ECT

Environmental Consulting & Technology, Inc.

March 29, 2007

Mr. Syed Arif, P.E.
Florida Department of Environmental Protection
Division of Air Resource Management
111 South Magnolia Drive, Suite 23
Tallahassee, Florida 32301

Re: Gainesville Regional Utilities
Deerhaven Generating Station Unit 2
Air Quality Control System Addition
DEP File No. 010006-005-AC
Responses to Request for Additional Information

Dear Mr. Arif:

Gainesville Regional Utilities (GRU) received your letter dated March 12, 2007 requesting additional information with regard to the addition of emission control equipment to Deerhaven Generating Station (DGS) Unit 2. On behalf of GRU, this correspondence provides a response to each specific issue raised by the Department of Environmental Protection (Department). For your convenience, the Department's comments and our responses are provided below.

Department Comment No. 1

Please provide a flow diagram of Unit 2 including any control equipment as it exists now. Also, provide a flow diagram showing all the changes taking place due to the proposed project. Include in the flow diagram material balance flow rates for all the criteria pollutants.

GRU Response:

Emission control equipment presently installed on Unit 2 consists of a hot-side electrostatic precipitator (ESP) for control of particulate matter (PM). As described in the air construction permit application submitted to the Department, additional emission control equipment proposed for Unit 2 includes Selective Catalytic Reduction (SCR) to control NO_x emissions, a circulating dry scrubber (CDS) to reduce SO_2 emissions, and a fabric filter (FF) to control emissions of PM. The existing hot-side ESP will remain in service. A flow diagram showing the current and proposed Unit 2 emission control equipment is attached (Attachment 1). The flow diagram also provides estimates of criteria pollutant emission rates as the boiler exhaust stream passes through the emission control equipment.

Department Comment No. 2

Please provide the capacity factors for Unit 2 based on heat input for the period 2002-2006. Explain the reasons for a less than 80 percent capacity factor for any year. Additionally, provide the maximum hourly heat input rate for Unit 2 during the same period. Provide the heat input rate to Unit 2 during annual compliance test for particulate matter (PM) during the same period of 2002-2006. Show the calculations in arriving at the heat input numbers for the period 2002-2006 as listed Table 6-1 of the application.
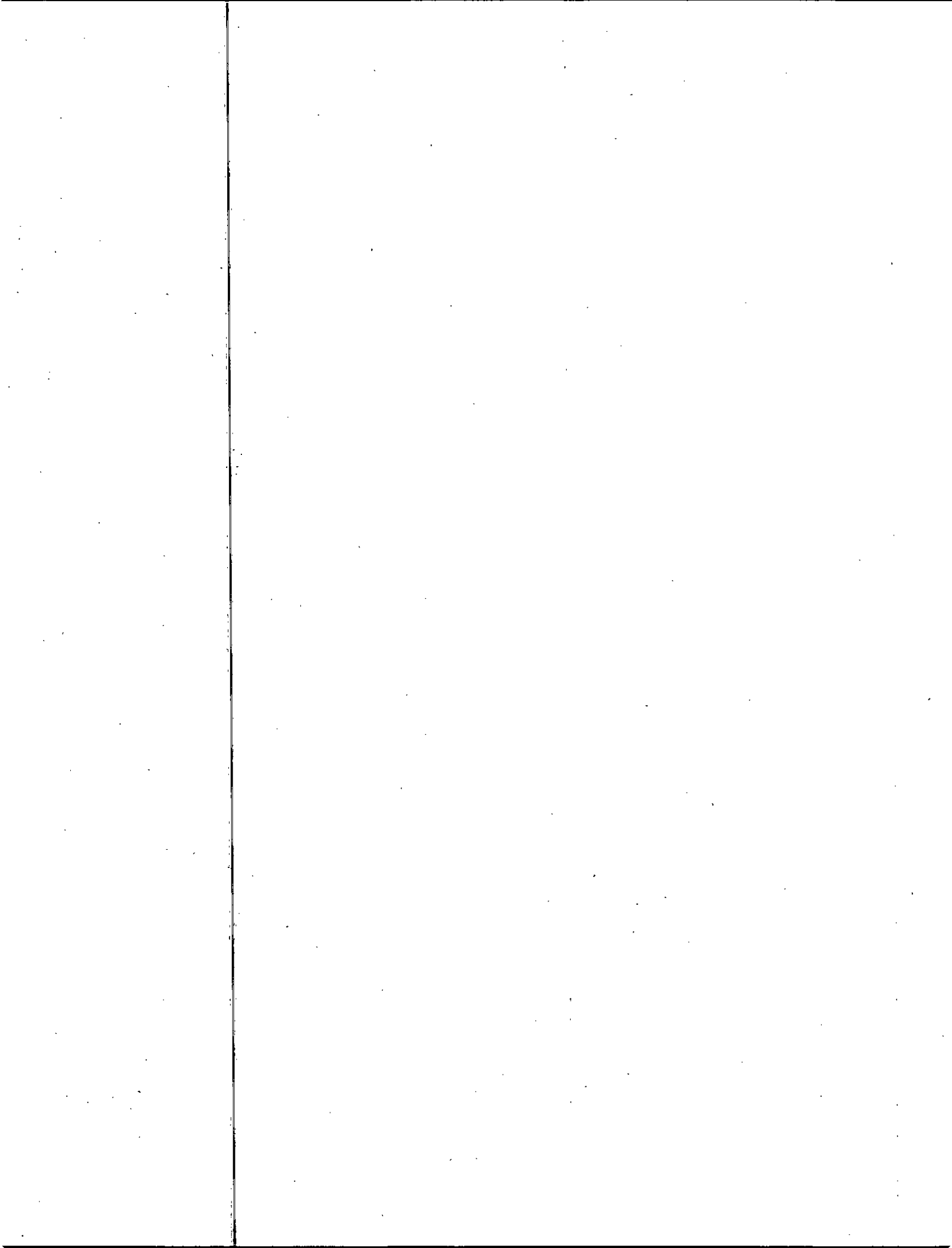
GRU Response:

Unit 2 has a net generation capability of approximately 228 megawatts (MW) resulting in a maximum annual net generation capacity of 1,997,280 MW based on continuous operation (i.e., 8760 hours/yr). Unit 2 capacity factors for the 2002 through 2006 period are provided in the following table:

Year	Net Generation (MWh/yr)	Capacity Factor (%)
2002	1,265,583	63
2003	1,350,868	68
2004	1,180,414	59
2005	1,546,277	77
2006	1,381,787	69

The capacity factors reflect the general demand for electricity, planned and unplanned unit outages, unit load limitations, and purchases of electricity from other utilities during the particular year. .

Unit 2 heat input data (based on fuel consumption and heat content) during the annual PM compliance tests is provided in the following table:

| Date of Compliance Test	Average Heat Input (10^6 Btu/hr)
06/18/02	2,219
06/23/03	2,376
06/08/04	2,390
08/15/05	2,393
07/20/06	2,209

The baseline annual heat input data shown in Table 6-1 of the submitted air construction permit application was obtained from the EPA Clean Air Markets Division (CAMD) website and reflects GRU hourly CEMs data reported to EPA pursuant to the Acid Rain Program. The EPA CAMD website can be accessed at http://cfpub.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard.

Department Comment No. 3

The application states that the selective catalytic reduction (SCR) system will be designed so that flue gas flows through it whenever Unit 2 is operating, i.e., there are no bypasses. Does this imply that ammonia injection to the SCR will always be on whenever Unit 2 is operating?

GRU Response:

In air construction permits for similar projects (e.g., Progress Energy Florida Crystal River Units 4 and 5), the Department states that "Because CAIR and CAMR afford the flexibility to evaluate market conditions to determine whether it will install controls, operate existing controls, or purchase allowances generated by other plants, the Department does not require the installation of this equipment nor its operation" (i.e., injection of reagents such as ammonia or lime).

