LANSING SMITH ELECTRIC GENERATING PLANT

UNITS 1 AND 2
FIVE-FACTOR BEST AVAILABLE RETROFIT TECHNOLOGY ANALYSIS

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

The Lansing Smith Electric Generating Plant (Plant Smith) located in Southport, Bay County, Florida, includes two coal-fired steam generators (Units 1 and 2), which are best available retrofit technology (BART)-eligible. With respect to the Regional Haze Rule (RHR) BART requirements, the U.S. Environmental Protection Agency (EPA) previously determined that emissions sources subject to the Clean Air Interstate Rule (CAIR) sulfur dioxide (SO_2) and nitrogen oxide (NO_x) trading programs would achieve SO_2 and NO_x emissions reductions that would result in visibility improvement that is better than BART; therefore, these two pollutants would not need to be addressed in BART determinations. Due to legal challenges to CAIR, EPA issued a final rule on July 6, 2011, to replace CAIR; i.e., the Cross-State Air Pollution Rule (CSAPR). For Florida electrical generating units (EGUs), CSAPR only addresses ozone season NO_x emissions. However, on December 30, 2011, the court stayed CSAPR and left CAIR in effect pending judicial review. Accordingly, Units 1 and 2 remain subject to CAIR, which, for Florida EGUs, addresses SO_2 and NO_x (both annual and ozone season).

Although Plant Smith Units 1 and 2 remain subject to CAIR and EPA has determined that both CAIR and CSAPR will result in visibility improvement that is better than BART, due to the regulatory uncertainty with CAIR and CSAPR, the Florida Department of Environmental Protection (FDEP) requested the submittal of a five-factor BART analysis for Plant Smith Units 1 and 2 for SO_2, NO_x, and particulate matter (PM). Gulf Power Company has prepared this BART analysis in response to the FDEP's request.

This submission is made in a cooperative effort to address RHR implementation issues resulting from recent regulatory developments related to EPA's CAIR and its successor, CSAPR. CSAPR is currently stayed, and CAIR remains in effect, pending judicial review of CSAPR. Depending on the court's decision on CSAPR, Gulf Power Company may revisit, revise, or withdraw this analysis and proposal.

1.2 SUMMARY

The five-factor BART analysis for Plant Smith Units 1 and 2 for each pollutant is summarized in the following paragraphs.

1.2.1 SO_2 BART

Section 4.0 provides the SO_2 BART analysis for Plant Smith Units 1 and 2. SO_2 retrofit control technologies evaluated include: (a) switch to lower sulfur Colombian coal, (b) dry sorbent injection (DSI) with use of lower sulfur Colombian coal, (c) dry flue gas desulfurization (DFGD) lime spray dryer absorber (SDA), and (d) wet flue gas desulfurization (WFGD). All of the identified available retrofit SO_2 control technologies are considered technically feasible for Units 1 and 2. However, DFGD lime SDA is considered an inferior technology compared to WFGD and was not evaluated further.

The proposed SO_2 BART determination for Plant Smith Units 1 and 2 is an SO_2 emissions rate of 0.74 pound per million British thermal units (lb/MMBtu) on a 30-day rolling average basis, which can be achieved with the use of DSI with trona as the alkaline reagent. The proposed BART SO_2 control technology will be installed and in operation no later than the Mercury and Air Toxics Standard (MATS) compliance deadline prior to the end of the first 10-year RHR planning period in 2018.

The DSI (trona) plus Colombian coal option represents the best level of control based on consideration of the statutory factors required by Section 169A(g)(7) of the Clean Air Act. A comprehensive evaluation of the three factors most relevant to the Plant Smith Units 1 and 2 BART SO_2 analysis (i.e., cost of compliance, energy and nonair-quality environmental impacts, and degree of improvement in visibility) leads to the conclusion that the DSI (trona) plus Colombian coal option is the best option due to its substantially lower cost, decreased energy cost, nonair-quality impacts, and the minimal additional visibility improvement that would occur with WFGD.

1.2.2 NO_x BART

Section 5.0 provides the NO_x BART analysis for Plant Smith Units 1 and 2. Plant Smith Units 1 and 2 are currently equipped with low-NO_x burner tips (LNBt) with high-momentum injection ports, and Unit 2 has low-NO_x burners (LNBs) with an overfire air control system. In addition to LNB technology, both units have selective non-catalytic reduction (SNCR) for additional NO_x control. These NO_x combustion controls were installed in response to CAIR. Since Units 1 and 2 are currently equipped with NO_x combustion controls and SNCR, this suite of NO_x controls served as the baseline, and the focus of the NO_x BART analysis for Units 1 and 2 was confined to the evaluation of selective catalytic reduction (SCR) technology.

The proposed NO_x BART determination for Plant Smith Units 1 and 2 is no additional control, with continued use of the existing NO_x combustion controls and SNCR with emissions limits specified by the current Plant Smith Title V air operation permit.

The existing NO_x combustion controls and SNCR represents the best level of control based on consideration of the statutory factors required by Section 169A(g)(7) of the Clean Air Act. Based on a comprehensive evaluation of the three factors particularly relevant to the Plant Smith Units 1 and 2 BART NO_x analysis (i.e., cost of compliance, existing pollution control technology in use at the source, and degree of improvement in visibility), the existing suite of NO_x controls is the best option due to the substantial cost and little, or no, additional visibility improvement of the SCR alternative.

1.2.3 PM BART

Section 6.0 provides the PM BART analysis for Plant Smith Units 1 and 2. Plant Smith Units 1 and 2 are equipped with highly efficient hot and cold side electrostatic precipitators (ESPs) that achieve very low PM emissions rates. The existing PM controls served as the baseline and the focus of the PM BART analysis for Units 1 and 2 was confined to the evaluation of fabric filter (i.e., baghouse) technology.

The proposed PM BART determination for Plant Smith Units 1 and 2 is no additional control and continued use of the existing hot and cold side ESPs, with the emissions limits specified by the current Plant Smith Title V air operation permit.

The existing hot and cold side ESPs represents the best level of control based on consideration of the statutory factors required by Section 169A(g)(7) of the Clean Air Act. Based on a comprehensive evaluation of the three factors most relevant to the Plant Smith Units 1 and 2 BART PM analysis (i.e., cost of compliance, existing pollution control technology in use at the source, and degree of improvement in visibility), the existing PM controls is the best option due to the substantial cost and little, if any, additional visibility improvement of the fabric filter alternative.

Following this introduction and summary, Section 2.0 provides a description of Units 1 and 2 and baseline conditions. Section 3.0 discusses the BART regulatory requirements. The Plant Smith BART analysis for Units 1 and 2 for SO_2 is provided in Section 4.0, for NO_x in Section 5.0, and for PM in Section 6.0. Appendices A and B contain the BART modeling protocol and modeling files, respectively.

2.0 DESCRIPTION OF UNITS 1 AND 2 AND BASELINE CONDITIONS

Plant Smith is located at 4300 County Road 2300 in Southport, Bay County, Florida. Plant Smith consists of two coal-fired steam generators (EU-001 and EU-002), two simple-cycle peaking units (EU-003), and two combined-cycle combustion turbines (EU-004 and EU-005). Operation of Plant Smith is currently authorized by FDEP Title V Air Operation Permit No. 0050014-018-AV, issued with an effective date of January 1, 2010, and an expiration date of December 31, 2014.

Information regarding the Units 1 and 2 process, emissions controls, permit emissions limits, and historical emissions rates is provided in the following subsections.

2.1 PROCESS DESCRIPTION

Units 1 and 2 are tangentially-fired, dry-bottom boilers that began commercial operation on May 12, 1965 (Unit 1), and April 9, 1967 (Unit 2); i.e., have been in service for 47 and 45 years, respectively. Units 1 and 2 have generation capacities of 175 and 205 megawatts (MW), respectively. Authorized fuels for Units 1 and 2 include coal, No. 2 fuel oil, and on-specification used oil. No. 2 fuel oil is only used during start-ups and for flame stabilization. Combustion of on-specification used oil is limited to no more than 50,000 gallons per calendar year per boiler. Onsite generated oil-contaminated soil is also periodically combusted for energy recovery. Each boiler may inject up to 420 pounds per hour of sodium carbonate to reduce visible emissions if necessary to comply with applicable opacity standards.

Unit 1 has maximum authorized heat input rates of 1,944.8 million British thermal units per hour (MMBtu/hr) for coal, and 153 MMBtu/hr for No. 2 fuel oil and on-specification used oil. Maximum authorized heat input rates for Unit 2 are 2,246.2 MMBtu/hr for coal and 76 MMBtu/hr for No. 2 fuel oil and on-specification used oil. Compliance with these heat input limits is demonstrated through the use of composite fuel samples. As noted in the permitting note to Condition A.32 of Title V Air Operation Permit No. 0050014-018-AV, continuous monitoring conducted pursuant to the Acid Rain Program (ARP) conservatively overestimates actual heat input rates.

Units 1 and 2 share a common stack and also share common continuous emissions monitoring systems (CEMS) for NO_x and SO_2 and a continuous monitor for carbon dioxide (CO_2). Each unit is equipped with a continuous opacity monitoring system (COMS).

2.2 EMISSIONS CONTROLS

Units 1 and 2 are each equipped with hot and cold side ESPs for controlling PM emissions. For NO_x control, Unit 1 uses LNBt with high momentum injection ports, and Unit 2 has LNBs with an overfire air control system. In addition to LNB technology, both units have SNCR for additional NO_x control.

2.3 REGULATORY REQUIREMENTS

Units 1 and 2 are subject to ARP requirements for NO_x and SO_2. Units 1 and 2 each have multiyear Phase II NO_x averaging plans. Units 1 and 2 are subject to the ARP SO_2 emissions allowance requirements.

Units 1 and 2 were also subject to the requirements of CAIR. Due to legal challenges to CAIR, EPA issued a final rule on July 6, 2011, to replace CAIR; i.e., CSAPR. For Florida EGUs, CSAPR only addresses ozone season NO_x emissions. However, on December 30, 2011, the court stayed CSAPR and left CAIR in effect pending judicial review. Accordingly, Units 1 and 2 remain subject to CAIR, which, for Florida EGUs, addresses SO_2 and NO_x (both annual and ozone season).

In addition, Units 1 and 2 are also subject to the recently adopted National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for coal-fired steam EGUs codified as Chapter 40, Part 63, Subpart UUUUU, Code of Federal Regulations (CFR). This rule, also known as the MATS or utility maximum achievable control technology (MACT), was issued with an effective date of April 16, 2012, and requires the installation of MACT. For existing coal-fired EGUs, MATS contains emissions limits for filterable PM (or total nonmercury hazardous air pollutant [HAP] metals or individual HAP metals), hydrogen chloride, and mercury. As alternatives to the filterable PM emissions limit, existing EGUs may comply with a total nonmercury HAP metals emissions limit or emissions limits for individual HAP metals. As an alternative to the hydrogen chloride emissions limit, existing coal-fired EGUs equipped with a flue gas desulfurization (FGD) system and an SO_2 CEMS may comply with a surrogate emissions limit for SO_2. The MATS compliance deadline for existing EGUs is April 16, 2015, with the possibility of two 1-year extensions.

Units 1 and 2 are subject to the requirements of the specific conditions of Title V Air Operation Permit No. 0050014-018-AV, including hourly heat input rate limits and emissions limits for SO_2, NO_x, and PM; these emissions limits are discussed in Section 2.4. The regulatory requirements associated with the RHR and BART are discussed in Section 3.0

2.4 PERMIT EMISSIONS LIMITS

Table 2-1 summarizes Units 1 and 2 emissions limits for SO_2, NO_x, and PM contained in Title V Air Operation Permit No. 0050014-018-AV.

2.5 HISTORICAL EMISSIONS RATES

Table 2-2 provides a summary of SO_2 and NO_x emissions rates for the 3-year 2003 through 2005 baseline period based on data obtained from the EPA Clean Air Markets Division (CAMD) Website.

2.6 BASELINE VISIBILITY IMPACTS

Modeling of Plant Smith Units 1 and 2 baseline (2003 through 2005) visibility impacts at the St. Marks National Wildlife Refuge (NWR) was conducted in accordance with the BART modeling protocol submitted to FDEP on May 30, 2012. The protocol was approved by FDEP in an e-mail from Mr. Tom Rogers dated June 6, 2012. The St. Marks NWR is the only Class I area subject to the RHR that is located within 300 kilometers of Plant Smith.

Table 2-1. Plant Smith Permit Emissions Limits

Pollutant	Units	Unit 1	Unit 2	Units 1 and 2
SO_2	lb/MMBtu	2.10*	2.70*	4.5*
NO_x	lb/MMBtu	0.62†	0.44†	N/A
	tpy	N/A	N/A	4,700‡
PM	lb/MMBtu	0.1§	0.1§	N/A
	lb/MMBtu	0.3£	0.3£	N/A

Note: lb/MMBtu = pound per million British thermal units.
tpy = ton per year.

*24-hour average.
†Annual average, ARP Phase II NO_x Averaging Plans; 2010 through 2013.
‡Rolling 12-month total.
§Steady-state operation.
£Soot blowing and load change.

Source: FDEP, 2012.

Table 2-2. Plant Smith Units 1 and 2 Baseline (2003 through 2005) Emissions Rates

Parameter	Units	2003	2004	2005	Average
Unit 1					
Heat input	MMBtu/yr	10,493,287.8	12,866,997.4	13,315,560.3	12,225,281.8
SO_2 emissions	tpy	6,671.1	9,709.3	9,754.4	8,711.6
	lb/MMBtu	1.27	1.51	1.47	1.42
NO_x emissions*	tpy	1,764.53	2,159.50	2,217.28	2,047.10
	lb/MMBtu	0.34	0.34	0.33	0.34
Unit 2					
Heat input	MMBtu/yr	10,554,145.3	15,185,196.2	12,830,353.2	12,856,564.9
SO_2 emissions	tpy	7,498.5	11,404.0	8,758.8	9,220.4
	lb/MMBtu	1.42	1.50	1.37	1.43
NO_x emissions*	tpy	1,421.13	2,075.03	1,691.30	1,729.15
	lb/MMBtu	0.27	0.27	0.26	0.27

Note: lb/MMBtu = pound per million British thermal units.
tpy = ton per year.

*Adjusted to reflect 30-percent removal due to SNCR controls.

Source: EPA Clean Air Markets Division (CAMD) Website, 2012.

Table 2-3 provides a summary of the St. Marks NWR baseline model results. The baseline modeling shows that Units 1 and 2 at Plant Smith cause a 1.58-deciview (dv) visibility impairment on the highest of the three annual 8th highest days over the 2003 through 2005 period modeled. SO_2 is the predominant pollutant with respect to visibility impacts, comprising 94.8 percent of the total. Visibility impacts due to NO_x, and particulate matter less than or equal to 10 micrometers (PM_{10}) emissions comprise 3.9 and 1.3 percent of the total impact, respectively.

Table 2-3. Plant Smith Units 1 and 2 Baseline Visibility Impacts—St. Marks NWR

Parameter	Units	Year of Meteorology 2001	2002	2003	Maximum
8th highest change in visibility (SO_2, NO_x, PM_{10})	delta deciviews	1.58	1.18	1.53	1.58
Pollutant contributions					
SO_2 emissions (SO_4)	delta deciviews	1.50	1.16	1.50	1.50
	% of total	94.8	98.3	98.3	94.8
NO_x emissions (NO_3 + NO_2)	delta deciviews	0.062	0.010	0.013	0.062
	% of total	3.9	0.82	0.86	3.9
PM_{10} emissions (OC + EC + PMC + PMF)	delta deciviews	0.020	0.010	0.013	0.020
	% of total	1.3	0.84	0.87	1.3

Parameter	Units	2001 through 2003
22nd highest change in visibility (SO_2, NO_x, PM_{10})	delta deciviews	1.40
Pollutant contributions		
SO_2 emissions (SO_4)	delta deciviews	1.27
	% of total	90.5
NO_x emissions (NO_3 + NO_2)	delta deciviews	0.12
	% of total	8.4
PM_{10} emissions (OC + EC + PMC + PMF)	delta deciviews	0.016
	% of total	1.2

Note: PM_{10} = particulate matter less than or equal to 10 micrometers.
OC = organic carbon.
EC = elemental carbon.
PMC = coarse PM.
PMF = fine PM.

Source: SCS, 2012.

3.0 BEST AVAILABLE RETROFIT TECHNOLOGY REQUIREMENTS

The 1977 Clean Air Act Amendments established a national goal of “preventing future, and remedying existing, visibility impairment” in 156 national parks and wilderness areas referred to as “mandatory Class I federal areas.” In response to this congressional mandate, EPA issued a rule addressing regional haze on July 1, 1999. The RHR (also known as the Clean Air Visibility Rule [CAVR]) sets a long-term ultimate goal of returning visibility in the Class I areas to “natural conditions” by the year 2064.

A key component of the 1999 RHR is a requirement for existing emissions sources (i.e., those determined to cause or contribute to visibility impairment in the mandatory Class I areas) to install BART. The RHR requires an analysis of visibility impacts for BART-eligible emissions units. Amendments to the 1999 RHR were issued on July 6, 2005, which provided guidance on determining source-specific BART determinations. These amendments are commonly referred to as the BART Rule. The BART Rule lists the following three steps in establishing BART emissions limitations:

- Identify sources that are BART-eligible.
- Determine if a BART-eligible source may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area (i.e., determine which sources are subject to BART).
- For each source subject to BART, identify the appropriate type and level of control for reducing emissions.

Plant Smith Units 1 and 2 are BART-eligible emissions sources since these units meet the following criteria:

- They are included in one of 26 defined source categories (i.e., the steam electric plant category).
- Units began operation after August 7, 1962, and were in existence on August 7, 1977.

- Units combined have potential emissions of 250 tons per year (tpy) or more of any single visibility impairing pollutant (SO_2, NO_x, PM_{10}, or volatile organic compounds).

The RHR implementing regulations are found in 40 CFR 51, Subpart P, Protection of Visibility. Regulatory guidance regarding BART determinations is provided in Appendix Y of 40 CFR 51, Guidelines for BART Determinations Under the RHR.

The five statutory factors required by Section 169A(g)(7) of the Clean Air Act that must be considered when making BART determinations are:

- Costs of compliance.
- Energy and nonair-quality environmental impacts of compliance.
- Existing pollution control technology in use at the source.
- Remaining useful life of the source.
- Degree of improvement in visibility, which may reasonably be anticipated to result from the use of such technology.

The BART Rule lists the following five basic steps of a case-by-case BART review:

- Step 1—Identify all available retrofit control technologies.
- Step 2—Eliminate technically infeasible options.
- Step 3—Evaluate control effectiveness of remaining control technologies.
- Step 4—Evaluate impacts and document the results.
- Step 5—Evaluate visibility impacts.

With respect to the RHR BART requirements, EPA previously determined that emissions sources subject to the CAIR SO_2 and NO_x trading programs would achieve SO_2 and NO_x emissions reductions that would result in visibility improvement that is “better than BART;” therefore, these two pollutants would not need to be addressed in BART determinations. Due to legal challenges to CAIR, EPA issued a final rule on July 6, 2011, to replace CAIR; i.e., CSAPR. For Florida EGUs, CSAPR only addresses ozone season NO_x emissions. However, on December 30, 2011, the court stayed CSAPR and left CAIR in effect pending judicial review. Accordingly, Units 1 and 2 remain subject to CAIR, which, for Florida EGUs, addresses SO_2 and NO_x (both annual and ozone season).

In December 2011 EPA proposed to consider EGUs subject to CSAPR to have emissions reductions that will result in visibility improvement that is better than BART. On June 7, 2012, EPA issued a final rule on this topic. In its final rule, EPA concluded that emissions sources subject to either the CSAPR annual or ozone season NO_x trading programs will result in visibility improvement that is better than BART. Accordingly, even under CSAPR, Florida's RHR State Implementation Plan (SIP) would not need to require affected BART-eligible EGUs to install, operate, and maintain BART for emissions of NO_x to receive EPA SIP approval, since Florida would participate in the CSAPR ozone season NO_x cap-and-trade program.

For Florida EGUs, both CAIR and CSAPR address NO_x emissions. For CAIR, EPA has determined that the CAIR NO_x trading program achieves NO_x emissions reductions that would result in visibility improvement that is better than BART; therefore, this pollutant does not need to be addressed in BART determinations. Similarly, EPA has issued a final determination that the CSAPR NO_x trading program also achieves NO_x emissions reductions that would result in visibility improvement that is better than BART. Accordingly, a BART analysis for NO_x for Plant Smith Units 1 and 2 is not required, because the units are currently subject to CAIR and would also be subject to CSAPR if the court upholds it. However, due to the uncertainty with CSAPR and at the request of FDEP, the Plant Smith BART analysis for Units 1 and 2 includes an analysis for NO_x.

