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BART CONTROL ANALYSIS
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA
BELLE GLADE, FLORIDA

Prepared For:

Sugar Cane Growers Cooperative of Florida
Belle Glade Facility
Belle Glade, Florida

Prepared By:

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6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

January 2008

063-7534

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TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

LIST OF TABLES

TABLE OF CONTENTS
(continued)

LIST OF APPENDICES

TABLE OF CONTENTS
(continued)

LIST OF ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
bbl	barrel
Btu/gal	British thermal units per gallon
CAA	Clean Air Act
CFR	Code of Federal Regulations
dv	deciview
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FDEP	Florida Department of Environmental Protection
FGD	flue gas desulfurization
FR	Federal Register
gal	gallon
IMPROVE	Interagency Monitoring of Protected Visual Environments
km	kilometer
LAER	lowest achievable emission rate
lb/hr	pounds per hour
lb/MMBtu	pounds per million British thermal units
LEA	less excess air
MACT	Maximum Achievable Control Technology
NCASI	National Council for Air and Stream Improvement
NO_x	nitrogen oxides
NP	National Park
NSPS	New Source Performance Standards
NSR	new source review
NWA	National Wilderness Area
OAQPS	Office of Air Quality Planning and Standards
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter equal to or less than 2.5 microns

TABLE OF CONTENTS
(continued)

LIST OF ACRONYMS AND ABBREVIATIONS (cont'd)

PM_{10}	particulate matter with an aerodynamic diameter less than or equal to 10 microns
PSD	prevention of significant deterioration
RBLC	RACT, BACT, LAER Clearinghouse
SCGCF	Sugar Cane Growers Cooperative of Florida
SO_2	sulfur dioxide
SO_4	sulfate
TPY	tons per year
UTM	Universal Transverse Mercator
VOC	volatile organic compound

1.0 INTRODUCTION

Sugar Cane Growers Cooperative of Florida (SCGCF) operates a sugar mill in Belle Glade, Palm Beach County, Florida (Belle Glade facility). The sugar mill consists of seven regulated emissions units – six carbonaceous (bagasse and residue) fuel fired boilers and one paint spray booth. The facility is currently operating under Title V Permit No. 0990026-012-AV.

Under the regional haze regulations, contained in Title 40, Part 51 of the Code of Federal Regulations (40 CFR 51), Subpart P – Protection of Visibility, the U.S. Environmental Protection Agency (EPA) has issued final rules and guidelines, dated July 6, 2005, for Best Available Retrofit Technology (BART) determinations [Federal Register (FR), Volume 70, pages 39104-39172]. BART applies to certain large stationary sources known as BART-eligible sources. Sources are BART-eligible if they meet the following three criteria:

- Contains emissions units that are one of the 26 listed source categories in the guidance;
- Contains emissions units that were put in place between August 7, 1962 and August 7, 1977; and
- Potential emissions from the emissions units of at least 250 tons per year (TPY) of a visibility-impairing pollutant [sulfur dioxide (SO_2), nitrogen oxides (NO_x), and direct particulate matter (PM) with aerodynamic diameter less than or equal to 10 microns (PM_{10})].

The Belle Glade facility has been identified as a BART-eligible source with multiple BART-eligible emissions units.

The Florida Department of Environmental Protection (FDEP) has adopted EPA's visibility protection rules and guidelines contained in 40 CFR 51, Subpart P. The newly adopted rules became effective on January 31, 2007.

The basic tenet of the regional haze program is the achievement of natural visibility conditions in Prevention of Significant Deterioration (PSD) Class I areas by the year 2064. Florida has four PSD Class I areas, while Georgia has two PSD Class I areas that can be affected by Florida sources [i.e., located in Florida or within 300 kilometers (km) of Florida].

BART requirements potentially apply to any BART-eligible source that, pursuant to the FDEP BART regulations, emits an air pollutant that may "reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area." The BART guidelines establish a threshold value of 0.5 deciview (dv) for any single source (facility) for determining whether the source contributes to visibility impairment. The term "BART-eligible emissions unit" is defined as any single emissions unit that meets the criteria described above, except for the 250 TPY criterion, which applies to the entire BART-eligible source. A "BART-eligible source" is defined as the collection of all BART-eligible emissions units at a single facility. If a source has several emissions units, only those that meet the BART-eligible criteria are included in the definition of "BART-eligible source."

SCGCF submitted a BART applicability analysis and BART modeling protocol to FDEP on September 30, 2006 for the Belle Glade facility. A revised modeling protocol and BART exemption modeling analysis, submitted in January 2007, demonstrated that the maximum visibility impairment values for the BART-eligible source were less than the FDEP's BART exemption criteria of 0.5 dv. However, these results did not include the effect of light absorption due to nitrogen dioxide gas, which has now been accounted for in the analyses. As a result, the maximum visibility impairment values are now slightly above the exemption criteria, which means the Belle Glade facility is subject to the BART requirements and a BART determination analysis is required for each BART-eligible emissions unit at the facility.

