Independent Statistics & Analysis
U.S. Energy Information Administration

	Form EIA-860 **ANNUAL ELECTRIC GENERATOR REPORT**	**Year: 2013** **Form Approval: OMB No. 1905-0129** **Approval Expires: 10/31/2013** **Burden: 9.4 Hours**

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 10 years of the specified reporting period. 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	The required respondents for Form EIA-860 are all existing plants and proposed (10-year plans) plants that: 1) have a total generator nameplate capacity (sum for generators at a single site) of 1 Megawatt (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. See General Instructions for related details to determine total capacity at a site. 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 29.
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 are having a problem with logging into or using the e-file system, contact the Help Center at: EIASurveyHelpCenter@eia.gov or 202-586-9595. 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. Vlad Dorjets (202) 586-3141 Suparna Ray (202) 586-5077 Tosha Richardson (202) 287-6597

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 and SCHEDULE 3.
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. 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 end of the data 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.
8. To request additional blank schedules contact the U.S. Energy Information Administration using the contact information on page 1, or download the form from http://www.eia.gov/cneaf/electricity/page/forms.html.
9. For definitions of terms, refer to the U.S. Energy Information Administration glossary at http://www.eia.gov/glossary/index.html.
10. For the purpose of determining reporting requirements, the capacity of a power plant is the sum of the maximum ratings (in MW) on the nameplates of all applicable generators at a specific site. For photovoltaic (PV) solar, use the AC ratings of the array for a specific site.

ITEM-BY-ITEM INSTRUCTIONS

SCHEDULE 1. IDENTIFICATION

1. **Survey Contact:** Provide the name, title, address, telephone number, fax number, and email address for the person that will be the primary contact for this form.
2. **Supervisor of Contact Person for Survey:** Provide the name, title, address, telephone number, Fax number and email address of the primary contact’s supervisor.
3. **Report For:** Provide (or verify) the operator name and year for which data are being reported. These fields cannot be revised online. Contact EIA if corrections are needed.

   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.
4. For **Operator Information**, enter the legal name of the operator and the address of its principal office. Include an attention line, room number, building designation, or other details if necessary.
5. For **Is the Operator an Electric Utility?** check “Yes” or “No,” as appropriate.

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 10 years of the specified reporting period. To report a new plant or a plant that is not already identified, use a blank SCHEDULE 2. 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 entity.

1. For line 1**, Plant Name,** 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 lines 2 through 5**,** enter the address at which the plant is located or will be located. 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 6, **Latitude and Longitude**, enter the latitude and longitude of the plant in either (1) degrees, minutes, and seconds, or (2) decimal format. The **coordinates should rel**ate to a central point within the plant's property such as a generator. Do not enter latitude and longitude 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.

4. For line 7, enter the **Datum** for the 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") to which the measurement is keyed. "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).

5. For line 8a, **NERC Region**, enter the NERC region in which the plant operates.

6. For line 8b, **Is this Plant in a RTO or ISO Territory?,** check "Yes" or "No" for whether the plant in the service territory of a Regional Transmission Organization or Independent System Operator.

7. For line 8c, **Name of RTO or ISO**, if you answered "Yes" in line 8b, select the RTO or ISO from the list. If your RTO or ISO does not appear on the list, select "Other" and explain in SCHEDULE 7. If you are filling out the form in EIA's Internet Data Collection System, enter appropriate the RTO or ISO.

8. For line 9, **Name of Water Source**, 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 "NA" for planned facilities for which the water source is not known.

9. The responses for lines 10 and 11 are entered by EIA survey managers 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.

10. For line 12, **Primary Purpose of the Plant**, enter the North American Industry Classification System (NAICS) code found in Table 2 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

11. For 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. 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 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. 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.
13. For 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. 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.
14. For line 16a, **Owner of Transmission/Distribution Facilities**, enter the name of the current owner of the transmission or distribution facilities to which the plant is interconnected. 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.
15. For line 16b, **Grid Voltage (in kilovolts)**, enter the grid voltage at the point of interconnection to the transmission/distribution facilities. If the plant is interconnected to multiple transmission/distribution facilities, enter the highest grid voltage and list the other grid voltages in SCHEDULE 7.

SCHEDULE 3. GENERATOR INFORMATION

1. 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 10 years of the specified reporting period and are either planned, under construction, or in testing stage. 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, etc.).
3. Treat energy storage facilities as generators and provide all necessary data requested below, even if maximum capability of facility is less than 1 MW. 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 3, **Generator ID**, 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.