The regulatory situation is different for SO_2, because only CAIR addresses this pollutant for Florida EGUs; i.e., CSAPR would not require Florida to participate in a SO_2 trading program. CAIR currently remains in effect and therefore a BART analysis for SO_2 is not required. However, if CSAPR goes into effect without revision or modification, the better-than-BART exclusion would not apply, and a BART SO_2 analysis would be required. Due to this regulatory uncertainty and at the request of FDEP, the Plant Smith BART analysis for Units 1 and 2 includes an analysis for SO_2.

Pursuant to the RHR, a BART-eligible source may be exempt from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. A BART-eligible emissions source that is responsible for a 1.0-dv change in visibility is considered to cause visibility impairment. A BART-eligible emissions source that is responsible for a 0.5-dv change in visibility is considered to contribute to visibility impairment. Since a BART-eligible source that causes visibility impairment will also contribute to visibility impairment, the 0.5-dv visibility impairment contribution test is the constraining metric for determining whether a BART-eligible source is exempt from the BART requirements. The 0.5-dv visibility impairment contribution criterion was adopted by FDEP in their RHR SIP, which EPA proposed to approve on May 25, 2012.

Gulf previously submitted a BART exemption modeling report for Plant Smith in December 2006. Since EGUs participating in the CAIR trading program also satisfy BART requirements for those pollutants addressed by CAIR (i.e., SO_2 and NO_x), the BART modeling for Plant Smith Units 1 and 2 was allowed to be confined to PM_{10} emissions. The modeling analysis demonstrated that Plant Smith Units 1 and 2 visibility impacts are well below the 0.5-dv change in visibility contribution threshold stated in 40 CFR 51, Appendix Y, BART Guidelines; i.e., the highest change in visibility was determined to be 10 times lower than the 0.5-dv BART exemption criterion. Therefore, Plant Smith Units 1 and 2 were not subject to BART. However, this exemption from PM_{10} BART would not apply under CSAPR since the exemption visibility modeling would then need to evaluate SO_2 and NO_x in addition to PM_{10}. As presented in Section 2.6, modeling of Plant Smith Units 1 and 2 baseline (2003 through 2005) emissions shows that the change in visibility due to all three pollutants (i.e., SO_2, NO_x, and PM_{10}) exceeds the 0.5-dv BART exemption threshold; therefore, Units 1 and 2 would be subject to BART. Accordingly, due to the regulatory uncertainty with CAIR and CSAPR and at the request of FDEP, the Plant Smith BART analysis for Units 1 and 2 includes an analysis for SO_2 (Section 4.0), NO_x (Section 5.0), and PM (Section 6.0).

4.0 SULFUR DIOXIDE BART EVALUATION

An SO_2 BART analysis for Plant Smith Units 1 and 2 using the five-factor approach discussed in Section 3.0 is provided in the following subsections.

4.1 IDENTIFICATION OF AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Available retrofit SO_2 control technologies were identified by reviewing information from a variety of sources including: (a) Gulf Power Company's and Southern Company's extensive experience regarding the evaluation and installation of retrofit SO_2 emissions controls; (b) EPA's Clean Air Technology Center, which includes the reasonably achievable control technology (RACT)/best available control technology (BACT)/lowest achievable emission rate (LAER) Clearinghouse (RBLC); (c) recent BART analyses for coal-fired steam boilers; (d) the EPA Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual; and (e) pertinent EPA technical documents (e.g., EPA's Controlling SO_2 Emissions: A Review of Technologies).

Based on a comprehensive review of SO_2 control technologies, the following retrofit SO_2 control technologies were identified as being available for Units 1 and 2:

- Switch to lower sulfur Colombian coal.
- DSI with use of lower sulfur Colombian coal.
- DFGD lime SDA.
- WFGD.

As previously discussed in Section 2.3, Units 1 and 2 are subject to the requirements of NESHAPs, Subpart UUUUU, MATS (or utility MACT). To comply with this regulation, Gulf Power Company is evaluating a switch to a lower sulfur Colombian coal and installation of DSI using lime as the reagent for hydrogen chloride control on or before the MATS compliance deadline. DSI with lime injection is a potential option to meet the MATS hydrogen chloride emissions limit but would provide little if any SO_2 reduction beyond that related to switching to Colombian coal. Accordingly, the BART analysis for the DSI with use of lower sulfur Colombian coal option evaluated the differences between this option (which may occur regardless of BART) and DSI using an alternative sorbent, highly reactive trona, instead of lime as the alkaline reagent to obtain an additional 30-percent removal of SO_2 beyond that related to switching to Colombian coal.

With the exception of the switch to lower sulfur Colombian coal (which is categorized as a pollution prevention technology), all of the SO_2 control technologies listed previously are categorized as once-through controls, since the captured SO_2 is permanently bound by the sorbent and must be disposed of as either a solid waste or used as a byproduct; e.g., gypsum. The available retrofit SO_2 control technologies are discussed in the following subsections.

4.1.1 SWITCH TO LOWER SULFUR COLOMBIAN COAL

The switch to a Colombian coal will reduce SO_2 emissions compared to baseline coal due to its lower sulfur content. No modifications to Units 1 and 2 are required to combust Colombian coal. As noted previously, the switch to Colombian coal is being evaluated as a possible component of the MATS compliance plan for Units 1 and 2.

4.1.2 DSI WITH USE OF LOWER SULFUR COLOMBIAN COAL

DSI is another once-through DFGD technology that uses an alkaline reagent to absorb SO_2. Typical alkaline sorbents used in DSI systems include hydrated lime, the mineral trona (sodium sesquicarbonate), and sodium bicarbonate. Hydrated lime is the least reactive reagent resulting in relatively low SO_2 removal efficiencies even at high injection rates. Although more expensive than lime, trona is highly reactive and can be used to achieve a range of SO_2 removal efficiencies depending on the amount injected and the boiler flue gas SO_2 concentration.

DSI control technology injects the alkaline reagent directly into the boiler flue gas in the ductwork between the air heater and the particulate collection device. No water is added to the lime or limestone or directly to the process. The sulfite/sulfate salts reaction products are then removed by a downstream PM control device.

Since a gas/sorbent contacting vessel is not required, DSI capital costs are lower, less physical space is required, and exhaust duct modifications are simpler compared to a DFGD lime SDA system. However, reagent costs are higher and SO_2 control efficiencies lower.

As noted previously, DSI with lime as the alkaline reagent is under consideration as a component of the MATS compliance approach for Units 1 and 2. Accordingly, the BART analysis for DSI evaluated the use of highly reactive trona instead of lime to achieve further reductions in SO_2 emissions.

4.1.3 DFGD LIME SDA

In a DFGD system, boiler flue gas mixes in a spray dryer with a mist of atomized fresh lime slurry. The types of DFGD systems typically installed on coal-fired boilers are those utilizing either an SDA or a circulating dry scrubber (CDS). SDA controls have typically been employed on smaller boilers that combust lower sulfur coals and where water resources are limited.

The most common form of DFGD control technology installed at coal-fired boilers is a semidry scrubbing system that uses an SDA and lime as the alkaline reagent. Fresh lime slurry is prepared in a slaker (most often a ball mill) to produce a slurry with the design concentration of solids. In the SDA, the slaked lime slurry is sprayed into the boiler flue gas. The liquid droplet sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried (i.e., water evaporated) by heat contained in the flue gas and then removed as a dry powder by a downstream PM control device. The reaction chemistry is similar to that described in Section 4.1.4 for WFGD technology.

For retrofit applications there must be adequate space to install the SDA upstream of the existing PM control device. In addition, a mixture of unreacted lime/flyash is recycled to the SDA reagent feed tank to provide efficient reagent utilization, resulting in a significant increase in PM loading on the downstream PM control device. For retrofit applications, the recycling of unreacted lime/flyash will require an increase in the capacity of the existing PM control device (or replacement; e.g., a post-SDA baghouse) and redesign of the flyash handling system. Lime SDA technology is typically employed on low to medium sulfur coals.

CDS technology removes SO_2 by reaction with hydrated lime similar to that described previously for lime SDA controls. The technology system includes a CDS vessel, adsorbent preparation and injection, water injection, product recycle injection, and a flue gas recycle system. Flue gas first passes through a group of venturi nozzles. The venturi nozzles serve to accelerate the flue gas just prior to the injection of high-pressure water, recycled solids, and adsorbent (i.e., lime). The reactor acts as a fluidized bed, assuring maximum contact between the pollutants in the flue gas and the adsorbent solids. The reactor is characterized by high turbulences and optimal chemical and physical heat and mass transfer rates. Water is added to bring the flue gas closer to the saturation temperature where SO_2 absorption is most effective. The high dust load leaving the reactor is captured in a downstream PM control device. To assure a high level of SO_2 removal, a portion of the solid products exiting the CDS vessel (i.e., primarily reaction products such as calcium sulfite [$CaSO_3$], calcium sulfate [$CaSO_4$], calcium carbonate [$CaCO_3$], calcium chloride [$CaCl_2$], and calcium fluoride [CaF_2] and inerts) are separated from the flue gas by the downstream PM control device and recycled to the CDS vessel inlet at a high ratio to the inlet solids. For retrofit installations, CDS technology has the same concerns expressed for lime SDA technology with respect to adequate available space upstream for the CDS equipment and need for a larger capacity (or replacement) PM control device.

4.1.4 WFGD

WFGD systems remove SO_2 from exhaust streams by contacting the flue gas with an alkaline reagent in an absorber to form sulfite and sulfate salts. WFGD scrubbers installed on coal-fired boilers often employ counterflow vertically oriented spray towers and either limestone or lime as the alkaline reagent. The primary advantage of limestone versus lime as the WFGD reagent is the significantly lower cost of limestone.

The alkaline reagent (e.g., limestone) is crushed into a fine powder using a ball mill to achieve a design particle size distribution. The fine powder is next mixed with water to form a slurry in a slurry preparation tank and then pumped to the spray tower reaction tank.

In the counterflow spray tower, boiler flue gas flows upward, and limestone slurry is sprayed downward by an array of spray nozzles. In the absorber, SO_2 is removed by both sorption and reaction with the slurry. Reactions initiated in the absorber are completed in a reaction tank, which provides retention time for the finely ground limestone particles to dissolve and to react with the dissolved SO_2. The primary WFGD chemical reactions are shown by the following equations:

Limestone: $CaCO_3$ (solid) + SO_2 (gas) → $CaSO_3$ (solid) + CO_2 (gas)
Lime: $Ca(OH)_2$ (solid) + SO_2 (gas) → $CaSO_3$ (solid) + H_2O (liquid)

The calcium sulfate reaction product can also be further oxidized to produce saleable gypsum in a process called limestone force oxidation (LSFO) as shown by the following equation:

LSFO: $CaSO_3$ (solid) + H_2O (liquid) + $\frac{1}{2}O_2$ (gas) → $CaSO_4$ (solid) + H_2O

Key WFGD process design variables include flue gas flow rate, liquid-to-gas ratio, recycle slurry pH, flue gas SO_2 concentration, and solids concentration and retention time. WFGD systems are typically located downstream of any PM control system; e.g., ESPs. Entrained slurry droplets that escape from the absorber's spray zone and are carried out by the flue gas are separated in an impaction-type mist eliminator. Induced draft fans are typically used to pull the boiler flue gas through the WFGD spray tower absorbers before the flue gas exits through the stack.

WFGD controls are most effective when used to remove SO_2 from the combustion of high sulfur coals. When installed as a retrofit technology, WFGD controls also require the use of a new stack due to corrosion concerns. Adequate space must be available for the ancillary equipment associated with WFGD systems including reagent grinding and slurry preparation, dry reagent storage area and reagent slurry storage tanks, and gypsum dewatering, storage, and handling equipment.

4.2 ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

All of the identified available retrofit SO_2 control technologies are considered technically feasible for Units 1 and 2. However, DFGD lime SDA is considered an inferior technology compared to WFGD and is not evaluated further for the following reasons:

- WFGD will achieve higher SO_2 removal rates (i.e., 95 versus 90 percent) and consequently lower SO_2 emissions.
- DFGD lime SDA technology is difficult to apply as a retrofit to existing boilers due to space considerations; i.e., the SDA must be located upstream of the existing PM control device.
- Due to increased PM loading, the capacity of the existing PM control device would need to be increased significantly or, more likely, completely replaced with a baghouse.
- Due to installation issues and the need to upgrade or replace existing PM controls, there has been limited application of DFGD lime SDA technology to existing coal-fired boilers.
- With the inclusion of the cost of a baghouse for the DFGD lime SDA option, WFGD will achieve greater emissions reductions at a lower cost compared to the DFGD lime SDA system.

4.3 EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

Table 4-1 summarizes estimated ranges of removal efficiencies for the remaining available SO_2 retrofit control technologies.

4.4 EVALUATE IMPACTS AND DOCUMENT THE RESULTS

With respect to impact analyses, the EPA BART guidelines list the following five factors:

- Cost of compliance.
- Energy impacts.
- Nonair-quality impacts.
- Remaining useful life.
- Degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology.

Table 4-1. Control Effectiveness of SO_2 Control Technologies

SO_2 Control Technology	Control Efficiency (% SO_2 removal)	Control Efficiency Assumed for Units 1 and 2 (% SO_2 removal)
Colombian coal	N/A	25
DSI plus Colombian coal	40 to 60	48
WFGD	80 to 95	95

Source: ECT, 2012.

Each of the first four of these factors is addressed in the following subsections, while Section 4.5 addresses the visibility improvement factor.

4.4.1 COST OF COMPLIANCE

Economic analyses were developed for the DSI plus Colombian coal and WFGD options. No additional costs are associated with the switch to Colombian coal. Since the capital cost of DSI and the operation and maintenance (O&M) costs associated with lime injection will be incurred as a possible component of the MATS compliance plan, additional cost associated with the DSI option is the difference in O&M costs for the use of trona instead of lime. WFGD costs were estimated based on a 20-year control system life, 7-percent interest rate, and energy penalty of 4 MW. Table 4-2 provides a summary of the capital, O&M, energy, and annualized costs for Units 1 and 2. All costs are expressed in 2012 dollars.

Since the switch to Colombian coal has no additional costs, no further economic analysis was conducted for this option. Table 4-3 shows the average and incremental cost effectiveness for the remaining two SO_2 control technology options for Units 1 and 2.

4.4.2 ENERGY IMPACTS

Energy impacts associated with DSI technology are minimal. In contrast, WFGD will impose a significant energy penalty of approximately 4 MW per unit due to parasitic energy use by the WFGD system. Primary energy penalty is due to the increased fan power required to compensate for the higher pressure drop of the absorber vessel. Other energy uses associated with WFGD operations include reagent preparation (i.e., grinding), pumps for reagent recirculation, dewatering of spent reagent, and material handling. The energy penalties result in costs due to the purchase of replacement power and capital recovery for additional generation capacity.

4.4.3 NONAIR-QUALITY IMPACTS

DSI technology will produce a dry solid waste comprised of a mixture of spent reagent and flyash. WFGD will generate a wet sludge of spent reagent that will require disposal.

Table 4-2. Compliance Costs for SO_2 Control Technologies

SO_2 Control Technology	Capital Cost ($)	O&M Cost ($ per year)	Energy Cost ($ per year)	Annualized Cost ($ per year)
Unit 1				
DSI plus Colombian coal	N/A	883,047	Minimal	883,047
WFGD	111,748,400	2,196,102	1,771,737	14,516,098
Unit 2				
DSI plus Colombian coal	N/A	929,241	Minimal	929,241
WFGD	133,188,500	2,420,949	1,593,028	16,586,029

Source: Southern Company Services, 2012.

Table 4-3. Cost Effectiveness of SO_2 Control Technologies

SO_2 Control Technology	Annualized Cost ($/yr)	Baseline SO_2 Emissions (tpy)	Baseline Heat Input (MMBtu/yr)	Controlled SO_2 Emissions Rates		SO_2 Emissions Reduction (tpy)	Cost Effectiveness ($/ton)	
				lb/MMBtu	tpy		Average	Incremental
<u>Unit 1</u>								
DSI (trona) plus Colombian coal	883,047	8,711	12,225,282	0.74	4,536	4,175	211	N/A
WFGD	14,516,098	8,711	12,225,282	0.15	917	7,794	1,862	3,767
<u>Unit 2</u>								
DSI (trona) plus Colombian coal	929,241	9,220	12,856,565	0.74	4,770	4,451	209	N/A
WFGD	16,586,029	9,220	12,856,565	0.15	964	8,256	2,009	4,114

Source: SCS, 2012.

If LSFO WFGD is feasible, a saleable byproduct (i.e., gypsum) will be generated. Accordingly, both DSI and WFGD will increase the quantities of solid waste that must be disposed of either onsite or in offsite landfills.

WFGD will require substantial amounts of water and will generate a wastewater stream that will require treatment. WFGD will result in a local visible plume under most meteorological conditions due to the condensation of moisture in the saturated flue gas, an ironic outcome in the context of the regional haze regulatory program.

4.4.4 REMAINING USEFUL LIFE

No adjustments were made to the annualized costs based on the conservative premise that the useful lives of Units 1 and 2 will be as long as the 20-year capital recovery period of the WFGD control equipment.

4.5 VISIBILITY IMPACTS

Modeling was conducted in accordance with the approved BART modeling protocol to determine the improvement in visibility at the St. Marks NWR for the three BART SO_2 control technologies evaluated; i.e., switch to Colombian coal, DSI (trona) plus Colombian coal, and WFGD. To determine visibility impacts for each unit, modeling was conducted separately for Units 1 and 2 for each SO_2 control technology evaluated. For each Unit 1 model run, the modeled SO_2 emissions rate for the Unit 1 and 2 common stack was the sum of: (a) the Unit 1 controlled SO_2 emissions rate, and (b) the Unit 2 baseline SO_2 emissions rate. The same approach was used for modeling Unit 2; i.e., the modeled SO_2 emissions rate was the sum of the Unit 2 controlled SO_2 emissions rate and the Unit 1 baseline SO_2 emissions rate. Table 4-4 provides a summary of the modeled visibility impacts (maximum 8th highest and highest 22nd over 3 years) for Units 1 and 2. Table 4-5 provides the incremental changes in visibility.

As shown in Table 4-5, the improvements in visibility compared to baseline levels due to reductions in Unit 1 SO_2 emissions range from 0.37 dv (for the switch to Colombian coal) to 0.67 dv (for WFGD) for the maximum 8th highest and from 0.34 and 0.51 dv, respectively, for the 22nd highest over 3 years. For Unit 2, the improvements in visibility

Table 4-4. Plant Smith Units 1 and 2 SO_2 Control Technology Visibility Impacts—Maximum 8th Highest and Highest 22nd Changes in Visibility: St. Marks NWR

Scenario ID	Scenario Description	Year of Meteorology (delta deciviews) 2001	2002	2003	Maximum
Unit 1 Impacts (Maximum 8th Highest)					
1	Switch to Colombian coal	1.21	0.89	1.15	1.21
2	DSI + switch to Colombian coal	1.10	0.80	1.04	1.10
3	WFGD	0.91	0.77	0.90	0.91
Unit 2 Impacts (Maximum 8th Highest)					
1	Switch to Colombian coal	1.31	0.97	1.26	1.31
2	DSI + switch to Colombian coal	1.19	0.87	1.13	1.19
3	WFGD	0.96	0.83	0.97	0.97

Scenario ID	Scenario Description	2001 through 2003
Unit 1 Impacts (Highest 22nd)		
1	Switch to Colombian coal	1.06
2	DSI + switch to Colombian coal	0.96
3	WFGD	0.89
Unit 2 Impacts (Highest 22nd)		
1	Switch to Colombian coal	1.16
2	DSI + switch to Colombian coal	1.04
3	WFGD	0.95

Source: SCS, 2012.

Table 4-5. Plant Smith Units 1 and 2 SO_2 Control Technology Visibility Impacts—Incremental Changes in Maximum 8th Highest and Highest 22nd Changes in Visibility: St. Marks NWR

Scenario ID	Scenario Description	2001 through 2003 (delta delta deciviews)	
		Maximum 8th Highest	Highest 22nd
Unit 1 Impacts			
1	Switch to Colombian coal		
	Change from baseline	-0.37	-0.34
2	DSI plus switch to Colombian coal		
	Change from baseline	-0.48	-0.44
	Change from Scenario 1	-0.11	-0.10
3	WFGD		
	Change from baseline	-0.67	-0.51
	Change from Scenario 2	-0.19	-0.07
Unit 2 Impacts			
1	Switch to Colombian coal		
	Change from baseline	-0.27	-0.24
2	DSI plus switch to Colombian coal		
	Change from baseline	-0.48	-0.36
	Change from Scenario 1	-0.12	-0.12
3	WFGD		
	Change from baseline	-0.61	-0.45
	Change from Scenario 2	-0.22	-0.09

Source: SCS, 2012.

compared to baseline levels due to reductions in SO_2 emissions range from 0.27 dv (for the switch to Colombian coal) to 0.61 dv (for WFGD) for the maximum 8th highest and from 0.24 and 0.45 dv, respectively, for the 22nd highest over 3 years.