As identified in the revised BART modeling protocol and the BART exemption modeling analysis submitted in January 2007, the list of BART-eligible, non-fugitive emissions units for the Belle Glade facility are as follows:

- Mill Boiler No. 1 (EU001),
- Mill Boiler No. 2 (EU002),
- Mill Boiler No. 4 (EU004), and
- Mill Boiler No. 5 (EU005).

Each of these emissions units requires an analysis of BART control options and a BART determination. This BART control analysis addresses these requirements and is organized into four additional sections, followed by appendices. A description of the BART-eligible emissions units, including air emission rates and air pollution control equipment, is presented in Section 2.0. The BART exemption modeling analysis results are presented in Section 3.0. The procedural requirements for the analysis of BART control options are presented in Section 4.0. The BART analysis for each emissions unit is presented in Section 5.0. The revised modeling protocol submitted in January 2007 is included in Appendix A.

2.0 DESCRIPTION OF BART-ELIGIBLE EMISSIONS UNITS

The Belle Glade facility is located in Palm Beach County, Florida. An area map showing the facility location and PSD Class I areas located within 300 km of the facility is presented in Figure 1-1 of the revised BART modeling protocol (see Appendix A). The PSD Class I areas and their distances from the Belle Glade facility are as follows:

- Everglades National Park (NP) – 105 km, and
- Chassahowitzka National Wilderness Area (NWA) – 289 km.

The Universal Transverse Mercator (UTM) coordinates of the Belle Glade facility are approximately 534.9 km east and 2,953.3 km north in UTM Zone 17.

BART-eligible emissions units at the Belle Glade facility are Boiler Nos. 1, 2, 4, and 5. The stack, operating, and SO_2, PM_{10}, and NO_x emissions data, including PM speciation, for the four boilers are presented in detail in the Protocol in Appendix A.

SCGCF is permitted to operate all of these boilers during the sugarcane processing season (October through April). All the boilers at the Belle Glade facility can fire bagasse and No. 6 fuel oil. Since bagasse firing and No. 6 fuel oil firing result in different air emissions, two cases were considered in developing the emissions used in the visibility modeling. The first case is 100 percent bagasse firing, which is the normal operating case. The second case is maximum No. 6 fuel oil firing, with the remainder of heat input due to bagasse. This second case occurs rarely in practice.

Based on the EPA BART guidelines (see FR, Vol. 70, No. 128, page 39162), SCGCF does not believe that the No. 6 fuel oil-firing scenario is a condition that should be modeled for visibility impacts. This fuel firing scenario occurs sporadically and is not reflective of "steady-state operating conditions during periods of high capacity utilization," making this operation inappropriate for modeling. Nevertheless, at FDEP's request, modeling for this operation was performed.

PM/PM_{10} emissions from the SCGCF boilers are controlled by impingement wet scrubbers preceded by multiple cyclone dust collectors. Operating hours for each boiler are limited to 7,296 hours per year. PM emissions from Boiler Nos. 1, 2, and 5 are limited to 0.25 pounds per million British thermal unit (lb/MMBtu) of heat input for carbonaceous fuels plus 0.1 lb/MMBtu heat input for fossil fuels. PM emissions from Boiler No. 4 are limited to 0.20 lb/MMBtu of heat input for carbonaceous fuels plus 0.1 lb/MMBtu heat input for fossil fuel. Total mass emissions are synthetically limited to 243.2, 240.6, 417.8, and 400.5 TPY for Boiler Nos. 1, 2, 4, and 5, respectively.

SO_2 emissions from all boilers are limited to 14 tons per day. The sulfur content of the No. 6 fuel oil is limited to 2.4 percent. NO_x emissions from each boiler are limited to 0.45 lb/MMBtu, which is not federally enforceable. Currently, there are no SO_2 or NO_x emissions add-on control systems in place for any of the boilers.

3.0 BART EXEMPTION MODELING ANALYSIS AND RESULTS

A BART modeling protocol for the Belle Glade facility was submitted to FDEP on September 30, 2006 and a revised protocol was submitted in January 2007. Initial visibility modeling was conducted to determine if the BART-eligible source could be exempt from BART, based on its impacts at the Class I areas. The baseline emissions and methodology used for the exemption modeling and the exemption modeling results are presented below.

3.1 Emission Rates

The emissions used for visibility modeling for the Belle Glade facility are contained in the BART modeling protocol, which is included as Appendix A.

3.2 Modeling Methodology

The CALPUFF model, Version 5.756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of the Belle Glade facility. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol. The 4-km spacing Florida domain was used for the BART exemption modeling. The refined CALMET domain used for the SCGCF modeling analysis has been provided by FDEP. The major features used in preparing these CALMET data have also been described in Section 4.0 of the Protocol.

