DOCUMENTATION FOR THE 2001 ELECTRIC GENERATING UNIT (EGU) TRENDS PROCEDURES REPORT, SECTION 4.2

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4.2 FUEL COMBUSTION - ELECTRIC UTILITY

4.2.1 Which sources does EPA include in the Fuel Combustion - Electric Generating Unit (EGU) category?

The point source categories under the "Electric Generating Unit" (EGU) heading include the following Tier I and Tier II categories:

Tier I Category	Tier II Category
(01) FUEL COMBUSTION - EGU	(01) Coal
	(02) Oil
	(03) Gas
	(04) Other Fuels including wood, waste, etc.

The emissions from the combustion of fuel by EGU are divided into two classifications: (1) steam EGUs (boilers) with Source Classification Codes (SCCs) = 101xxxxx; and (2) non-steam EGUs such as gas turbines (GT) and internal combustion (IC) engines with SCCs = 201xxxxx. Estimating emissions for these two classes requires two very different methodologies, each of which is described separately. This section describes the methodology for EGUs that are included in either the Department of Energy's (DOE's) Energy Information Administration (EIA)-767 or the U.S. Environmental Protection Agency's (EPA's) Emission Tracking System/Continuous Emissions Monitoring (ETS/CEM) data frames (with specified restrictions).[1,2] The methodology used to estimate most emissions for nonsteam EGUs (excluding those who report data to EPA's ETS/CEM and are included in the EGU frame, and thus, in this section) is described in section 4.3.

4.2.2 What units are included in the Trends EGU inventory?

The *Trends* databases for EGUs use the boilers in the EIA-767 electric power survey as the frame for the National Emission Inventory (NEI) EGU inventory. For the 2001 EGU inventory, ETS/CEM units (primarily nonsteam turbines) are added to the EGU component of the NEI if they are not included in the original EIA-767 frame and if they meet specified conditions. Additional units are added, as the EIA-767 frame was expanded by well over one-third to include not just fossil-fuel but also renewable steam generating utility and nonutility boilers. This NEI EGU steam component does not include data from gas turbine or internal combustion engines (which account for a very small share of EGU fuel use and corresponding emissions) unless companies report that data to EIA, or if the units are among the ETS/CEM-only additional units added.

4.2.3 What emissions data for EGU are included in the Trends inventory?

The EGU database includes annual emission estimates of volatile organic compounds (VOC), nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), filterable particulate matter $(PM)_{10}$, and filterable $PM_{2.5}$ for the years 1985 through 2001. In addition, ammonia (NH_3,) condensable PM, primary PM_{10}, and primary $PM_{2.5}$ were added in 1996. Table 4.2-1 summarizes the methods used to estimate emissions for each pollutant for 1989 through 2001. EPA does not develop emissions estimates for sulfates (SO_4) because no known EGU emission factors exist for this pollutant. Emission estimates for NH_3 are only included for coal, oil, and gas boilers, since there are only NH_3 emission factors for these categories.

4.2.4 How does EPA develop emission estimates for EGUs?

To estimate emissions for EGUs for the years 1985 through 2001, the following are considered: (1) fuel consumption; (2) the latest (August 2003) EPA-approved uncontrolled emission factors, which relate the quantity of fuel consumed to the quantity of pollutant emitted;[3] (3) fuel quality characteristics, such as sulfur content, ash content, and heating value; (4) control efficiency, which indicates the percent of pollutant emissions not removed through control methods; (5) whether ETS/CEM data exist for SO_2, NO_x, and heat input (from 1995 on); and (6) whether State data were submitted (for 1999).

To derive 2001 emissions estimates, EPA first estimates the 2001 boiler-level emissions and heat input from EIA data and uncontrolled AP-42 emission factors.

EPA computes SO_2 emissions using uncontrolled AP-42 emissions factors, and fuel use and sulfur content of the fuel as specified in the EIA-767 data; controlled emissions are estimated if there are control efficiencies provided in the EIA-767.

EPA computes NO_x emissions using uncontrolled AP-42 emissions factors, and fuel use as specified in the EIA-767 data; controlled NO_x emissions are estimated – if the boiler has positive NO_x control device in-service hours and it also has an annual NO_x controlled rate in lbs/million British thermal units (MMBtu) – by multiplying the heat input (in MMBtu, the product of the fuel quantity burned and the fuel heat content) and the NO_x controlled rate. Methodology for calculating controlled NO_x emissions when the control data are inconsistent entails the use of an EIA-obtained NO_x removal rate that is applied to the uncontrolled emissions; this is further explained in section 4.2.6.

Filterable PM_{10} and $PM_{2.5}$ emissions are estimated using uncontrolled AP-42 emissions factors, and fuel use and ash content of the fuel as specified in the EIA-767 data; controlled emissions are estimated if there are control efficiencies provided by the PM Calculator,[4] based on EIA-767 data (see above). The PM_{10} and $PM_{2.5}$ emissions included in the *Trends* inventory for all years through the 1999 data year represent filterable PM_{10} and $PM_{2.5}$ emissions. Beginning with data year 1996, condensable PM emissions were estimated (as the product of heat input and an emissions factor in lbs/MMBtu) and summed with filterable PM_{10} and $PM_{2.5}$ emissions to estimate primary PM_{10} and primary $PM_{2.5}$ emissions. The rules used to determine the PM condensable emission factors are described in Table 4.2-2. The algorithms to compute all pollutant emissions are presented in Tables 4.2-3 and 4.2-4.

The CO and VOC emissions are calculated as uncontrolled emissions since there are no control device data available. For oil and gas boilers, VOC is augmented using aldehyde and methane weight percents by SCC profile.

Although no NH_3 AP-42 emission factors officially exist for EGUs, in 1998 EPA developed coal, oil, and gas NH_3 emission factors for boilers that are applied to the specified quantity of fuel used (see Table 4.2-5). Thus, beginning with the 1996 data year, NH_3 estimates are included in the *Trends* database.

After all emissions for the EIA-767 boilers are initially estimated, 2001 ETS/CEM boiler-level annual estimates for SO_2 and NO_x, and heat input values, if they exist, are disaggregated to the boiler-SCC level based on their EIA heat input, and overlaid on the EIA-767-based data. An additional 280 boilers with 2001 ETS/CEM data (2001 "ETS/CEM-only units") have been added to the 2001 EIA-767 frame based on the following criteria: they are (primary fuel only) units that (1) are not in the 2001 EIA-767, are in the 2001 ETS/CEM, and are in plants that have at least one unit that reports emitting at least 100 tons of NO_x in the 2001 ETS/CEM; or (2) are not in the 2001 EIA-767, are in the 2001 ETS/CEM with less than 100 tons of NO_x, but are included in the list of 1999 or 2000 ETS/CEM-only units; or (3) are not in the 2001 EIA-767, are in the 2001 ETS/CEM, and the plant the unit is in has other units in the 2001 EIA-767.

Ozone season day emissions and heat input are also developed (see section 4.2.7) and included in the EGU database.

4.2.5 Where does EPA obtain the EGU data necessary for emissions estimates?

Primary electric power data collected by the EIA serves as the basis for the EGU component of the NEI *Trends* inventory. The EIA uses Form EIA-767, *Steam-Electric Plant Operation and Design Report,*[1] to collect monthly boiler-level data on an annual basis from steam EGUs, whether they are utility (regulated) or nonutility (unregulated) entities. Currently, data from Form EIA-767 are available for the years 1985 through 2001. The 2001 data were collected by EIA beginning in January 2002; companies responded either by filling out paper copies of the form for each plant, or by responding on-line. EIA's Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF) collects and disseminates the data. The data are available on the EIA website at http://www.eia.doe.gov/cneaf/electricity/page/eia767.html.

The EPA's Clean Air Markets Division (CAMD) collects the ETS/CEM data annually. These data have been collected since 1995 as a result of implementation of Title IV of the 1990 Clean Air Act Amendments. The data can be found at http://www.epa.gov/airmarkets/emissions/score01/index.html or http://cfpub.epa.gov/gdm/.[5] The sources which must report ETS/CEM data to EPA are called "affected sources," as determined by CAMD in accordance with the Code of Federal Regulations (CFR). Specifically, the 40CFR Part 72.6 applicability rules can be found at http://www.access.gpo.gov/nara/cfr/waisidx_00/40cfr72_00.html. The ETS/CEM ozone season data can also be found at http://cfpub.epa.gov/gdm/.

The EGU inventory data for 1985 through 2001 are initially based on the aggregated monthly steam-electric boiler-level data obtained from Form EIA-767. All plants of at least 10 megawatts (MW) that have at least one operating boiler are required to provide this information to EIA, although the amount of data required from plants with less than 100 MW of steam-electric generating capacity is not as extensive as the amount required from those plants of at least 100 MW. In 2001, for plants with a generator nameplate rating from 10 MW to less than 100 MW, only those pages of Form EIA-767 containing identification (ID) information (i.e., plant code (ORISPL), State name, county name, plant name, operator name, boiler ID), boiler fuel quantity and quality, and control device information for SO_2, NO_x, and PM must be completed.

Other sources of data for NO_x, SO_2, and heat input are used in place of the EIA-based estimated data when the data are known to be better: EPA's ETS/CEM annual NO_x and SO_2 emissions and heat input have been used to overlay the EIA-based data for affected acid rain utility boilers since 1995 (the data are also available for Phase 1 units for 1994).[2] For 1999, submitted State data were used for those boilers for whom ETS/CEM data were unavailable. These sources are summarized in Table 4.2-6.

4.2.5.1 What data does Form EIA-767 contain?

The EIA requires that the operating utility for each plant with EGU steam boilers of 10 MW or greater submit at least some sections of Form EIA-767. This form is designed so that information for each plant is reported on separate pages that relate to different data levels. The relevant levels of data include the following:

- Plant-level: Delineation of the plant configuration, which establishes the number of boilers and the IDs for each boiler, as well as the associated generator(s), flue gas desulfurization (FGD) unit(s) (SO_2 scrubbers), flue gas particulate collectors (FGP), flue(s), and stack(s). These do not necessarily have a one-to-one correspondence. In addition, plant name, location, and operating utility are provided.