Use of WFGD instead of the DSI plus Colombian coal option results in an incremental improvement in visibility of only 0.19 dv (for Unit 1) and 0.22 dv (for Unit 2) for the maximum 8th highest and only 0.07 dv (for Unit 1) and 0.09 dv (for Unit 2) for the 22nd highest over 3 years. As previously noted in Section 3.0, emissions sources that have less than a 0.5-dv change in visibility are not considered to contribute to visibility impairment. In addition, the minimum humanly perceptible change in visibility is considered to be 1.0 dv as stated in the RHR.

4.6 PROPOSED BART FOR SO_2

The proposed SO_2 BART determination for Plant Smith Units 1 and 2 is an SO_2 emissions rate of 0.74 lb/MMBtu on a 30-day rolling average basis, which can be achieved with the use of DSI with trona as the alkaline reagent. The proposed BART SO_2 control technology will be installed and in operation no later than the MATS compliance deadline prior to the end of the first 10-year RHR planning period in 2018.

The proposed SO_2 BART determination meets the requirements of the BART Rule as the “best” level of control for the following reasons:

- Average cost effectiveness of the DSI (trona) plus Colombian coal option is approximately nine times lower than WFGD.
- Incremental cost effectiveness of WFGD compared to the DSI (trona) plus Colombian coal option exceeds $3,500 per ton of SO_2 removed, which is considered excessive.
- The DSI (trona) plus Colombian coal option does not have the adverse energy and nonair-quality impacts associated with WFGD.
- The incremental improvement in visibility for WFGD compared to the DSI (trona) plus Colombian coal option is only 0.19 dv (for Unit 1) and 0.22 dv (for Unit 2) for the maximum 8th highest and only 0.07 dv (for Unit 1) and 0.09 dv (for Unit 2) for the 22nd highest over 3 years.

In conclusion, the DSI (trona) plus Colombian coal option represents the best level of control based on consideration of the statutory factors required by Section 169A(g)(7) of the Clean Air Act. A comprehensive evaluation of the three factors most relevant to the Plant Smith Units 1 and 2 BART SO_2 analysis (i.e., cost of compliance, energy and nonair-quality environmental impacts, and degree of improvement in visibility) leads to the conclusion that the DSI (trona) plus Colombian coal option is the best option due to its substantially lower cost, decreased energy cost and nonair-quality impacts, and the minimal additional visibility improvement that will occur with WFGD.

5.0 NO$_x$ BART EVAULATION

EPA has determined that both CAIR (currently in effect) and CSAPR (currently stayed) achieve greater reasonable progress toward the national goal of achieving natural visibility conditions in Class I areas than source-specific BART in those states, such as Florida, that are covered by CSAPR (reference EPA's final rule [Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific BART Determinations, Limited SIP Disapprovals, and Federal Implementation Plans] in the June 7, 2012, Federal Register, Page 33642). In its final rule, EPA indicated that a state in the CSAPR region whose EGUs are subject to the requirements of the CSAPR trading program only for ozone season NO$_x$ is allowed to rely on EPA's determination that CSAPR makes greater reasonable progress than source-specific BART for NO$_x$, specifically mentioning Florida as one of the states affected by this decision. Accordingly, Florida's RHR SIP would not need to require affected BART-eligible EGUs to install, operate, and maintain BART for emissions of NO$_x$ to receive EPA SIP approval since Florida would participate in the CSAPR ozone season NO$_x$ cap-and-trade program. Since Florida's RHR SIP adopted this approach for CAIR, it is reasonable to assume that Florida will also adopt the same approach for CSAPR.

Nonetheless, in response to FDEP's request (which was made prior to EPA's final rule on June 7, 2012), a NO$_x$ BART analysis for Plant Smith Units 1 and 2 using the five-factor approach discussed in Section 3.0 is provided in the following subsections.

5.1 IDENTIFICATION OF AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Available retrofit NO$_x$ control technologies were identified by reviewing information from a variety of sources including: (a) Gulf Power Company's and Southern Company's extensive experience regarding the evaluation and installation of retrofit NO$_x$ emissions controls; (b) EPA's Clean Air Technology Center, which includes the RBLC; (c) recent BART analyses for coal-fired steam boilers; (d) the EPA OAQPS Air Pollution Control Cost Manual; and (e) pertinent agency technical documents (e.g., EPA's Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, Chapter 5 Emissions Control Technologies).

Plant Smith Units 1 and 2 are currently equipped with LNBt with high momentum injection ports, and Unit 2 has LNBs with an overfire air control system. In addition to LNB technology, both units have SNCR for additional NO_x control. These NO_x combustion controls were installed in response to CAIR.

Since Units 1 and 2 are currently equipped with NO_x combustion controls and SNCR, this suite of NO_x controls serves as the baseline and the focus of the NO_x BART analysis for Units 1 and 2 was confined to the evaluation of selective catalytic reduction (SCR) technology.

SCR reduces NO_x emissions by reacting ammonia (NH_3) with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \qquad (1)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (2)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750 degrees Fahrenheit [°F]). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NO_x molar ratio, catalyst reactivity, catalyst age, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with ammonia theoretically requires a one-to-one molar ratio. Ammonia/NO_x molar ratios greater than one-to-one are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO_x molar ratios are typically maintained at one-to-one or lower to prevent excessive ammonia slip emissions.

Reaction temperature is critical for proper SCR operation. The optimum temperature range for SCR operation is dependent on the type of catalyst used. The two main groups of catalyst are base metal (vanadium-platinum or -titanium) and zeolite. The optimum temperature range for a vanadium-platinum catalyst is less than 500°F, while the optimum temperature range for a vanadium-titanium catalyst is to 550 to 800°F. The zeolite catalyst is used for higher temperature applications and can operate effectively at temperatures as high as 1,000°F. At temperatures below the optimum range for the specified catalyst, reduction reactions (1) and (2) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NO_x emissions.

SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium. The catalyst life does not include this potential for degradation, which could cause early replacement of the catalyst.

Ammonia slip becomes a greater issue as the catalyst degrades because of the increased amount of ammonia injected to achieve the appropriate NO_x control. Vendors typically can provide SCR systems that have the ability to limit the concentration of ammonia slip to 10 parts per million by dry volume (ppmvd) throughout the life of the catalyst.

5.2 ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The option to retrofit Units 1 and 2 with SCR is considered technically feasible.

5.3 EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

SCR NO_x removal efficiencies range from 70 to 90 percent.

5.4 EVALUATE IMPACTS AND DOCUMENT THE RESULTS

With respect to impact analyses, the EPA BART guidelines list the following five factors:

- Cost of compliance.
- Energy impacts.
- Non-air quality impacts.
- Remaining useful life.
- Degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology.

Each of the first four of these factors is addressed in the following subsections, while the visibility improvement factor is addressed in Section 5.5.

5.4.1 COST OF COMPLIANCE

SCR costs were estimated based on a 20-year control system life, 7-percent interest rate, and energy penalty of 1 MW. Table 5-1 provides a summary of the capital, O&M, energy, and annualized costs for Units 1 and 2. All costs are expressed in 2012 dollars.

Table 5-2 shows average cost effectiveness for Units 1 and 2.

5.4.2 ENERGY IMPACTS

SCR systems will require additional electricity to run pumps and the extra fan horsepower needed to overcome the high-pressure drop in the systems. The electricity needs will reduce the net plant output and represents a sizable energy penalty (estimated to be 1 MW for each unit).

5.4.3 NONAIR-QUALITY IMPACTS

Both SNCR and SCR require the storage and handling of ammonia. The existing Plant Smith SNCR controls utilize urea in a 50-percent aqueous solution. Storage of aqueous

Table 5-1. Compliance Costs for NO_x Control Technologies

NO_x Control Technology SCR	Capital Cost ($)	O&M Cost ($ per year)	Energy Cost ($ per year)	Annualized Cost ($ per year)
Unit 1	65,950,000	1,277,953	442,934	7,945,908
Unit 2	74,940,000	1,427,537	398,257	8,899,381

Source: Southern Company Services, 2012.

Table 5-2. Cost Effectiveness for NO_x Control Technologies

NO_x Control Technology	Annualized Cost ($/yr)	Baseline Heat Input (MMBtu/yr)	Controlled NO_x Emissions Rates		NO_x Emissions Reduction (tpy)	Average Cost Effectiveness ($/ton)
			lb/MMBtu	tpy		
<u>Unit 1</u>						
Baseline (combustion controls plus SNCR)	N/A	12,225,282	0.34	2,047	N/A	N/A
SCR	7,945,908	12,225,282	0.07	428	1,619	4,907
<u>Unit 2</u>						
Baseline (combustion controls plus SNCR)	N/A	12,856,565	0.27	1,729	N/A	N/A
SCR	8,899,381	12,856,565	0.07	450	1,279	6,957

Source: SCS, 2012.

ammonia above 10,000 pounds is regulated by a risk management program, since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release.

Similar to SNCR, ammonia slip from SCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_x, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution, which also leads to an excess of unreacted ammonia.

5.4.4 REMAINING USEFUL LIFE

No adjustment was made to the annualized cost based on the conservative premise that the useful lives of Units 1 and 2 will be as long as the 20-year capital recovery period of the SCR control equipment.

5.5 VISIBILITY IMPACTS

As previously discussed in Section 2.6, the contribution of Units 1 and 2 NO_x emissions to visibility impairment is low. Baseline visibility impacts due to NO_x emissions are only 3.9 percent of the total baseline impact.

Modeling was conducted in accordance with the approved BART modeling protocol to determine the improvement in visibility at the St. Marks NWR due to the addition of SCR at Plant Smith Units 1 and 2. To determine visibility impacts for each unit, modeling was conducted separately for Units 1 and 2 using the same modeling approach previously described for SO_2 in Section 4.5. Table 5-3 provides a summary of the modeled visibility impacts (maximum 8th highest and highest 22nd over 3 years). Table 5-4 presents the incremental changes in visibility.

As shown in Table 5-3, there will be little, or no, improvement in visibility compared to baseline levels due to the use of SCR technology for Units 1 and 2. For Unit 1, the highest improvement in baseline visibility (maximum 8th highest) is 0.01 dv. For Unit 2, the model results for the maximum 8th highest impact show no improvement in baseline

Table 5-3. Plant Smith Units 1 and 2 NO_x Control Technology Impacts—Maximum 8th Highest and Highest 22nd Changes in Visibility: St. Marks NWR

Unit ID	Scenario Description	Year of Meteorology (delta deciviews) 2001	2002	2003	Maximum
Units 1 and 2 Impacts (Maximum 8th Highest)					
1	SCR	1.57	1.18	1.53	1.57
2	SCR	1.58	1.18	1.53	1.58
		2001 through 2003			
Units 1 and 2 Impacts (Highest 22nd)					
1	SCR	1.37			
2	SCR	1.38			

Source: SCS, 2012.

Table 5-4. Plant Smith Units 1 and 2 NO_x Control Technology Impacts—Incremental Changes in Maximum 8th Highest and Highest 22nd Changes in Visibility: St. Marks NWR

Unit ID	Scenario Description	2001 through 2003 (delta delta deciviews) Maximum 8th Highest	 Highest 22nd
1	SCR—change from baseline	-0.01	-0.03
2	SCR—change from baseline	0.00	-0.02

Source: SCS, 2012.

visibility. For the 22nd highest visibility impacts, the visibility improvements for SCR are only 0.03 dv (for Unit 1) and 0.02 dv (for Unit 2).

5.6 PROPOSED BART FOR NO_x

The proposed NO_x BART determination for Plant Smith Units 1 and 2 is no additional control, with continued use of the existing NO_x combustion controls and SNCR, with emissions limits specified by the current Plant Smith Title V air operation permit.

The proposed NO_x BART determination meets the requirements of the BART Rule as the best level of control for the following reasons:

- Units 1 and 2 are currently equipped with combustion controls and SNCR to reduce NO_x emissions.
- Average cost effectiveness of SCR is approximately $5,000 per ton for Unit 1 and $7,000 per ton for Unit 2. These cost-effectiveness values are well above those considered reasonable for BART.
- There will be essentially no improvement in baseline visibility due to the installation of SCR controls.

In conclusion, the existing NO_x combustion controls and SNCR represents the best level of control based on consideration of the statutory factors required by Section 169A(g)(7) of the Clean Air Act. Based on a comprehensive evaluation of the three factors particularly relevant to the Plant Smith Units 1 and 2 BART NO_x analysis (i.e., cost of compliance, existing pollution control technology in use at the source, and degree of improvement in visibility), the existing suite of NO_x controls is the best option due to the substantial cost and little, or no, additional visibility improvement of the SCR alternative.

6.0 PM BART EVALUATION

PM emissions resulting from the combustion of coal are due to the oxidation of ash and sulfur contained in these fuels. PM emissions rates depend on coal composition (i.e., ash content), boiler design and operation, and emissions control equipment. Uncontrolled PM emissions from coal-fired boilers include the ash from fuel combustion, unburned carbon resulting from incomplete combustion, and condensable compounds. Pulverized coal-fired boilers achieve a high combustion efficiency resulting in PM emissions that are primarily comprised of inorganic ash residues.

Ash generated by the combustion of coal will exit the boiler as either bottom ash or fly ash. Fly ash is entrained in the boiler exhaust gas stream and will be discharged to the atmosphere unless removed by emissions control equipment. Bottom ash is the noncombustible slag or residue remaining after the coal is combusted. Bottom ash is removed mechanically from the boiler and is handled and processed as a solid combustion byproduct.

Plant Smith Units 1 and 2 are equipped with highly efficient hot and cold side ESPs that achieve very low PM emissions rates. In addition, baseline modeling of visibility impacts demonstrates that Unit 1 and 2 PM emissions have only a small contribution to visibility impairment at the St. Marks NWR. Visibility impacts due to PM_{10} emissions comprise only 1.3 percent of the total baseline visibility impact. Accordingly, additional PM controls will provide little visibility improvement.

However, in response to FDEP’s request, a PM BART analysis for Plant Smith Units 1 and 2 using the five-factor approach discussed in Section 3.0 is provided in the following subsections.

6.1 IDENTIFICATION OF AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Available retrofit PM control technologies were identified by reviewing information from a variety of sources including: (a) Gulf Power Company’s and Southern Company’s extensive experience regarding the evaluation and installation of retrofit PM emissions controls; (b) EPA's Clean Air Technology Center, which includes the RBLC; (c) recent BART analyses for coal-fired steam boilers; (d) the EPA OAQPS Air Pollution Control Cost Manual; and (e) pertinent agency technical documents (e.g., the Northeast States for Coordinated Air Use Management's Assessment of Control Technology Options for BART-Eligible Sources).

Since Plant Smith Units 1 and 2 are currently equipped with hot and cold side ESPs resulting in a high PM removal efficiency, these PM controls serve as the baseline. It was anticipated, based on screening modeling and confirmed from the visibility impacts analysis (see Section 6.5), that PM emissions have a minimal impact on visibility at the St. Marks NWR. Therefore, the PM BART analysis was conducted for only the most stringent PM control option (fabric filter technology) compared to the existing ESPs to evaluate visibility improvements, other impacts, and economic costs. This approach was taken based on the theory that if the most stringent control (i.e., fabric filters) shows minimal to no improvement in visibility and cannot be justified based on the five BART criteria, none of the ESP upgrade options will be justified at any cost, given they have unquantifiable and negligible PM emissions reductions. Therefore, the PM BART analysis was confined to the evaluation of fabric filter (i.e., baghouse) technology.

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot (cfm-ft^2). Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

6.2 ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The option to retrofit Units 1 and 2 with fabric filters is considered technically feasible.

6.3 EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

Fabric filter total PM removal efficiencies range from 99 to 99.9 percent.

6.4 EVALUATE IMPACTS AND DOCUMENT THE RESULTS

With respect to impact analyses, the EPA BART guidelines list the following five factors:

- Cost of compliance.
- Energy impacts.
- Nonair -uality impacts.
- Remaining useful life.
- Degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology.

Each of the first four of these factors is addressed in the following subsections, while the visibility improvement factor is addressed in Section 6.5.

6.4.1 COST OF COMPLIANCE

Fabric filter costs were estimated based on a 20-year control system life, 7-percent interest rate, and energy penalty of 1 MW. Table 6-1 provides a summary of the capital, O&M, energy, and annualized costs for Units 1 and 2. All costs are expressed in 2012 dollars.

Table 6-2 shows the average cost effectiveness for Units 1 and 2.

6.4.2 ENERGY IMPACTS

Fabric filters will increase the pressure drop in the boiler exhaust system requiring extra fan horsepower needed to overcome the increased pressure drop. The electricity needs will reduce the net plant output and represents a sizable energy penalty.

Table 6-1. Compliance Costs for PM Control Technologies

PM Control Technology Fabric Filter	Capital Cost ($)	O&M Cost ($ per year)	Energy Cost ($ per year)	Annualized Cost ($ per year)
Unit 1	35,776,000	957,056	442,934	4,776,887
Unit 2	42,640,000	1,182,527	398,257	5,605,574

Source: Southern Company Services, 2012.

Table 6-2. Cost Effectiveness for PM Control Technologies

PM Control Technology	Annualized Cost ($/yr)	Baseline Heat Input (MMBtu/yr)	Controlled PM Emissions Rates		PM Emissions Reduction (tpy)	Average Cost Effectiveness ($/ton)
			lb/MMBtu	tpy		
<u>Unit 1</u>						
Baseline (hot and cold side ESPs)	N/A	12,225,282	0.015	92	N/A	N/A
Fabric filter	4,776,887	12,225,282	0.008	48	44	108,566
<u>Unit 2</u>						
Baseline (hot and cold side ESPs)	N/A	12,856,565	0.014	88	N/A	N/A
Fabric filter	5,605,574	12,856,565	0.008	51	37	153,268

Source: SCS, 2012.

6.4.3 NONAIR-QUALITY IMPACTS

Due to its higher PM removal efficiency compared to the existing ESPs, fabric filters will increases the amount of solid waste that will need to be disposed of either onsite or in offsite landfills.

6.4.4 REMAINING USEFUL LIFE

No adjustment was made to the annualized cost based on the conservative premise that the useful lives of Units 1 and 2 will be as long as the 20-year capital recovery period of the fabric filters.

6.5 VISIBILITY IMPACTS

The contribution of Units 1 and 2 PM emissions to visibility impairment is low. Baseline visibility impacts due to PM emissions are only 1.3 percent of the total baseline impact.

Modeling was conducted in accordance with the approved BART modeling protocol to determine the improvement in visibility at the St. Marks NWR due to the addition of fabric filters at Plant Smith Units 1 and 2. To determine visibility impacts for each unit, modeling was conducted separately for Units 1 and 2 using the same modeling approach previously described for SO_2 in Section 4.5. Table 6-3 provides a summary of the modeled visibility impacts (maximum 8th highest and highest 22nd over 3 years). Table 6-4 presents the incremental changes in visibility.

As shown in Table 6-4, there will be no improvement in visibility for both the maximum 8th highest and highest 22nd impacts compared to baseline levels due to the use of fabric filter technology for Units 1 and 2.

6.6 PROPOSED BART FOR PM

The proposed PM BART determination for Plant Smith Units 1 is 2 is no additional controls, with continued use of the existing hot and cold side ESPs with the emissions limits specified by the current Plant Smith Title V air operation permit.

Table 6-3. Plant Smith Units 1 and 2 PM Control Technology Impacts—Maximum 8th Highest and Highest 22nd Changes in Visibility: St. Marks NWR

Unit ID	Scenario Description	Year of Meteorology (delta deciviews) 2001	2002	2003	Maximum
Units 1 and 2 Impacts (Maximum 8th Highest)					
1	Fabric filter	1.58	1.18	1.52	1.58
2	Fabric filter	1.58	1.18	1.52	1.58
		2001 through 2003			
Units 1 and 2 Impacts (Highest 22nd)					
1	Fabric filter	1.40			
2	Fabric filter	1.40			

Source: SCS, 2012.

Table 6-4. Plant Smith Units 1 and 2 PM Control Technology Impacts—Incremental Changes in Maximum 8th Highest and Highest 22nd Changes in Visibility: St. Marks NWR

Unit ID	Scenario Description	2001 through 2003 (delta delta deciviews) Maximum 8th Highest	 Highest 22nd
1	Fabric filter—change from baseline	0.00	0.00
2	Fabric filter—change from baseline	0.00	0.00

Source: SCS, 2012.

The proposed PM BART determination meets the requirements of the BART Rule as the best level of control for the following reasons:

- Units 1 and 2 are currently equipped with highly efficient hot and cold side ESPs to reduce PM emissions.
- Average cost effectiveness of fabric filters is $108,566 per ton for Unit 1 and $153,268 per ton for Unit 2. These cost effectiveness values are well above those considered reasonable for BART.
- There will be no improvement in baseline visibility due to the installation of fabric filter controls.

In conclusion, the existing hot and cold side ESPs represents the best level of control based on consideration of the statutory factors required by Section 169A(g)(7) of the Clean Air Act. Based on a comprehensive evaluation of the three factors most relevant to the Plant Smith Units 1 and 2 BART PM analysis (i.e., cost of compliance, existing pollution control technology in use at the source impacts, and degree of improvement in visibility), the existing PM controls is the best option due to the substantial cost and lack of any additional visibility improvement for the fabric filter alternative.