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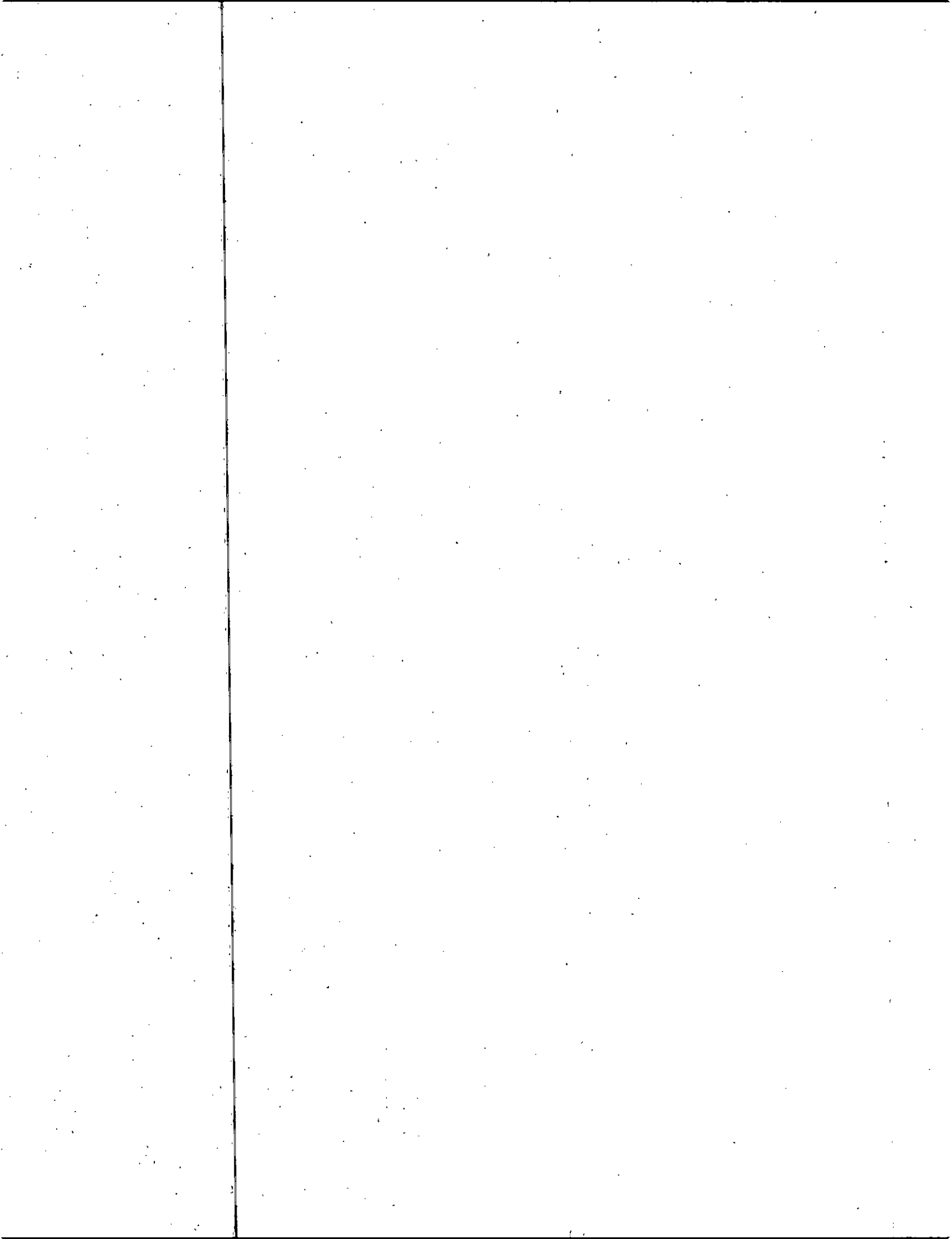
Per our telephone conversation, CAIR affords a regulated facility the flexibility to evaluate market conditions to determine whether it will install controls, operate existing controls, or purchase allowances generated by other plants. Therefore, GRU is not required by regulation to install nor operate the proposed air quality control system (AQCS) to meet CAIR requirements.

Department Comment No. 4

The application states that the Circulating Dry Scrubber (CDS) system to control SO_2 and SO_3 emissions will be designed so that flue gas flows through it whenever Unit 2 is operating, i.e., there are no bypasses. Does this imply that hydrated lime will be introduced into the scrubber at all times when Unit 2 is operating?

GRU Response:

Please see response to Department Comment No. 3 above.

Department Comment No. 5

Please explain where hydrogen fluoride (HF) and sulfuric acid mist (SAM) emissions are being formed and what steps are being taken to mitigate them.
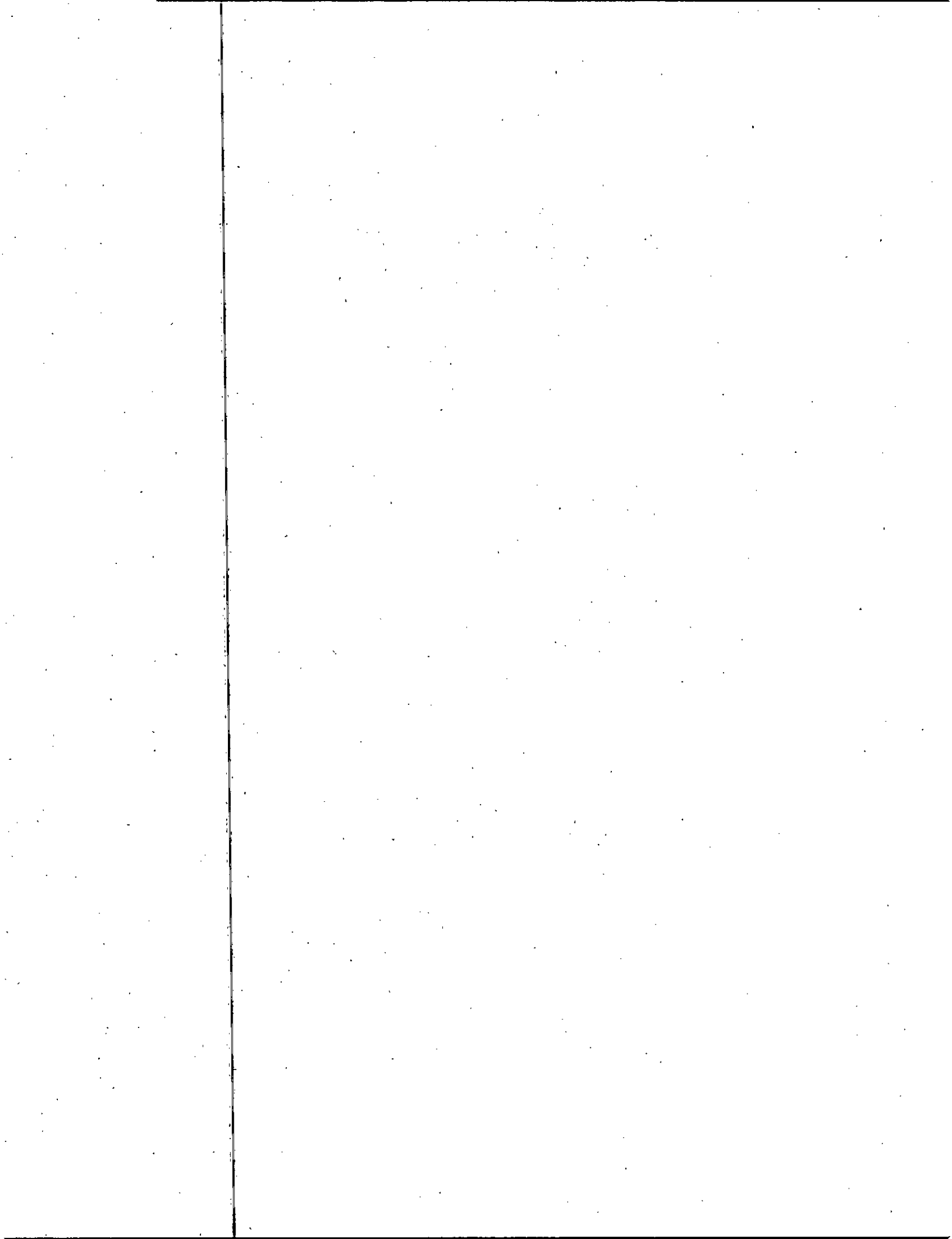
GRU Response:

Coal combusted in Unit 2 contains trace amounts of fluoride compounds. During the combustion process, hydrogen fluoride (HF) aerosols are formed, a portion of which may be adsorbed on fly ash or bottom ash.

EPA (reference Section 1.1 of AP-42) estimates that approximately 0.7 percent of the sulfur contained in coal combusted in pulverized coal-fired boilers will be oxidized to SO_3 during the combustion process. The SCR NO_x control system planned for Unit 2 will also catalytically oxidize a small portion of the exhaust stream SO_2 to SO_3. SO_3 readily reacts with water to form sulfuric acid mist (SAM) aerosols. Accordingly, any SO_3 formed during the combustion of coal in Unit 2 or by the SCR control system will be converted to SAM.

Both HF and SAM are acid gas aerosols that can be neutralized by reaction with an alkaline reagent. Alkaline sorbent injection is an established control technology for reducing emissions of acid gases such as HF and SAM. As stated in the Unit 2 AQCS air construction permit application on Page 6-3, the CDS proposed for Unit 2 will employ an alkaline reagent (i.e., lime) that is projected to reduce HF and SAM emissions by over 90 percent. HF and SAM that are neutralized by lime in the CDS will be collected as particulate calcium compounds by the downstream fabric filter. Reductions in actual Unit 2 HF and SAM emissions are estimated to be approximately 28 and 67 tons per year, respectively.

Department Comment No. 6

Please provide the calculations in arriving at the actual HF and SAM emissions for the period 2002-2006. How does it compare with the emissions number obtained by doing material balance calculations? Please provide those calculations as well.

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GRU Response:

As stated in the Unit 2 AQCS air construction permit application on Page 6-2, baseline (2002-2006) HF and SAM emissions were estimated using regulatory and industry guidance developed for to the Toxic Release Inventory (TRI) regulatory program.