- Boiler-level: Monthly fuel consumption and quality data (for coal, oil, gas, and other through 2000; and for all fuel types beginning with 2001), regulatory data, and design parameters including NO_x control devices (and controlled NO_x controlled emissions rate in lbs/MMBtu beginning in 2001).

- FGD-level: FGD units for annual operating data (including SO_2 control efficiency) and design parameter data (including types of SO_2 control devices and sorbents).

- FGP collector-level: PM units for operating data (including PM control efficiency) and design specifications (including type of particulate control devices).

- Stack- and flue-level: Design parameter data (including temperature, height, velocity, flow, and cross sectional area).

Form EIA-767 data for 1985 through 1997 are processed in a series of steps aimed at converting the mainframe-level computerized data into a usable database form. Only certain information is extracted. For example, Form EIA-767 includes fuel-related boiler data such as monthly values for each fuel burned, along with the fuel's associated sulfur, ash, and heat content. Only information regarding coal, oil, and gas fuel type data is processed for the *Trends* inventory, and only data from the first stack associated with a boiler are used. Beginning with the 1998 data, EIA provided 15 database files to display the EIA-767 data on its website, and for the first time, the 'other fuel' data (including wood and refuse) were processed. Thus, a maximum of four fuels per boiler were allowed. Beginning with 2001 data, all fuels for each boiler were reported, dramatically increasing the number of fuel types.

The data are aggregated for each fuel to produce annual estimates for each boiler before they are combined with other data such as control devices and efficiencies, plant location data, and associated stack parameters. An SCC, which has eight digits, is assigned to each fuel. This SCC list is developed by EPA, which creates new SCCs as needed to reflect the additional boiler-fuel combinations in the 2001 EIA-767. A complete list of the EGU SCCs (those that begin with 101 or 201) is included in Table 4.2-7. Once SCCs are assigned to each boiler's fuel data in a given plant, the SCC-specific data are then separated so that each new data base record is on the plant-boiler-SCC level.

Note that extensive quality assessment/quality control (QA/QC) reviews are conducted. Items that are checked include ORISPL and boiler and generator IDs (matching across EIA-767 years as well as between EIA-767 and ETS/CEM); fuel quantity outliers; missing values for fuel quality data (heat, sulfur, and ash content); calculated emissions and heat input outliers; fuel and generation comparisons with EIA-906 data;[6] comparison of boilers that are included or excluded in relation to previous year's EIA-767, same year's EIA-860,[7] and same year's ETS/CEM; and ETS/CEM annual heat input and NO_x values in relation to their ozone season values. Whenever possible, data resolution is obtained by working with EIA CNEAF and EPA CAMD staff. When that is not possible (as in the case of the 2001 NO_x control data), reasonable assumptions are made and documented.

4.2.6 How does EPA develop the necessary data not supplied by the EIA forms?

Algorithms created in the 1980s are used to develop values for SCC, heat input, emissions, and NO_x control efficiencies for data not contained in the computerized EIA data files, or to convert data to other measurement units.

Although Form EIA-767 reports generator nameplate capacity, this information cannot be used to represent the boiler size when a one-to-one correspondence does not exist between boiler and generator. This is referred to as a multiheader situation–for example, if one boiler is associated with two or more generators or if several boilers are reciprocally associated with several generators. Therefore, EPA developed a boiler design capacity variable (in MMBtu/hr) based on the reported maximum continuous boiler steam flow at 100 percent load (in thousand pounds per hour) by multiplying the steam flow value by a units conversion of 1.36. (EPA revised the boiler capacity methodology and updated the previous value of 1.25 to 1.36 beginning with the 1997 data year.)

Uncontrolled AP-42[8] emission factors are used to calculate emissions (see Table 4.2-5). The emission factor used depends upon the SCC and pollutant, as explained below.

- The appropriate SCC is assigned to each source based on its fuel and boiler characteristics. Through 2000, for sources using coal, the SCC is based on the American Society for Testing and Materials (ASTM) criteria for moisture, mineral-free matter basis (if greater than 11,500 Btu/lb, coal type is designated to be bituminous; if between 8,300 and 11,500 Btu/lb, coal type is designated to be subbituminous; and if less than 8,300 Btu/lb, coal type is designated to be lignite) and the boiler type (firing configuration and bottom type) as specified by AP-42. Fluidized bed combustion coal boiler SCCs are assigned based on the fuel type. If both coal and oil are burned in the same boiler, it is assumed that the oil is distillate; if coal is not burned, the oil burned is assumed to be residual. Beginning with 2001, the EIA-767 respondent identified the type of fuel, so there is now no need to determine subcategories.

Since Form EIA-767 does not provide control efficiencies for NO_x, PM_{10}, or $PM_{2.5}$, control efficiencies are derived using the following methods:

- Through 2000, NO_x control efficiency is based on the assumption that the boiler would be controlled so that its emission rate would equal its emission limit, expressed on an annual equivalent basis. After calculating the heat input, EPA back-calculated controlled emissions assuming compliance with the applicable standard. The NO_x net control efficiency is calculated by dividing the controlled by the uncontrolled NO_x emissions.

- For 2001, because the NO_x control information is very inconsistent, specific rules were formulated as follows:

  (1) If a boiler had no positive NO_x control device in-service hours – regardless if it reported an operating control device of controlled rate – it was treated as if there were no NO_x controls and the emissions were assumed to be uncontrolled.

  (2) If a boiler had positive NO_x control device in-service hours and it also had an annual NO_x controlled rate in lbs/MMBtu, the controlled NO_x emissions (in tons) were estimated by multiplying the heat input (in MMBtu), which is the product of the fuel quantity burned and the fuel heat content, and the NO_x controlled rate.

  (3) If a boiler reported positive NO_x control device in-service hours of at least 4,000 hours, but an annual NO_x controlled rate was not provided; or if the boiler had positive NO_x control device in-service hours but the annual NO_x controlled rate was greater than 1.0, it was considered to be a controlled unit, and a device-related removal rate obtained from Table A-4 of EIA's *Electric Power Annual 2001*[9] was used after calculating uncontrolled emissions to estimate controlled emissions.

- Since Form EIA-767 only reports PM control efficiency, EPA uses the PM_{10} Calculator[4] to derive filterable PM_{10} and $PM_{2.5}$ control efficiencies. (The PM Calculator estimates PM_{10} and $PM_{2.5}$ control efficiencies based on the SCC and the primary and secondary control devices. These device codes are NEDS codes that are derived from EIA-767 reported PM control devices and efficiencies rules as explained in documentation for the PM Calculator. The control efficiencies from the PM Calculator are based on particle size distribution data from AP-42 for specific SCCs, where available. These control efficiencies were revised beginning with the 1998 data file.) Beginning with 2001, if a coal boiler does not have a PM efficiency, it is assumed that there is an electrostatic precipitator PM control device, and a default PM_{10} and $PM_{2.5}$ efficiency of 99.2% is assigned; similarly, if a wood burning boiler does not have a PM efficiency, it is assumed that there is a multicyclone PM control device, and a default PM_{10} and $PM_{2.5}$ efficiency of 65% is assigned.

Since fewer required data elements (only identification data, boiler fuel quantity and quality data, and FGD data, if applicable) exist for those plants with a total capacity between 10 MW and 100 MW, many values are missing. Most data elements are assigned a default value of zero; however, if information on boiler firing and bottom type are missing, default values of wall (front)-fired and dry bottom types are assigned. One exception is that beginning with 2001, if the unit is included in the ETS/CEM data file and boiler firing and/or bottom types are provided, those values are used instead of the default values.

4.2.6.1 What EIA data have been replaced with data from other sources?

EPA replaced the 1985 SO_2 emissions and heat input calculated from the 1985 Form EIA-767 data with corresponding boiler-level data (disaggregated to the SCC level) from the National Allowance Data Base Version 3.11 (NADBV311).[10] These data underwent two public comment periods in 1991 and 1992 and are considered the best available data for 1985. Aggregations at the fuel levels (Tier III) are approximations only and are based on the methodology described in Section 4.2.1.

In 1996, CAMD completed research on utility coal boiler-level NO_x rates. Approximately 90 percent of the rates were based on relative accuracy tests performed in 1993 and 1994 as a requirement for CEM certification, while the remaining boilers' rates were obtained from utility stack tests from various years. These coal boiler-specific NO_x rates were considered, on the whole, to be significantly better than those calculated from EPA's NO_x AP-42 emission factors, which are SCC-category averages.

Thus, whenever these new NO_x rates were available, EPA recalculated NO_x coal emissions at the coal SCC level, using the heat input (EIA's 767 fuel throughput multiplied by the fuel heat content) and adjusting units, according to the following equation:

$$NOXCOAL_{SCC} = NOXRT_{coal} * HTI_{SCC} * \frac{1}{2000} \qquad \text{(Eq. 4.2-1)}$$

where:

where:	NOXCOAL	=	NO_x emissions for the boiler coal SCC (in tons)
	NOXRT	=	CAMD's coal NO_x rate for the given boiler (in lbs/MMBtu)
	HTI	=	heat input for the boiler's coal SCC (in MMBtu)

These new NO_x SCC-level coal emissions replaced the AP-42 calculated emissions for most of the coal SCCs in the 1985-1994 data years (when ETS/CEM data were unavailable). As of January 1, 1994, Title IV (Acid Deposition Control) of the Clean Air Act Amendments of 1990 required Phase I affected EGU units to report heat input, SO_2, and NO_x data to EPA. Beginning January 1, 1995, all affected units were required to report heat input and SO_2 emissions; most also had to report NO_x emissions, although some units received extensions until July 1, 1995 or January 1, 1996 for NO_x reporting.

The ETS/CEM data files generally contain actual, rather than estimated, data. The annual data undergo QA/QC to verify that current ORISPL and boiler IDs are used, to see whether there are any significant changes from the previous year, and to check that the annual NO_x and heat input values for a boiler are not less than the ozone season day value. The data concerns, if any, are compiled and then discussed with

EPA/CAMD to obtain data resolution where possible. If that is not possible, reasonable assumptions are made.