APPENDIX A

BART MODELING PROTOCOL

BART Modeling Protocol:

Gulf Power Company
Plant Smith

Prepared by:

Southern Company Services
for Gulf Power Company

June 2012

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1.0 Introduction

1.1 Objectives

The Regional Haze Rule requires Best Available Retrofit Technology (BART) for any BART-eligible source that “emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility” in any mandatory Class I federal area. Pursuant to federal regulations, states have the option of exempting a BART-eligible source from the BART requirements based on dispersion modeling demonstrating that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. .

In 2005, the Environmental Protection Agency (EPA) promulgated a rule allowing states subject to the Clean Air Interstate Rule (CAIR) to determine that CAIR satisfies the BART requirements for SO_2 and NO_x for electric generating units (EGUs). On December 23, 2008, the U.S. Court of Appeals for the D.C. Circuit remanded the CAIR rule to EPA, and on July 6, 2011, EPA promulgated the Cross State Air Pollution Rule (CSAPR) as a replacement to CAIR. However, while the state of Florida was included in CAIR for both ozone and $PM_{2.5}$, it is not included in CSAPR for $PM_{2.5}$. On May 11, 2012,, the Florida Department of Environmental Protection (FDEP) requested that Gulf Power Company (Gulf) conduct BART analyses for SO_2, NO_x and PM for the BART-eligible units at Plant Smith. This modeling protocol discusses the methodology that Gulf will apply for performing the BART modeling analysis for SO_2, NO_x and PM.

Units 1 and 2 at Plant Smith, located near Lynn Haven, which are owned and operated by Gulf Power Company, have been identified as a BART-eligible source. The purpose of this document is to summarize the procedures by which a modeling analysis will be conducted for this source. The modeling procedures outlined will be used to determine whether the source is subject to BART requirements (exemption modeling). If it is determined that the source is subject to BART, this protocol will be updated (e.g., adding data to Table 2-1) and then the procedures below will be used to evaluate the visibility improvement factor in the BART determination step (determination modeling). The modeling procedures are consistent with those outlined in the updated final VISTAS common BART modeling protocol (dated December 22, 2005, revision 3.2 – August 31, 2006), available at http://www.vistas-sesarm.org/BART/index.asp. This source-specific BART modeling protocol references relevant portions of the common VISTAS modeling protocol.

1.2 Location of source vs. relevant Class I Areas

The Florida Department of Environmental Protection, which is in charge of the state’s BART program, has determined that Units 1 and 2 at Plant Smith are BART-eligible. Figure 1-1 shows a plot of Plant Smith relative to nearby Class I Areas. There is one Class I area within 300 km of the plant: Saint Marks (118.6 km). The BART exemption modeling will be conducted for this Class I area in accordance with the referenced VISTAS common BART modeling protocol and the procedures described in this source-specific BART modeling protocol. If necessary, visibility improvement modeling for the BART determination step will be performed for this Class I area if the exemption modeling shows a greater than 0.5 deciview impact.

1.3 Organization of protocol document

Section 2 of this protocol describes the source emissions that will be used as input to the BART exemption modeling and, if necessary, the BART determination modeling. Section 3 describes the input data to be used for the modeling including the modeling domain, terrain and land use, and meteorological data. Section 4 describes the air quality modeling procedures and Section 5 discusses the presentation of modeling results. Since all of the references cited are also included in the VISTAS common BART modeling protocol (Section 7.), no additional references section is included in this document. Appendices A and B provide additional information on the baseline source emissions and Appendix C provides support for alternative background ammonia concentrations.

Figure 1-1 Location of Class I Areas in Relation to Plant Smith

2.0 Source description and emissions data

2.1 Unit-specific source data

The emissions data used to assess the visibility impacts at the Class I areas within 300 km of Plant Smith are discussed in this section. This protocol addresses SO_2, NOx and PM10 emissions.

Baseline SO_2 is based on the highest measured 24-hour CEMS emission rate for the 3-year period of 2003-2005. Since the baseline period, selective non-catalytic reduction control (SNCR) technology has been installed on Smith Unit 1 (May 2009) and Unit 2 (December 2008) to reduce NOx emissions. For the purposes of this BART analysis, it is assumed that the SNCRs results in 30% reduction in NOx emissions, which is applied to the highest measured 24-hour NOx CEMS emission rate over the 3-year period of 2003-2005.

Since various components of PM_{10} emissions have different visibility extinction efficiencies, the PM_{10} emissions are divided, or "speciated," into several components (VISTAS common protocol Sections 4.3.3 and 4.4.2). The VISTAS protocol (Section 5.) allows for the use of source-specific emissions and speciation factors and/or default values from AP-42. The PM_{10} emissions and speciation approach to be used for the modeling described in this protocol is indicated in the bullets below. Where default speciation values are used, the data represents a unit where baseline emission controls include electrostatic precipitators (ESPs) and SNCRs, but no post-combustion SO_2 control equipment exists.

- Total PM_{10} is comprised of filterable and condensable emissions.
- Baseline filterable PM_{10} emissions are based on the highest stack test for the most recent 3-year period (2003-2005). Plant Smith has a Title V permit limitation on heat input of 1,944.8 and 2,246.2 lb/MMBtu for Units 1 and 2, respectively. Compliance with this limit is based on composite fuel samples taken daily by on-site personnel. For this BART analysis, the unit-specific heat input limit is combined with the highest stack test PM_{10} emissions to calculate the "maximum 24-hour average emission rate" for PM_{10}.
- Filterable PM_{10} will be subdivided by size category consistent with the default approach from AP-42 Table 1-1.6, and as noted on pages 43 and 44 of the VISTAS common BART modeling protocol. The AP-42 Table 1-1.6 specifies for the emission controls indicated above that 55.6% of filterable PM_{10} emissions is coarse (greater than 2.5 microns in size) and 44.4% is fine. Of the fine portion, 3.7% is elemental carbon and the remainder is inorganic fine particulates (soil).
- Condensable PM_{10} consists of inorganic and organic compounds. The inorganic portion is by default assumed to be H_2SO_4, although other non-sulfate inorganic condensables could be present. The organic portion is modeled as organic aerosols.
- Baseline H_2SO_4 emissions are calculated consistent with the method used by Gulf Power to derive these emissions for TRI purposes. This approach assumes that the H_2SO_4 emissions released from the stack are proportional to SO_2 emissions from combustion and are dependent on the fuel type and the removal of H_2SO_4 by downstream equipment (i.e., ESP and air heater). For eastern bituminous coal the baseline H_2SO_4 release rate is in the range of 0.2 to 0.5% of the SO_2 emissions. Appendix A provides the basis for the site-specific values used.
- Baseline emissions of condensable organics (the remaining portion of condensable PM_{10}) are derived based on the supporting field observational information in Appendix B and is estimated as 0.32% of SO_2 emitted.
- Coarse filterable particles (between 2.5 and 10 microns in size) will be modeled with a geometric mass mean diameter of 5 microns, while fine filterable and all condensable particles will be modeled with a geometric mass mean diameter of 0.48 microns, consistent with the CALPUFF default value for fine particles. The geometric standard deviation for both fine and coarse particles will be set to 2 microns, consistent with the CALPUFF default value. The 0.48 micron diameter value for fine particles comes

from the default values in sample input files presented on the TRC web site. There is no default value presented for the coarse particles on the TRC web site. However, since 5 is the geometric mass mean diameter of 2.5 and 10 (the bounds of coarse particle sizes), it is a reasonable estimate for the geometric mass mean diameter for that class of particles.

In practice, CALPUFF allows for the user to input certain components of PM_{10} as separate species and separate sizes, which will result in more accurate wet and dry deposition velocity results and also more accurate effects on light scattering. As noted above, the particle size distribution information is provided in AP-42 Table 1-1.6, and will be used for the BART exemption modeling as well as the BART determination modeling, if needed.

Table 2-1 provides a summary of the modeling emission parameters to be used in the BART CALPUFF modeling, consistent with the source emissions data presented in Appendices A and B for the baseline. The SO_2 and NO_x emissions in Table 2-1 were derived from CEMS data for the 2003 to 2005 period and represent the maximum 24-hour average lb/hr rates (excluding days where startup, shutdown, or malfunctions occurred). The NO_x emissions were adjusted for a 30% reduction due to SNCR. Filterable PM_{10} emissions were calculated using the highest PM stack test over the 2003 to 2005 period and multiplying these values times the Title V permitted heat input limit. These values were then adjusted using AP-42 factors from Table 1.1-6 that indicate that PM_{10} is 67% of total PM for a pulverized coal unit with an ESP. PM_{10} speciation was then performed as indicated above such that total Filterable PM_{10} is made up of Coarse Soil plus total Fine PM and total Fine PM is made up of Fine Soil plus Elemental Carbon (EC).

The flue gas velocity and temperature reported in Table 2-1 are based on combined flue measurements during RATA testing conducted in 2011 for CEMS certification.

If the BART exemption modeling indicates that a BART determination is required, then one or more SO_2, NO_x and particulate matter control options will be considered for the modeling to determine visibility improvement from the baseline case. The BART engineering analysis will provide the justifications for the selected, technically feasible options and the species-specific control efficiencies. Table 2-1 will be updated to provide the modeling parameters for these feasible options and resubmitted to the Florida Department of Environmental Protection for review. Any site-specific deviations from the default particulate matter speciation guidance would be outlined at that time.

Table 2-1 Plant Smith modeling parameters

Case	Source / Unit	Location UTM (Zone 16 NAD-83)		Actual Stack Ht	Base Elev.	Flue Dia-meter	Gas Exit Vel[1]	Stack Gas Exit Temp[1]	Emissions			Particle Speciation[2]							
		UTM East	UTM North						SO_2	NO_X	PM_{10}	Filt. PM_{10}	Coarse Soil	Fine PM	Fine Soil	EC	Cond. PM_{10}	H_2SO_4	Organic
		m	m	m	m	m	m/s	deg K	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr
Baseline Data - Current Configuration (Unit Basis)																			
Baseline	Unit 1	625,053	3,349,243	60.7	1.5	5.5	28.5	428.6	4194.00	945.00	47.87	27.36	15.21	12.15	11.70	0.45	20.51	7.09	13.42
Baseline	Unit 2	625,053	3,349,243	60.7	1.5	5.5	28.5	428.6	3922.00	622.57	47.92	28.74	15.98	12.76	12.29	0.47	19.18	6.63	12.55
Baseline Data - Current Configuration (Stack Basis)																			
				Modeled Stk Ht[3]															
		m	m	m	m	m	m/s	deg K	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/hr
Stack 1	1&2	625,053	3,349,243	60.7	1.5	5.5	28.5	428.6	8116.00	1567.57	95.80	56.11	31.20	24.91	23.99	0.92	39.69	13.72	25.97
Stack Basis Emissions Converted to g/sec									g/sec	g/sec	g/sec	g/sec	g/sec	g/sec	g/sec	g/sec	g/sec	g/sec	g/sec
Stack 1	1&2	625,053	3,349,243	60.7	1.5	5.5	28.5	428.6	1022.62	197.51	12.07	7.07	3.93	3.14	3.02	0.12	5.00	1.73	3.27
Retrofit Control Options (if BART analysis is required[4]																			
Control 1	Unit 1																		
↓	Unit 1																		
Control n	Unit 1																		
Control 1	Unit 2																		
↓	Unit 2																		
Control n	Unit 2																		

[1] Flue gas exit velocity and temperature are based on 2011 RATA testing at high load.

[2] Elemental carbon (EC) and Fine PM are a part of Filterable PM_{10} and H_2SO_4 and Organics are a part of Condensable PM_{10}. Note that H_2SO_4 is input to CALPUFF as SO_4. The molecular weights of H_2SO_4 and SO_4 are 98 and 96 respectively, therefore the conversion factor from H_2SO_4 to SO_4 is 96/98.

[3] Stack height credit is equal to actual stack height. Stack height regulations do not apply to the existing Smith stack since the stack was “in existence” prior to December 31, 1970.

[4] This data will be provided later if a BART determination analysis is required.

3.0 Input data to the CALPUFF model

3.1 General modeling procedures:

VISTAS has developed five sub-regional 4-km CALMET meteorological databases for three years (2001-2003) (VISTAS common protocol Section 4.4.2). The sub-regional modeling domains are strategically designed to cover all potential BART eligible sources within VISTAS states and all PSD Class I areas within 300 km of those sources (to the nearest edge). The extents of the 4-km sub-regional domains are shown in Figure 4-4 of the VISTAS common BART modeling protocol. The BART modeling for Plant Smith will be done using the 4-km subdomain 4.

USGS 90-meter Digital Elevation Model (DEM) files were used by VISTAS to generate the terrain data at 4-km resolution for input to the 4-km sub-regional CALMET run. Likewise, USGS 90-meter Composite Theme Grid (CTG) files were used by VISTAS to generate the land use data at 4-km resolution for input to the 4-km sub-regional CALMET run.

Three years of MM5 data (2001-2003) were used by VISTAS to generate the 4-km sub-regional meteorological datasets. See Sections 4.3.2 and 4.4.2 in the VISTAS common BART modeling protocol for more detail on these issues.

Subsequent to VISTAS's development of the 2001-2003 meteorological datasets, the U.S. Fish and Wildlife Service (USFWS) reprocessed the VISTAS CALMET dataset using settings that are acceptable to FLMs. This reprocessed dataset has been obtained from Mr. Tim Allen of the USFWS and will be used for all BART CALPUFF modeling. .

3.2 Air quality database (background ozone and ammonia)

Hourly measurements of ozone from all non-urban monitors, as generated by VISTAS, will be used as input to CALPUFF. For ammonia, five years (2004-2008) of 24-hour ammonia concentrations measured at a representative SEARCH air quality monitoring site (OAK) will be used to calculate monthly median concentrations. OAK is a rural monitoring site in southern Mississippi, approximately 65 km inland from the Gulf Coast. It is reasonable to assume that this site is representative of the regional background, and that the observations from OAK are more appropriate than using the VISTAS default background of 0.5 ppb. The observed monthly background concentrations will be input into POSTUTIL for HNO_3/NO_3 partitioning. The OAK SEARCH NH_3 data for 2004-2008 are available from the SEARCH ftp site (ftp://mail.atmospheric-research.com/24-hr%20NH3%20Data/). See Appendix C for a discussion of the representativeness of the OAK SEARCH NH_3 data for the Gulf of Mexico.

3.3 Natural conditions and monthly f(RH) at Class I Areas

For each of the applicable Class I areas, natural background conditions must be established in order to determine a change in natural conditions related to a source's emissions. The modeling described by this protocol document intends to use annual average natural background light extinction (Table 6, FLAG Phase I Report – Revised 2010).

To determine the input to CALPUFF, it is first necessary to convert the deciviews to extinction using the equation:

$$Extinction\ (Mm^{-1}) = 10\ \exp\left[\frac{deciviews}{10}\right]$$

The monthly values for f(RH) large and small ammonium sulfate and ammonium nitrate and for sea salt, which CALPOST uses to calculate extinction, will be taken from the FLAG Phase I Report – Revised (2010). See section 4.3 for additional discussion of the visibility calculation.

4.0 Air quality modeling procedures

This section provides a summary of the modeling procedures outlined in the VISTAS protocol that will be used for the refined CALPUFF analysis to be conducted for Plant Smith.

4.1 Model selection and features

The current regulatory version of the CALPUFF modeling system includes CALPUFF Version 5.8 (Level 070623) CALMET Version 5.8 (Level 070623), CALPOST Version 5.6394 (Level 070622) and other postprocessors.

Gulf Power will use CALPUFF Version 5.8 (Level 070623) to conduct BART related modeling. However, the current regulatory version of CALPOST is not capable of employing the revised IMPROVE equation to calculate light extinction. An updated version of CALPOST (Version 6.292, Level 110406) does include the capability of applying the revised IMPROVE equation (Method 8) (see section 4.3 for additional discussion of the revised IMPROVE equation). Therefore, we will use this updated version of CALPOST for postprocessing the CALPUFF model runs.

Gulf Power has obtained the reprocessed CALMET meteorological dataset from the USFWS and does not intend to run CALMET to generate additional meteorological data for refined modeling.

4.2 Modeling domain and receptors

The Plant Smith BART runs will use the VISTAS sub-domain 4, 4-km reprocessed CALMET data supplied by the FWS, as discussed above. This domain includes all Class I areas within 300 km of the source, plus a 50-km buffer.

The receptors used for each of the Class I areas are based on the NPS database of Class I receptors, as recommended by the VISTAS common protocol (Section 4.3.3).

The BART exemption modeling will be conducted for Smith Units 1 and 2 (BART eligible units) for each Class I area within 300 km of the source (i.e., Saint Marks). If exemption modeling shows a greater than 0.5 deciview impact, Unit 1 and 2 will each be modeled separately for the visibility improvement modeling for the BART determination step for Saint Marks.

4.3 Technical options used in the modeling

For CALPUFF model options, Plant Smith will follow the VISTAS common BART modeling protocol (Section 4.4.1), which states that we should use IWAQM (EPA, 1998) guidance. The VISTAS protocol (Section 4.3.3) also notes that building downwash effects are not required to be included unless the state directs the source to include these effects. Since Plant Smith is more than 50 km from the nearest Class I area, building downwash effects will not be included in the CALPUFF modeling.

The POSTUTIL (Version 1.56, Level 070627) utility program will be used to repartition HNO_3 and NO_3 (VISTAS common protocol Section 4.4.2) using monthly median ambient ammonia (NH_3) concentrations obtained from a regionally representative SEARCH air quality monitoring site (OAK)

Light extinction and haze impact calculations

The new IMPROVE equation will be used to analyze the visibility impacts from the CALPUFF model results. The new IMPROVE equation is appropriate for this analysis because of the following rationale:

1) The new equation is the result of an extensive evaluation of the most recent scientific data, undertaken by an ad hoc group of scientists including representatives from the National Park Service,

the National Oceanic and Atmospheric Administration, academia, and industry. The old equation was based on data and information that was over a decade old, whereas the new equation is based on the most recent data and information gleaned from scientific studies done over the past decade. The new equation adds more accurate terms for estimating light extinction due to sulfate and nitrate, through the incorporation of size differentiation and revisions to the extinction coefficients. Organic matter estimates are improved through a refinement to the organic compound mass to organic mass ratio

2) The new equation corrects several errors and omissions in the old equation. For example, sea salt, which affects light extinction, was not part of the old equation, but has been added to the new equation. Moreover, the old equation's constant Rayleigh scattering term (corresponding to scattering at 10,000 feet elevation) has been revised to reflect the actual elevation of the specific Class I area.

The ad hoc group of scientists who recommended the changes to the equation drafted a technical support document entitled "Revised IMPROVE Algorithm for Estimating Light Extinction from Particle Speciation Data" (November 30, 2005). That document demonstrates that, for 21 Class I areas with nephelometer data, the new equation produces more accurate results than the old equation. The IMPROVE Steering Committee reviewed the work of the ad hoc group and its technical support document, and approved the new equation in December 2005.

The revisions to the IMPROVE equation are particularly important for coastal sites (such as Saint Marks). Sea salt is an important component of extinction at coastal sites, and thus should be included in the equation for estimating visibility impacts. In addition, the site-specific Rayleigh scattering term is important for coastal sites because the default value in the old equation (10 Mm-1) was based on an elevation of 10,000 feet. At near-zero sea level, the new equation uses a more accurate coefficient of 11 Mm-1.

The new formula is shown below.

$$\begin{aligned} b_{ext} \approx\ & 2.2\times f_S(RH)\times[\mathit{Small\ Sulfate}] + 4.8\times f_L(RH)\times[\mathit{Large\ Sulfate}] \\ & + 2.4\times f_S(RH)\times[\mathit{Small\ Nitrate}] + 5.1\times f_L(RH)\times[\mathit{Large\ Nitrate}] \\ & + 2.8\times[\mathit{Small\ Organic\ Mass}] + 6.1\times[\mathit{Large\ Organic\ Mass}] \\ & + 10\times[\mathit{Elemental\ Carbon}] \\ & + 1\times[\mathit{Fine\ Soil}] \\ & + 1.7\times f_{SS}(RH)\times[\mathit{Sea\ Salt}] \\ & + 0.6\times[\mathit{Course\ Mass}] \\ & + \mathit{Rayleigh\ Scattering}\ (\mathit{Site\ Specific}) \\ & + 0.33\times[NO_2\ (ppb)] \end{aligned}$$

The apportionment of the total concentration of sulfate compounds into the concentrations of the small and large size fractions is accomplished using the following equations.

$$[\mathit{Large\ Sulfate}] = \frac{[\mathit{Total\ Sulfate}]}{20\mu g/m^3}\times[\mathit{Total\ Sulfate}], \quad [\mathit{Total\ Sulfate}] < 20\mu g/m^3$$

$$[\mathit{Large\ Sulfate}] = [\mathit{Total\ Sulfate}], \quad [\mathit{Total\ Sulfate}] \geq 20\mu g/m^3$$

$$[\mathit{Small\ Sulfate}] = [\mathit{Total\ Sulfate}] - [\mathit{Large\ Sulfate}]$$

The new formula has separate f(RH) values for large (f_L) and small (f_s) sulfate and nitrate size fractions, and for sea salt (f_{ss})

The algorithm for calculating light extinction based on this revised formula has been implemented in CALPOST Version 6.292 as Method 8. The f(RH) values for large and small sulfate and nitrate and for sea salt will be obtained from the FLAG Phase I Report – Revised (2010).

