other Coal. Including anthracite culm, bituminous gob, fine coal, lignite waste, waste 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
	RFO	barrels	5.8	6.8	Residual Fuel Oil. Including No. 5, No. 6 Fuel Oils, and Bunker C Fuel Oil.
	WO	barrels	3.0	5.8	Waste/Other Oil. Including Crude Oil, Liquid Butane, Liquid Propane, 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, COMMENTS
	PG	Mcf	2.5	2.75	Gaseous Propane

	SG	Mcf	0.2	1.1	Synthetic Gas, other than coal-derived
	SGC	Mcf	0.2	0.3	Synthetic Gas, derived from coal
Renewable Fuels					
Solid Renewable Fuels	AB	tons	9	18	Agricultural Crop Byproducts/Straw/Energy Crops
	MSW	tons	9	12	Municipal Solid Waste
	OBS	tons	8	25	Other Biomass Solids Specify in Comment Section
	TDF	tons	16	32	Tire-derived Fuels
	WDS	tons	7	18	Wood/Wood Waste Solids. Including paper pellets, railroad ties, utility poles, wood chips, bark, & wood waste solids.
Liquid Renewable Fuels	OBL	barrels	3.5	4.0	Other Biomass Liquids. Specify in SCHEDULE 7, COMMENTS.
	SLW	tons	10	16	Sludge Waste
	BLQ	tons	10	14	Black Liquor
	WDL	barrels	8	14	Wood Waste Liquids excluding Black Liquor, includes red liquor, sludge wood, spent sulfite liquor, and other wood-based liquids
	LFG	Mcf	0.3	0.6	Landfill gas
	OBG	Mcf	0.36	1.6	Other Biomass Gas, includes digestor gas, methane, and other biomass gases. Specify in Comment Section
	SUN	N/A	0	0	Solar
	WND	N/A	0	0	Wind
	GEO	N/A	0	0	Geothermal
	WAT	N/A	0	0	Water at a conventional hydroelectric turbine
All Other Energy Sources					
All Other Energy Sources	PUR	N/A	0	0	Purchased Steam
	WH	N/A	0	0	Waste heat not directly attributed to an energy source. WH should only be reported where the energy source for the waste heat is undetermined
	NUC				Nuclear including Uranium, Plutonium, Thorium
	OTH	N/A	0	0	Specify in Comment Section

Table 2. Commonly Used North American Industry Classification System (NAICS) Codes

Code	Description
	AGRICULTURE, FORESTRY, AND FISHING
111	Agriculture production - crops
112	Agriculture production, livestock and animal specialties
113	Forestry
114	Fishing, hunting, and trapping
115	Agricultural services
	MINING
211	Oil and gas extraction
2121	Coal mining
2122	Metal mining
2123	Mining and quarrying of nonmetallic minerals except fuels
23	**CONSTRUCTION**
	MANUFACTURING

311	Food and kindred products
3122	Tobacco products
314	Textile and mill products
315	Apparel and other finished products made from fabrics and similar materials
316	Leather and leather products
321	Lumber and wood products, except furniture
322	Paper and allied products (other than 322122 or 32213)
322122	Paper mills, except building paper
32213	Paperboard mills
323	Printing and publishing
324	Petroleum refining and related industries (other than 32411)
32411	Petroleum refining
325	Chemicals and allied products (other than 325188, 325211, 32512, or 325311)
32512	Industrial organic chemicals
325188	Industrial inorganic chemicals
325211	Plastic materials and resins
325311	Nitrogenous fertilizers
326	Rubber and miscellaneous plastic products
327	Stone, clay, glass, and concrete products (other than 32731)
32731	Cement, hydraulic
331	Primary metal industries (other than 331111 or 331312)
331111	Blast furnaces and steel mills
331312	Primary aluminum
332	Fabricated metal products, except machinery and transportation equipment
333	Industrial and commercial equipment and components except computer equipment
3345	Measuring, analyzing, and controlling instruments, photographic, medical, and optical goods, watches and clocks
335	Electronic and other electrical equipment and components except computer equipment
336	Transportation equipment
337	Furniture and fixtures
339	Miscellaneous manufacturing industries
	TRANSPORTATION AND PUBLIC UTILITIES
482	Railroad transportation
485	Local and suburban transit and interurban highway passenger transport
484	Motor freight transportation and warehousing
22	Electric, gas, and sanitary services
2212	Natural gas transmission
2213	Water supply
22131	Irrigation systems
22132	Sewerage systems
481	Transportation by air
482	Railroad Transportation
483	Water transportation
484	Motor freight transportation and warehousing
485	Local and suburban transit and interurban highway passenger transport
486	Pipelines, except natural gas
487	Transportation services
513	Communications
562212	Refuse systems
421 to 422	**WHOLESALE TRADE**
441 to 454	**RETAIL TRADE**
521 to 533	**FINANCE, INSURANCE, AND REAL ESTATE**
	SERVICES

512	Motion pictures
514	Business services
514199	Miscellaneous services
541	Legal services
561	Engineering, accounting, research, management, and related services
611	Education services
622	Health services
624	Social services
712	Museums, art galleries, and botanical and zoological gardens
713	Amusement and recreation services
721	Hotels
811	Miscellaneous repair services
8111	Automotive repair, services, and parking
812	Personal services
813	Membership organizations
814	Private Households
92	**PUBLIC ADMINISTRATION**

GLOSSARY

The glossary for this form is available online at the following URL: http://www.eia.doe.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 6.0 hours per response for respondents without environmental information and 11.3 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. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Energy Information Administration, Statistics and Methods Group, EI-70, 1000 Independence Avenue S.W., Forrestal Building, Washington, 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.

PROVISIONS REGARDING CONFIDENTIALITY OF INFORMATION

Information reported on Form EIA-860 will be treated as non-sensitive and may be publicly released in identifiable form except as noted below.

The information reported for the data element "Tested Heat Rate" contained on SCHEDULE 3. PART B will be treated as sensitive and protected 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 regulations, 10 C.F.R. §1004.11, implementing the FOIA, and the Trade Secrets Act, 18 U.S.C. §1905.

The Federal Energy Administration Act requires the 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.

Disclosure limitation procedures are applied to the sensitive statistical data published from SCHEDULE 3. PART B, Tested Heat Rate, on Form EIA-860 to ensure that the risk of disclosure of identifiable information is very small.