If a complete set of ETS/CEM annual SO_2 and/or NO_x emissions and/or heat input data existed for 1994 and 1995, those data values replaced the data estimated from EIA-767 data. This process involved the following steps:

- Aggregation of ETS/CEM hourly or quarterly data to annual data.
- Assignment of ETS/CEM data, reported on a monitoring stack or pipe level, to the boiler level.
- Matching the ETS/CEM boiler-level annual data to the processed EIA-767 annual data.
- Disaggregating the boiler-level ETS/CEM data to the boiler SCC level based on each SCC's fractional share of the boiler EIA-based heat input, SO_2, and NO_x, respectively. The algorithms used are included in Table 4.2-9.

Beginning with 1996 data, the ETS/CEM annual Scorecard data replaced EIA-derived SO_2 and NO_x emissions and heat input for all boilers included in EIA-767 and in ETS/CEM. For those records in which the ETS/CEM heat input replaces the EIA-calculated value, the heat input does not equal the product of the EIA-reported fuel throughput and heat content. Additionally, CO_2 and condensable PM values are recalculated using the ETS/CEM heat input value, thus also changing the values of primary PM_{10} and primary $PM_{2.5.}$ (For the 1999 NEI, submitted State EGU data replaced all other emissions data except for SO_2 and NO_x data from ETS/CEM.)

4.2.7 How does EPA calculate ozone season daily emissions?

Ozone season daily (OSD) emissions and heat input are estimated for data years 1990-1999 by assuming the day to be a typical or average summer July day. Emissions for VOC, NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, and NH_3 are calculated at the SCC level by taking the ratio of the Form EIA-767 July monthly to annual heat input, dividing it by 31, and then multiplying this value by the already calculated annual emissions. Beginning in data year 1998, a weighted average of the heat inputs for the five ozone season months (July-September) was used in place of the July month heat input. The equation is:

$$EOSD_{SCC} = \frac{HTISUM_{SCC}}{31 * HTIANN_{SCC}} * EANN_{SCC} \qquad \text{(Eq. 4.2-2)}$$

where:

EOSD	=	Ozone season daily emissions for a given pollutant at the SCC level (in tons)
HTISUM	=	July monthly or ozone season monthly average Form EIA-767 calculated heat input for the given boiler's SCC (in MMBtu)
HTIANN	=	annual Form EIA-767 calculated heat input for the given boiler's SCC (in MMBtu)
EANN	=	Annual emissions for a given pollutant at the SCC level (in tons) for that year

For 1999 and 2000 data, for the OSD SO_2 and NO_x emissions, EPA's hourly ETS/CEM data files underwent QA/QC and were then aggregated to daily data; these data were used. The data for July 21 was first chosen for OSD values; if 0, the next day on either side was chosen (July 20 then July 22) and so on until non-zero values, if they existed during the five months, were found.

For 2001 data, EPA's hourly ETS/CEM data have not yet undergone QA/QC, so the ozone season day emissions and heat input are estimated using the methodology described below:

- For the units in the EIA-767, the ratio of the EIA-767 July heat input to the annual input is determined, and divided by 31 to obtain the ozone season day fraction. If there is no July heat input, the August, June, September, or May heat input is used, in this order of preference. If all five of these months have no heat input, then the ozone season fraction is zero. To obtain the ozone season day emissions and heat input, the annual data are multiplied by this fraction.

- For the units only in the ETS/CEM data file, the ratio of the ozone season heat input to the annual heat input is determined, and divided by 153 (the number of days in the ozone season from May through September) to obtain the ozone season day fraction; this fraction is multiplied by annual heat input and all annual emissions except NO_x to obtain the ozone season day values. For estimating the ozone season day NO_x value, the ozone season NO_x value is divided by 153.

4.2.8 What additional emissions estimates adjustments does EPA make?

To derive VOC emission estimates, an adjustment is made to account for the underestimation of aldehydes, which are not included in the VOC emission factors for the following SCCs: 10100401, 10100404, 10100501, 10100601, and 10100604. The VOC emissions for these SCCs are augmented according to the methodology used in the Hydrocarbon Preprocessor (HCPREP) of the Flexible Regional Emissions Data System (FREDS).[11] This augmentation was made for steam emission inventories beginning in 1985. No adjustments are made for a combined heat and power (CHP)/cogenerator unit.

4.2.9 How does EPA perform its calculations?

In order for annual emissions to be estimated, the monthly data are used to obtain annual estimates as follows:

(1) The annual fuel quantity is determined by summing the monthly values. There need not be (positive) data for all months.

(2) The annual fuel quality values (heat content, sulfur content, and ash content) are calculated as a fuel quantity-weighted average if data values for each month are available. If, for a given boiler and fuel type, there is a positive monthly fuel quantity value but no fuel quality value, the missing value(s) are populated with the boiler fuel quantity-weighted average. If that is missing because there are no fuel quality values at all for the boiler, the missing value(s) are populated with the 2001 EIA-767 fuel quantity-weighted average for the entire file. If there is no other boiler which has that fuel in the entire

file, the missing value(s) are populated with the 2000 EIA-860B fuel quantity-weighted average for the entire file for the specified fuel quality.[6] If need be, the EPA-provided default ash content values from Footnote 3 in Table 4.2-5 are used.

The following provides an example calculation for estimating annual SO_2 emissions for a tangentially-fired dry-bottom EGU boiler burning bituminous coal. This 1996 base year example shows how the emissions are initially calculated using data reported to EIA-767 and an AP-42 uncontrolled emission factor, and then overlaid with SO_2 emissions reported to ETS/CEM. See section 4.2.6.1 for details on what EIA-767 data are replaced with ETS/CEM data for calculating emissions.

Variable Description	**Variable Name**	**Value**	**Units**
Source classification code	SCC	10100212	–
Annual fuel throughput	thruput	1300000	SCC units
Heat content of fuel	heatcon	23.1849046	MMBtu/SCC units
Sulfur content of fuel	sulfcon	3.1716	%
SO_2 control efficiency	coneff4	89.30	%
Final emissions for inventory	emiss4	9332.5590	tons
Final heat input for inventory	htinpt	31782453.38	MMBtu
Annual heat input calculated from EIA-767 data	eiahti	30140376.00	MMBtu
Annual SO_2 emissions calculated from EIA 767 data	eiaso2	8382.2216	tons
SO_2 emission factor	emf4	38 (39 from 1985-1995)	lbs SO_2/ton coal
Annual SO_2 emissions reported to ETS/CEM	so2ets	9332.5590	tons
Annual heat input reported to ETS/CEM	htiets	31782453.38	MMBtu

- Equation:

$$EIASO_2 = \frac{coal\ thruput * EMF4 * sulfcon * (1 - (coneff4/100))}{2000} \qquad \text{(Eq. 4.2-3)}$$

- Calculation:

- Result:

$$EIASO_2 = 8{,}382\ tons$$

But replaced by 1995 ETS/CEM SO_2 emissions (SO_2ets) = 9,332.5590 (tons/year) = final emissions (EMISS4)
Therefore $EIASO_2$ = 8,382 (tons/year); and SO_2ets = EMISS4 = 9,333 (tons/year) in the Inventory

Note that the AP-42 SO_2 emission factor for SCC 10100212 was changed from 39 to 38 lbs/ton of coal beginning with data year 1996, reflecting the updated emission factor value.

$$EIASO_2 = \frac{(1{,}300{,}000)\ (38)\ (3.1716)\ (1 - 0.893)}{2000}$$

4.2.10 References

1. *Steam-Electric Plant Operation and Design Report*, Form EIA-767, data files for 1985 - 2001, U.S. Department of Energy, Energy Information Administration, Washington, DC, 2002.

2. *Acid Rain Program CEMS Submissions Instructions for Monitoring Plans, Certification Test Notifications, and Quarterly Reports*, U.S. Environmental Protection Agency, Washington, DC, May 1995.

3. August 13, 2003 EPA-approved updated EGU Uncontrolled Emission Factor File, AP-42, U.S. Environmental Protection Agency/Emission Factor and Inventory (EFIG) Group, Research Triangle Park, NC.

4. *Enhanced Particulate Matter Controlled Emissions Calculator, User's Manual*, Emission Factor and Inventory Group, Emissions Monitoring and Analysis Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC. September 2000.

5. August 7, 2003 (Not Final) 2001 Emission Tracking System/Continuous Emissions Monitoring (ETS/CEM) Annual and Ozone Season Data Files, U.S. Environmental Protection Agency/Clean Air Markets Division (CAMD), Washington, DC.

6. *Form EIA-906 Database Monthly Utility Plant Database.* U.S. Department of Energy, Energy Information Administration, Washington, DC.

7. *Annual Electric Generator Report,* Form EIA-860. U.S. Department of Energy, Energy Information Administration, Washington, DC.

8. *Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, Fifth Edition,* AP-42, U.S. Environmental Protection Agency, Research Triangle Park, NC.

9. *Electric Power Annual 2001.* DOE/EIA-0348 (2001). The Energy Information Administration, Washington, D.C., March 2003.

10. *The National Allowance Data Base Version 3.11: Technical Support Document*, Acid Rain Division, Office of Atmospheric Programs, U.S. Environmental Protection Agency, Washington, DC, March 1993.

11. *The Flexible Regional Emissions Data System (FREDS) Documentation for the 1985 NAPAP Emission Inventory: Preparation for the National Acid Precipitation Assessment Program*. Appendix A. EPA-600/9-89-047. U.S. Environmental Protection Agency, Office of Research and Development, Air and Energy Engineering Research Laboratory, Research Triangle Park, NC, May 1989.