The BART rule significance threshold for the contribution to visibility impairment is 0.5 deciviews. The VISTAS protocol (Section 4.3.2) indicates that with the use of the 4-km sub-regional CALMET database, a source does not cause or contribute to visibility impairment if the 98th percentile (or 8th highest) day’s change in extinction from natural conditions does not exceed 0.5 deciviews for any of the modeled years (an added check is that the 22nd highest prediction over the three years modeled should also not exceed 0.5 deciviews for a source to be exempted from a BART determination). Both the 98th percentile (or 8th highest) day's change in extinction from natural conditions for any modeled year and the 22nd highest prediction over the three years modeled will be evaluated. The maximum impact from each method should not exceed 0.5 deciviews for the source to be exempted from a BART determination.

Figure 4-1 of the VISTAS common BART modeling protocol presents a flow chart showing the components of that protocol for the analysis to determine whether a source is subject to BART. Again, it should be noted that the modeling for Plant Smith will focus on sub-regional fine-scale modeling as depicted in the lower half of the figure.

If the exemption modeling demonstrates that Plant Smith does not cause or contribute to visibility impairment in Class I areas, then the source will not be subject to BART requirements, and no further analysis is needed. Otherwise, the source will proceed to perform BART determination modeling for each unit for the baseline and each control option in a similar manner as has been described in this document. This protocol will be supplemented with a revised Table 2-1 and any other source specific adjustments if the source is determined to be subject-to-BART.

5.0 Presentation of modeling results

The BART exemption and, if necessary, the BART determination modeling results for Plant Smith will be provided to the state agency in a manner as described in the VISTAS protocol (Section 4.5). A report will be produced that includes the following elements (as suggested in the VISTAS protocol):

1. A map of the source location and Class I areas within 300 km of the source.
2. For the CALPUFF modeling domain, a table listing all Class I areas in the VISTAS domain and those in neighboring states and impacts from the BART 4-km grid exemption modeling at those Class I areas within 300 km of the source, as illustrated in Table 4-3 of the VISTAS protocol.
3. A discussion of the number of Class I areas with visibility impairment due to source emissions for the 98th percentile days in each year (and the 98th percentile over all three years modeled) greater than 0.5 dv.
4. For the Class I area with the maximum impact, a discussion of the number of days beyond those excluded (e.g., the 98th percentile for refined analyses) that the impact of the source exceeds 0.5 dv, the number of receptors in the Class I area where the impact exceeds 0.5 dv, and the maximum impact.

The BART determination modeling will be performed for those Class I areas shown in the exemption modeling to exceed 0.5 dv impact. The extent of the BART determination modeling results will depend on the number of technically viable controls identified in the engineering analysis phase of the BART assessment. The results presented will be a comparison of the 98th percentile value (in deciviews) for the baseline and each control strategy derived as is outlined above for the exemption modeling. The same statistics as those mentioned above in Steps 3 and 4 would be provided, and a summary of the relative results among all emission scenarios run would be produced.

Additionally, the appropriate electronic files used to conduct the CALPUFF modeling will be submitted on CD-ROM or DVD media.

Appendix A

Basis for Source-Specific Sulfuric Acid Emissions for BART Baseline Case

Appendix A

Basis for Source-Specific Sulfuric Acid Emissions for BART Baseline Case

Sulfuric Acid (H2SO4) Emissions

During the combustion of sulfur-containing fuels, a percentage of the SO_2 formed is further oxidized to SO_3. As the flue gas cools across the air heater, this SO_3 combines with flue gas moisture to form vapor-phase and/or condensed sulfuric acid (H_2SO_4). The baseline H_2SO_4 emissions shown in Table 2-1 of the BART modeling protocol have been revised to reflect the most recent method used by Southern Company to derive these emissions for Toxics Release Inventory (TRI) purposes. This method is documented in a report titled *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants*, Version 2010a prepared by the Electric Power Research Institute. The approach described in this report assumes that H_2SO_4 emissions released from the stack are proportional to SO_2 emissions from combustion and are dependent on the fuel type and the removal of H_2SO_4 by downstream equipment (i.e., ESP and air heater).

The calculations below show baseline sulfuric acid emissions that are expected. Since this facility does not contain post combustion SO_2 controls, the baseline sulfuric acid emissions estimate only accounts for the manufacture of H_2SO_4 through combustion. This facility contains a selective non-catalytic reduction (SNCR) system. The sulfuric acid emissions estimate also accounts for the removal of H_2SO_4 from the ammonia slip from the SNCR system. Calculated sulfuric acid releases then account for loss or removal within the system.

Sulfuric Acid Manufactured from Combustion (EM_{Comb}):
EM_{Comb} = K x F1 x E2
where,
EM_{Comb} = total sulfuric acid manufactured from combustion, lbs/yr
K = Molecular weight and units conversion constant = 98.07 / 64.04 * 2000 = 3,063
(98.07 = Molecular weight of sulfuric acid; 64.04 = Molecular weight of SO2; Conversion from tons per year to pounds per year – multiply by 2000.)
F1 = Fuel Impact Factor (from the emissions estimating report based on sulfur content and heating value of coal)
E2 = Sulfur dioxide emissions, tons (from CEMS data).

Sulfuric Acid Manufactured from Combustion is:
Smith 1:
EM_{Comb} = 3,063 x 0.00724 x 4,194 lbs/hr / 2000 = 46.51 lbs/hr
Smith 2
EM_{Comb} = 3,063 x 0.00724 x 3,922 lbs/hr / 2000 = 43.16 lbs/hr

Sulfuric Acid Released from Combustion (ER_{Comb})
ER_{Comb} = EM_{Comb} x F2 (technology impact factors for air heater and two ESPs)
ER_{Comb} = EM_{Comb} x (0.5) x (0.31)
Smith 1
ER_{Comb} = 46.51 lbs/hr x (0.155) = 7.21 lbs/hr
Smith 2
ER_{Comb} = 43.16 lbs/hr x (0.155) = 6.74 lbs/hr

Sulfuric Acid Released from SNCR (ER_{SNCR}):
ER_{SNCR} = [ER_{SNCR} – (K_s x B x $f_{sreagent}$ x S_{NH3})] x $F2_x$
where,
ER_{SNCR} = total sulfuric acid released from SNCR, lbs/hr
K_s = Conversion Factor = 3,799
B = Coal burn in TBtu/hr
$f_{sreagent}$ = Operating factor of SNCR system, when residual NH_3 is produced that will remove SO_3

S_{NH3} = NH_3 slip from the SNCR, ppmv at 6% O_2, wet
$F2_x$ = technology impact factors, all that apply

Sulfuric Acid Released from SNCR (ER_{SNCR}):
Smith 1
ER_{SNCR} = [0 – (3799 x 9.19x10^{-5}) x 0.98 x 2.3 x 0.5 x 0.31] = -0.12 lbs/hr
Smith 2
ER_{SNCR} = [0 – (3799 x 8.46x10^{-5}) x 0.98 x 2.3 x 0.5 x 0.31] = -0.11 lbs/hr

Total Sulfuric Acid Released (TSAR):
TSAR = ER_{Comb} + ER_{SNCR}
Smith 1:
TSAR = 7.21- 0.12 = 7.09 lb/hr
Smith 2:
TSAR = 6.74 – 0.11 = 6.63 lb/hr

Appendix B

Estimated Emissions of Primary Total Carbon and Primary Sulfate From Coal-Fired Power Plants

[The above titled paper is included as a separate document along with this site specific BART modeling protocol. This paper was prepared for Southern Company by Eric S. Edgerton of Atmospheric Research & Analysis, Inc.]

Estimated Emissions of Primary Total Carbon and Primary Sulfate From Coal-Fired Power Plants

Prepared for

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Prepared by

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June 11, 2006

ABSTRACT

Data from the SEARCH network were used to estimate condensable carbon and condensable SO_3 emissions from coal-fired power plants (CFPPs). Continuous trace gas and $PM_{2.5}$ measurements were used to identify CFPP plumes and to quantify incremental fine particulate total carbon (TC) and fine particulate total sulfate (SO_4) during the period October 2005-May 2006. As measured in the field, incremental TC includes emitted particulate OC, particulate EC and condensable carbon as well as secondary organic aerosol (SOA). Incremental SO_4 includes emitted particulate SO_4, condensable SO_3, and secondary SO_4. As such, TC and SO_4 provide upper bounds for CFPP emissions of condensable carbon and condensable SO_3. Plume events were selected so as to avoid confounding of TC and SO_4 signals by other sources, and to minimize in-plume production of secondary SO_4 and SOA. Results are presented as ratios relative to SO_2, for example, pounds TC per pound SO_2 (lb TC/lb SO_2,). Plume increments can be interpreted as emission ratios for TC and primary SO_4. For TC, 14 plume events from 4 sites and 7 CFPPs exhibited sufficiently stable data for analysis. Of these, 11 events yielded an average TC/SO_2 emission ratio of 3.2×10^{-3} lb/lb (range 1.1×10^{-3} to 6.6×10^{-3}). In other words, TC emissions represented about 0.32 percent of SO_2 emissions, on a mass basis. The 3 remaining events yielded negative emission ratios using the default approach, and an average emission ratio of 1.5×10^{-3} using an alternate approach. For SO_4, a total of 20 events from 4 sites and 8 CFPPs were analyzed. Results showed an average SO_4/SO_2 emission ratio of 6.4×10^{-3} lb/lb (range 2.1×10^{-3} to 15.0×10^{-3}). On average, SO_4 was found to represent about 0.64 percent of SO_2 emissions during the study period. Inferred emission ratios should be considered upper bound estimates because: 1) the measurements include, in addition to the condensable

carbon and condensable SO_3 emissions of interest, primary particulate carbon (EC and OC) and primary particulate sulfate emitted by the CFPP; 2) may include secondary carbon and secondary sulfate produced in the atmosphere; and 3) could be inflated due to preferential loss of SO_2 from the plume (due to conversion and/or dry deposition) in transit from the CFPP to the research site.

INTRODUCTION

The Southeastern Aerosol Research and Characterization Study (SEARCH) was designed to provide extensive, long-term data on the sources and chemical characteristics of $PM_{2.5}$ and PM_{coarse} for the southeastern U. S. SEARCH is unique in that continuous $PM_{2.5}$ measurements of all major components are made at urban/rural pairs of sites in and around four southeastern U. S. cities. In conjunction with co-measured meteorological and trace gas data, continuous $PM_{2.5}$ measurements provide opportunities for: (1) investigating sources and physico-chemical dynamics of $PM_{2.5}$; (2) evaluating chemical transport and transformation models; (3) assessing the effectiveness of emissions reduction programs; and (4) examining relationships between PM mass and composition and various health end points.

CFPPs emit three forms of primary particulate carbon to the atmosphere: filterable organic carbon (OC), filterable elemental carbon (EC) and condensable carbon. OC and EC are emitted as particles, while condensable carbon is emitted in the vapor phase and is presumed to condense rapidly onto pre-existing particles. These three forms of carbon, plus secondary organic aerosol

(SOA), are measured collectively in the SEARCH network, as total carbon (TC), using continuous measurement techniques. CFPPs also emit two forms of primary particulate sulfate: filterable sulfate and condensable sulfur trioxide (SO_3). In the atmosphere, condensable SO_3 reacts more or less instantaneously with water vapor to produce particulate sulfate. These forms of sulfate, plus secondary sulfate from oxidation of SO_2, are also measured in the SEARCH network using continuous techniques.

This report uses SEARCH data to: (1) identify CFPP plumes observed at numerous sites during the fall of 2005 through spring of 2006; and, (2) calculate total carbon (TC) and total sulfate (SO_4) associated with such plumes. Results are used to estimate CFPP emission ratios of TC and SO_4, relative to SO_2. Given that the measurement techniques do not discriminate between the various form of particulate carbon and particulate sulfate present in the plume, results can be used as upper bound estimates of emission ratios for condensable carbon and condensable SO_3.

EXPERIMENTAL

Continuous measurements of trace gases fine particulate TC and fine particulate SO_4 were made at the Southeastern Aerosol Research and Characterization (SEARCH) sites shown in Figure 1. Analyzable plume events were observed at 5 of the 8 SEARCH sites between early October 2005 and early May 2006: Yorkville, GA; Jefferson Street, GA; Centreville, AL; OLF, FL; and Gulfport, MS. Brief descriptions for these 5 sites are provided below.

Yorkville, GA - Yorkville (lat. 33.9283 N, long. 85.0456 W) is a rural/agricultural site 55 km WNW and 40 km SSW of Atlanta, GA and Rome, GA, respectively. The site is on a broad ridge (elev. 395 m) in a large (>150 ha) clearing devoted largely to pasture. CFPPs in the vicinity of Yorkville are shown in Figure 2.

Centreville, AL – Centreville (lat. 32.9029 N, long. 87.2497 W) is located on private property in rural Bibb County, approximately 85 km SSW of Birmingham, AL. The surrounding area includes the Talladega National Forest and is heavily wooded with mixed deciduous (oak-hickory) and loblolly pine. CFPPs in the vicinity of Centreville are shown in Figure 2.

Jefferson Street (Atlanta), GA - Jefferson Street (lat. 33.7775 N, long. 84.4167 W) is an urban/industrial-residential site 4.5 kilometers NW of downtown Atlanta, GA. The site is located at 829 Jefferson Street NW, on Georgia Power Company property in a 70m by 125m grass-covered clearing on a knoll 15 meters above street level. CFPPs in the vicinity of Jefferson Street are shown in Figure 3.

Outlying Landing Field #8 (OLF), FL - OLF (lat. 30.5496 N, long. 87.3734 W) is a suburban site 21 km NW of downtown Pensacola, FL and 20 km N of the Gulf of Mexico. The site is adjacent to a paved, lightly traveled (< 200 vehicles/day) road on the northern edge of a large (>500 ha) grass-covered field. CFPPs in the vicinity of OLF are shown in Figure 3.

Gulfport, MS – Gulfport (lat. 30.3901 N, long. 89.0498 W) is located 1.5 km from the Gulf of Mexico on the premises of the Harrison County Youth Court at 47 Maples Ave. The area is covered with sparse forest and grass, with single family homes to the east, an elementary school to the north and athletic fields to the south. CFPPs in the vicinity of OLF are shown in Figure 3.

Continuous Trace Gas and Particle Measurements

SO_2, NO_y and CO are measured at each site and used to: 1) screen for periods of influence from point sources (specifically CFPPs) and non-point sources; 2) identify specific CFPPs based on SO_2:NO_y ratios; and 3) calculate TC/SO_2 and SO_4/SO_2 ratios. Continuous (1-minute average) measurements were made at a reference height of 10 m above ground level. Sample air is pulled through a weather-proof inlet box and then into the equipment shelter via ¼" o.d. heavy wall PFA Teflon tubing. The inlet box contains catalytic converters (for NOy), solenoids and plumbing for introduction of zero air and calibrant gases. Calibration gases (+/- 1% for CO and NO and +/- 2% for SO_2) were supplied by Scott-Marrin, Inc. (Riverside, CA).

SO_2 is measured via pulsed UV fluorescence with a TEI Model 43ctl analyzer operated on a 0-200 ppb scale. The instrument is calibrated every third day by gas replacement and zeroed 10 out of every 90 minutes by diverting sample air through a sodium carbonate impregnated annular denuder (URG, Carrboro, NC). The analyzer is also subjected to weekly multipoint gas replacement calibrations (GRC).

CO is measured via gas filter correlation with non-dispersive infrared detection using a TEI Model 48ctl analyzer operated on a 0-3000 ppb scale (0-10,000 ppb at JST). The analyzer is calibrated and zeroed on the same schedule as the SO2 analyzer. Zeroing is performed by diverting the sample stream through a heated (50-100C) trap containing approximately 200 grams of 1% Pt on alumina (DeGussa, Seviersville, TN).

NO_y is measured via ozone-NO chemiluminescence following reduction to NO on a 350 ºC Mo catalytic converter, using a dual-channel TEI Model ctl NO-NO_x analyzer operated on a 0-200 ppb scale. The analyzer is zeroed four times per day and calibrated every third day via gas replacement. Converter efficiency is checked once a week with n-propyl nitrate.

SO_4 is measured continuously using a variation of the Harvard School of Public Health (HSPH) approach. This method uses a 1000 °C inconel steel tube to reduce particulate SO4 to sulfur dioxide (SO_2). The SO_2 is then detected using a Thermo-Environmental Instruments (TEI, Franklin, MA) Model 43S or 43Ctl high sensitivity, pulsed ultra-violet fluorescence SO_2 analyzer. Sample air is pulled through a 2.5 µm sharp-cut cyclone inlet (BGI, Atlanta, GA), then through two 30 mm o.d., 254 mm long sodium carbonate and citric acid coated annular denuders (URG, Carrboro, NC) followed by a 30 mm o.d., 100 mm long carbon honeycomb denuder (MAST Carbon Ltd., Surrey, UK). The denuders effectively remove a wide range of interferents, including SO_2, reduced sulfur gases, nitrogen oxides and volatile organic compounds. Sample air then passes through a 300 mm section of inconel tubing heated to 1000 °C in a Lindberg/Blue M horizontal tube furnace. Every 90 minutes, the system is zeroed for 10 minutes by diverting sample air through an inline filter upstream of the converter. The SO_2 analyzer is subjected to manual and automated gas replacement audits on a weekly schedule.

Total carbon (TC) is measured continuously with a Sunset Laboratory Model RT-OCEC Aerosol Carbon Analyzer. This device operates on an hourly cycle, with 47 minutes devoted to sample collection and 13 minutes devoted to sample analysis. In sample mode, ambient air is pulled through an activated carbon monolith denuder (Novacarb^{TM}, Mast Carbon Ltd., UK) at a flow rate of 8.5 lpm, then through dual quartz fiber filters. In analysis mode, the filters are heated through several temperature plateaus to a final temperature of 900 ºC. CO_2 produced during the heating cycle is quantified with a non-dispersive infra-red (NDIR) detector and TC is calculated based on CO_2 produced and sample volume. The TC analyzer is automatically calibrated with 5% methane in helium after every analysis cycle.

Trajectory Calculations

Twenty-four hour back trajectories are generated using the interactive version of the NOAA HYSPLIT4 model on the NOAA-ARL web site (*12*). Back trajectories use EDAS 40 km meteorological data and default vertical motion, with starting heights of 1000 m, 500 m and 250 m, for the time (hour) of peak SO_2 concentration during each event. The 250 m trajectory is used to determine which CFPP affected the site, as well as time of emission at the CFPP.

Event Selection and Data Reduction

Event selection attempted to identify episodes with minimal contamination from non-CFPP sources. In general, this means that different episodes are used for TC and SO_4 analyses. For TC, we look for clean, well-ventilated conditions during the middle of the day, with low and stable CO concentrations. This avoids rush hour emissions and near-surface sources that tend to accumulate under the nocturnal boundary layer. While some VOC to SOA conversion is possible, the effect should be small during fall and winter because of: 1) low biogenic precursor emissions; and 2) low temperatures; and 3) low solar insolation. For SO_4, in contrast, we are less concerned with contamination from non-CFPP sources, but want to avoid strong sunlight and consequent photochemical production of secondary SO_4 within the plume. Thus, the majority of SO_4 events selected for this analysis occurred either at night or during the early morning hours.

TC emission ratios are calculated using the "ratio of deltas" method, as shown below,

$$ER_{TC} = (TC_{Plume}-TC_{Base})/(SO2_{Plume}-SO2_{Base}) = \Delta TC/\Delta SO_2, \quad \text{(Eq. 1)}$$

where subscripts Plume and Base refer to concentrations measured during the plume event and before or after the event, respectively. The technique is illustrated in Figure 4, which shows an event that occurred at Yorkville on April 9, 2006. The upper panel shows SO_2 and CO during the course of the day. Note that the regular gaps in the time series reflect zeroing cycles. SO_2 concentrations were <5 ppb until about 1430 local standard time (LST), when they increased sharply and remained above 40 ppb until about 1630, then fell below 5 ppb for the remainder of the day. CO concentrations were between 80 and 100 ppb for the entire day, indicating no evidence of plumes from biomass burning, transportation and other activities.