2. Leave **Generator Status** blank in as it is entered in SCHEDULE 3B or SCHEDULE 3C, as appropriate.

3. For line 4, **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
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 (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)
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.

4. For line 5, **Associated Boiler Identifications**, enter the identification (ID) code for each boiler that provides steam to each combustible-fuel steam generator (including steam generators with duct firing) with 10 MW or more nameplate capacity and for each combined cycle steam turbine generator without duct firing with 100 MW or more nameplate capacity (needed to associate cooling system data with generators). Boilers may be associated with multiple generators. The identification code should, preferably, be one that is commonly used by plant management as it will be used throughout all EIA forms. However, the code cannot be more than six characters long and cannot have any blanks. Combined cycle units with and without auxiliary firing should report codes for the heat recovery steam generators (HRSGs) on line 5.

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 generator?,** an *electric utility generator* shall mean a generator that is owned by an electric utility, or a jointly owned generator with the greatest share of the generator being electric utility owned. (Note: If two or more owners have equal shares of ownership in a generator, it is considered to be an electric utility generator if any one of the owners meets the definition of electric utility). For each electric utility generator, check “Yes” or “No.”
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.
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 generator has a combined-cycle prime mover code of “CA,”, “CS” or “CC,” check “Yes” if the unit has duct-burners for supplementary firing of the turbine exhaust gas. Otherwise, check “No.”

SCHEDULE 3, PART B. GENERATOR INFORMATION – EXISTING GENERATORS

1. For line 1, **Generator Nameplate Capacity**, report the highest value on the nameplate in MW rounded to the nearest tenth as measured in alternating current (AC). If the nameplate capacity is expressed in kilovolt amperes (kVA), convert to kilowatts by multiplying the corresponding power factor by the kVA, dividing by 1,000, and rounding to the nearest tenth to express the capacity in MW. If generator nameplate capacity is less than net summer capacity, provide the reason(s) in SCHEDULE 7.
2. For line 2, **Net Capacity**, enter the generator's net summer and net winter capacities for the primary energy source. Report in alternating current (AC) MW, 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 generators, report the instantaneous capacity at maximum water flow. If net capacity is only available as direct current (DC), estimate the effective AC output and explain in SCHEDULE 7.
3. For line 3a, **Maximum Reactive Power Output (MVAR)**, if the reactive power capability has been tested, enter the maximum reactive power outputs (MVAR) at the high side of the generator step-up transformer for generators with nameplate capacity of 10 MW or greater. A MVAR is a Mega Voltampere Reactive.
4. For line 3b**, Maximum Reactive Power Absorption (MVAR)**, if the reactive power capability has been tested, enter the maximum reactive power absorptions of the generator at the high side of the generator step-up transformer for generators with nameplate capacity of 10 MW or greater. 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.
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 7A, **Actual Retirement Date,** enter the month and year that the generator was retired.
9. For line 7B, **Planned Retirement Date**, enter a best-available date (MM-YYYY) if the generator is expected to be retired within the next 10 years.
10. For line 8A, if the generator is associated with a combined heat and power system, select whether it is part of a topping or bottoming 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.
11. If you enter “Yes” on line 8A, indicate whether the generator is part of a topping or bottoming cycle on line 8B.
12. 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).
13. 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.
14. For line 10, if the prime mover is ST (steam turbine) report the **Start-Up and Flame Stabilization Energy Sources** used by the combustion unit(s) associated with this generator; otherwise leave blank.
15. 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).
16. 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).
17. For line 13, **Is This Generator Part of a Solid Fuel Gasification System,** check “Yes” or “No” as appropriate.

18. For line 14, **Number of Turbines, Buoys, Inverters, or Micro-Turbines**, if energy source is wind, enter the number of turbines; if the energy source is wave energy, enter the number of buoys; if energy source is other hydrokinetics, enter the number of turbines; if the energy source is solar photovoltaic, enter the number of inverters. If generator consists of micro-turbines, enter how many of them there are.
19. For line 15a, **Tested Heat Rate**, enter the tested heat rate under full load conditions for all combustible-fueled generators, nuclear-fueled generators, concentrated solar generators and geothermal generators. 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. For solar photovoltaic generators, provide the average module efficiency for all installed modules. If the reported value is not a tested heat rate, specify in SCHEDULE 7.
20. For line 15b, **Fuel Used for Heat Rate Test**, enter the fuel code or "M" for multiple fuels for the fuel used to calculate the heat rate reported above. 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).
21. For line 16, **Operating Efficiency for Solar Photovoltaic Generators**, enter the manufacturer's rated efficiency at standard test conditions, if available.