HF is calculated by using the concentration of fluorine in the coal based upon analysis results and the quantity of coal combusted. It is assumed that all of the HF created by combustion is released from the stack. Details of the calculation are shown below:

$$\frac{\text{tons of coal}}{\text{yr}} \times \frac{2000 \text{ lbs.}}{1 \text{ ton}} \times \frac{\text{lbs. of F}}{10^6 \text{ lbs. of coal}} \times \frac{\text{MW of HF}}{\text{MW of F}} = \frac{\text{lbs. of HF}}{\text{yr}}$$

H_2SO_4 (aerosol) is calculated by using the concentration of sulfur in the coal based upon analysis results and the quantity of coal combusted as provided in <u>Estimating Total Sulfuric Acid Emissions from Coal-Fired Power Plants</u> (Southern Company Services, Inc.) included herein as Attachment 2. These estimating procedures were developed specifically for tangentially-fired and dry-bottom wall-fired boilers such as Unit 2.

Additional assumptions about the type of particulate control device at the plant (i.e., hot-side ESP and air heater) are used to estimate the amount H_2SO_4 (aerosol) released. For purposes of the TRI reports, the following equation is used for the release estimate for sulfuric acid mist:

$$E = (K)(F1)(F2)(E2) \qquad \text{See pg. 6 and Example 3 on pg. 16}$$

Where:
K = molecular weight and units conversion constant = 3,063   See pg. 5
F1 = Fuel impact factor for eastern bituminous coal = 0.008   See Table 3, pg. 9
F2 = Technology impact factor for control devices = (1*0.50) = 0.5   See Table 4, pg. 10
E2 = SO_2 emissions calculated from coal burned in tons/year   See pg. 5 and 6

As noted above in the response to FDEP Comment No. 5, the CDS proposed for Unit 2 will employ an alkaline reagent that is projected to reduce HF and SAM emissions by over 90 percent. Reductions in actual Unit 2 HF and SAM emissions are estimated to be approximately 28 and 68 tons per year, respectively. Accordingly, the use of a CDS achieving 90 percent removal of HF and SAM provides reasonable assurance that emission increases of these two pollutants will not occur due to installation of the Unit 2 AQCS.

<u>Department Comment No. 7</u>

Please explain why the highest heat input for the year 2006 was used in determining the projected actual emissions instead of using the annual average for the period 2005-2006.

GRU Response:

To conservatively estimate future projected actual emissions, the highest annual heat input over the 2002-2006 five year period was used consistent with the Rule 62-210.200(247), F.A.C. definition of *projected actual emissions*. Use of the average heat input for the 2002-2006 period would result in a slightly lower estimate of future projected actual emissions.

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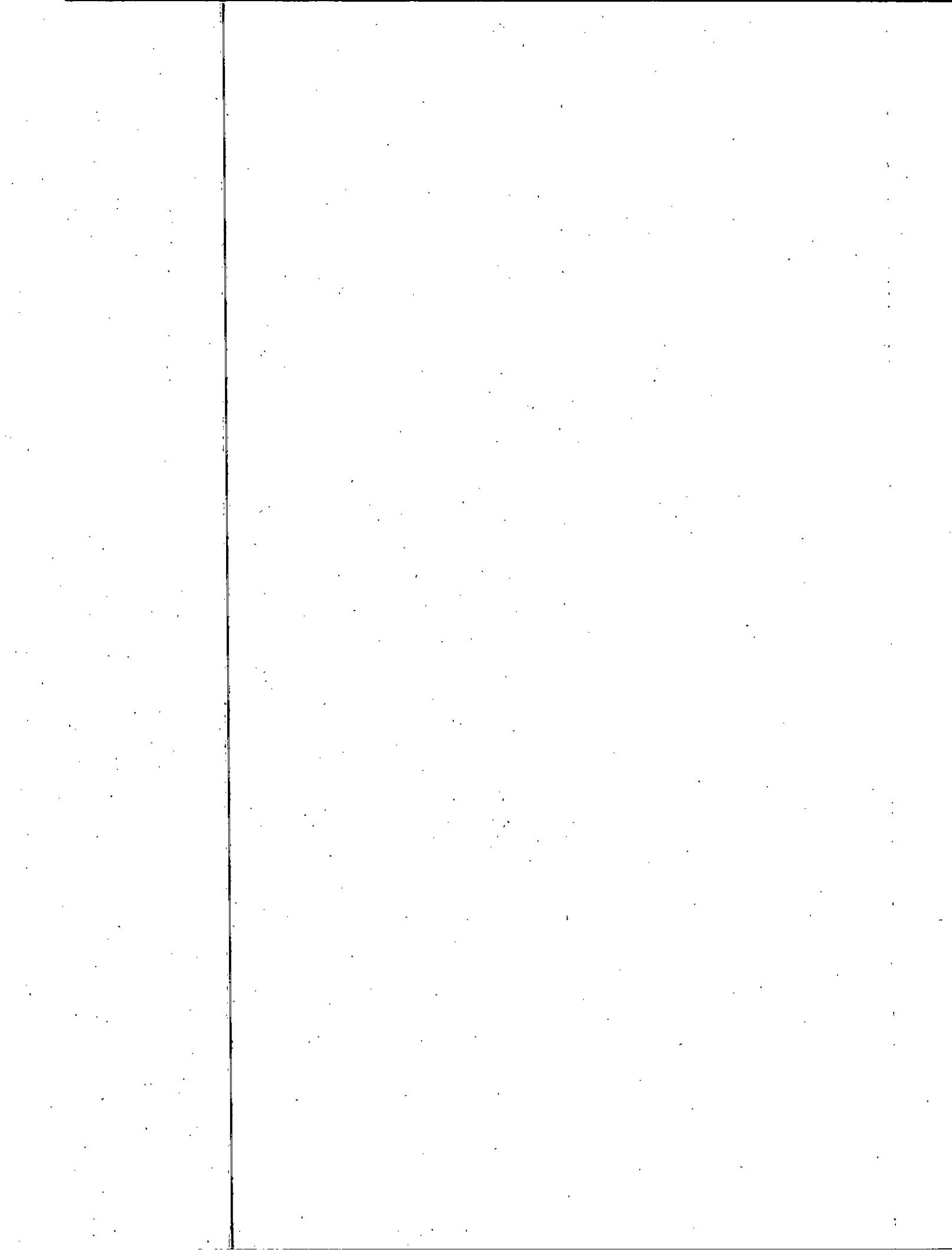
Department Comment No. 8

Please provide emissions data for CO. How will the change affect CO emissions? How is the baseline actual CO emissions determined and how will the projected actual CO emissions be monitored?

GRU Response:

Unit 2 CO emissions, based on Annual Operating Report (AOR) data, for the 2002-2006 period are provided in the following table.

Year	Unit 2 CO Emissions (ton/year)
2002	151
2003	163
2004	141
2005	192
2006	173

As noted on Page 6-2 of the air construction permit application, no changes are planned to the DGS Unit 2 combustion process. Accordingly, no change in actual emissions of combustion related pollutants such as CO will result due to the AQCS project. There are no requirements to monitor CO emissions from Unit 2. GRU will continue to provide Unit 2 actual annual CO emissions in the AORs submitted to the Department in March of each year based on fuel usage and fuel-specific AP-42 emission factors.

As requested, a professional engineer certification is attached (Attachment 3). GRU understands that with the submission of this additional information, the Department will continue processing the air construction permit application for the DGS Unit 2 AQCS project. The AQCS planned for DGS Unit 2 will achieve target NO_x, SO_2, and PM emission rates that are approximately ten times lower than current Unit 2 emission limits. Accordingly, the Department's continued expeditious processing of the Unit 2 AQCS air construction permit application will be appreciated.