The lower panel shows time series for SO_2 (red symbols) and TC (black bars), also for April 9, 2006. In this case, SO_2 concentrations have been averaged to coincide exactly with the 47-minute Sunset collection period. The plume event is shown in the red box and the downward facing arrows indicate the two values used (i.e., averaged) to calculate Base concentration. The symbols and bars at 1500 LST and 1600 LST are averaged to calculate Plume concentration. Base and Plume concentrations are then used to calculate the ratio of deltas, as shown in Equation 1. Note that ΔTC during this event (0.22 µg/m^3) is quite small compared to the overall range of TC observed during the day, despite the fact that average SO_2 concentrations exceeded 75 ppb for the 47-minute period beginning at 1600 LST. This is typical of CFPP plume events and underscores the fact that CFPPs are minor sources of particulate carbon. In other words, large plumes are needed in order to even "see" an increase in TC. The small increment of TC associated with CFPP events places a high premium on stable TC measurements.

For several CFPP events, ΔTC was negative, indicating that Base concentrations were slightly higher than the Plume concentrations. Based on Equation 1, this implies a physically unrealistic negative ER. For these events, we used the detection limit for the Sunset analyzer (0.1 µg/m^3) in the numerator of Equation 1.

SO_4 emission ratios are calculated by linear least square regression of 1-minute SO_4 concentrations versus 1-minute SO_2 concentrations. The regression slope is equivalent to the primary SO_4/SO_2 emission ratio and the intercept is equivalent to the baseline SO_4 concentration in absence of the plume. Figure 5 illustrates an example SO_4 event which occurred at Yorkville on February 25, 2006. In the upper panel, SO_2 concentration is < 5 ppb until approximately 0400 (LST), increases to nearly 50 ppb just before 0600, then falls below 5 ppb by 0900. SO_4 concentrations (right hand scale) are < 1 ppb ($3.9\ \mu g/m^3$) the entire day, but show several minor excursions, some of which are associated with SO_2 excursions and some of which are not. The lower panel shows the scattergram of SO_4 versus SO_2 and associated regression statistics. Data for the regression correspond to the red box in the upper panel. Results show a highly significant relationship between SO_4 and SO_2 ($p<0.01$) with a regression slope of 0.0042 on a ppb/ppb basis. Given that the molecular weight of SO_4 is 1.5 times that of SO_2, the emission ratio for this event is 0.0063 lb/lb or 0.63 %.

It should be noted that both the ratio of deltas approach and the linear regression approach give upper bound estimates of TC and SO_4. The principal reason for this is dry deposition, which removes gaseous SO_2 from the plume much faster than particles. If we assume dry deposition to be a first order loss process, then the effect is to reduce ΔSO_2 in the denominator of equation 1 and thereby inflate the ratio $\Delta TC/\Delta SO_2$. Another reason is photochemical or non-photochemical production of secondary SO_4 and OC, which would increase SO_4 and, at the same time, decrease SO_2 in the plume. Although events have been carefully selected to minimize these effects, we cannot be certain they have been eliminated completely.

RESULTS

Table 1 summarizes results for 14 TC plume events observed at 4 sites. Data include the site which observed the CFPP plume, the likely source of the plume (based on trajectory analyses and SO_2/NO_y ratios) and concentration data for the ratio of deltas calculation. Mean $\Delta TC/\Delta SO_2$ for 11 events is 0.0032 +/- 0.0014 with a range of 0.0011 to 0.0066. OLF and Yorkville both observed 5 events. At OLF, all 5 events were from the Crist CFPP and these gave an emission ratio of 0.0020 +/- 0.0012 lb/lb. At Yorkville, the plume events likely originated from 3 different CFPPs and these gave an average ratio of 0.0033 +/- 0.0021 lb/lb. These events clearly show that TC is a small and difficult to detect component of CFPP emissions.

Table 2 summarizes results for 20 SO_4 plume events observed at 4 sites and likely originating from 8 different CFPPs. Data include the maximum observed 1-minute SO_2 concentration, plus the regression slope and r-squared for SO_4 vs. SO_2. Calculated values for $\Delta SO_4/\Delta SO_2$ range from 0.0030 to 0.0180 lb/lb with an average of 0.0064 lb/lb. In most cases, the regression is highly significant; however, r-square tends to decrease as slope decreases because instrument noise starts to dominate the SO_4 signal. These events clearly show that SO_4 is a small and difficult to detect component of CFPP emissions.

CONCLUSIONS

Continuous field measurements can be used to derive emission estimates for TC and SO_4 from CFPPs which are upper bound estimates of condensable carbon and condensable SO_3. Careful attention must be paid to plume event selection in order to avoid contamination from non-CFPP sources (TC) and photochemical activity in the CFPP plume (SO_4). Optimal conditions for both TC and SO_4 estimates appear to occur during the cooler months when photochemical activity is low and persistent winds advect relatively fresh CFPP plumes to the research sites. Plume analysis results show that primary TC emissions and primary SO_4 emissions from CFPPs are well below 1% of SO2 on a mass basis. For primary TC, analysis of 14 events from 7 different CFPPs gave an overall average emission ratio of 0.0032 lb TC/lb SO_2 (or 0.32% of SO2. For primary SO_4, analysis of 20 events from 8 different CFPPs gave an overall average emission ratio of 0.0064 lb SO_4/lb SO_2 (or 0.64% of SO_2).

Figure 1. The SEARCH Network

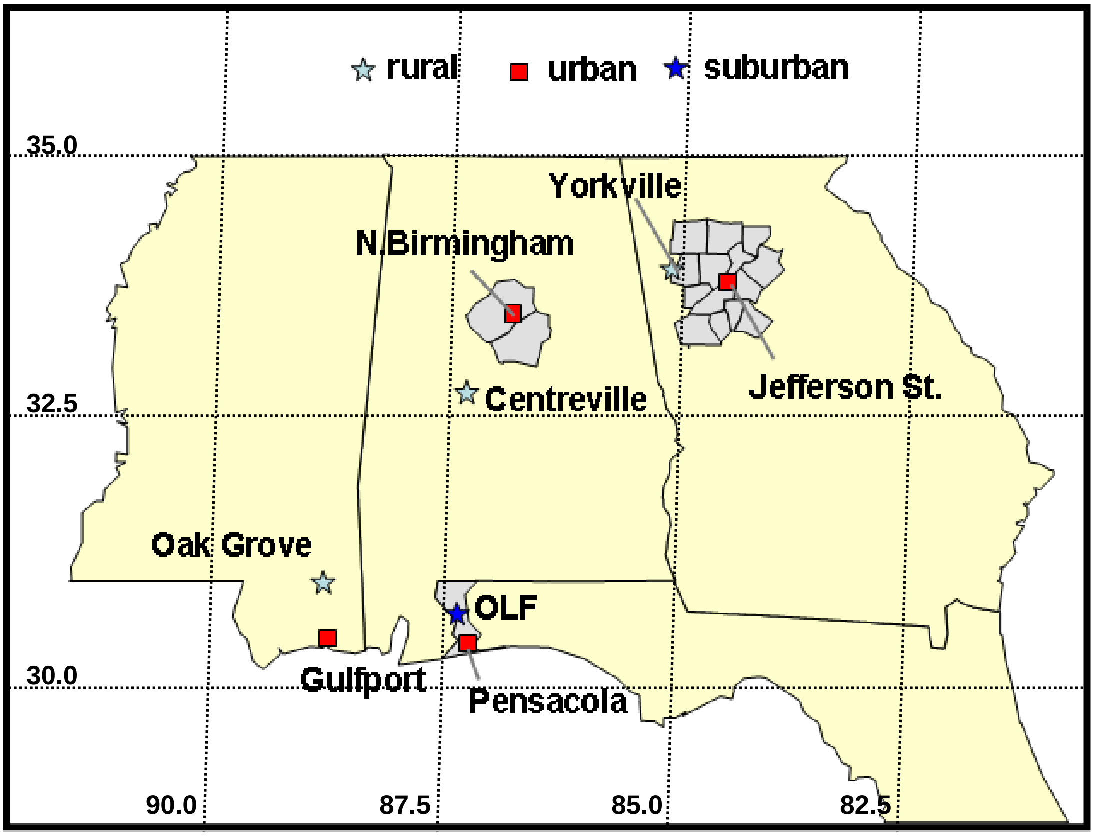


Figure 2. CFPPs observed at YRK (top) and CTR (bottom).

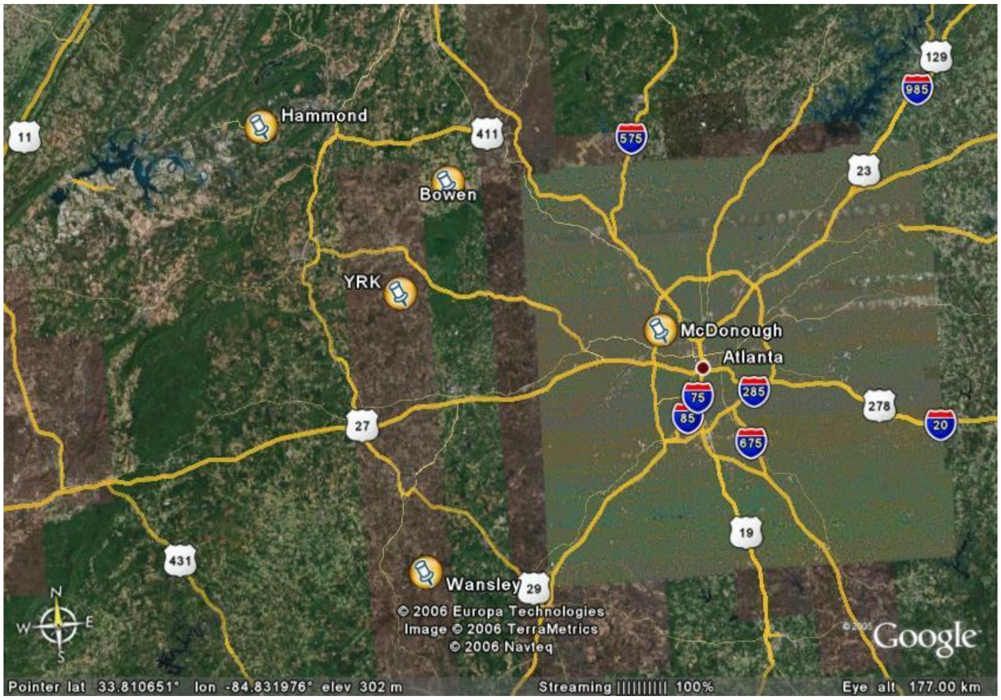


Figure 3. CFPPs observed at JST (top), OLF (middle) and GFP (bottom).

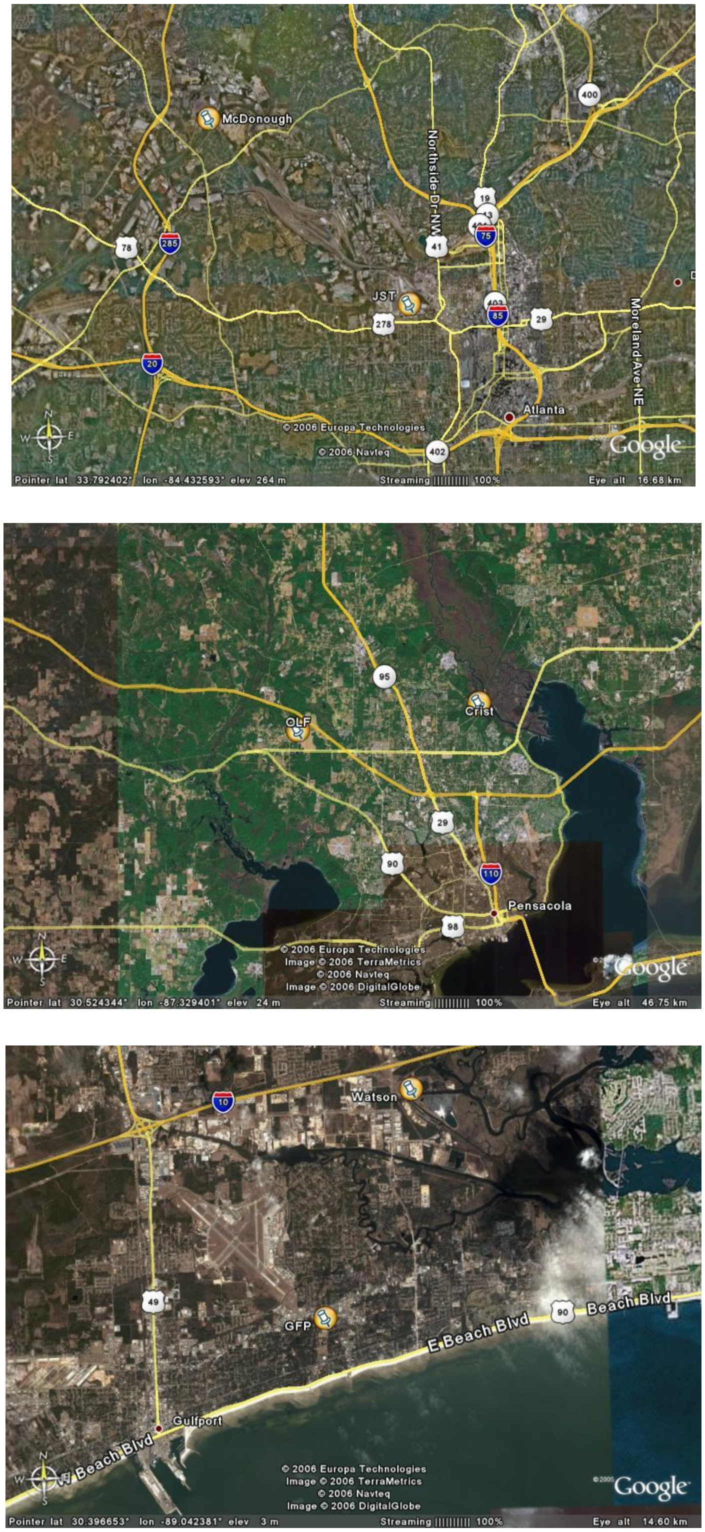
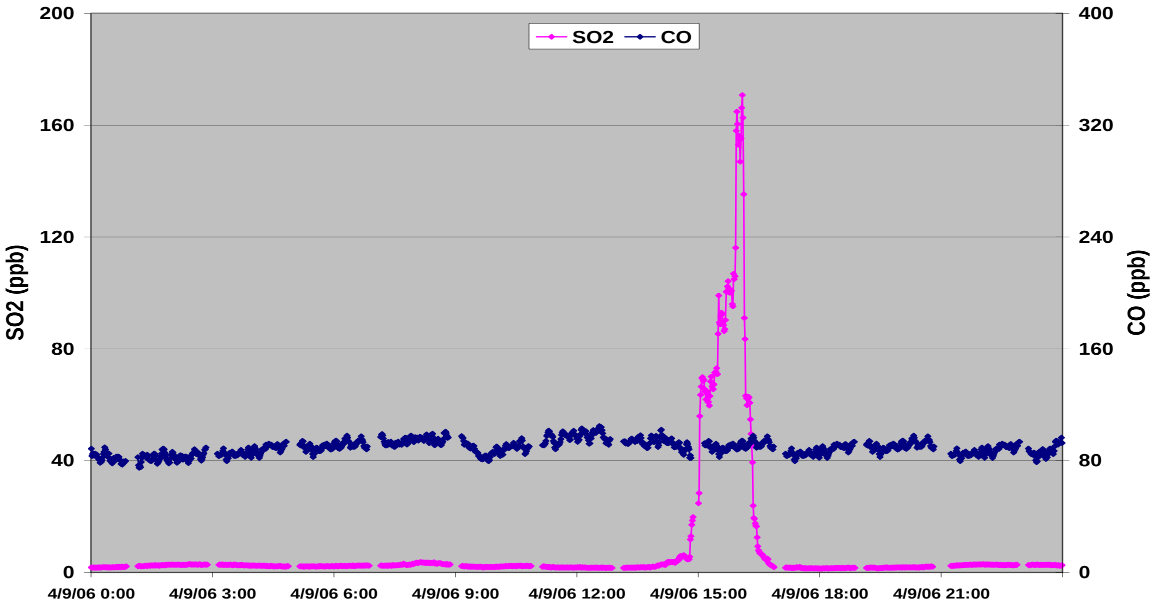


Figure 4. CFPP plume event at YRK showing 1-minute SO_2 and CO (top), 47-minute SO_2 and TC (bottom).



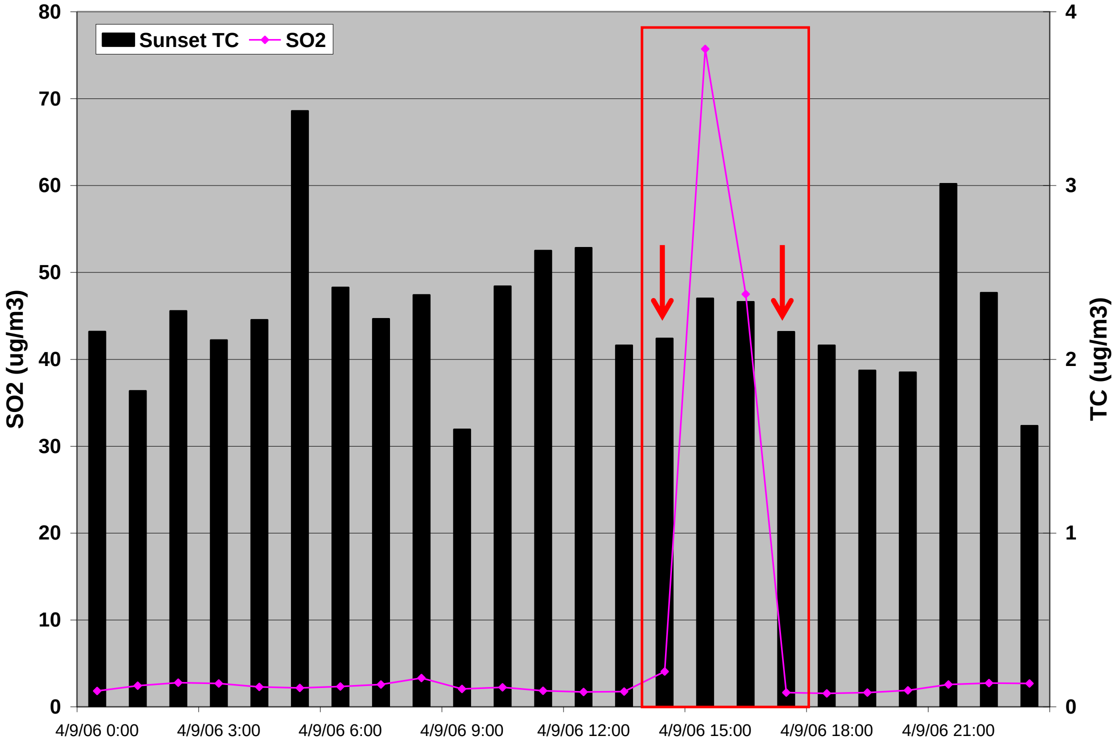


Figure 5. CFPP plume event at YRK showing SO_2 and SO_4 (top) and SO_4 vs. SO_2 (bottom).

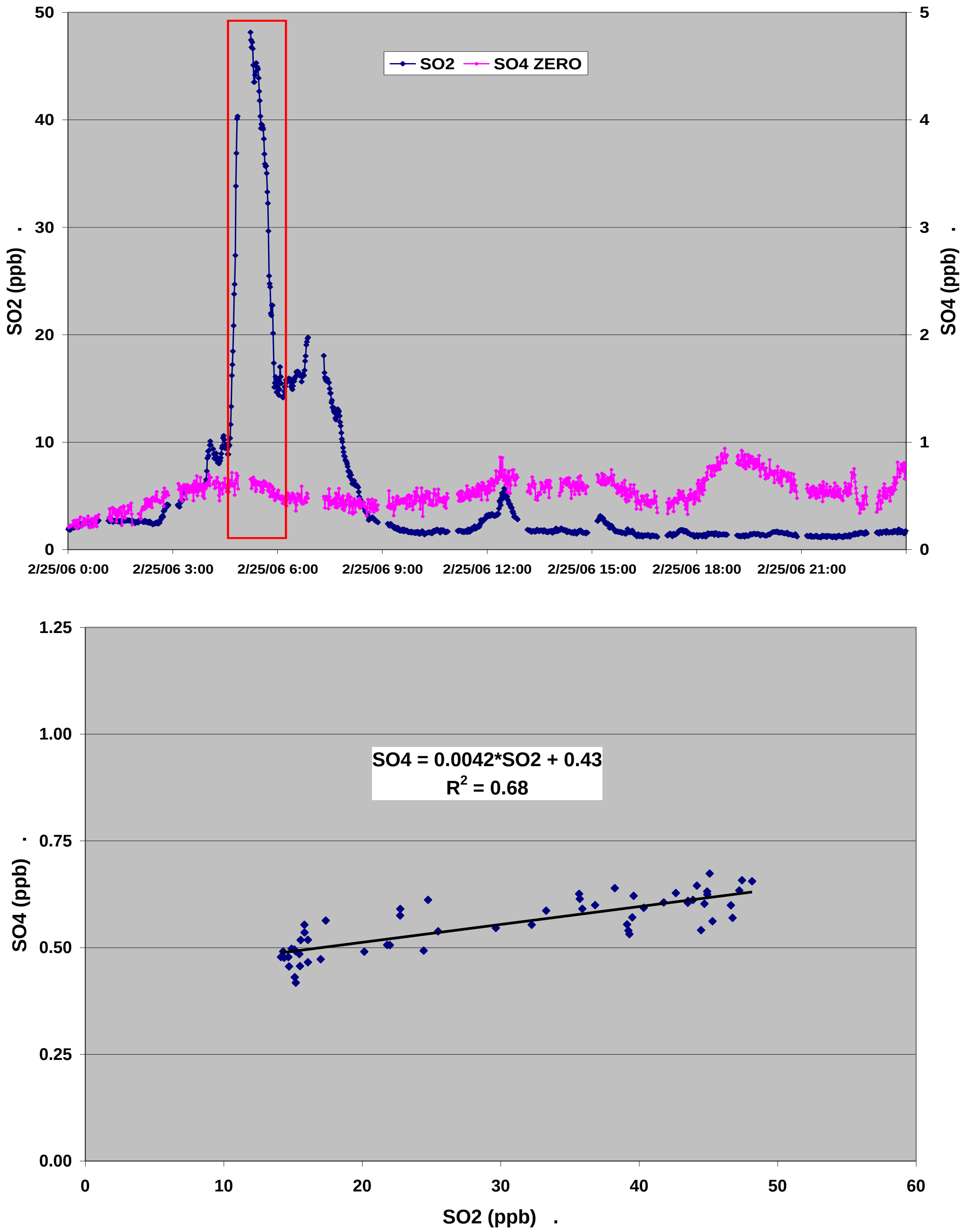


Table 1. Summary of Total Carbon Events.