Table 4.2-1. Methods for Developing Annual Emission Estimates for Steam EGU for the Years 1989-2001

For the data years	For the pollutant(s)	EPA estimated emissions by
1989-1993	NO_x	If coal is burned, EIA data and EPA/ARD emission factors and heat input are used; if coal is not burned, EIA data and uncontrolled AP-42 emission factors (and control efficiencies if applicable) applied to fuel quantity are used.
1994-1995	NO_x	If the boiler in reported in both EIA-767 and ETS/CEM, and the ETS/CEM NO_x data are complete for the year, then the ETS/CEM data are used. Otherwise, if a boiler burned coal, EIA data and EPA emission factors and heat input are used; if coal is not burned, EIA data and uncontrolled AP-42 emission factors (and control efficiencies if applicable) applied to fuel quantity are used.
1996-2001	NO_x	If the boiler is reported in both EIA-767 and ETS/CEM, then the ETS/CEM data are used. Otherwise, EIA data and uncontrolled AP-42 emission factors (and control efficiencies if applicable) applied to fuel quantity are used. Note that AP-42 emission factors for some SCCs changed from data years 1985-1995 to data year 1996, and again in data year 1997.
1989-1993	SO_2	EIA data and uncontrolled AP-42 emission factors (and control efficiencies if applicable) applied to fuel quantity are used.
1994-2001	SO_2	If the boiler is reported in both EIA-767 and ETS/CEM, then the ETS/CEM data are used. Otherwise, EIA data and uncontrolled AP-42 emission factors (and control efficiencies if applicable) applied to fuel quantity are used. Note that AP-42 emission factors for some SCCs changed from data years 1985-1995 to data year 1996.
1989-2001	VOC, CO	EIA data and AP-42 emission factors applied to fuel quantity are used. Note that AP-42 emission factors for some SCCs changed from data years 1985-1995 to data year 1996 for VOC and CO.
1989-1997	PM_{10}, $PM_{2.5}$ (Filterable)	EIA data and AP-42 emission factors applied to fuel quantity are used. Note that AP-42 emission factors for some SCCs changed from data years 1985-1995 to data year 1996 for PM_{10}.
1998-2001	PM_{10}, $PM_{2.5}$ (Filterable)	EIA data and uncontrolled AP-42 emission factors (and control efficiencies if applicable) applied to fuel quantity are used. Note that AP-42 emission factors for some SCCs changed from data year 1996 to data year 1998 for PM_{10} and $PM_{2.5}$. Since the PM_{10} Calculator Program was updated in 1999-2000, updated PM efficiencies are derived for emissions calculations.
1996-2001	PM Condensable, Primary PM_{10}, Primary $PM_{2.5}$	EIA data and AP-42 emission factors applied to heat input are used to estimate condensable PM. Condensable PM is summed with filterable PM_{10} and $PM_{2.5}$, respectively, to estimate primary PM_{10} and $PM_{2.5}$. However, if the boiler is reported in both EIA-767 and ETS/CEM, then the ETS/CEM heat input overlays EIA-based heat input, condensable PM is recalculated, and primary PM_{10} and $PM_{2.5}$ emissions are updated.

Table 4.2-1 (continued).

For the data years	For the pollutant(s)	EPA estimated emissions by
1999	VOC, CO, Filterable and Primary PM_{10} and $PM_{2.5}$, NH_3	Emissions are overlaid by State submitted data when available.
1999	NO_x and SO_2	Emissions are overlaid by State submitted data when available, and if no ETS/CEM data available.
1996-2001	NH_3	EIA data and emission factors applied to fuel content to estimate ammonia emissions. For data years prior to 1996, NH_3 emissions were not estimated for EGU boilers.

Table 4.2-2. PM Condensable Emission Factor Rules

Fuel	Applicable Source Classification Codes	PM Condensable Emission Factor (lb/MMBtu)
Coal (including waste coal and syn coal)*	10100204, 10100205, 10100224, 10100225, 10100304, 10100306	0.04
	10100217, 10100218, 10100237,10100238, 10100317, 10100318, 10102018	0.01
	10100201, 10100202, 10100203, 10100212, 10100221, 10100222, 10100223, 10100226, 10100301, 10100302, 10100303, 10101901, 10102001	0.02**
	10100201, 10100202, 10100203,10100212, 10100221, 10100222,10100223, 10100226, 10100301, 10100302, 10100303, 10101901, 10102001	(0.1 * sulfur content [as a decimal] - .03)***
Light Oil (Distillate, Diesel)	10100401 - 10100499	0.01
Heavy Oil (Residual)	10100501 - 10100599	0.009
Natural Gas	10100601 - 10100699	0.0057
Other Process Gases	10100701 - 10100799	0.0056
Petroleum Coke	10100801 - 10100899	0.01
Wood, Biomass (including Black Liquor), Waste/Refuse	10100901 - 10100999, 10101201 - 10101299, 10101304	0.017
LPG (Propane, Butane)	10101001 - 10101099	0.0056
Other Liquid Waste/Oil, Methanol	10101301, 10101302, 10101305, 10101306, 0101307, 10101308, 10102101, 10101601	0.009

* If the emission factor is less than 0.01, then it is set equal to 0.01.

** AND there is either an SO_2 FGD or a PM wet scrubber.

*** And there is any PM control other than a wet scrubber and there is no SO_2 control, OR SCC = 10100222 and there is no PM control.

Table 4.2-3. Algorithms Used to Estimate EIA-Based VOC, NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, and NH_3 Annual Emissions from EGU Boilers

$$E_{NO_x, SCC} = FC_{SCC} * EF_{NO_x, SCC} * (1 - CE_{NO_x, b}) * UCF$$

$$E_{CO\ or\ VOC^{\dagger}, SCC} = FC_{SCC} * EF_{CO\ or\ VOC, SCC}$$

$$E_{PM_{10}\ or\ PM_{2.5}, SCC} = FC_{SCC} * EF_{PM_{10}\ or\ PM_{2.5}, SCC} * A_f * (1 - CE_{PM_{10}\ or\ PM_{2.5}, b}) * UCF$$

$$E_{SO_2, SCC} = FC_{SCC} * EF_{SO_2, SCC} * S_f * (1 - CE_{SO_2, b}) * UCF$$

$$E_{NH_3, SCC} = FC_{SCC} * EF_{NH_3, SCC} * UCF$$

where:	E	=	annual estimated emission (in tons/year)
	FC	=	annual fuel consumption (in units/year)
	EF	=	emission factor (in lbs/$unit_f$)
	S	=	sulfur content (expressed as a decimal)
	A	=	ash content (expressed as a decimal)
	CE	=	control efficiency (expressed as a decimal)
	b	=	boiler
	f	=	fuel type
	UCF	=	units conversion factor (1 ton/2000 lbs)
	$unit_{coal}$	=	tons burned
	$unit_{oil}$	=	1000 gallons burned
	$unit_{gas}$	=	million cubic feet burned

† Note that VOC also undergoes an augmentation procedure.

Table 4.2-4. Algorithms Used to Estimate EIA-Based Condensable PM, Primary PM_{10} and Primary $PM_{2.5}$ Annual Emissions for EGU Boilers

$$E_{PMCD,\,SCC} = HTI_{SCC} * EF_{PMCD,\,SCC} * CF$$

$$E_{TotPM_{10}\text{ or }TotPM_{2.5},\,SCC} = E_{PM_{10}\text{ or }PM_{2.5},\,SCC} * E_{PMCD,\,SCC}$$

where:	PMCD	=	particulate matter condensable
	E	=	annual estimated emissions (in tons/year)
	HTI	=	annual heat input (in MMBtu/year)$
	EF	=	emission factor (in tons/MMBtu)

† Note that VOC also undergoes an augmentation procedure.

$ Calculate using EIA fuel consumption and heat content values, but use ETS/CEM heat input data if available and recalculate PMCD, TOTPM10, and TOTPM25.

Table 4.2-5. EPA- Approved EGU Uncontrolled Emission Factors

SCC	Fuel	CO Emission Factor	NO_x Emission Factor [2]	VOC Emission Factor	PM_{10} Emission Factor	PM_{25} Emission Factor	SO_2 Emission Factor	NH_3 Emission Factor	PM Flag [3]	SO_2 Flag[3]
10100101	ANT	0.6000	18.0000	0.0700	2.3000	0.6000	39.0000	0.000565	A	S
10100102	ANT	0.6000	9.0000	0.0700	4.8000	2.4000	39.0000	0.000565		S
10100201	BIT	0.5000	31.0000	0.0400	2.6000	1.4800	38.0000	0.000565	A	S
10100202	BIT [4]	0.5000	22.0000	0.0600	2.3000	0.6000	38.0000	0.000565	A	S
10100203	BIT	0.5000	33.0000	0.1100	0.2600	0.1100	38.0000	0.000565	A	S
10100204	BIT	5.0000	11.0000	0.0500	13.2000	4.6000	38.0000	0.000565		S
10100205	BIT	6.0000	7.5000	0.0500	6.0000	2.2000	38.0000	0.000565		S
10100211	BIT	0.5000	14.0000	0.0400	2.6000	1.4800	38.0000	0.000565	A	S
10100212	BIT [4]	0.5000	15.0000	0.0600	2.3000	0.6000	38.0000	0.000565	A	S
10100215	BIT	0.5000	31.0000	0.0600	2.3000	0.6000	38.0000	0.000565	A	S
10100217	BIT	18.000	15.2000	0.0500	12.4000	3.2000	31.0000	0.000565		S
10100218	BIT	18.000	5.0000	0.0500	12.4000	3.2000	31.0000	0.000565		S
10100221	SUB	0.5000	24.0000	0.0400	2.6000	1.4800	35.0000	0.000565	A	S
10100222	SUB [4]	0.5000	12.0000	0.0600	2.3000	0.6000	35.0000	0.000565	A	S
10100223	SUB	0.5000	17.0000	0.1100	0.2600	0.1100	35.0000	0.000565	A	S
10100224	SUB	5.0000	8.8000	0.0500	13.2000	4.6000	35.0000	0.000565		S
10100225	SUB	6.0000	7.5000	0.0500	6.0000	2.2000	35.0000	0.000565		S
10100226	SUB [4]	0.5000	8.4000	0.0600	2.3000	0.6000	35.0000	0.000565	A	S
10100235	SUB	0.5000	14.0000	0.0600	2.3000	0.6000	35.0000	0.000565	A	S
10100237	SUB	18.000	15.2000	0.0500	16.1000	4.2000	31.0000	0.000565		S
10100238	SUB	18.000	5.0000	0.0500	16.1000	4.2000	31.0000	0.000565		S
10100300	LIG	N/A	N/A	N/A	N/A	N/A	N/A	0.000565		
10100301	LIG [4]	0.2500	13.0000	0.0700	1.8170	0.5214	30.0000	0.000565	A	S
10100302	LIG	0.6000	7.1000	0.0700	2.3000	0.6600	30.0000	0.000565	A	S
10100303	LIG	0.6000	15.0000	0.0700	0.8700	0.1100	30.0000	0.000565	A	S
10100304	LIG	6.0000	6.0000	0.0700	1.6000	0.5600	30.0000	0.000565	A	S
10100306	LIG	5.0000	5.8000	0.0700	1.6000	0.5600	30.0000	0.000565	A	S
10100316	LIG	0.1500	3.6000	0.0300	12.0000	1.4000	10.0000	0.000565		S
10100317	LIG	0.1500	3.6000	0.0300	12.0000	1.4000	10.0000	0.000565		S
10100318	LIG	0.1500	3.6000	0.0300	12.0000	1.4000	10.0000	0.000565		S
10100401	RFO	5.0000	47.0000	0.7600	[5]	[6]	157.0000	0.800000		S
10100404	RFO	5.0000	32.0000	0.7600	[5]	[6]	157.0000	0.800000		S
10100405	RFO	5.0000	47.0000	0.7600	5.9000	4.3000	157.0000	0.800000	A	S
10100406	RFO	5.0000	32.0000	0.7600	5.9000	4.3000	157.0000	0.800000	A	S
10100501	DFO	5.0000	24.0000	0.2000	1.0000	0.2500	142.0000	0.800000		S
10100504	DFO	5.0000	47.0000	0.7600	5.9000	4.3000	150.0000	0.800000	A	S
10100505	DFO	5.0000	32.0000	0.7600	5.0000	3.6000	150.0000	0.800000		S