If you have any further questions regarding this matter, please contact me at (352) 332-0444, Ext. 351.
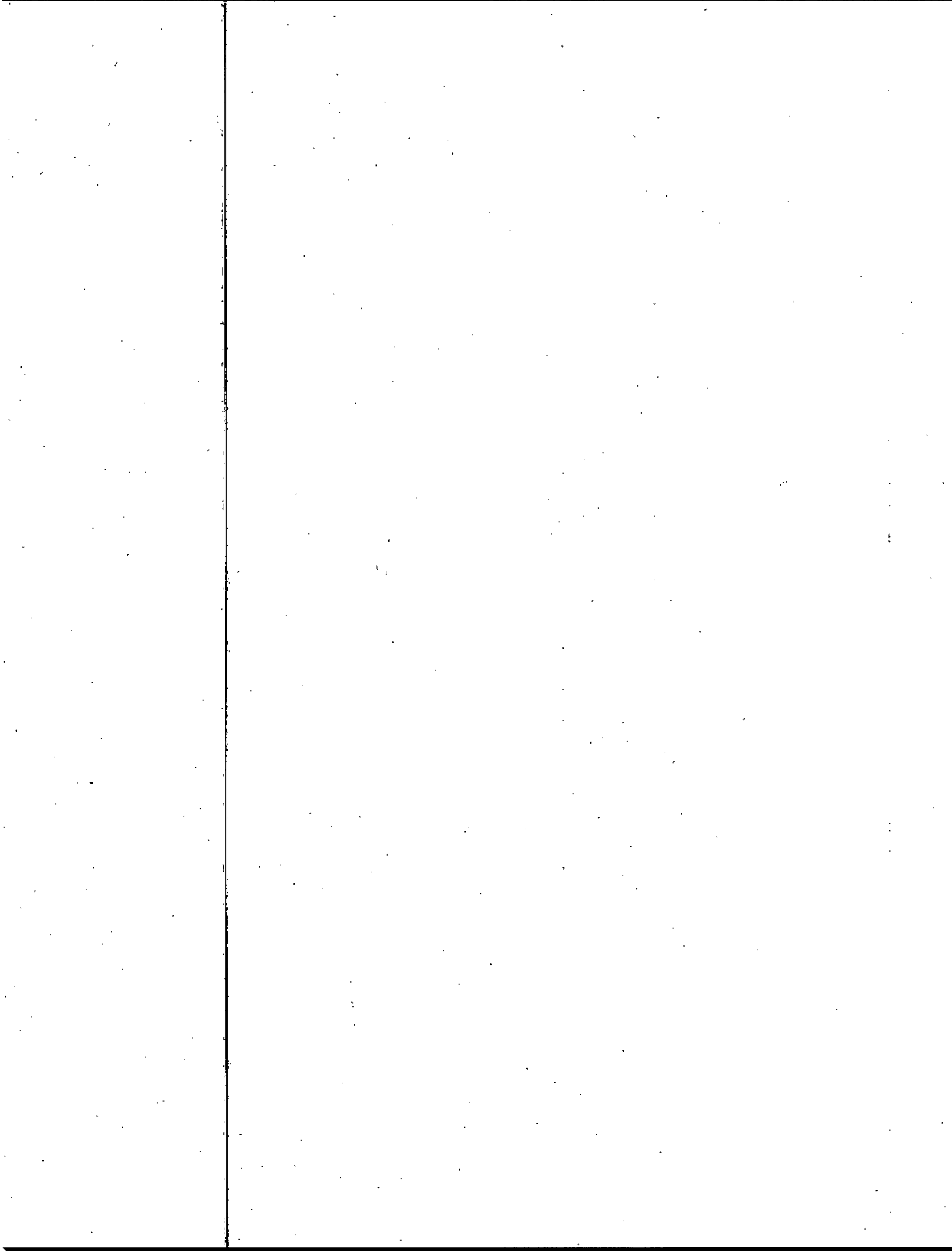
Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

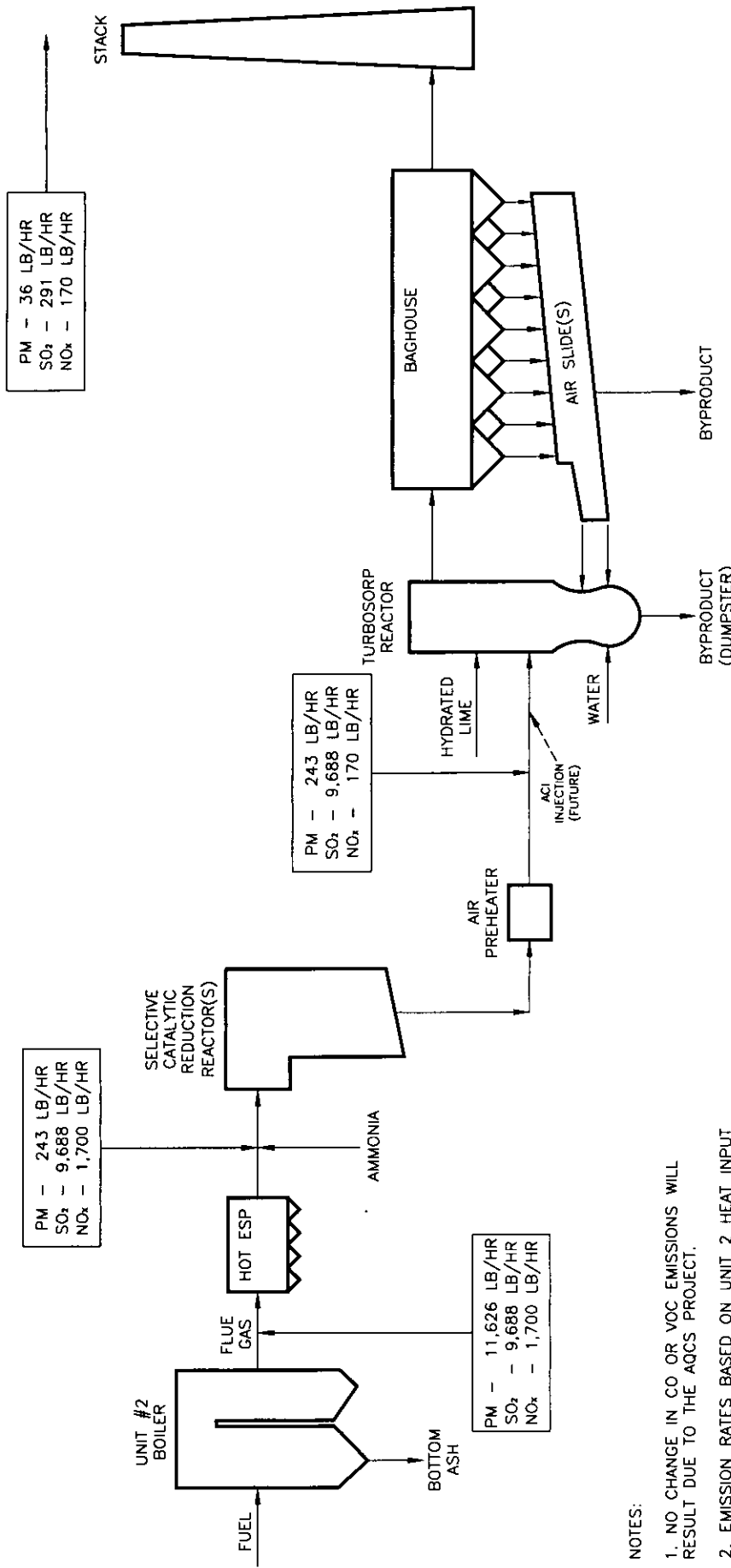Thomas W. Davis, P.E.
Principal Engineer

Attachments

cc: Chris Kirts, FDEP Northeast District
        Yolanta Jonynas, GRU
        Doug Beck, GRU
        Angela Morrison Uhland, Hopping Green & Sams, P.A

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ATTACHMENT 1

DGS UNIT 2 AQCS FLOW DIAGRAM

STACK

PM	–	36	LB/HR
SO₂	–	291	LB/HR
NOx	–	170	LB/HR

BAGHOUSE

AIR SLIDE(S)

BYPRODUCT

TURBOSORP REACTOR

PM	–	243	LB/HR
SO₂	–	9,688	LB/HR
NOx	–	170	LB/HR

HYDRATED LIME

ACI INJECTION (FUTURE)

WATER

BYPRODUCT (DUMPSTER)

AIR PREHEATER

SELECTIVE CATALYTIC REDUCTION REACTOR(S)

PM	–	243	LB/HR
SO₂	–	9,688	LB/HR
NOx	–	1,700	LB/HR

AMMONIA

HOT ESP

FLUE GAS

PM	–	11,626	LB/HR
SO₂	–	9,688	LB/HR
NOx	–	1,700	LB/HR

UNIT #2 BOILER

BOTTOM ASH

FUEL

NOTES:

1. NO CHANGE IN CO OR VOC EMISSIONS WILL RESULT DUE TO THE AQCS PROJECT.

2. EMISSION RATES BASED ON UNIT 2 HEAT INPUT OF 2,428 MMBTU/HR, COAL HEAT CONTENT OF 12,531 BTU/LB, AND COAL COMBUSTION RATE OF 96.9 TONS/HR.

3. BOILER OUTLET PM EMISSIONS BASED ON A COAL ASH CONTENT OF 12% AND AP-42 FACTOR (LB PM/TON COAL) OF 10 × % ASH.

4. BOILER OUTLET SO₂ EMISSIONS BASED ON A COAL SULFUR CONTENT OF 2.5% AND ASSUMED COMPLETE OXIDATION OF FUEL SULFUR TO SO₂.

5. BOILER OUTLET NOx EMISSIONS BASED ON 0.7 LB/MMBTU.

6. STACK PM, NOx AND SO₂ EMISSIONS RATE BASED ON CONTROLLED RATES OF 0.015, 0.07, AND 0.12 LB/MMBTU RESPECTIVELY

GRU
More than Energy

STRATEGIC PLANNING DEPARTMENT
GAINESVILLE REGIONAL UTILITIES
PO BOX 147117
GAINESVILLE, FL 32614-7117

DH2 PROCESS FLOW DIAGRAM
WITH AIR QUALITY CONTROL SYSTEM

Estimating Total Sulfuric Acid Emissions
from Coal-Fired Power Plants

R. Hardman
R. Stacy
Southern Company Services

E. Dismukes, retired
Southern Research Institute

September 1998

REVISED[1]
K. Harrison
L. Monroe
Southern Company Services

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[1] Revised September 1998. Based on feedback from technical review, some calculations in this document have been revised since the original publication [1] and since the August 1998, version.