Site	**Date**	**Probable CFPP**	**Base SO_2 (ppb)**	**Plume SO_2 (ppb)**	**Base TC (μg/m3)**	**Plume TC (μg/m3)**	**$\Delta TC/\Delta SO_2$ (lb/lb)**	**Alternate $\Delta TC/\Delta SO_2$ (lb/lb)**
CTR	12/18/05	Gaston	15.6	51.2	2.96	3.30	3.7×10^{-3}	
CTR	12/20/05	Gorgas	15.1	23.1	1.30	1.38	3.8×10^{-3}	
CTR	02/23/06	Miller	5.1	20.6	1.71	1.49	< 0	2.5×10^{-3}
JST	05/06/06	McDonough	3.5	64.5	3.35	3.6	1.6×10^{-3}	
OLF	11/25/05	Crist	11.9	38.9	2.22	2.38	2.3×10^{-3}	
OLF	02/07/06	Crist	4.2	34.6	2.22	2.38	2.0×10^{-3}	
OLF	02/24/06	Crist	11.1	35.0	1.48	1.70	3.5×10^{-3}	
OLF	04/28/06	Crist	4.3	41.2	3.53	3.48	< 0	1.2×10^{-3}
OLF	05/06/06	Crist	3.3	85.3	3.31	3.55	1.1×10^{-3}	
YRK	10/31/05	McDonough	6.3	48.8	2.72	3.45	6.59×10^{-3}	
YRK	02/25/06	Bowen	4.7	39.5	2.24	2.52	3.08×10^{-3}	
YRK	03/04/06	Bowen	5.5	33.4	3.49	3.72	3.15×10^{-3}	
YRK	03/11/06	Wansley	1.8	52.2	4.06	3.87	< 0	7.6×10^{-4}
YRK	04/09/06	Bowen	1.7	61.6	2.12	2.34	3.63×10^{-3}	
Mean **(s.d.)**							**3.2×10^{-3}** **(1.4×10^{-3})**	**1.5×10^{-3}** **(0.9×10^{-3})**

Note: Base and Peak concentrations based on 47-minute averages.

Table 2. Summary of SO_4 Events.

Site	Date	Probable CFPP	1-min Max. SO_2 (ppb)	SO_4 vs. SO_2 Slope	SO_4 vs. SO_2 R^2	$\Delta SO_4/\Delta SO_2$ (lb/lb)
CTR	12/07/05	Gorgas	49.7	5.6×10^{-3}	0.77	8.4×10^{-3}
CTR	12/17/05	Gorgas	21.4	2.0×10^{-3}	0.02	3.0×10^{-3}
CTR	12/17/05	Miller	29.6	2.5×10^{-3}	0.09	3.7×10^{-3}
CTR	12/18/05	Gaston	55.3	4.4×10^{-3}	0.70	6.6×10^{-3}
CTR	12/19/05	Gorgas	30.1	3.6×10^{-3}	0.13	5.4×10^{-3}
CTR	12/20/05	Gorgas	43.3	5.9×10^{-3}	0.81	8.9×10^{-3}
CTR	01/27/06	Miller	20.2	5.1×10^{-3}	0.20	7.7×10^{-3}
GFP	01/26/06	Watson	137.1	3.8 x 10-3	0.95	5.7×10^{-3}
GFP	02/19/06	Watson	49.9	3.6 x 10-3	0.34	5.4×10^{-3}
OLF	11/19/05	Crist	42.8	2.5×10^{-3}	0.08	3.7×10^{-3}
OLF	02/07/06	Crist	52.1	1.4×10^{-3}	0.02	2.1×10^{-3}
OLF	02/24/06	Crist	59.1	4.3×10^{-3}	0.29	6.5×10^{-3}
OLF	4/13/06	Crist	186.	5.4×10^{-3}	0.68	8.1×10^{-3}
YRK	10/09/05	Bowen	33.8	1.2×10^{-3}	0.10	1.8×10^{-3}
YRK	10/31/05	McDonough	73.4	10.0×10^{-3}	0.90	15.0×10^{-3}
YRK	11/11/05	McDonough	48.3	3.3×10^{-3}	0.43	4.9×10^{-3}
YRK	12/18/05	Bowen	202.8	6.6×10^{-3}	0.96	9.9×10^{-3}
YRK	02/08/06	Hammond	31.2	7.6×10^{-3}	0.64	11.4×10^{-3}
YRK	02/25/06	Bowen	47.4	4.4×10^{-3}	0.69	6.6×10^{-3}
YRK	03/04/06	Bowen	60.9	2.4×10^{-3}	0.09	3.6×10^{-3}
Mean **(s.d.)**						**6.4×10^{-3}** **(3.3×10^{-3})**

Appendix C

Use of Oak Grove SEARCH Data for Estimating Ambient NH3 Concentrations over the Gulf of Mexico

[The above titled paper is included as a separate document along with this site specific BART modeling protocol. This paper was prepared for Southern Company by Eric S. Edgerton of Atmospheric Research & Analysis, Inc.]

Use of Oak Grove Data for Estimating Ambient NH_3 Concentrations over the Gulf of Mexico

Submitted to

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Submitted by

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Cary, NC

December 20, 2011

Introduction

Gaseous ammonia (NH_3) is the predominant alkaline compound in the atmosphere and, as such, plays important roles in particle nucleation, aerosol neutralization and $PM_{2.5}$ accumulation. NH_3 is also of interest in regulatory circles as an input variable for Best Available Retrofit Technology (BART) modeling of aerosol concentrations in Class I areas. Most Class I areas are located on land, but some (including the Breton Island NWR) are located in marine environments. Hence, there is a regulatory requirement to specify NH_3 concentrations over the open waters of the Gulf of Mexico for model calculations. Unfortunately, there are no systematic measurements of NH_3 over the Gulf of Mexico. Therefore, it is necessary to estimate NH_3 concentrations based on other considerations. This report uses a weight of evidence approach to estimate NH_3 concentrations over the Gulf of Mexico and to recommend use of data from the Oak Grove, MS SEARCH site for BART calculations.

The SEARCH network is shown in Figure 1. SEARCH includes eight sites arranged in four rural-urban pairs in and around the cities of Atlanta, GA; Birmingham, AL; Pensacola, FL and Gulfport, MS. Four of the eight SEARCH sites that were operational between 2004 and 2008 are within 80 kilometers of the Gulf of Mexico. Of these, two are urban (GFP and PNS) one is suburban (OLF) and one is rural (OAK).

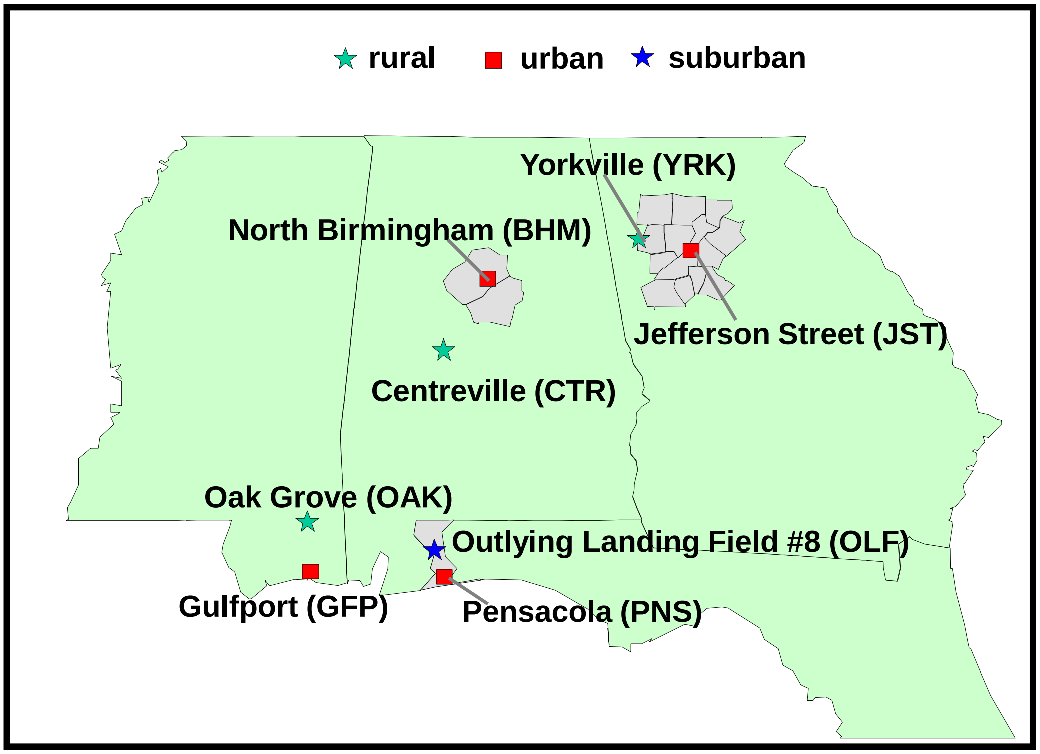

Figure 1. SEARCH air quality sites.

Figure 2 shows average NH3 concentrations for the SEARCH network for the 5-year period 2004-2008. Details of the sampling method are described in Edgerton et al. (2007). Briefly, 24-hour samples were collected on citric acid impregnated annular denuders following the USEPA 1 in 3 day national $PM_{2.5}$ sampling schedule. Denuder samples were extracted in 20 mL of deionized water then analyzed for dissolved NH_4^+ via ion chromatography. Field blanks were collected at each site and used to blank-correct data and to calculate the method detection limit (24 ppt). Measurement precision was 60 parts per trillion (ppt), based on collocated samplers at one site. SEARCH observations show roughly a 10-fold range of concentrations across the southeastern U.S. Lowest concentrations (c. 300 ppt) occur at rural-forested sites, while the highest concentrations (>2000 ppt) are observed at an urban-industrial site (BHM) or rural sites influenced by nearby animal husbandry (YRK). Average concentration for the four sites in proximity to the Gulf of Mexico range from 300 ppt at OAK to 700-800 ppt at GFP and PNS. If we take the regional signal to be on the order of 300 ppt, then the medium sized cities along the Gulf of Mexico are enhanced by about 500 ppt and the largest city (Atlanta) is enhanced by about 1000 ppt. NH_3 concentrations for the only suburban site in the network (OLF) are 50% (150 ppt) above the regional signal.

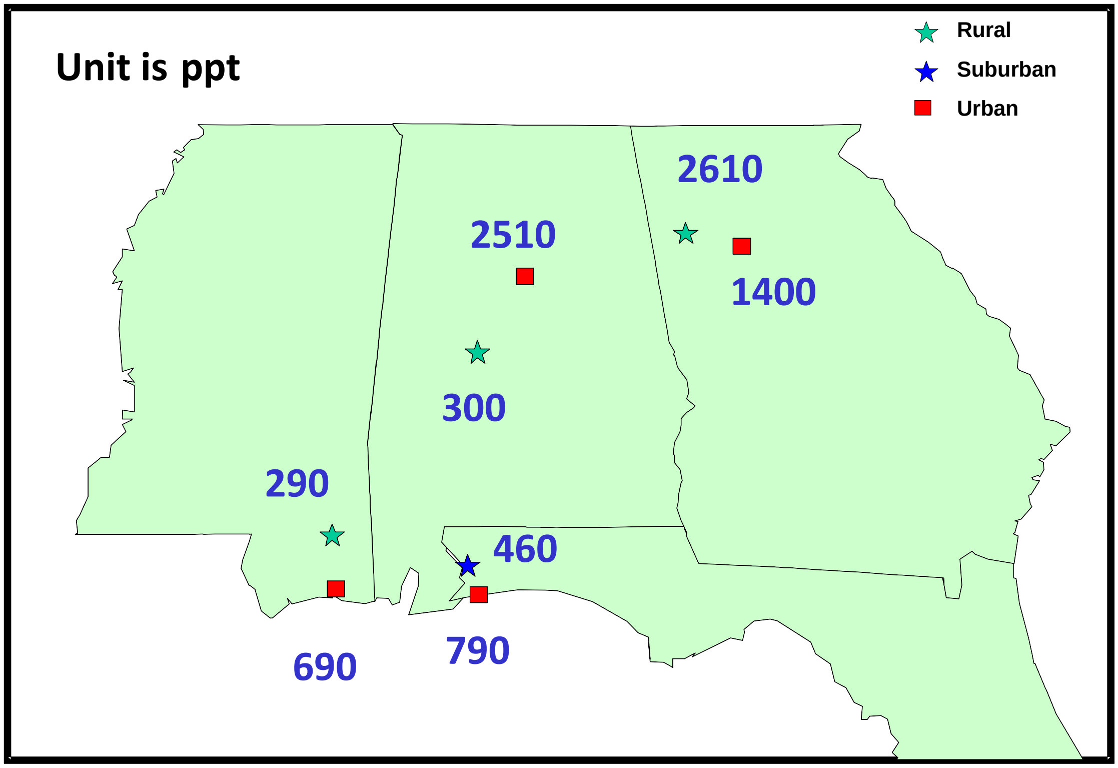

Figure 2. Average NH_3 concentrations at SEARCH sites, 2004-2008.

As a point of comparison, it is instructive to review NH_3 data from the major oceans of the world (see Table 1). These data are quite limited, but they show that NH_3 concentrations removed from terrestrial sources are uniformly <250 ppt. Data also suggest hemispheric differences, with values of approximately 100-250 ppt in the northern hemisphere and <100 ppt in the southern hemisphere. Broadly speaking, then, we would expect Gulf of Mexico NH_3 to fall somewhere in the range of northern hemispheric concentrations (i.e., 100-250 ppt).

Table 1. Mean atmospheric NH_3 concentrations from cruises in various oceanic regions.

Oceanic Region	Year	$NH_{3(g)}$ ppt	Reference
North Atlantic	2005	105	Johnson et al., 2008
Central Atlantic	2003	238	Norman and Leck, 2005
South Atlantic	2003	51	Norman and Leck, 2005
North Sea	2002	71	Johnson et al., 2008
Norwegian Sea	2001	184	Johnson et al., 2008
Indian Ocean	2003	27	Norman and Leck, 2005
Central pacific	1998	16	Quinn et al., 1990
Southern Ocean	1978	86	Ayers and Gras, 1980

NH_3 Emission Rates from Terrestrial and Marine Areas

Emission rate information can also shed light on concentrations because gradients in primary pollutants inevitably occur between areas with high emission density and those with low emission density. Figure 3 shows county-level NH_3 emission rates (kg-N/ha/yr) for the lower 48 states. These data are from the 2002 national emissions inventory compiled by the USEPA. Clearly, there is a broad range of emissions across the country as a whole as well as the southeast. The highest emission rates (>20 kg-N/ha/yr) are associated with agricultural areas (e.g., Iowa) and large urban centers (e.g., Atlanta, New York, Dallas); the lowest emission rates (≤1 kg-N/ha/yr) are associated with sparsely populated areas of the west, southeast, upper midwest and upper northeast. Not surprisingly, the pattern of emission rates across the southeast closely matches that of NH_3 concentrations observed in SEARCH. The overall ranges suggest a ratio of concentration to emission of roughly 100:1 to 200:1; that is, an emission rate of 1 kg-N/ha/yr equates to an ambient concentration of roughly 100-200 ppt.

Similar emissions data for the Gulf of Mexico would allow us to extrapolate NH_3 concentrations to the region of interest. Unfortunately, emissions data specific to the Gulf of Mexico are unavailable; however, Johnson et al. (2007) recently reviewed oceanic emission rates based on a series of research cruises that were conducted between 1995 and 2005. In general, results showed that that NH3 fluxes were higher in equatorial oceans (i.e., 20 degrees S latitude to 20 degrees N latitude) and lower in the more northern regions (i.e., ≥40 degrees N or S latitude), and that surface water temperature largely determined whether the ocean was a source or sink for NH_3 (Johnson et al. 2007). Maximum emission rates of about 0.75 kg-N/ha/yr were observed in the equatorial Atlantic and minimum emission rates of about 0.25 kg-N/ha/yr were observed in the north Atlantic. Intermediate emission rates were observed for latitudes bracketing the Gulf of Mexico. Combining these findings with the emission-concentration ratio from above suggests that average NH_3 concentrations in the Gulf of Mexico are likely to be ≤200 ppt.

Air Mass Trajectories

As noted above, average NH_3 concentrations at GFP, 1.6 kilometers from the Gulf of Mexico, are about 400 ppt higher than those at OAK, 70 kilometers from the Gulf which can be explained largely by emissions density as discussed above. This is the case on average, but there are many occasions when concentrations at GFP and OAK are much closer than 400 ppt. This feature of the data can be exploited to gain insight into concentrations over the Gulf of Mexico. Figure 4 shows individual 24-hour measurements for GFP and OAK for 2008 and 2009. GFP concentrations are usually higher, but concentrations converge to within +/- 100 ppt about 20% of the time. Air mass back trajectories were calculated to determine whether days with similar NH_3 concentrations at GFP and OAK were dominated by marine or terrestrial air masses. Twenty-four hour back trajectories were calculated for GFP with the NOAA-HY-SPLIT model using 40km resolution meteorological data as input and three starting elevations (200, 500 and 1000 meters above mean sea level). Results of these calculations show three general transport conditions for convergent NH_3 concentrations. The first and by far most common condition involves advection of air from the Gulf of Mexico (left panel). Advection from the Gulf of Mexico prevails on about 81% of the convergent days and is associated with an average NH_3 concentration of 260 ppt at GFP. The two other conditions (middle and right panels) involve rapid transport from Texas and the southwest (12%, 330 ppt) and transport from the north and northwest (8%, 220 ppt). These results show that NH_3 concentrations over the Gulf must be lower than average concentrations in GFP and are very likely on par with those at OAK.

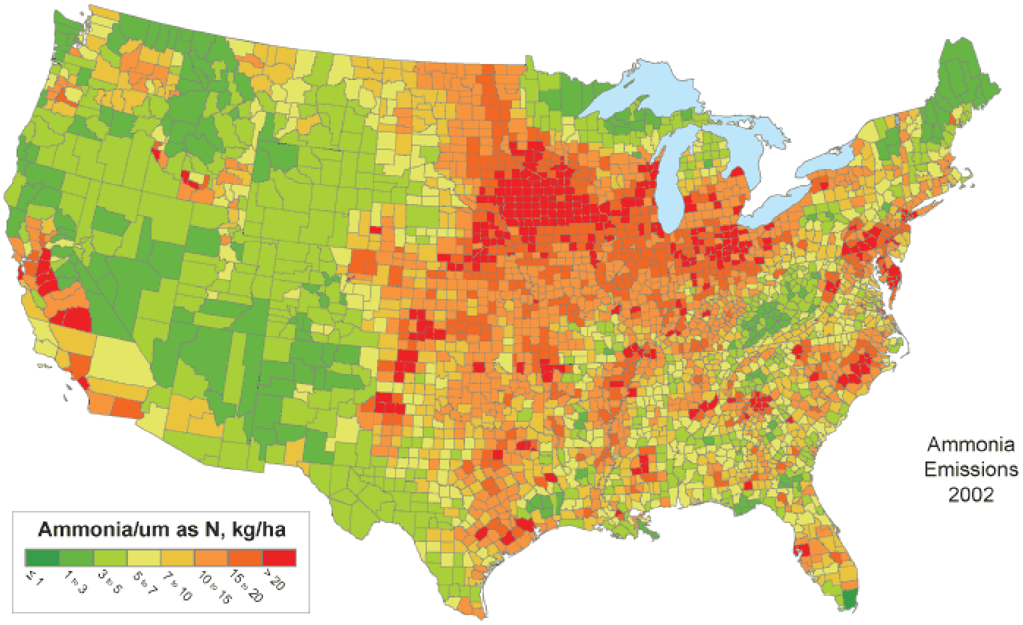

Figure 3. County-level NH_3 emission rates for CY2002 (NEI, 2002).