Table 4.2-5 (continued).

SCC	Fuel	CO Emission Factor	NO_x Emission Factor [2]	VOC Emission Factor	PM_{10} Emission Factor	$PM_{2.5}$ Emission Factor	SO_2 Emission Factor	NH_3 Emission Factor	PM Flag [3]	SO_2 Flag [3]
10100601	NG [4]	84.0000	190.0000	5.5000	1.9000	1.9000	3.5000	3.200000		
10100602	NG	84.0000	100.0000	5.5000	1.9000	1.9000	3.5000	3.200000		
10100604	NG	24.0000	170.0000	5.5000	1.9000	1.9000	3.5000	3.200000		
10100602	ME [7, 8]	81.0400	183.3048	5.3062	1.8330	1.8330	3.5000	N/A		
10100701	PRG [7]	6.5718	14.8647	0.4303	0.1486	0.1486	3.5000	N/A		
10100702	PRG [7]	6.5718	14.8647	0.4303	0.1486	0.1486	3.5000	N/A		
10100702	OG [7]	67.5644	152.8242	4.4239	1.5282	1.5282	3.5000	N/A		
10100703	RG [7]	66.9620	151.4617	4.3844	1.5146	1.5146	3.5000	N/A		
10100704	BFG [7]	6.8064	15.3955	0.4457	0.1540	0.1540	3.5000	N/A		
10100707	COG [7]	41.0024	92.7435	2.6847	0.9274	0.9274	3.5000	N/A		
10100711	LFG [7]	32.0274	72.4429	2.0970	0.7244	0.7244	3.5000	N/A		
10100712	DG [7]	49.8809	112.8258	3.2660	1.1283	1.1283	3.5000	N/A		
10100801	PC	0.6000	21.0000	0.0700	7.9000	4.5000	39.0000	N/A	A	S
10100818	PC [8]	18.0000	5.0000	0.0500	12.4000	3.2000	31.0000	N/A		S
10100901	bark	5.4000	2.0000	0.1170	4.5000	3.8700	0.2300	N/A		
10100902	WDS	5.4000	2.0000	0.1170	4.5000	3.8700	0.2300	N/A		
10100912	WDS [8]	1.4000	2.0000	0.1170	4.5000	3.8700	0.0750	N/A		
10100902	woodbark	5.4000	2.0000	0.1170	4.5000	3.8700	0.2300	N/A		
10100903	wood	5.4000	2.0000	0.1170	2.6100	2.2500	0.2300	N/A		
10101001	BL	3.6000	21.0000	0.2600	0.6000	0.6000	96.8000	N/A		S
10101001	BU [7, 9]	269.6000	609.8095	17.6524	6.0981	6.0981	3.5000	N/A		
10101002	PG [7, 9]	67.5644	152.8242	4.4239	4.6867	4.6867	3.5000	N/A		
10101002	PL [10]	207.2000	468.6667	13.5667	0.1636	0.1636	0.1222	N/A		
10101101	bagasse	2.0000	1.2000	2.0000	5.6000	1.4000	0.0000	N/A		
10101201	OTS [11, 12]	1.2992	1.2000	0.7218	15.8796	3.9699	0.0800	N/A		
10101201	solidwaste	0.0165	3.8000	2.0000	11.4000	7.8000	3.9000	N/A		
10101202	MSW [11]	0.7044	5.9000	0.3913	8.6089	2.1522	2.0000	N/A		
10101202	rdf	3.6000	5.9000	2.0000	44.0000	11.0000	2.0000	N/A		
10101204	TDF [13]	0.5000	22.0000	0.0600	2.3000	0.6000	38.0000	N/A	A	S
10101205	SLW [11]	0.3958	5.0000	0.2199	4.8375	1.2094	2.8000	N/A		
10101206	AB [14]	0.6000	1.2000	0.1700	15.6000	15.6000	0.0800	N/A		
10101207	OBS [11]	0.8741	2.0000	0.4856	10.6834	2.6708	0.2300	N/A		
10101208	PP [15]	5.4000	2.0000	0.1170	4.5000	3.8700	0.2300	N/A		
10101301	LB [16]	3.7232	17.8714	0.1489	0.7446	0.1862	142.0000	N/A		S
10101301	liquid waste	5.0000	19.0000	1.0000	51.0000	13.0000	142.0000	N/A	A	S
10101301	OTL [16]	0.2857	1.3714	0.0114	0.0571	0.0143	142.0000	N/A		S
10101302	OW [17]	5.0000	24.0000	0.2000	1.0000	0.2500	142.0000	N/A		S

Table 4.2-5 (continued).

SCC	Fuel	CO Emission Factor	NO_x Emission Factor [2]	VOC Emission Factor	PM_{10} Emission Factor	PM_{25} Emission Factor	SO_2 Emission Factor	NH_3 Emission Factor	PM Flag [3]	SO_2 Flag [3]
10101304	BLQ [11]	0.7627	1.5000	0.4237	9.3220	2.3305	7.0000	N/A		
10101305	RL [16]	1.1179	5.3657	0.0447	0.2236	0.0559	142.0000	N/A		S
10101306	SS [16]	1.6071	7.7143	0.0643	0.3214	0.0804	142.0000	N/A		S
10101307	TO [16]	4.4571	1.5000	0.1783	0.8914	0.2229	142.0000	N/A		S
10101308	WDL [16, 18]	1.1316	5.4315	0.0453	0.2263	0.0566	142.0000	N/A		S
10101601	MH [16]	0.3464	1.6629	0.0139	0.0693	0.0173	142.0000	N/A		S
10101801	HY [9, 19]	0.0000	32.0000	0.0000	0.0000	0.0000	0.0000	N/A		
10101901	SC [13]	0.5000	22.0000	0.0600	2.3000	0.6000	38.0000	0.000565	A	S
10102001	WC [20]	0.2500	13.0000	0.0700	1.8170	0.5214	30.0000	0.000565	A	S
10100218	WC [8, 20]	0.1500	3.6000	0.0300	12.0000	1.4000	10.0000	0.000565		S
10102101	OO [17]	5.0000	24.0000	0.2000	1.0000	0.2500	142.0000	N/A		S
20100101	DFO	0.4587	122.3200	0.0570	0.6020	0.6020	142.0000	N/A		S
20100102	DFO	130.0000	448.0000	0.0570	14.0000	14.0000	142.0000	N/A		S
20100201	NG	83.6400	326.4000	2.1420	1.9380	1.9380	3.5000	N/A		
20100202	NG	399.0000	2840.0000	116.0000	9.6900	9.6900	3.5000	N/A		
20100301	IGCC	34.6500	N/A	2.2050	11.5500	11.5500	N/A	N/A		
20100901	KE, JF [17]	0.4455	122.3200	2.3800	8.5400	8.5400	142.0000	N/A		S
20100902	KE, JF [17]	128.2500	448.0000	49.3000	41.8500	41.8500	142.0000	N/A		S

[1] For SCCs beginning with 101001, 101002, or 101003 (coal), 101008 (coke), 101009 (wood), 101011 (bagasse), 101012 (solid waste), 101019 (synfuel), or 101020 (waste coal), emission factors (EF) are in pounds per ton; for SCCs beginning with 101004, 101005, and 201001 (oil), 101010 (propane/butane), 101013 (liquid waste), 101016 (methanol), 101021 (other oil), or 201009 (kerosene/jet fuel), EFs are in pounds per thousand gallons; for SCCs beginning with 101006 or 201002 (natural gas), 101007 (process gas), 101018 (hydrogen), or 201003 (IGCC) EFs are in pounds per million cubic feet.

[2] For DG (Digester Gas), LFG (Landfill Gas), and ME (Methane), only the steam NO_x EFs are shown; different factors are used for GT and IC records. In eGRID, these factors are offset by a flare burnoff EF (for example, for DG/ST the NO_x EF in eGRID2002 was 39.0 (65.0 minus 26.0 for flare burnoff)), BUT per Roy Huntley on 5/9/03, we are NOT incorporating these offsets for the NEI.

[3] When plant specific ash or sulfur content is not available, fuel average ash and sulfur content are used; if fuel average ash or sulfur content is not available 8 percent ash content and 2 percent sulfur content are used for solid fuels and 1 percent sulfur content is used for liquid fuels, per Roy Huntley on 5/15/03.