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ABSTRACT

This paper presents a method for estimating both the *manufacturing* threshold value and *release* of sulfuric acid (H_2SO_4) from coal-fired boilers. The U. S. Environmental Protection Agency's Toxic Release Inventory (TRI) reporting system requires that, beginning in 1998, electric utilities estimate their emissions of over 600 chemical compounds. "Sulfuric acid aerosol[EPA]" is one of the compounds included in the TRI. EPA defines sulfuric acid aerosols as "includ[ing] mists, vapors, gas, fog, and other airborne forms of any particle size." Since this definition is technically inaccurate but necessary to follow EPA requirements, these forms of sulfuric acid will be identified as aerosol[EPA] to avoid confusion. In coal-fired plants, the chemical H_2SO_4 is created in the ductwork downstream of the boiler by the combination of water vapor and sulfur trioxide (SO_3), both of which are manufactured during the coal combustion process. The TRI reporting rules do not require the collection of any new data. The estimation method presented herein uses data and information already available at most coal-fired plants. These factors include the SO_2 emissions level from either continuous emissions monitors (CEMs) or fuel data, the type of fuel being burned, and the particulate control device(s) used to control dust emissions. Although this method could be applied to many types of coal-fired boilers, the estimates contained herein were developed specifically for dry-bottom, wall-fired and tangentially fired boilers.

Introduction
Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA), also known as the Toxic Release Inventory (TRI), requires facilities that "manufacture," "process" or "otherwise use" a listed chemical above certain threshold amounts to report their annual releases of the chemical to EPA and state agencies. The TRI reporting requirements are triggered if a facility "manufactures" or "processes" more than 25,000 pounds of a listed chemical or "otherwise uses" more than 10,000 pounds of a listed chemical in a given calendar year. TRI releases are reported on a report called the "Form R."

Sulfuric acid is a listed TRI chemical. In June 1995, the U. S. Environmental Protection Agency (EPA) modified the list of chemicals subject to the EPCRA § 313 reporting requirements so that only aerosol forms of sulfuric acid would be subject to the TRI reporting requirements[2]. EPA defines sulfuric acid aerosols as "includ[ing] mists, vapors, gas, fog, and other airborne forms of any particle size." Since this definition is technically inaccurate but necessary to follow EPA requirements, these forms of sulfuric acid will be identified as aerosol[EPA] to avoid confusion.

Beginning on July 1, 1999, certain coal- and oil-fired electric power plants will be required to report annual releases of TRI chemicals that they manufacture, process or otherwise use above threshold amounts. Under EPA's EPCRA § 313 regulations, coal- and oil-fired electric utilities are deemed to "manufacture" sulfuric acid aerosol[EPA]. Thus, electric utilities will have to submit TRI reports on sulfuric acid aerosol[EPA] releases if they "manufacture" more than 25,000 pounds of the chemical in a given reporting year[3].

In coal-fired power plants, sulfuric acid (H_2SO_4) is created in the ductwork downstream of the boiler by the combination of water vapor and sulfur trioxide (SO_3), both of which are manufactured during the coal combustion process. This paper presents a method for estimating the total aerosol[EPA] amount of H_2SO_4 *manufactured* in coal-fired utility boilers. Also, this paper provides a method of estimating the amount of sulfuric acid aerosol[EPA] *released* if the unit's production of H_2SO_4 aerosol[EPA] exceeds the threshold, making this amount the reportable quantity.

Following the presentation of the proposed prediction method, supporting information regarding the impact of fuel grade on the formation of SO_3, the conversion of SO_3 to H_2SO_4, and the effect of particulate control equipment on H_2SO_4 collection are presented. Then, trends are presented which provide insight on the volume of H_2SO_4 aerosol[EPA] emitted by power plants of varying sizes, efficiencies, and configurations. The effect of coal sulfur content is also shown. Finally, sample calculations are provided. Although this method could be applied to many types of coal-fired boilers, the estimates contained herein were developed specifically for dry-bottom wall-fired and tangentially-fired boilers. Cyclone fired boilers may be added in a future version of this paper.

THRESHOLD DETERMINATION AND RELEASE PREDICTION METHOD
TRI reporting is required for sulfuric acid aerosol[EPA] only if any of the three activity thresholds (manufacture, process or otherwise use) is exceeded in a given calendar year. The quantity of sulfuric acid aerosol[EPA] which is released to the environment does not determine whether a reporting requirement has been triggered. If an activity threshold is not exceeded, no Form R report is required, regardless of the amount of sulfuric acid aerosol[EPA] released. All sulfuric acid aerosol[EPA] manufactured, processed or otherwise used is to be counted toward threshold

determinations. However, electric utilities are likely to be concerned only with the "manufacture" of sulfuric acid aerosol[EPA]. This includes any amount of sulfuric acid aerosol[EPA] that may be generated in closed systems or that is generated in stacks prior to or after being treated by scrubbers [3].

The following relationship is proposed to estimate the total H_2SO_4 aerosol[EPA] *manufactured* in a coal-fired utility boiler:

$$E1 = K \bullet F1 \bullet E2$$

where, E1 = total H_2SO_4 aerosol[EPA] *manufactured*, lbs/yr

K = Molecular weight and units conversion constant = 98.07 / 64.04 $\bullet$ 2000 = 3,063
98.07 = Molecular weight of H_2SO_4; 64.04 = Molecular weight of SO_2
Conversion from tons per year to pounds per year – multiply by 2000.

F1 = Fuel Impact Factor

E2 = Sulfur dioxide (SO_2) emissions either: (1) recorded by a continuous emissions monitor and corrected for positive flow bias and bias due to wall effects, tons/yr, or (2) calculated from coal burn data, tons/yr.

In the derivation of this relationship, the following assumptions are made:
- SO_3 concentrations are proportional to SO_2 concentrations.
- The grade of coal being burned impacts the rate of conversion from SO_2 to SO_3.
- All SO_3 that forms is converted to H_2SO_4 aerosol[EPA].
- The boiler is wall-fired or tangentially-fired.
- The rate of SO_3 formation is independent of the boiler firing rate (unit load).

The rate of SO_2 emissions as derived from continuous emissions monitor (CEM) data follows. If any flue gas desulfurization (FGD) equipment is used, however, then the calculation of SO_2 mass rate from coal burn mass rate must be used. A correction method accounting for flow bias and wall effects on SO_2 emissions reported by a CEM has been proposed, as well [4]. The following relationship is used to correct SO_2 mass rate from the CEM:

$$E2 = E3\left[1 - \frac{\left(C_1 R^2 + C_2 R + C_3\right)}{100}\right]$$

where, E2 = Corrected SO_2 mass rate, tons/yr

E3 = CEM-derived SO_2 mass rate, tons/yr

C_1 = 0.0264 (non-axial flow bias factor)

C_2 = 0.183 (non-axial flow bias factor)

C_3 = 1.5 (wall effects bias factor)

R = Stack/duct average resultant angle (or swirl angle) from site verification tests, degrees.

The relationship is derived from knowledge of (1) an inherent bias resulting from CEM installations in non-axial flow situations, and (2) bias introduced from poor velocity sampling at the stack/duct wall. Both of the errors can be attributed to the required use of EPA Methods 1 and 2 for CEM flow monitor setup and validation under the guidelines described in 40 CFR Part 60, Appendix A. Supporting information for and derivation of the correction factors are presented in the previously mentioned reference [4].

The mass rate of SO_2 produced by combustion can also be calculated from the coal burn data [5]. The following relationship is used to estimate the rate of SO_2 emissions:

$$E2 = K1 \bullet K2 \bullet C1 \bullet S1$$

where, $E2 = SO_2$ mass rate, tons/yr
   $C1$ = Coal burn, tons/yr
   $S1$ = Coal sulfur weighted average, %
   $K1$ = Molecular weight and units conversion constant = $(64.04)/(100 \bullet 32.06) = 0.02$
      64.04 = molecular weight of SO_2; 32.06 = molecular weight of S;
      100 = conversion of % S to fraction
   $K2$ = Sulfur conversion to SO_2, implicit from EPA AP-42 [5]
            = 0.95 for bituminous coals
            = 0.875 for subbituminous coals
            = 0.55 to 0.85 for lignite, based on the Na content

When the estimate of total H_2SO_4 aerosol[EPA] *manufactured* by a facility exceeds 25,000 pounds per year, the facility is required to estimate how much of this H_2SO_4 aerosol[EPA] is *released* in airborne form to the atmosphere. This amount, then, is the reportable quantity.

The following relationship is proposed to predict the quantity of H_2SO_4 aerosol[EPA] *released*:

$$E1' = K \bullet F1 \bullet F2 \bullet E2$$

where, $E1'$ = total H_2SO_4 aerosol[EPA] *released*, lbs/yr
   $F2$ = Technology Impact Factor.