Proposed Changes to Existing Generators (within the next 10 years)

22. For line 17a, indicate whether there are any planned capacity uprates/derates, repowering, other modifications, or generator retirements scheduled to take place within the next 10 years.
23. For line 17b, **Planned Uprates,** enter the increase in capacity expected to be realized from the uprate. Enter the planned effective date (MM-YYYY) that the generator is scheduled to enter operation after the modification.
24. For line 17c, **Planned Derates**, enter the decrease in capacity expected to be realized from the derate. Enter the planned effective date (MM-YYYY) that the generator is scheduled to enter operation after the modification.
25. For line 17d, **Planned Repowering**, if a repowering of the generator is planned, enter the new prime mover, the new energy source, and new nameplate capacity as well as the planned effective date (MM-YYYY) that the generator is scheduled to enter operation after the re-powering is complete.
26. For line 17e, **Other Modifications,** 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. Other planned changes may include a second uprate or derate to a unit or a reactivation of a previously retired generator.
27. For line 18, **Can This Generator be Powered by 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.

28. For line 19, **Can This Unit Co-Fire Fuels?**, indicate whether or not the combustion system that powers the generator has, in working order, the equipment and the regulatory permits necessary to co-fire fuels. If the answer is "No," skip to line 23.
29. 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 1 in 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).
30. For line 21, **Can This Generator be Powered by Co-Fired Fuel Oil and Natural Gas?**, indicate if the combustion system that powers the generator can co-fire fuel oil with natural gas. If the answer is "No," skip to line 23.
31. For line 22, **Can This Generator be Run on 100% 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 it is "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, taking into account all applicable legal, regulatory, and technical limits. Also provide the maximum output (summer net MW) that the unit can achieve, taking into account all applicable legal, regulatory, and technical limits when making the maximum use of oil and co-firing natural gas.
32. For line 23, **Can This Unit 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. If "No," skip to SCHEDULE 3, PART C.
33. For line 24, **Can This Unit Switch Between Oil and Natural Gas?**, indicate whether or not the combustion system that powers the generator has, in working order, the equipment and the regulatory permits necessary to switch between oil and natural gas. If "No," go to line 26. If "Yes," indicate whether the unit can switch fuels while operating (i.e., without shutting down the unit). Also 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, 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, and how long it takes to switch the generator from using 100 percent natural gas to 100 percent oil.
34. For line 25, **Are There Factors That Limit the Unit's Ability to Switch From Natural Gas to Oil?**, 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.
35. 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, **Expected Generator Nameplate Capacity**, enter the expected nameplate capacity in MW rounded to the nearest tenth as measured in alternating current (AC). If the nameplate capacity is expressed in kilovolt amperes (kVA), convert to kilowatts by multiplying the corresponding power factor by the kVA, dividing by 1,000, and rounding to the nearest tenth to

express the capacity in MW.

2. For line 2, **Expected Net Capacity**, enter the generator's net summer and net winter capacities for the primary energy source. Report the values in alternating current (AC) MW rounded to the nearest tenth that are expected when the generator goes into commercial operation.
3. For line 3a, **Maximum Expected Reactive Power Output (MVAR)**, enter the maximum expected reactive power outputs (MVAR) at the high side of the generator step-up transformer for generators with nameplate capacity of 10 MW or greater. A MVAR is a Mega Voltampere Reactive.
4. For line 3b**, Maximum Expected Reactive Power Absorption (MVAR)**, enter the maximum expected reactive power absorptions of the generator at the high side of the generator step-up transformer for generators with nameplate capacity of 10 MW or greater. 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 (specify in SCHEDULE 7)

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?** 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 Expected 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, **Expected Number of Turbines, Buoys, or Inverters,** if the energy source will be wind, enter the number of turbines; if the energy source will be wave energy, enter the number of buoys; if the energy source will be other hydrokinetics, enter the number of turbines; if the energy source will be solar photovoltaic, enter the number of inverters.