[4] For these 6 SCCs there are two NO_x EFs, one representing pre-NSPS and one representing post-NSPS. Pre-NSPS is before 1974, while post-NSPS is 1974 and beyond. The pre-NSPS is used as the default when the date of operation is not known (except for 10100601, where the post-NSPS is used as the default). The post-NSPS NO_x EFs are below for reference (except for 10100601, where the pre-NSPS is shown below for reference).

10100202	12.0000		10100222	7.4000		10100301	6.3000			
10100212	10.0000		10100226	7.2000		1010061	280.0000			

[5] From FIRE 6.23, the equation for this PM_{10} EF is [5.9*(1.12*S+0.37)]

[6] From FIRE 6.23, the equation for this $PM_{2.5}$ EF is [4.3*(1.12*S+0.37)]

Table 4.2-5 (continued).

[7] BFG (Blast Furnace Gas), BG (Butane (gas)), COG (Coke Oven Gas), DG (Digester Gas), LFG (Landfill Gas), ME (Methane), OG (Other Gas), PG (Propane (gas)), PRG (Process Gas), and RG (Refinery Gas) are similar to NG (Natural Gas). For these fuels' EFs, per Roy Huntley on 5/12/03 and 5/15/03, we are using NG EFs adjusted by the ratio of each fuels' heat content divided by NG's heat content (assuming NG has a heat content of 1050 btu/cf); however, for these fuels' SO2 EFs, NG's SO2 EF is used without modification.
[8] PC (Petroleum Coke), WC (Waste Coal), and WDS (Wood/Wood Waste Solid) with circulating fluidized beds (CFB) were added (SCCs for PC and WC were approved by Ron Ryan on 8/12/03) with EFs provided by Roy Huntley on 8/12/03 and 8/13/03. For PC, bituminous coal CFB EFs are used; for WC, lignite coal CFB EFS are used. For WDS, WDS CFB EFs are used from FIRE 6.23 for CO, NOx, and SO_2; for all other EFs, standard WDS EFs are used.
[9] BU (Butane (gas), HY (Hydrogen), ME (Methane), and PG (Propane (gas) heat contents were provided by Roy Huntley on 5/15/03.
[10] Per Roy Huntley on 5/12/03, PL (Propane (liquid)) is converted into PG (Propane (gas)) before being used as a fuel. Therefore, we use the PG EFs after converting from PL in gallons to PG in cubic feet (the conversion factor is multiplying by 34.9 -- see Roy's 5/12/03 email for details of this conversion factor). Also, since PL is in thousand gallons and PG is in million cubic feet we must divide by 1000.
[11] BLQ (Black Liquor), MSW (Municipal Solid Waste (refuse)), OBS (Other Biomass Solids), OTS (Other Solids), and SLW (Sludge Waste) are similar to solid waste. For these fuels' EFs, per Roy Huntley on 5/12/03, we are using solid waste EFs adjusted by the ratio of each fuels' heat content divided by solid waste's heat content (assuming solid waste has a heat content of 26,000 Btu/pound); however, NO_x and SO2 EFs are not ratioed as they are available for these fuels.
[12] The heat content for OTS (Other Solids) is derived from the 2000 EIA-860B and is documented in Jason Radgowski's 5/6/03 email.
[13] SC (Synfuel) and TDF (Tires) are similar to BIT (Bituminous Coal). For these fuels' EFs, per Roy Huntley on 5/9/03 and 5/12/03, we are using all of the BIT EFs.
[14] AB (Agricultural Byproducts) EFs were provided by Roy Huntley on 5/9/03; they are based on bagasse EFs.
[15] PP (Paper Pellets) is similar to WDS (Wood/Wood Waste Solid). For this fuels' EFs, per Roy Huntley on 5/12/03, we are using all of the WDS EFs.
[16] LB (Liquid Byproduct), MH (Methanol), OTL (Other Liquid), RL (Red Liquor), SS (Spent Sulfite Liquor), TO (Tall Oil), and WDL (Wood/Wood Waste Liquid) are similar to DFO (Distillate Fuel Oil). For these fuels' EFs, per Roy Huntley on 5/12/03 and 5/15/03, we are using DFO EFs adjusted by the ratio of each fuels' heat content divided by DFO's heat content (assuming DFO has a heat content of 140,000 btu/gallon); however, for these fuels' SO2 EFs, DFO's SO2 EF is used without modification.
[17] JF (Jet Fuel), KE (Kerosene), OO (Other Oil), and OW (Oil Waste) are similar to DFO (Distillate Fuel Oil). For these fuels' EFs, per Roy Huntley on 5/12/03, we are using all of the DFO EFs.
[18] In all previous EF files, EFs for WDS (Wood/Wood Waste Solid) were used for WDL (Wood/Wood Waste Liquid); this was incorrect as the units are different for these two fuels.
[19] HY (Hydrogen) EFs were provided by Roy Huntley on 5/9/03 and 5/15/03.
[20] WC (Waste Coal) is similar to LIG (Lignite Coal). For this fuels' EFs, per Roy Huntley on 8/12/03, we are using all of the LIG EFs.
N/A, not available, indicates a missing emission factor.

FUEL	Fuel Description
AB	Agricultural Byproducts (bagasse, rice hulls, peanut hulls, nut shells, cow manure)
ANT	Anthracite Coal
BFG	Blast Furnace Gas
BIT	Bituminous Coal
BL	Butane (liquid)

Table 4.2-5 (continued).

FUEL	Fuel Description
BLQ	Black Liquor
BU	Butane (gas)
COG	Coke Oven Gas
DFO	Distillate Fuel Oil/Light Oil
DG	Digester Gas
HY	Hydrogen
IGCC	Integrated Gasification Combined Cycle
JF	Jet Fuel
KE	Kerosene
LB	Liquid Byproduct
LFG	Landfill Gas
LIG	Lignite Coal
ME	Methane
MH	Methanol
MSW	Municipal Solid Waste (refuse)
NG	Natural Gas
OBS	Other biomass Solids (Animal Manure and Waste, Solid Byproducts, and other solid biomass not specified)
OG	Other Gas (blast furnace, coke oven, refinery, and process)
OO	Other Oil
OTL	Other Liquid (originally 'OTH' – could not be further classified)
OTS	Other Solids (originally 'OTH' -- could not be further classified)
OW	Oil Waste
PC	Petroleum Coke
PG	Propane (gas)
PL	Propane (liquid)
PP	Paper Pellets
PRG	Process Gas
PUR	Purchased Steam
RDF	Refuse Derived Fuel
RFO	Heavy Oil/Residual Fuel Oil
RG	Refinery Gas
RL	Red Liquor

Table 4.2-5 (continued).

FUEL	Fuel Description
SC	Coal-based Synfuel
SLW	Sludge Waste
SS	Spent Sulfite Liquor
SUB	Subbituminous Coal
TDF	Tires
TO	Tall Oil
WC	Waste Coal
WDL	Wood/Wood Waste Liquid
WDS	Wood/Wood Waste Solid

Table 4.2-6. Boiler Emissions Data Sources (Other than EIA-767) for NO_x, SO_2, and Other Pollutant Emissions Data by Year, 1985-2001

Year	NO_x	SO_2	Other Pollutant Emissions
1985	Overlaid with CAMD coal NO_x rate calculations when possible	NADBV311 data	Calculated from EIA-767 data
1986	Overlaid with CAMD coal NO_x rate calculations when possible	Calculated from EIA-767 data	Calculated from EIA-767 data
1987	Overlaid with CAMD coal NO_x rate calculations when possible	Calculated from EIA-767 data	Calculated from EIA-767 data
1988	Overlaid with CAMD coal NO_x rate calculations when possible	Calculated from EIA-767 data	Calculated from EIA-767 data
1989	Overlaid with CAMD coal NO_x rate calculations when possible	Calculated from EIA-767 data	Calculated from EIA-767 data
1990	Overlaid with CAMD coal NO_x rate calculations when possible	Calculated from EIA-767 data	Calculated from EIA-767 data
1991	Overlaid with CAMD coal NO_x rate calculations when possible	Calculated from EIA-767 data	Calculated from EIA-767 data
1992	Overlaid with CAMD coal NO_x rate calculations when possible	Calculated from EIA-767 data	Calculated from EIA-767 data
1993	Overlaid with CAMD coal NO_x rate calculations when possible	Calculated from EIA-767 data	Calculated from EIA-767 data
1994	Overlaid with CAMD coal NO_x rate calculations when possible; overlaid ETS/CEM data when possible	Overlaid with ETS/CEM data when possible	Calculated from EIA-767 data
1995	Overlaid with ETS/CEM data when available	Overlaid with ETS/CEM data when possible	Calculated from EIA-767 data
1996	Overlaid with ETS/CEM data when available	Overlaid with ETS/CEM data when possible	Calculated from EIA-767 data; if ETS/CEM heat input are available, PMCD is recalculated using ETS/CEM heat input, and then primary PM_{10} and primary $PM_{2.5}$ are recalculated, too
1997	Overlaid with ETS/CEM data when available	Overlaid with ETS/CEM data when possible	Calculated from EIA-767 data; if ETS/CEM heat input are available, PMCD is recalculated using ETS/CEM heat input, and then primary PM_{10} and primary $PM_{2.5}$ are recalculated, too
1998	Overlaid with ETS/CEM data when available	Overlaid with ETS/CEM data when possible	Calculated from EIA-767 data; if ETS/CEM heat input are available, PMCD is recalculated using ETS/CEM heat input, and then primary PM_{10} and primary $PM_{2.5}$ are recalculated, too
1999	Overlaid with ETS/CEM data when available; otherwise overlaid by State submitted data when available	Overlaid with ETS/CEM data when available; otherwise overlaid by State submitted data when available	Calculated from EIA-767 data; if ETS/CEM heat input are available, PMCD is recalculated using ETS/CEM heat input, and then primary PM_{10} and primary $PM_{2.5}$ are recalculated, too. Overlaid with State submitted data when available.

Table 4.2-6 (continued).