In the derivation of this relationship, the additional assumption made is that the type of particulate control device at the plant impacts the airborne emissions of H_2SO_4 aerosol[EPA].

Supporting information and specific values for the Fuel Impact Factor (F1) and the Technology Impact Factor (F2) are provided in the section below. Following this, applications of this relationship to various plant configurations and sample calculations are provided.

SUPPORTING INFORMATION
Fuel Impact Factor (F1)

In coal-fired electric utility boilers, gaseous sulfur-bearing compounds are generated during the combustion process. The majority of the sulfur in the coal combines with oxygen to form SO_2. However, a small minority of the sulfur is further oxidized to form SO_3. The formation of SO_3 is a complex process that is not thoroughly understood even after many years of investigation [6, 7]. The rate of formation is dependant upon a number of factors such as the sulfur content of the fuel, firing method, amount of excess air, and the presence of some form of catalyst.

Three mechanisms have been proposed to explain the oxidation of SO_2 to SO_3 [8, 9].

1. Oxidation of SO_2 in the flame by atomic oxygen
$$SO_2 + O \leftrightarrow SO_3$$

2. Oxidation of SO_2 by molecular oxygen
$$SO_2 + \frac{1}{2}O_2 \leftrightarrow SO_3$$

3. Catalytic oxidation via molecular oxygen.

This last mechanism is a result of catalytic oxidation of SO_2 to SO_3 by both ash particles and metal heat transfer surfaces. This oxidation occurs at the temperature found in the convective section of utility boilers.

In the literature, varying and sometimes conflicting estimates exist regarding the conversion of SO_2 to SO_3. For example, in one publication the conversion rate is estimated to vary from 3 to 5 percent, from 1.25 to 5 percent, and from 1 to 4 percent, depending on the section of the book being read [10]. In other reports, which focused on the performance of cold-side electrostatic precipitators, the ratio of SO_2 to SO_3 at the air heater outlet is presented. These ratios are lower since a portion of the SO_3 generated during the coal combustion process condenses onto the cold sections of the air heater baskets as the flue gas temperature drops. For example, in one evaluation average flue gas SO_3 concentrations dropped from 25 ppm to 11 ppm (56 percent) across a hot-side electrostatic precipitator and an air heater [11]. Other reports, such as an EPA documented ratio of 0.4 percent [12], confirm these results. The same EPA study reports that the SO_2 levels from six different power stations varied from undetectable levels to 0.67 percent of the SO_2 concentration (Table 1). Other full-scale experimental results based on measurements during 16 field tests showed concentrations ranging from 0.1 to 0.41 percent of the SO_2 levels (Table 2) [13]. In both of these examples, the SO_3 concentrations with western coals were lower than the SO_3 concentrations when burning eastern coals. Laboratory analyses have confirmed the directly proportional relationship between the SO_2 to SO_3 conversion rate and the sulfur content of the fuel [14].

Table 1. SO_2 and SO_3 Measurements from 6 Different Power Plants
At the Air Heater Outlet/ESP Inlet

Station Number	SO_2, ppm	SO_3, ppm	SO_3 / SO_2 ratio
1 (western coal)	262	<1	<0.0038
5 (western coal)	480	<1	<0.0021
13 (western coal)	430	<1	<0.0023
3 (eastern coal)	2440	6-9	0.0025 – 0.0037
4 (eastern coal)	755	2-3	0.0026 – 0.0040
7 (eastern coal)	600	3-4	0.0050 – 0.0067

Table 2. Ratio of SO_3/SO_2 Based on In Situ Measurements for 16 Field Tests
At the Air Heater Outlet/ESP Inlet

	SO_3 / SO_2 ratio	
Coals Burned	average	Standard deviation
9 eastern bituminous coals	0.0041	0.0027
7 western subbituminous and lignite coals	0.0011	0.0005

The threshold determination requires that the total amount of H_2SO_4 aerosol[EPA] *manufactured* during the combustion process be estimated. Since the air heater removes around 50% of the sulfuric acid formed, the threshold calculation should be made on the amount of SO_3 and H_2SO_4 entering the air heater. There is very limited data on the actual amount of SO_3 and H_2SO_4 entering the air heater, however. For the purposes of this estimation procedure, the 56 percent capture in an air heater [10] mentioned earlier and engineering judgement is combined to assume a generic 50% capture of H_2SO_4 in an air heater for bituminous coals. However, the Western bituminous coals and the subbituminous coals produce fly ash that reacts with the SO_3 and which accounts for the lower conversion rates seen in Tables 1 and 2. The low amount of H_2SO_4 in the air heater from these coals' flue gas will substantially increase the sulfuric acid dewpoint. Thus the air heater capture for these fuels is judged to be 10%. More data is being sought to collaborate these air heater capture levels.

Based on the data provided in Tables 1 and 2 along with the air heater capture efficiencies stated above, proposed values for the Fuel Impact Factor (F1) are provided in Table 3. In proposing these factors, corroborating and/or conflicting information regarding the Fuel Impact Factor for these and other fuels is sought. These values should only apply to dry bottom wall-fired and tangentially fired boilers. Cyclone boilers are known to produce higher levels of H_2SO_4, probably because of higher temperatures and more fine fly ash to catalyze the reaction. Thus, cyclones would have higher Fuel Impact Factors.

Table 3. Fuel Impact Factors for Various Coals	
Coal	**F1**
Eastern bituminous	0.008
Western bituminous	0.00111
Powder River Basin	0.000556

Formation of Sulfuric Acid (H_2SO_4)

Sulfur trioxide is a hygroscopic material and will absorb moisture at temperatures well above the its dewpoint, resulting in the formation of a sulfuric acid mist (H_2SO_4) [15, 16, 17]. By definition, a hygroscopic material has solvent properties, and its moisture content will approach equilibrium with the moisture content of the surrounding air. The temperature slightly affects the degree of absorption, but the relative humidity of the surrounding air is the principal property that influences the moisture content of a hygroscopic material. In the flue gas, SO_3 exists as a dry vapor at temperatures above 600°F [18]. At temperatures approximately 400°F, SO_3 and water combine to form sulfuric acid:

$$SO_3 + H_2O \leftrightarrow H_2SO_4$$
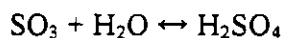
The kinetics of the reaction is fast, ensuring that in the flue gas below 400°F, all of the SO_3 is present as H_2SO_4. Although varying degrees of association occur from 400°F to 600°F, the equilibrium shifts away from the H_2SO_4 as the temperature increases.

Technology Impact Factor (F2)

As mentioned above, the air heaters downstream of a coal-fired boiler will remove some portion of the total H_2SO_4 produced in that plant; the amount removed, however, depends on the coal type being fired. While electrostatic precipitators (ESPs) and baghouses function primarily to remove particulates from the flue gas stream, in the process, they also remove acid gases that have condensed onto the particulate matter. Since hot-side ESPs function at temperatures where SO_3 exists as a dry vapor, no SO_3 condenses in these devices. However, in cold-side ESPs and baghouses, SO_3 condensation occurs. As the flue gas temperature is reduced, SO_3 adsorbs on the fly ash to form an acid layer on the surface of the ash particles that allows electrical currents to flow more easily, thereby lowering the ash resistivity. The amount of SO_3 interacting with the fly ash increases as the temperature falls [19].

Little definitive data are available describing the SO_3/H_2SO_4 collection rate in cold-side particulate collection equipment. However, anecdotal evidence suggests that SO_3 condensation and acid mist collection do occur. For example, in flue gas from the combustion of low-sulfur coal (low native SO_3 concentrations), SO_3 injection systems are used for flue gas treatment to improve particulate collection efficiency. The SO_3 injection rate is controlled to provide optimal performance with minimal SO_3 utilization. In doing this, SO_3 injection is increased to the point where no appreciable increases in ESP performance occur (i.e., no additional H_2SO_4 is being adsorbed by the ash). With respect to baghouses, the dust cake on the bags acts as a barrier filter through

which all H_2SO_4 must pass. It is assumed that a majority of the H_2SO_4 is adsorbed by the fly ash as it passes through the dust cake.

Wet scrubbers tend to remove only a portion of the H_2SO_4 that enters due to the condensation of H_2SO_4 into an acid mist during the quenching of the flue gas. A portion of the nucleated sulfuric acid droplets escapes capture by the alkaline chemicals in the scrubber. A value of 50% capture of sulfuric acid in a wet scrubbing system is suggested for this estimation procedure. However, more data on the range of this value is sought. Conversely, dry scrubbing systems with a baghouse installed tend to remove virtually all of the sulfuric acid from the flue gas. A 1% escape of sulfuric acid is assumed for making this estimate. Again, more data is sought to collaborate this value.

Technology Impact Factors (F2) for ESPs, air heaters, baghouses, and FGD systems are proposed in Table 4. **In sites where multiple devices are installed, the individual factors should be multiplied together to account for the total reduction in H_2SO_4.** This resultant should then be used as the F2 Factor. These factors are engineering estimates based on available data and operational experience. In proposing these factors, corroborating and/or conflicting information is sought.