16. For line 15, **Will This Generator be Able to be Powered by 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, in working order, 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, **Will this Unit be Able to Co-Fire Fuels?**, 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, **Will This Generator be Able to be Powered by Co-Fired Fuel 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, **Will This Generator be able to Run on 100% 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, **Will This Unit be Able 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, **Will This Unit be Able to Switch Between Oil and Natural Gas?**, indicate whether or not the combustion system that will power the generator will have the necessary equipment and the regulatory permits in place to switch between oil and natural gas. If “No,” skip to line 23. If “Yes,” indicate whether the unit will be able to switch fuels while operating (i.e., without shutting down the unit). Also enter the maximum output (summer net MW) that the unit is expected to achieve, taking into account all applicable legal, regulatory, and technical limits, when running on natural gas, the maximum output (summer net MW) that the unit is expected to achieve, taking into account all applicable legal, regulatory, and technical limits, when running on oil, and how

long it is expected to take to switch the generator from using 100 percent natural gas to 100 percent oil.

23. For line 22, **Limits Are There Factors That Will Limit the Unit's Ability to Switch From Natural Gas to Oil?**, 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 Code, as listed on SCHEDULE 3, PART A.
3. Enter the **Owner/Joint Owner Name and Address,** in descending order of ownership share.
4. Enter the **EIA Owner Code** for the owner, if known, otherwise leave blank.
5. 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." Include any notes or comments in SCHEDULE 7.

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 **Generator ID**, 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 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.
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

Some or all parts of this schedule are required to be completed for all existing and planned (10 year plans) combustible-fueled steam generators (including heat recovery steam generators with and without duct firing and combustible renewable-fueled generators) with a combined nameplate capacity of at least 10 MW, all nuclear generators and applicable solar thermal generators with a total generator nameplate capacity of at least 10 MW.

All parts of this schedule are to be completed for combustible-fueled steam generators at a plant with a combined nameplate capacity of at least 100 MW (including steam generators with duct firing).

Only PART B, PART D, PART E, PART G, and PART H are to be completed for combustible-fueled steam generators at a plant with a combined nameplate capacity of at least 10 MW but less than 100 MW.

Only PART F is to be completed for nuclear generators, steam generators without duct firing, and applicable solar generators using a steam cycle.

SCHEDULE 6, PART A. PLANT CONFIGURATION

The e-file system will pre-populate the boiler identification codes throughout SCHEDULE 6 based on the codes entered in SCHEDULE 3, PART A. Plants with a Steam Plant Type of 1, as defined and set out on line 11 of SCHEDULE 2, should complete all lines on SCHEDULE 6, PART A. Plants with a Steam Plant Type of 2 should only complete lines 2, 3, and, if applicable, lines 5 and 6. Plants with a Steam Plant Type of 3 should complete lines 2, 3 and 4. Planned equipment that is on order and expected to go into commercial service within 10 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 pre-populated equipment identifications.

1. 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.).
2. 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.
3. For line 2, **Associated Generator ID(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.

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

5. For line 4, **Associated Cooling System ID(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.

6. For line 5, **Associated Flue Gas Particulate Collector ID(s)**, enter an identification number for each piece of equipment designed primarily to collect flue gas particulates including fabric filter / baghouse and electrostatic precipitator. 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.

7. For line 6, **Associated Flue Gas Desulfurization Units ID(s)**, enter an identification number for each piece of equipment designed primarily to desulfurize flue gas including dry powder injection systems. 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.

8. For line 7, **Associated Flue ID(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.

9. For line 8, **Associated Stack ID(s)**, a stack is defined as a tall, vertical structure containing one or more flues used to discharge products of combustion into the atmosphere.

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 as reported on line 1 of 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 following codes of the New Source Performance Standards (NSPS):

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.

3. 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.

4. 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

NA No Applicable Standard

5. For line 4, **Emission Standard Specified**, refer 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 the emission rate in terms of pounds of sulfur dioxide per million Btu on line 4a and report the percent scrubbed in terms of percent sulfur removal efficiency (by weight) on line 4b.

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)

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)

8. For line 5, **Unit of Measurement Specified**, column (c), Nitrogen Oxides, select from the following unit of measurement codes (NP* is the preferred measurement):

Code	Unit of Measurement
NH	Pounds of nitrogen oxides emitted per hour
NL	Annual nitrogen oxides emission level less than a level in a previous year
NM	Parts per million of nitrogen oxides in stack gas
NO	Ambient air quality concentration of nitrogen oxides (parts per million)
NP*	Pounds of nitrogen oxides per million Btu in fuel
OT	Other (specify in SCHEDULE 7)

9. 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	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)

10. 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.