Year	NO_x	SO_2	Other Pollutant Emissions
2000	Overlaid with ETS/CEM data when available	Overlaid with ETS/CEM data when available	Calculated from EIA-767 data; if ETS/CEM heat input are available, PMCD is recalculated using ETS/CEM heat input, and then primary PM_{10} and primary $PM_{2.5}$ are recalculated, too
2001	Overlaid with ETS/CEM data when available	Overlaid with ETS/CEM data when available	Calculated from EIA-767 data; if ETS/CEM heat input are available, PMCD is recalculated using ETS/CEM heat input, and then primary PM_{10} and primary $PM_{2.5}$ are recalculated, too.

CAMD = EPA's Clean Air Markets Division
NADBv311 = National Allowance Data Base Version 3.11
ETS/CEM = EPA's Emissions Tracking System/Continuous Emissions Monitoring data

Table 4.2-7. EGU Source Classification Code (SCC) List

SCC	SCC1_desc	SCC3_desc	SCC6_desc	SCC8_desc	Measure	Material
10100101	External Combustion Boilers	Electric Generation	Anthracite Coal	Pulverized Coal	Tons	Anthracite
10100102	External Combustion Boilers	Electric Generation	Anthracite Coal	Traveling Grate (Overfeed) Stoker	Tons	Anthracite
10100201	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Pulverized Coal: Wet Bottom (Bituminous Coal)	Tons	Bituminous Coal
10100202	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Pulverized Coal: Dry Bottom (Bituminous Coal)	Tons	Bituminous Coal
10100203	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Cyclone Furnace (Bituminous Coal)	Tons	Bituminous Coal
10100204	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Spreader Stoker (Bituminous Coal)	Tons	Bituminous Coal
10100205	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Traveling Grate - Overfeed Stoker (Bituminous Coal)	Tons	Bituminous Coal
10100211	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Wet Bottom Tangential (Bituminous Coal)	Tons	Bituminous Coal
10100212	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Pulverized Coal: Dry Bottom Tangential (Bituminous Coal)	Tons	Bituminous Coal
10100215	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Cell Burner (Bituminous Coal)	Tons	Bituminous Coal
10100217	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Atmospheric Fluidized Bed Combustion - Bubbling Bed (Bit. Coal)	Tons	Bituminous Coal
10100218	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Atmospheric Fluidized Bed Combustion - Circulating Bed (Bit. Coal)	Tons	Bituminous Coal
10100221	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Pulverized Coal: Wet Bottom (Subbituminous Coal)	Tons	Subbituminous Coal
10100222	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Pulverized Coal: Dry Bottom (Subbituminous Coal)	Tons	Subbituminous Coal
10100223	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Cyclone Furnace (Subbituminous Coal)	Tons	Subbituminous Coal
10100224	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Spreader Stoker (Subbituminous Coal)	Tons	Subbituminous Coal
10100225	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	Tons	Subbituminous Coal
10100226	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	Tons	Subbituminous Coal
10100235	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Cell Burner (Subbituminous Coal)	Tons	Subbituminous Coal
10100237	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Atmospheric Fluidized Bed Combustion - Bubbling Bed (Sub. Coal)	Tons	Subbituminous Coal
10100238	External Combustion Boilers	Electric Generation	Bituminous/Subbituminous Coal	Atmospheric Fluidized Bed Combustion - Circulating Bed (Sub. Coal)	Tons	Subbituminous Coal
10100300	External Combustion Boilers	Electric Generation	Lignite	Pulverized Coal: Wet Bottom	Tons	Lignite

Table 4.2-7 (continued).

SCC	SCC1_desc	SCC3_desc	SCC6_desc	SCC8_desc	Measure	Material
10100301	External Combustion Boilers	Electric Generation	Lignite	Pulverized Coal: Dry Bottom, Wall Fired	Tons	Lignite
10100302	External Combustion Boilers	Electric Generation	Lignite	Pulverized Coal: Dry Bottom, Tangential Fired	Tons	Lignite
10100303	External Combustion Boilers	Electric Generation	Lignite	Cyclone Furnace	Tons	Lignite
10100304	External Combustion Boilers	Electric Generation	Lignite	Traveling Grate (Overfeed) Stoker	Tons	Lignite
10100306	External Combustion Boilers	Electric Generation	Lignite	Spreader Stoker	Tons	Lignite
10100316	External Combustion Boilers	Electric Generation	Lignite	Atmospheric Fluidized Bed Combustion	Tons	Lignite
10100317	External Combustion Boilers	Electric Generation	Lignite	Atmospheric Fluidized Bed Combustion - Bubbling Bed	Tons	Lignite
10100318	External Combustion Boilers	Electric Generation	Lignite	Atmospheric Fluidized Bed Combustion - Circulating Bed	Tons	Lignite
10100401	External Combustion Boilers	Electric Generation	Residual Oil	Grade 6 Oil: Normal Firing	1000 Gallons	Residual Oil (No. 6)
10100404	External Combustion Boilers	Electric Generation	Residual Oil	Grade 6 Oil: Tangential Firing	1000 Gallons	Residual Oil (No. 6)
10100405	External Combustion Boilers	Electric Generation	Residual Oil	Grade 5 Oil: Normal Firing	1000 Gallons	Residual Oil (No. 5)
10100406	External Combustion Boilers	Electric Generation	Residual Oil	Grade 5 Oil: Tangential Firing	1000 Gallons	Residual Oil (No. 5)
10100501	External Combustion Boilers	Electric Generation	Distillate Oil	Grades 1 and 2 Oil	1000 Gallons	Distillate Oil (No. 1 & 2)
10100504	External Combustion Boilers	Electric Generation	Distillate Oil	Grade 4 Oil: Normal Firing	1000 Gallons	Distillate Oil (No. 4)
10100505	External Combustion Boilers	Electric Generation	Distillate Oil	Grade 4 Oil: Tangential Firing	1000 Gallons	Distillate Oil (No. 4)
10100601	External Combustion Boilers	Electric Generation	Natural Gas	Boilers > 100 Million Btu/hr except Tangential	Million Cubic Feet	Natural Gas
10100602	External Combustion Boilers	Electric Generation	Natural Gas	Boilers < 100 Million Btu/hr except Tangential	Million Cubic Feet	Natural Gas
10100604	External Combustion Boilers	Electric Generation	Natural Gas	Tangentially Fired Units	Million Cubic Feet	Natural Gas
10100701	External Combustion Boilers	Electric Generation	Process Gas	Boilers > 100 Million Btu/hr	Million Cubic Feet	Process Gas
10100702	External Combustion Boilers	Electric Generation	Process Gas	Boilers < 100 Million Btu/hr	Million Cubic Feet	Process Gas
10100703	External Combustion Boilers	Electric Generation	Process Gas	Petroleum Refinery Gas	Million Cubic Feet	Process Gas
10100704	External Combustion Boilers	Electric Generation	Process Gas	Blast Furnace Gas	Million Cubic Feet	Process Gas

Table 4.2-7 (continued).

SCC	SCC1_desc	SCC3_desc	SCC6_desc	SCC8_desc	Measure	Material
10100707	External Combustion Boilers	Electric Generation	Process Gas	Coke Oven Gas	Million Cubic Feet	Process Gas
10100711	External Combustion Boilers	Electric Generation	Process Gas	Landfill Gas	Million Cubic Feet	Process Gas
10100712	External Combustion Boilers	Electric Generation	Process Gas	Digester Gas	Million Cubic Feet	Process Gas
10100801	External Combustion Boilers	Electric Generation	Coke	All Boiler Sizes	Tons	Coke
10100818	External Combustion Boilers	Electric Generation	Coke	Atmospheric Fluidized Bed Combustion - Circulating Bed	Tons	Coke
10100901	External Combustion Boilers	Electric Generation	Wood/Bark Waste	Bark-fired Boiler	Tons	Bark
10100902	External Combustion Boilers	Electric Generation	Wood/Bark Waste	Wood/Bark Fired Boiler	Tons	Wood/Bark
10100903	External Combustion Boilers	Electric Generation	Wood/Bark Waste	Wood-fired Boiler	Tons	Wood
10100910	External Combustion Boilers	Electric Generation	Wood/Bark Waste	Fuel cell/Dutch oven boilers	Tons	Wood/Bark
10100911	External Combustion Boilers	Electric Generation	Wood/Bark Waste	Stoker boilers	Tons	Wood/Bark
10100912	External Combustion Boilers	Electric Generation	Wood/Bark Waste	Atmospheric Fluidized Bed Combustion	Tons	Wood/Bark
10101001	External Combustion Boilers	Electric Generation	Liquified Petroleum Gas (LPG)	Butane	1000 Gallons	Butane
10101002	External Combustion Boilers	Electric Generation	Liquified Petroleum Gas (LPG)	Propane	1000 Gallons	Propane, LPG
10101003	External Combustion Boilers	Electric Generation	Liquified Petroleum Gas (LPG)	Butane/Propane Mixture: Specify Percent Butane in Comments	1000 Gallons	Propane/Butane
10101101	External Combustion Boilers	Electric Generation	Bagasse	All Boiler Sizes	Tons	Bagasse
10101201	External Combustion Boilers	Electric Generation	Solid Waste	Specify Waste Material in Comments	Tons	Solid Waste
10101202	External Combustion Boilers	Electric Generation	Solid Waste	Refuse Derived Fuel	Tons	Refuse Derived Fuel
10101204	External Combustion Boilers	Electric Generation	Solid Waste	Tire Derived Fuel : Shredded	Tons	Tire Derived Fuel
10101205	External Combustion Boilers	Electric Generation	Solid Waste	Sludge Waste	Tons	Sludge Waste
10101206	External Combustion Boilers	Electric Generation	Solid Waste	Agricultural Byproducts (rice or peanut hulls, shells, cow manure, etc.)	Tons	Agricultural Byproducts
10101207	External Combustion Boilers	Electric Generation	Solid Waste	Other Biomass Solids	Tons	Other Biomass Solids
10101208	External Combustion Boilers	Electric Generation	Solid Waste	Paper Pellets	Tons	Paper Pellets

Table 4.2-7 (continued).