Table 4. Technology Impact Factors for Control Devices	
Particulate Control Device	**F2**
Air Heater – bituminous coal	0.50
Air Heater – Western bituminous and subbituminous coals	0.90
Hot-side electrostatic precipitator	1.00
Cold-side electrostatic precipitator	0.75
Baghouse	0.10
Wet Scrubber	0.50
Spray Dryer-Baghouse	0.01

The fate of H_2SO_4 collected by these devices depends on whether the device is an air heater, a particulate control device, or an SO_2 scrubbing system. In an air heater, the acid normally condenses on the metal surfaces of the air heater where it can react with the metal to form salts or capture fly ash from the flue gas forming a deposit. Some portion of the H_2SO_4 captured reacts with the fly ash collected to form salts (thus destroying the acid), and the unreacted remainder of the sulfuric acid is present as a liquid mixed with the ash. Similarly, the sulfuric acid collected along with the ash in a cold-side ESP or a baghouse will partially react with the ash to form salts and the unreacted remainder will be a liquid which forms a physical mixture with the fly ash. However, a scrubbing system will typically neutralize all of the H_2SO_4 captured, and the captured acid is destroyed.

Other Impacts

In addition to the factors considered above, the following site-specific characteristics may impact H_2SO_4 emissions rates. These factors are not considered in this proposed method.

1. NOx reduction catalysts. Typically, catalysts used to reduce NOx emissions increase flue gas SO_3 concentrations. Results from a U.S. Department of Energy-sponsored evaluation of several different catalysts treating flue gas from the combustion of high-sulfur U.S. coals reported average SO_3 oxidation levels of 0.31 percent [20].

2. Ammonia injection systems. Ammonia injection systems are used to improve the performance of cold-side electrostatic precipitators and in NOx controls technologies (selective catalytic reduction and selective non-catalytic reduction.) At temperatures below approximately 500° F, ammonia preferentially reacts with SO_3 to form ammonium sulfate and ammonium bisulfate. These reactions can act to reduce the presence of SO_3 (and subsequently H_2SO_4) in the flue gas stream.

3. SO_3 injection systems. SO_3 injection systems (sometimes called sulfur burners) are used to improve the particulate collection capabilities of cold-side electrostatic precipitators. The SO_3 is injected into the flue gas upstream of the ESP. The SO_3 reacts with moisture in the flue gas to create H_2SO_4, which improves the resistivity of the fly ash making it easier to collect. Some of the H_2SO_4 (~1 ppm) generated by the sulfur burners may slip through the ESP resulting in higher plant H_2SO_4 emissions levels.

4. Natural gas co-firing. Since natural gas does not contain sulfur, co-firing or reburning natural gas in a boiler will reduce the amount of SO_3 produced.

H_2SO_4 EMISSIONS PROJECTIONS

Based on the relationship proposed above, trends can be developed which demonstrate the variation in H_2SO_4 aerosol[EPA] emissions levels that occur in coal-fired plants with varying characteristics (Table 5). Unit size and coal-sulfur content will obviously impact the total H_2SO_4 aerosol[EPA] emissions (Figure 1). In both of these cases, the increase (or decrease) in H_2SO_4 aerosol[EPA] is proportional to the change in unit capacity or coal-sulfur content. The type of fuel burned also impacts H_2SO_4 aerosol[EPA] emissions (Figure 2). However, the relationship is not directly proportional to the coal-sulfur content. The heating value of PRB coal is lower that the heating value of most Eastern bituminous coals. As a result, a greater amount of PRB fuel is required to provide a heat input comparable to an Eastern bituminous coal.

Although not shown graphically, a decrease in unit heat rate, an increase in the fuel heat content, and/or a decrease in the capacity factor will decrease aerosol[EPA] emissions of H_2SO_4. The conversion from a hot-side ESP to a cold-side ESP or baghouse also will decrease H_2SO_4 aerosol[EPA] emissions. In the same manner, the conversion from a cold-side ESP to a baghouse will decrease H_2SO_4 aerosol[EPA] emissions.

Table 5. Coal-fired plant characteristics that impact H_2SO_4 aerosol[EPA] emissions

Unit size	100 to 900 MW
Coal sulfur content, %	0.5 – 3.0
Boiler type	Tangentially fired or wall-fired, (dry bottom)
NOx controls	No post-combustion controls
Flue gas treatment	None (no NH_3 injection or sulfur burners)
Heat rate	9,500 Btu/kW-hr
Capacity factor	65 percent
Particulate control	Hot-side ESP, cold-side ESP, or baghouse

Coal Ranks	Eastern Bituminous	Western Bituminous	Powder River Basin
Sulfur content, %	0.5 – 3.0	0.7	0.3
Heating value, Btu/lb	12,000	12,000	8,000
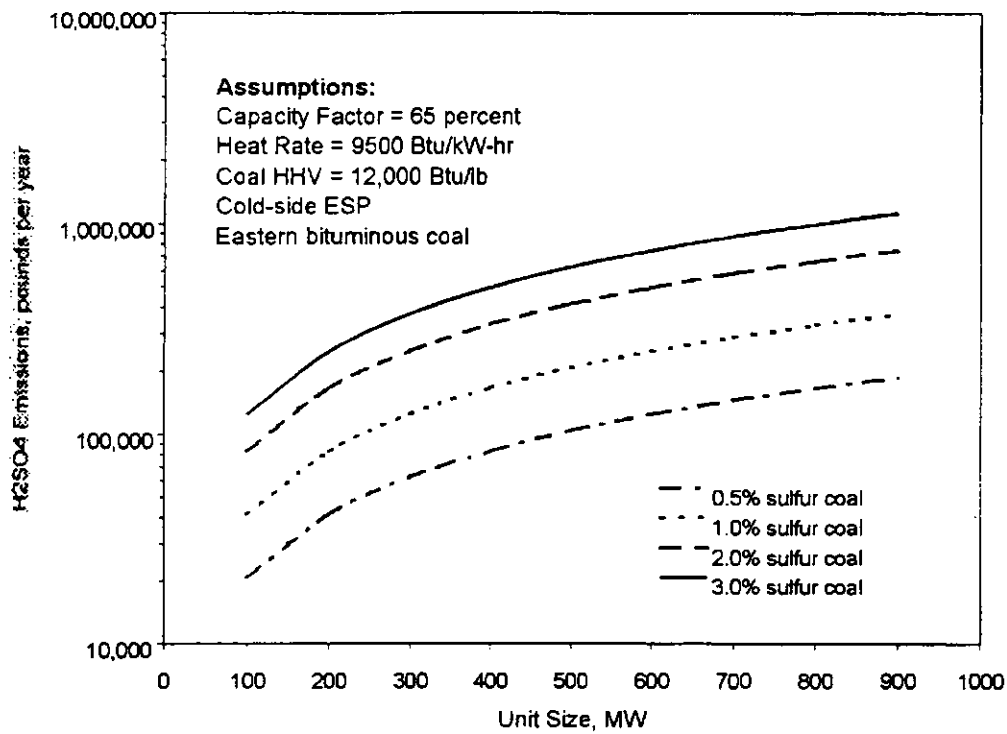
Figure 1. Effect of fuel sulfur content and unit size on H_2SO_4 aerosol[EPA] emissions (log-linear scale)
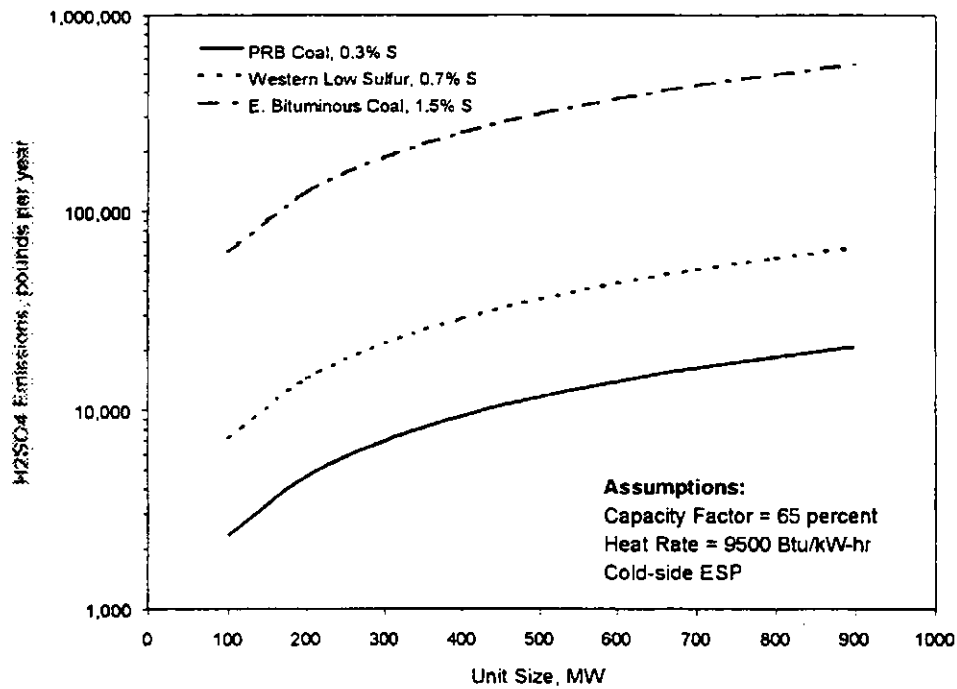

Figure 2. Effect of fuel type on H_2SO_4 aerosol[EPA] emissions (log-linear scale)

Example Calculations

This section presents a series of sample calculations based on the assumptions provided above.