11. For line 8, **If Not in Compliance, Strategy for Compliance**, 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)

12. 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

WA	Allocated allowances and purchase allowances
OT	Other (specify in SCHEDULE 7)

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
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)

SCHEDULE 6, PART C. BOILER INFORMATION – DESIGN PARAMETERS (DATA FOR LINES 3 – 18 NOT REQUIRED FOR PLANTS LESS THAN 100 MW)

1. Complete for each existing or planned boiler as reported on line 1 of SCHEDULE 6, PART A. 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 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.

2. For line 2, select the boiler status 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 (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, **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 08-1959. If the month is unknown, use the month of June.

4. 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 Jong Coen bv
CE	Combustion Engineering
CN	Coen
DL	Deltak
DS	Doosan
EC	Econotherm
ER	Erie City Iron Works
ET	Entek
FW	Foster Wheeler
GE	General Electric
GT	Gotaverken
HT	Hitachi
ID	Indeck
IH	In House Design
IHI	Ishikawajima-Harima Heavy Industries
IS	Innovative Steam Technology
KL	Keeler Dorr Oliver
KP	Kvaerner Pulping
KW	Kawasaki Heavy Industries
ME	Mitchell Engineering
NB	Nebraska Boiler
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)

5. For line 6, **Type of Boiler**, select from the following firing codes (separate multiple entries (up to three) with commas):

Code	Type of Boiler
AF	Arch Firing
CB	Cell Burner
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
OT	Other (specify in SCHEDULE 7)

6. 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.
7. For line 12, **Design Waste Heat Input Rate at Maximum Continuous Steam Flow**, 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.
8. 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.
9. For line 16, **Total Air Flow**, report at standard temperature and pressure, i.e., 68 degrees Fahrenheit and one atmosphere pressure.
10. 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
NA	Not Applicable
NC	No plans to control
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 (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, **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
H2O	Water Injection
LA	Low Excess Air
LN	Low NOx Burner
NA	Not Applicable
NH3	Ammonia Injection
OV	Overfire Air
SC	Slagging
SN	Selective Noncatalytic Reduction
SR	Selective Catalytic Reduction
STM	Steam Injection
NC	No change in historic operation of unit anticipated
RP	Repower Unit
UE	Decrease utilization - rely on energy conservation and/or improved efficiency
OT	Other (specify in SCHEDULE 7)

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
AP	AirPol
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
CSI	Combustion Solutions Inc
CT	Callidus Technologies
DB	Deutsche-Babcock
DD	Damper Design Inc
DQ	Duquesne Light Company & Energy Systems Associates
DV	Davis
DX	Deltex
EA	Eagle Air
EG	Energy and Environmental Research Corp (EER)
EL	Electric Power Technologies
EP	EPRI
ET	Entek
ETE	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 Design
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
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
TEC	Thermal Equipment Corporation
TM	Tampella
TS	Toshiba
WG	Weigel Engineering
ZC	Zeeco
OT	Other (specify in SCHEDULE 7)

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

1. For line 2, if "Yes" is checked on line 1, enter all applicable mercury emissions controls codes, separated by commas, from the following list:

Code	Mercury Emission Control
ACI	Activated Carbon Injection System
BS	Baghouse, shake and deflate
BP	Baghouse, pulse
BR	Baghouse, reverse air
DS	Dry Scrubber
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
FGD	Flue Gas Desulfurization
LIJ	Lime Injection
WS	Wet Scrubber
OT	Other (specify in SCHEDULE 7)

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) specify in SCHEDULE 7 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 (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 4a, **Type of Cooling System**, select from the following cooling system codes (separate multiple entries (up to four) with commas):

Code	Cooling System 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)

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.

4. For line 4b, 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 5a, **Source of Cooling Water**, provide name of river, lake, etc. For line 5b, select the **Type of Cooling Water Source** from the following codes:

Code	Type of Water Source
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)

6. For line 5c, **Type of Cooling Water**, select the **Type of Cooling Water** from the following codes:

Code	Type of Water
BR	Brackish Water
FR	Fresh Water
TW	Treated Wastewater
SA	Saline Water
OT	Other (specify in SCHEDULE 7)

7. For line 6, **Design Cooling Water Flow Rate at 100 percent Load at Intake**, 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 6.

8. 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.

9. 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
OT	Other (specify in SCHEDULE 7)

10. 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. 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.

11. 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.

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 (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 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):

Code	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
WS	Wet Scrubber
OT	Other (specify in SCHEDULE 7)

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

4. For 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 (INCLUDES COMBUSTION TECHNOLOGIES)

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) specify in SCHEDULE 7 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.