SCC	SCC1_desc	SCC3_desc	SCC6_desc	SCC8_desc	Measure	Material
10101301	External Combustion Boilers	Electric Generation	Liquid Waste	Specify Waste Material in Comments	1000 Gallons	Liquid Waste
10101302	External Combustion Boilers	Electric Generation	Liquid Waste	Waste Oil	1000 Gallons	Waste Oil
10101304	External Combustion Boilers	Electric Generation	Liquid Waste	Black Liquor	1000 Gallons	Black Liquor Biomass
10101305	External Combustion Boilers	Electric Generation	Liquid Waste	Red Liquor	1000 Gallons	Red Liquor
10101306	External Combustion Boilers	Electric Generation	Liquid Waste	Spent Sulfite Liquor	1000 Gallons	Spent Sulfite Liquor
10101307	External Combustion Boilers	Electric Generation	Liquid Waste	Tall Oil	1000 Gallons	Tall Oil
10101308	External Combustion Boilers	Electric Generation	Liquid Waste	Wood/Wood Waste Liquid	1000 Gallons	Wood/Wood Waste Liquid
10101501	External Combustion Boilers	Electric Generation	Geothermal Power Plants	Geothermal Power Plant: Off-gas Ejectors	Megawatt-Hour	Electricity
10101502	External Combustion Boilers	Electric Generation	Geothermal Power Plants	Geothermal Power Plant: Cooling Tower Exhaust	Megawatt-Hour	Electricity
10101601	External Combustion Boilers	Electric Generation	Methanol	All	1000 Gallons	Methanol
10101801	External Combustion Boilers	Electric Generation	Hydrogen	All	Million Cubic Feet	Hydrogen
10101901	External Combustion Boilers	Electric Generation	Coal-based Synfuel	All	Tons	Coal-based Synfuel
10102001	External Combustion Boilers	Electric Generation	Waste Coal	All	Tons	Waste Coal
10102018	External Combustion Boilers	Electric Generation	Waste Coal	Atmospheric Fluidized Bed Combustion - Circulating Bed	Tons	Waste Coal
10102101	External Combustion Boilers	Electric Generation	Other Oil	All	1000 Gallons	Other Oil
20100101	Internal Combustion Engines	Electric Generation	Distillate Oil (Diesel)	Turbine	1000 Gallons	Distillate Oil (Diesel)
20100102	Internal Combustion Engines	Electric Generation	Distillate Oil (Diesel)	Reciprocating	1000 Gallons	Distillate Oil (Diesel)
20100105	Internal Combustion Engines	Electric Generation	Distillate Oil (Diesel)	Reciprocating: Crankcase Blowby	1000 Gallons	Distillate Oil (Diesel)
20100106	Internal Combustion Engines	Electric Generation	Distillate Oil (Diesel)	Reciprocating: Evaporative Losses (Fuel Storage and Delivery System)	1000 Gallons	Distillate Oil (Diesel)
20100107	Internal Combustion Engines	Electric Generation	Distillate Oil (Diesel)	Reciprocating: Exhaust	1000 Gallons	Distillate Oil (Diesel)
20100108	Internal Combustion Engines	Electric Generation	Distillate Oil (Diesel)	Turbine: Evaporative Losses (Fuel Storage and Delivery System)	1000 Gallons	Distillate Oil (Diesel)
20100109	Internal Combustion Engines	Electric Generation	Distillate Oil (Diesel)	Turbine: Exhaust	1000 Gallons	Distillate Oil (Diesel)

Table 4.2-7 (continued).

SCC	SCC1_desc	SCC3_desc	SCC6_desc	SCC8_desc	Measure	Material
20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine	Million Cubic Feet	Natural Gas
20100202	Internal Combustion Engines	Electric Generation	Natural Gas	Reciprocating	Million Cubic Feet	Natural Gas
20100205	Internal Combustion Engines	Electric Generation	Natural Gas	Reciprocating: Crankcase Blowby	Million Cubic Feet	Natural Gas
20100206	Internal Combustion Engines	Electric Generation	Natural Gas	Reciprocating: Evaporative Losses (Fuel Delivery System)	Million Cubic Feet	Natural Gas
20100207	Internal Combustion Engines	Electric Generation	Natural Gas	Reciprocating: Exhaust	Million Cubic Feet	Natural Gas
20100208	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine: Evaporative Losses (Fuel Delivery System)	Million Cubic Feet	Natural Gas
20100209	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine: Exhaust	Million Cubic Feet	Natural Gas
20100301	Internal Combustion Engines	Electric Generation	Gasified Coal	Integrated Gasification Combined Cycle (IGCC)		Gasified Coal
20100702	Internal Combustion Engines	Electric Generation	Process Gas	Reciprocating	Million Cubic Feet	Process Gas
20100705	Internal Combustion Engines	Electric Generation	Process Gas	Reciprocating: Crankcase Blowby	Million Cubic Feet	Process Gas
20100706	Internal Combustion Engines	Electric Generation	Process Gas	Reciprocating: Evaporative Losses (Fuel Delivery System)	Million Cubic Feet	Process Gas
20100707	Internal Combustion Engines	Electric Generation	Process Gas	Reciprocating: Exhaust	Million Cubic Feet	Process Gas
20100801	Internal Combustion Engines	Electric Generation	Landfill Gas	Turbine	Million Cubic Feet	Landfill Gas
20100802	Internal Combustion Engines	Electric Generation	Landfill Gas	Reciprocating	Million Cubic Feet	Landfill Gas
20100805	Internal Combustion Engines	Electric Generation	Landfill Gas	Reciprocating: Crankcase Blowby	Million Cubic Feet	Landfill Gas
20100806	Internal Combustion Engines	Electric Generation	Landfill Gas	Reciprocating: Evaporative Losses (Fuel Delivery System)	Million Cubic Feet	Landfill Gas
20100807	Internal Combustion Engines	Electric Generation	Landfill Gas	Reciprocating: Exhaust	Million Cubic Feet	Landfill Gas
20100808	Internal Combustion Engines	Electric Generation	Landfill Gas	Turbine: Evaporative Losses (Fuel Delivery System)	Million Cubic Feet	Landfill Gas
20100809	Internal Combustion Engines	Electric Generation	Landfill Gas	Turbine: Exhaust	Million Cubic Feet	Landfill Gas
20100901	Internal Combustion Engines	Electric Generation	Kerosene/Naphtha (Jet Fuel)	Turbine	1000 Gallons	Jet Fuel
20100902	Internal Combustion Engines	Electric Generation	Kerosene/Naphtha (Jet Fuel)	Reciprocating	1000 Gallons	Jet Fuel
20100905	Internal Combustion Engines	Electric Generation	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Crankcase Blowby	1000 Gallons	Jet Fuel

Table 4.2-7 (continued).

SCC	SCC1_desc	SCC3_desc	SCC6_desc	SCC8_desc	Measure	Material
20100906	Internal Combustion Engines	Electric Generation	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Evaporative Losses (Fuel Delivery System)	1000 Gallons	Jet Fuel
20100907	Internal Combustion Engines	Electric Generation	Kerosene/Naphtha (Jet Fuel)	Reciprocating: Exhaust	1000 Gallons	Jet Fuel
20100908	Internal Combustion Engines	Electric Generation	Kerosene/Naphtha (Jet Fuel)	Turbine: Evaporative Losses (Fuel Storage and Delivery System)	1000 Gallons	Jet Fuel
20100909	Internal Combustion Engines	Electric Generation	Kerosene/Naphtha (Jet Fuel)	Turbine: Exhaust	1000 Gallons	Jet Fuel
20101001	Internal Combustion Engines	Electric Generation	Geysers/Geothermal	Steam Turbine	Tons	Steam
20101010	Internal Combustion Engines	Electric Generation	Geysers/Geothermal	Well Drilling: Steam Emissions	Tons	Steam
20101020	Internal Combustion Engines	Electric Generation	Geysers/Geothermal	Well Pad Fugitives: Blowdown	Tons	Steam
20101030	Internal Combustion Engines	Electric Generation	Geysers/Geothermal	Pipeline Fugitives: Blowdown	Tons	Steam
20101031	Internal Combustion Engines	Electric Generation	Geysers/Geothermal	Pipeline Fugitives: Vents/Leaks	Tons	Steam
20101302	Internal Combustion Engines	Electric Generation	Liquid Waste	Waste Oil - Turbine	1000 Gallons	Waste Oil

Table 4.2-8. Rules for Assigning Primary and Secondary PM Control Device NEDS Codes

If the PM device is missing, then it is defaulted to an electrostatic precipitator (ESP)

If the PM device is an electrostatic precipitator (ESP) and the PM control efficiency is at least 95 percent, then the NEDS control device code = 10.

If the PM device is an electrostatic precipitator (ESP) and the PM control efficiency is at least 80 but less than 95 percent, then the NEDS control device code = 11.

If the PM device is an electrostatic precipitator (ESP) and the PM control efficiency is less than 80 percent, then the NEDS control device code = 12.

If the PM device is a wet scrubber and the PM control efficiency is at least 95 percent, then the NEDS control device code = 1.

If the PM device is a wet scrubber and the PM control efficiency is at least at least 80 but less than 95 percent, then the NEDS control device code = 2.

If the PM device is a wet scrubber and the PM control efficiency is less than 80 percent, then the NEDS control device code = 3.

If the PM device is a baghouse, then the NEDS control device code = 17.

If the PM device is a single cyclone, then the NEDS control device code = 75.

If the PM device is a multiple cyclone, then the NEDS control device code = 76.

If the PM device is other, then the NEDS control device code = 99.

Table 4.2-9. Algorithms Used to Disaggregate ETS/CEM Boiler Data to the Boiler-SCC Level

$$CEMSO2_{SCC} = \left(\frac{767SO2_{SCC,b}}{767SO2_{b}} \right) * CEMSO2_{b}$$

$$CEMNOX_{SCC} = \left(\frac{767NOX_{SCC,b}}{767NOX_{b}} \right) * CEMNOX_{b}$$

$$CEMHTI_{SCC} = \left(\frac{767HTI_{SCC,b}}{767HTI_{b}} \right) * CEMHTI_{b}$$

where:	b	=	boiler-level
	CEMSO2, CEMNOX, CEMHTI	=	ETS/CEM annual boiler data for given parameter
	767SO2, 767NOX, 767HTI	=	Form EIA-767-based calculated data for given parameter