Example 1. A 700-MW coal-fired boiler equipped with a baghouse and a cold-side electrostatic precipitator burns an Eastern bituminous coal. SO_2 emissions are 37,000 tons per year. Flue gas flow reference method site verification testing indicates an average flow resultant angle of $9.2°$.

Solution 1. First, calculate the corrected SO_2 emissions rate. Then, determine if the unit meets the threshold requirement for reporting.

$$E2 = E3 \left[1 - \frac{\left(C_1 R^2 + C_2 R + C_3 \right)}{100} \right]$$

$$E2 = 37,000 \left[1 - \frac{\left((0.0264)(9.2°)^2 + (0.183)(9.2°) + 1.5 \right)}{100} \right]$$

E2 = 34,995 tons SO_2/yr

$E1 = K \bullet F1 \bullet E2$
$E1 = 3063 \bullet 0.008 \bullet 34,995 = 857,517$ lbs H_2SO_4/yr

The amount of H_2SO_4 aerosol[EPA] manufactured by the unit is well over the threshold, therefore, the amount released should be estimated and reported. Incorporate the combined technology factors for the air heater, baghouse, and cold-side ESP into the equation to account for the reductions through these devices. The result is the amount of H_2SO_4 aerosol[EPA] that should be reported on Form R.

$E1' = K \bullet F1 \bullet F2 \bullet E2$
$E1' = 3063 \bullet 0.008 \bullet (0.5 \bullet 0.75 \bullet 0.1) \bullet 34,995 = 32,157$ lbs/yr

Where F2 = Air Heater $\bullet$ Cold-Side ESP $\bullet$ Baghouse
$F2 = (0.5 \bullet 0.75 \bullet 0.1) = 0.0375$

Example 2. A 600-MW coal-fired boiler equipped with a baghouse burns a PRB coal. SO_2 emissions are 14,000 tons per year. The average flow resultant angle is $8.4°$.

Solution 2. Calculate the corrected SO_2 emissions rate. Then determine if the unit meets the threshold requirement for reporting.

$$E2 = E3\left[1 - \frac{\left(C_1 R^2 + C_2 R + C_3\right)}{100}\right]$$

$$E2 = 14,000\left[1 - \frac{\left((0.0264)(8.4^\circ)^2 + (0.183)(8.4^\circ) + 1.5\right)}{100}\right]$$

$E2 = 13,314$ tons SO_2/yr

$E1 = K \bullet F1 \bullet E2$
$E1 = 3063 \bullet 0.000556 \bullet 13,314 = 22,674$ lbs H_2SO_4/yr

The amount of H_2SO_4 aerosol[EPA] produced does not exceed the threshold requirement for reporting. Therefore, the utility is not required to estimate the amount released and does not have to report the emissions from this site on Form R.

Example 3. *(SO₂ tonnage rates are unavailable).* A 250-MW coal-fired boiler equipped with a hot-side electrostatic precipitator burns an Eastern bituminous coal. The flue gas SO_2 concentration is 770 ppm corrected to 3% O_2. The heat input for the unit is 18,993,100 MBtu/year. The average resultant angle is 9.1°.

Solution 3. First, convert SO_2 concentration to an emissions rate [21] and correct for CEM bias. Then, determine if the threshold for H_2SO_4 aerosol[EPA] has been exceeded.

$$SO_2\left(\frac{lb}{MBtu}\right) = \text{Conversion Factor} \bullet \text{Fuel Factor} \bullet SO_2 \text{ Concentration} \bullet O_2 \text{ Correction}$$

$$SO_2\left(\frac{lb}{MBtu}\right) = 1.660 \times 10^{-7}\left(\frac{lb}{scf \cdot ppm}\right) \bullet 9780\left(\frac{scf}{MBtu}\right) \bullet 770 \text{ ppm} \bullet \frac{20.9}{(20.9 - 3)}$$

$SO_2 = 1.46 \quad lb/MBtu$

$$SO_2\left(\frac{tons}{yr}\right) = SO_2\left(\frac{lb}{MBtu}\right) \bullet \text{Heat input}$$

$$SO_2\left(\frac{tons}{yr}\right) = 1.46\left(\frac{lbs}{MBtu}\right) \bullet 18,993,100\left(\frac{MBtu}{yr}\right) \bullet \frac{1}{2000}\left(\frac{ton}{lbs}\right)$$

$SO_2 = 13,800$ tons/yr

$$E2 = E3\left[1 - \frac{\left(C_1 R^2 + C_2 R + C_3\right)}{100}\right]$$

$$E2 = 13,800 \left[1 - \frac{\left((0.0264)(9.1°)^2 + (0.183)(9.1°) + 1.5 \right)}{100} \right]$$

E2 = 13,060 tons SO₂/yr

E1 = K • F1 • E2
E1 = 3063 • 0.008 • 13,060 = 320,022 lbs H₂SO₄/yr

The 25,000 lbs/yr threshold has.been exceeded, therefore a release estimate must be made and the result reported on Form R.

E1' = K • F1 • F2 • E2
E1' = 3063 • 0.008 • (1.0 • 0.5) • 13,060 = 160,011 lbs H₂SO₄/yr

Where F2 = Hot-Side ESP • Air Heater
F2 = (1.0 • 0.5) = 0.5

Example 4. A 500-MW coal-fired boiler equipped with a cold-side electrostatic precipitator and a wet scrubber burns an Eastern bituminous coal. The coal used in the reporting year is 1,126,938 tons with a weighted average sulfur concentration of 2.0%.

Solution 4. First, find SO₂ production rate. Then estimate H₂SO₄ aerosol[EPA] threshold requirement for reporting and calculate emissions if over the threshold limit.

E2 = K1 • K2 • C1 • S1
E2 = 0.02 • 0.95 • 1,126,938 • 2.0 = 42,824 tons SO₂/yr

E1 = K • F1 • E2
E1 = 3063 • 0.008 • 42,824 = 1,049,351 lbs H₂SO₄/yr

The 25,000 lbs/yr aerosol[EPA] threshold has been exceeded, therefore a release estimate must be made and the result reported on Form R.

E1' = K • F1 • F2 • E2
E1' = 3063 • 0.008 • (0.5 • 0.75 • 0.5) • 42,824 = 196,755 lbs H₂SO₄/yr

Where F2 = Air Heater • Cold-Side ESP • Wet Scrubber
F2 = 0.5 • 0.75 • 0.5 = 0.1875

Conclusions

This paper presents a method for predicting both the sulfuric acid aerosol[EPA] *manufacturing* threshold value and the *release* of sulfuric acid aerosol[EPA] from coal-fired power plants. The calculation, limited at present to dry-bottom wall-fired or tangentially-fired boilers, is based on the unit's SO_2 emission rate as recorded by either (1) a continuous emissions monitor and corrected for positive flow bias and for bias due to wall effects or (2) the total coal tonnage burned and the average sulfur content. The method estimates the total amount of sulfuric aerosol[EPA] *manufactured* by using a fixed conversion of SO_2 to SO_3, based on the rank of the coal being burned. The method also predicts the release of sulfuric acid aerosol[EPA] by accounting for the amount of H_2SO_4 captured by the air heater, particulate control device(s), and any flue gas desulfurization equipment installed at the facility. While the process presented herein could have application to any type of coal-fired boiler, the SO_3 conversion rates presented are specific to dry bottom, wall-fired and tangentially-fired boilers. Due to their different combustion characteristics, the H_2SO_4 aerosol[EPA] emissions characteristics of other boiler types may be higher or lower.

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ATTACHMENT 2

ESTIMATING TOTAL SULFURIC ACID EMISSIONS FROM COAL-FIRED POWER PLANTS

ATTACHMENT 3

PROFESSIONAL ENGINEER CERTIFICATION

ATTACHMENT 3

GAINESVILLE REGIONAL UTILITIES
DEERHAVEN GENERATING STATION
UNIT 2 AIR QUALITY CONTROL SYSTEM PROJECT

Professional Engineer Certification

Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:

(1) To the best of my knowledge, the information provided in response to the Department's Request for Additional Information dated March 12, 2007 regarding the Gainesville Regional Utilities (GRU) air construction permit application for the installation of emission control equipment on Deerhaven Generating Station Unit 2 is true, accurate, and complete based on my review of material provided by GRU engineering and environmental staff; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this submittal are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of air pollutants not regulated for an emissions unit, based solely upon the materials, information and calculations provided with this certification.

_____   3/29/07
Signature   Date

Thomas W. Davis, P.E.

(seal)