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

Code	Status
CN	Cancelled (only if 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 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)

3. If the code selected is "OP" complete lines 4 through 14, otherwise do not complete these lines.
4. 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
DP	Dry sorbent (powder) injection type (DSI)
MA	Mechanically aided type
PA	Packed type
SD	Spray dryer type
SP	Spray type
TR	Tray type
VE	Venturi type
OT	Other (specify in SCHEDULE 7)

5. 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
CEF	CE filtrate
CSH	Caustic Sodium hydroxide
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
SB	Sodium bicarbonate
SC	Sodium carbonate
SF	Sodium formate
SL	Soda liquid
SS	Sodium sulfite
TW	Treated wastewater
WT	Water
OT	Other (specify in SCHEDULE 7)

6. 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

BMD	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
GF	Grafwolff
HA	Hamon
IH	In House Design
JO	Joy Manufacturing
KC	Korea Cottrell
KE	M.W. Kellogg
KR	Krebs Equipment
LLB	Lurgi Lentjes Bischoff
MC	Macrotek
MG	McGill Air Clean
MI	Mitsubishi Industry
MT	Mobotec
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
TK	Turbotak
TP	Tempala Power
UE	Utility Engineering
UM	United McGill
UO	Universal Oil Products
WAP	Wheelabrator Air Pollution Control
ZN	Zurn
OT	Other (specify in SCHEDULE 7)

7. For line 15, **Removal Efficiency for Sulfur Dioxide**, report the removal efficiency as the percent by weight of gases removed from the flue gas.
8. 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) specify in SCHEDULE 7 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 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).

5. For lines 7 and 8, the rate should be approximately equal to the cross-sectional area multiplied by the velocity, multiplied by 60.
6. For lines 13 and 14, seasonal average flue gas exit temperatures should be reported in degrees Fahrenheit, based on the arithmetic mean of measurements during operating hours. Summer season includes June, July, and August. Winter season includes January, February, and December.
7. For line 15, **Source**, enter “M” for measured or “E” for estimated.
8. For lines 16 and 17, **Stack Location**, enter the latitude and longitude in either degrees, minutes, and seconds or as a decimal.
9. 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).

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 and use additional pages, if necessary.

Table 1. Energy Source Codes and Heat Content

Fuel Type	Energy Source Code	Unit Label	Higher Heating Value Range MMBtu Lower	Higher Heating Value Range MMBtu Upper	Energy Source Description
Fossil Fuels					
Coal	ANT	Tons	22	28	Anthracite Coal
	BIT	Tons	20	29	Bituminous Coal
	LIG	Tons	10	14.5	Lignite Coal
	SUB	Tons	15	20	Subbituminous Coal
	SGC	Mcf	0.2	0.3	Coal-Derived Synthesis Gas
	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
	PG	Mcf	2.5	2.75	Gaseous Propane
	RFO	barrels	5.8	6.8	Residual Fuel Oil (including No. 5, and No. 6 fuel oils, and bunker C fuel oil)
	SG	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 (including paper pellets, railroad ties, utility poles, wood chips, bark, and wood waste solids)

Fuel Type	Energy Source Code	Unit Label	Higher Heating Value Range MMBtu Lower	Higher Heating Value Range MMBtu Upper	Energy Source Description
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 but 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	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, and water used in Wave Buoy Hydrokinetic Technology, Current Hydrokinetic Technology, and Tidal Hydrokinetic Technology
All Other Fuels					
All Other Energy Sources	WAT	MWh	0	0	Pumping Energy for Reversible (Pumped Storage) Hydroelectric Turbine
	NUC	N/A	0	0	Nuclear (including Uranium, Plutonium, and Thorium)
	PUR	N/A	0	0	Purchased Steam
	WH	N/A	0	0	Waste heat not directly attributed to a fuel source (WH should only be reported where the fuel source for the waste heat is undetermined, and for combined cycle steam turbines that do not have supplemental firing.)
	TDF	Tons	16	32	Tire-Derived Fuels
	MWH	MWh	0	0	Electricity used for energy storage
	OTH	N/A	0	0	Specify in SCHEDULE 7

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

	Agriculture, Forestry, Fishing and Hunting
111	Crop Production
112	Animal Production
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, 325188, 3252 325211, 3253 or 325311)
32511	Petrochemical Manufacturing
32512	Industrial Gas Manufacturing
325193	Ethyl Alcohol Manufacturing (including Ethanol)
325188	Industrial Inorganic Chemicals
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 331111 or 331312)
331111	Iron and Steel Mills
331312	Primary Aluminum Production
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)