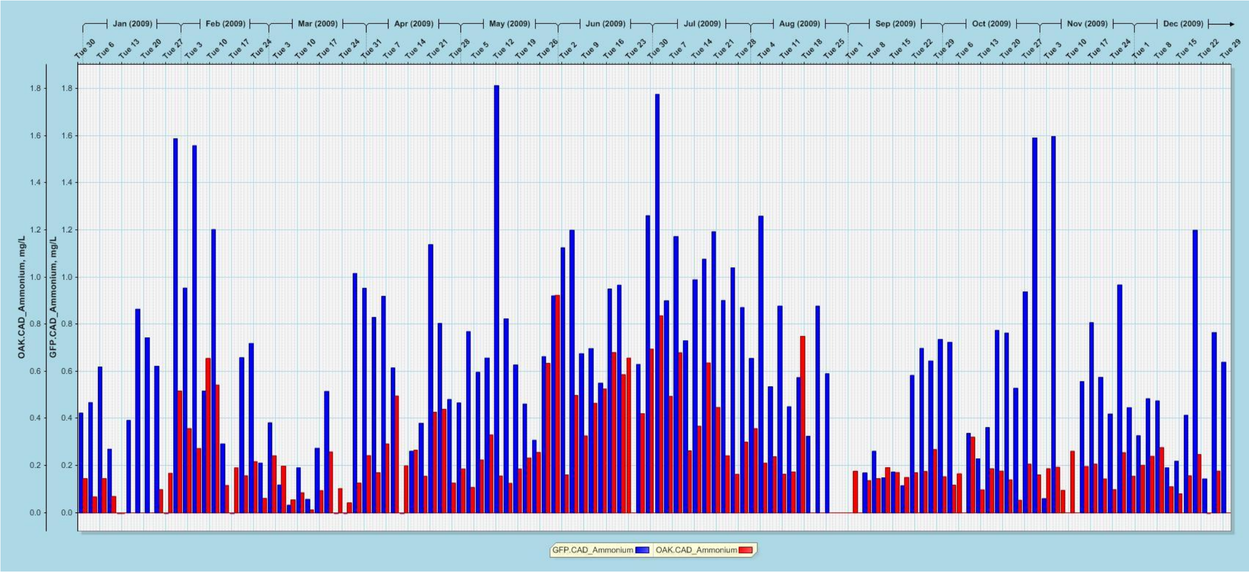

Figure 4. Daily NH_3 concentrations for GFP (blue) and OAK (red).

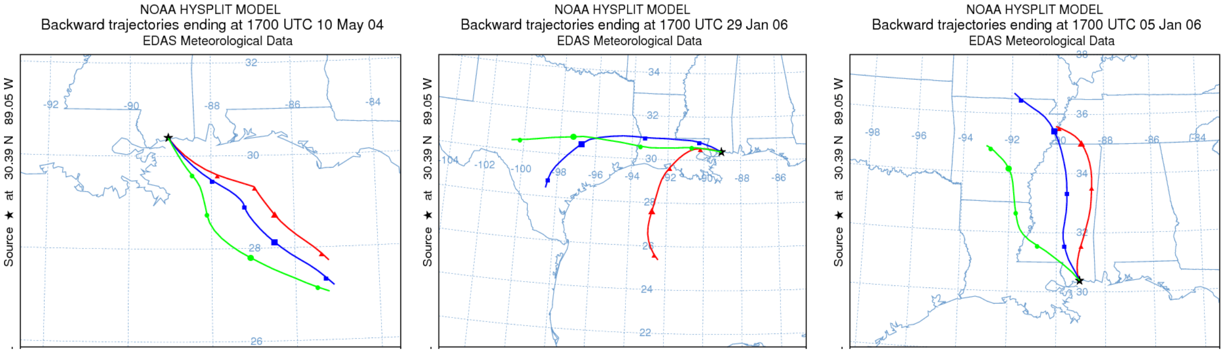

Figure 5. 1-day back trajectories for GFP illustrating transport on days when GFP NH_3 = OAK NH_3 ±100 ppt (200 m trajectory in green, 500 m blue, 1000 m red). Advection from Gulf (left), TX and SW (middle), N and NW (right).

Near-Coastal Monitoring Data from AMON

In addition to SEARCH, the National Acid Deposition Program operates the atmospheric ammonia monitoring network (AMON) to establish spatial patterns and temporal trends of NH_3 across the US and Canada. AMON has approximately 24 sites, some of which date back to 2007, but most were established in 2010. AMON uses a passive sampler (Radiello, Inc.) exposed continuously for 2-week periods to measure NH_3. The advantages of this approach include low cost and complete temporal coverage. Disadvantages of this approach include inability to quantify effects of short-term events (e.g., forest fires) and the assumption of a constant diffusion velocity to the passive collection surface. Despite the latter, long-term average concentrations from passive samplers are generally considered to be to comparable to those from active sampling techniques such as denuders.

One of the original AMON sites is located at Cape Romain, SC (see Figure 6). Cape Romain is a coastal-forested site located within a few kilometers of the Atlantic Ocean and has a complete data record for three calendar years (2008-2010).

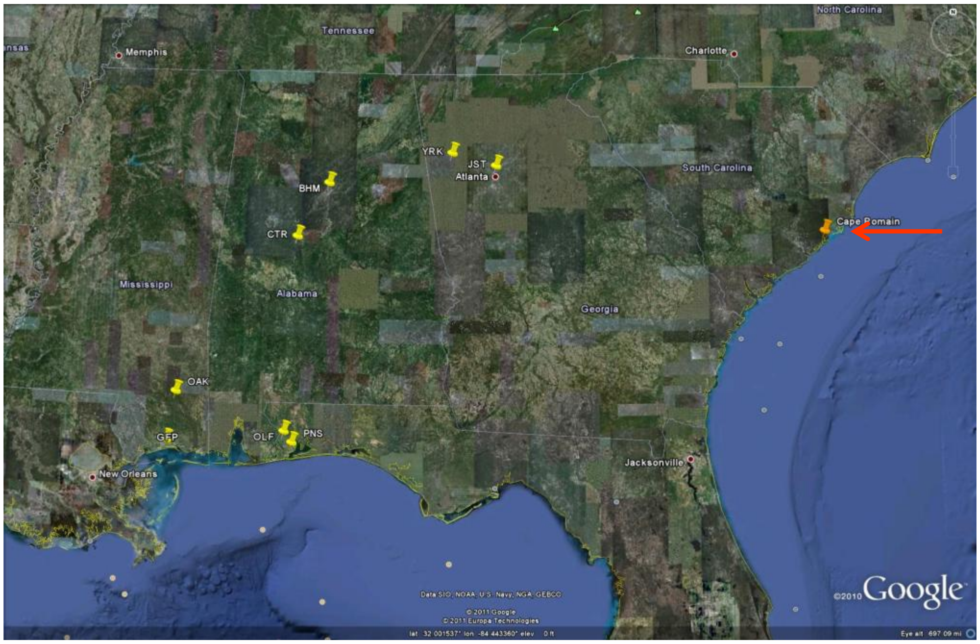

Figure 6. Google-Earth image showing SEARCH network and Cape Romain AMON site.

Table 2 shows ranked averages of NH_3 concentrations for the SEARCH network, plus Cape Romain. As can be seen, average NH_3 for Cape Romain (280 ppt) is virtually identical to OAK and CTR and appreciably lower than any other SEARCH site. Given the proximity of Cape Romain to the Atlantic, these data confirm low concentrations for marine air masses. de Kluizenaar and Farrell (2000) reported similarly low NH_3 concentrations for several coastal sites in western Ireland. For example, data from Connemara National Park in west central Ireland showed an annual average NH_3 concentration of 260 ppt. The authors noted that concentrations were well below average when transport was from the Atlantic, but did not attempt to stratify concentrations based on marine versus terrestrial provenance.

Table. 2. Ranked NH_3 concentrations for Cape Romain and SEARCH sites, 2008-2010.

Site	**Environment**	**Mean NH3, ppt**	**95% CI, ppt**
Yorkville, GA	Rural-Agricultural	2600	200
Birmingham, AL	Urban-Industrial	2460	160
Jefferson Street, GA	Urban	1270	70
Gulfport, MS	Urban	700	50
OLF, FL	Suburban	450	40
Centreville, AL	Inland-Forested	310	30
Oak Grove, MS	Inland-Forested	300	30
Cape Romain, SC	*Coastal-Forested*	*280*	*40*

Atmosphere-Seawater Equilibrium Calculations

Absent direct measurements, NH_3 concentrations can be estimated based on equilibrium partitioning between seawater and the atmosphere. This calculation requires seawater measurements of total dissolved ammonium, pH, temperature and salinity as shown below (Johnson et al, 2008):

$$NH_{3(g)eq} = 24.5x10^3 K_H[NH_x]K_a^* \qquad \text{(eq. 1)}$$

where,

$NH_{3(g)eq}$ = equilibrium NH_3 concentration in air, parts per trillion
K_H = Henry's Law constant for NH_3 solubility in seawater, unitless
= $1/[17.93x(T/273.15)exp((4092/T-9.70)]$
T = seawater temperature, K
$[NH_x]$ = total dissolved ammonium (NH_4^+ and NH_3) in seawater, nmol/L
$K_a^* = K_a/(K_a+[H^+])$, unitless
$[H^+]$ = seawater H^+ concentration = $10^{(-pH)}$
K_a = acidity constant for NH_3 = $10^{(-pKa)}$
$pK_a = -0.467 + 0.00113xS + 2887.9/T$
S = seawater salinity, parts per thousand

$NH_{3(g)eq}$ is weakly dependent on salinity, but highly dependent on both temperature and pH. As temperature increases, the Henry's Law constant increases, shifting NH_3 from the dissolved phase to the gas phase. As pH increases, K_a* increases, also shifting NH_3 to the gas phase.

There is an abundance of temperature, pH and salinity data for the Gulf of Mexico, but a paucity of good quality $[NH_x]$ data . One of the most extensive NH_x data sets was collected from July to August 2007 during the NOAA-Sponsored Gulf of Mexico East Coast Carbon (GOMECC) project (R/V Ronald H. Brown Cruise Report RB-07-05). The cruise started in Galveston, TX, traversed the Gulf of Mexico and eastern seaboard of the U.S. and ended in Boston, MA. The cruise track is shown in Figure 7. Semi-continuous surface water measurements of NH_x, salinity, temperature and pH were made at all stations (circles) in Figure 7 and along much of the path in between stations. The data set for the Gulf of Mexico includes 479 valid data points for $[NH_x]$ with an average value of 110 ± 60 nmol/L. Seawater temperature, salinity and pH during the Gulf of Mexico portion of the cruise were 29-31 degrees C, 35-36 and 8.0-8.1, respectively.

Table 3 shows estimated $NH_{3(g)eq}$ for the GoM based on GOMECC data. Bold values in Table 1 indicate the range of expected $NH_{3(g)eq}$ under observed conditions of pH and temperature, while other values are for lower temperatures outside the range of cruise observations, but encountered at other times of the year. For $[NH_x] = 110$ nmol/L, expected $NH_{3(g)eq}$ is in the range of 197 ppt (29C, pH 8.0) and 303 ppt (31C, pH 8.1). These results are very consistent with observed concentrations from the SEARCH Oak Grove site (inland-forested) and the AMON Cape Romain site (coastal-forested). Calculations also show much lower $NH_{3(g)eq}$ (50-150 ppt) for temperatures in the range of 15-25 C. In other words, if water chemistry is assumed to be more or less constant, then water temperature will drive expected $NH_{3(g)eq}$ even lower during cooler periods of the year.

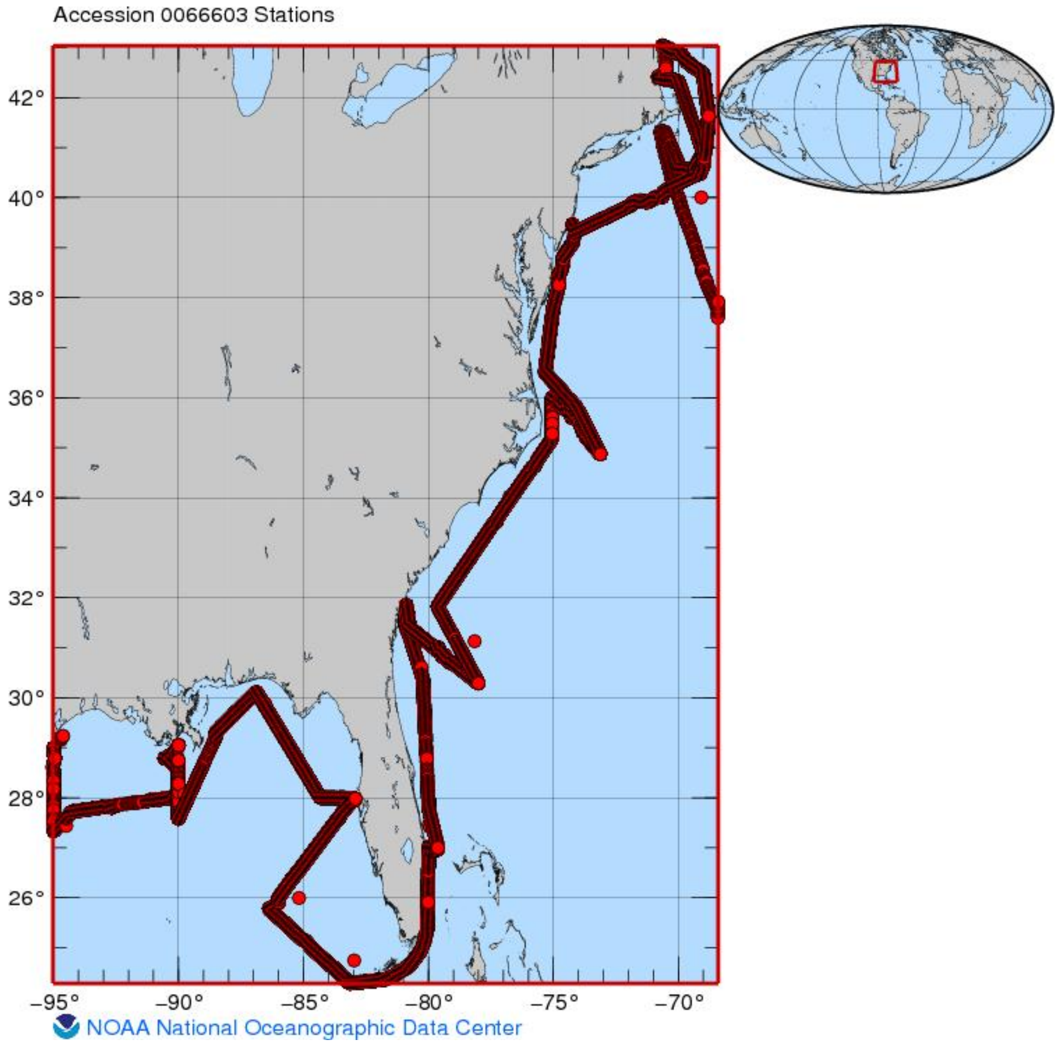

Figure 7. Cruise track for RV Brown GOMECC Project, July 11, 2007-August 4, 2007 (from R/V Ronald H. Brown Cruise Report RB-07-05).

Table 3. Calculated $NH_{3(g)eq}$ based on GOMECC observations (mean [NH_x]=110 nmol/L).

T, C	pH	pKa	K_H	[H+]	K_a	K_a*	$NH_{3(g)eq}$, ppt
29	**8.00**	**9.136**	**0.0011**	**1.00E-08**	**7.31E-10**	**0.068**	**197**
29	**8.05**	**9.136**	**0.0011**	**8.91E-09**	**7.31E-10**	**0.076**	**220**
29	**8.10**	**9.136**	**0.0011**	**7.94E-09**	**7.31E-10**	**0.084**	**244**
30	**8.00**	**9.105**	**0.0011**	**1.00E-08**	**7.86E-10**	**0.073**	**220**
30	**8.05**	**9.105**	**0.0011**	**8.91E-09**	**7.86E-10**	**0.081**	**245**
30	**8.10**	**9.105**	**0.0011**	**7.94E-09**	**7.86E-10**	**0.090**	**272**
31	**8.00**	**9.073**	**0.0012**	**1.00E-08**	**8.45E-10**	**0.078**	**245**
31	**8.05**	**9.073**	**0.0012**	**8.91E-09**	**8.45E-10**	**0.087**	**273**
31	**8.10**	**9.073**	**0.0012**	**7.94E-09**	**8.45E-10**	**0.096**	**303**
25	8.10	9.265	0.0009	7.94E-09	5.44E-10	0.064	157
20	8.10	9.430	0.0007	7.94E-09	3.72E-10	0.045	88
15	8.10	9.601	0.0006	7.94E-09	2.51E-10	0.031	48

Conclusions

Systematic measurements of atmospheric NH_3 concentrations over the Gulf of Mexico are non-existent and therefore it is necessary to use measurements from land-based stations or to estimate concentrations from other sources of information for the purpose of input into BART calculations. In this analysis, four convergent lines of evidence show that NH_3 concentrations at the Oak Grove, MS SEARCH site represent a realistic upper limit estimate for those over the Gulf of Mexico. These lines of evidence are as follows: 1) NH_3 emission rates imply lower NH_3 concentrations over the Gulf of Mexico than adjoining near-coastal areas; 2) NH_3 concentrations at the SEARCH site in Gulfport, MS average 260 ppt when air mass transport is on-shore from the Gulf of Mexico; 3) data from the near-coastal NADP AMON site at Cape Romain, SC exhibit long-term (2008-2010) average NH_3 concentrations of 280 ppt; and 4) equilibrium calculations based on Gulf of Mexico surface water chemistry suggest summertime NH_3 concentrations of roughly 200-300 ppt and much lower concentrations (<100 ppt) when water temperature is lower.

Table 4 contains monthly median concentration from OAK for the period 2004-2008. Given the large n for each month, it is suggested that these data comprise the most representative estimate of monthly variation over the Gulf of Mexico. It should be noted that the OAK data show peak NH3 concentrations in the spring, whereas seawater temperatures would suggest peak concentrations over the Gulf of Mexico during the summer (assuming constant seawater chemistry). Considering that fine particulate nitrate formation (i.e., NH_4NO_3) is promoted at lower temperatures (Seinfeld and Pandis, 1998), this implies that model calculations using OAK NH_3 data will tend to overestimate fine particulate nitrate concentrations over the Gulf of Mexico.

Table 4. Monthly median NH_3 concentrations at Oak Grove, MS SEARCH site, 2004-2008 (n ~ 50/month).

Month	Median NH3, ppt
1	205
2	190
3	290
4	395
5	380
6	220
7	190
8	150
9	180
10	190
11	180
12	200

References

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Galveston, TX – Boston, MA USA. Accessed from http://www.nodc.noaa.gov/General/gulfmex.html on 12/12/11.

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Pandis, S.N. 1998. Atmospheric Chemistry and Physics: From Air Pollution to Climate Change. Wiley-Interscience. New York, NY.

APPENDIX B

MODELING FILES

Plant Smith Units 1 and 2 - BART
Visibility Modeling Files

A. Baseline

Scenario	Compressed File Name
Baseline (2003-2005)	BASELINE.ZIP

B. Unit 1 Controlled, Unit 2 Uncontrolled

Scenario	Compressed File Name
SO_2	
Colombian Coal	U1SO2COAL.ZIP
DSI + Colombian Coal	U1SO2DSI_COAL.ZIP
WFGD	U1SO2WFGD.ZIP
NO_x	
SCR	U1NOXSCR.ZIP
PM	
Fabric Filter	UIPMFF.ZIP

C. Unit 2 Controlled, Unit 1 Uncontrolled

Scenario	Compressed File Name
SO_2	
Colombian Coal	U2SO2COAL.ZIP
DSI + Colombian Coal	U2SO2DSI_COAL.ZIP
WFGD	U2SO2WFGD.ZIP
NO_x	
SCR	U2NOXSCR.ZIP
PM	
Fabric Filter	U2PMFF.ZIP

D. File Organization

Each compressed file listed above contains the following 18 files:

XX = year of meteorology
01 = 2001, 02 = 2002, 03 = 2003

File Name	Description	No. of Files
Smith-4km_XX.inp	CALPUFF input file	3
Smith-4km_XX.lst	CALPUFF list file	3
PU-MNITRATE-4km_XX.inp	POSTUTIL input file	3
PU-MNITRATE-4km_XX.lst	POSTUTIL list file	3
vis-m8-stmarks-XX.inp	CALPOST input file	3
vis-m8-stmarks-XX.lst	CALPOST list file	3
	Total	18