Currently, atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the EPA under the 1999 Regional Haze Rule and is referred to as the "1999 IMPROVE" algorithm. This algorithm for estimating light extinction from particle speciation data tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near coastal areas. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3.4 of the Protocol.

Both the 1999 IMPROVE algorithm and the new IMPROVE algorithm were used to calculate the natural background light extinction at the Class I areas for the SCGCF modeling analysis. Visibility impacts were predicted at each PSD Class I area using receptors provided by the National Park Service, as presented in the BART protocol.

3.3 BART Exemption Modeling Results

Summaries of the maximum visibility impairment values for the SCGCF BART-eligible emissions units estimated using the 1999 IMPROVE algorithm, and for the "normal operations" scenario (100-percent bagasse firing), are presented in Tables 3-1 and 3-2. In Table 3-1, the 98th percentile 24-hr average visibility impairment values (i.e., 8th highest) for the years 2001, 2002 and 2003, and the 22nd-highest 24-hr average visibility impairment value over the 3 years, are presented. This table also presents the number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv. The eight highest visibility impairment values predicted at the PSD Class I areas for each year are presented in Table 3-2.

As shown in Tables 3-1 and 3-2, the 8th-highest visibility impairment values predicted for each year for the normal operation scenario, using the 1999 IMPROVE algorithm, are greater than 0.5 dv at the Everglades NP, but are below 0.5 dv at the Chassahowitzka NWA. The 22nd-highest visibility impairment value predicted over the 3-year period is also greater than 0.5 dv at the Everglades NP, but less than 0.5 dv at Chassahowitzka NWA.

The 8th-highest and the 22nd-highest visibility impairment values for the SCGCF BART-eligible emissions units, estimated for the normal operation scenario using the new IMPROVE algorithm, are presented in Table 3-3. The eight highest values for each year are shown in Table 3-4. As shown, the 8th-highest visibility impairment values predicted for each year using the new IMPROVE algorithm are lower than those predicted with the 1999 IMPROVE algorithm, but the value for 2003 is still slightly greater than 0.5 dv.

The 8th-highest visibility impairment values and the eight highest values, predicted for each year for the No. 6 fuel oil firing scenario using the 1999 IMPROVE algorithm, are presented in Tables 3-5 and 3-6. The results show that the impacts are greater than 0.5 dv at the Everglades NP, but are below 0.5 dv at the Chassahowitzka NWA. The 22nd-highest visibility impairment value predicted over the 3-year period is also greater than 0.5 dv at the Everglades NP but less than 0.5 dv at Chassahowitzka NWA.

The 8th-highest, and the eight highest, visibility impairment values for the SCGCF BART-eligible emissions units, estimated for the No. 6 fuel oil firing scenario using the new IMPROVE algorithm, are presented in Tables 3-7 and 3-8. As shown, the 8th-highest visibility impairment values predicted for each year using the new IMPROVE algorithm are lower than those predicted with the 1999 IMPROVE algorithm, but the values for all years are still greater than 0.5 dv.

Based on these results, the Belle Glade facility is subject to the BART requirements and a BART determination analysis is required for each of the BART-eligible emissions units at the facility. Since the visibility impacts due to the facility were found to be more than 0.5 dv only at the Everglades NP, the BART determination analysis will include only this Class I area.

The 8th highest impacts of each BART-eligible unit and the contributions of the individual visibility impairing pollutants to those impacts for each unit predicted at the Everglades NP for the normal operation and the No. 6 fuel oil firing scenario are presented in Tables 3-9 and 3-10, respectively. The visibility impairing pollutants include sulfate (SO_4), nitrate, and PM_{10}.

TABLE 3-1
SUMMARY OF BART EXEMPTION MODELING RESULTS, NORMAL OPERATION - 1999 IMPROVE ALGORITHM
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA

Class I Area	Distance from Source to Nearest Class I Area Boundary (km)	Number of Days and Receptors with Change in Haze Index > 0.5 dv									22nd Highest Impact (dv) Over 3-Yr Period
		2001			2002			2003			
		No. of Days	No. of Receptors	8th Highest Impact (dv)	No. of Days	No. of Receptors	8th Highest Impact (dv)	No. of Days	No. of Receptors	8th Highest Impact (dv)	
Everglades NP	105	8	528	0.497	7	208	0.492	12	578	0.609	0.508
Chassahowitzka NWR	289	0	0	0.133	0	0	0.135	0	0	0.091	0.124

TABLE 3-2
VISIBILITY IMPACT RANKINGS AT CLASS I AREAS, NORMAL OPERATION
1999 IMPROVE ALGORITHM
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA

		Predicted Change in Visibility Impact (dv)		
Class I Area	**Rank**	**2001**	**2002**	**2003**
Everglades NP	1	1.095	0.908	1.163
	2	0.612	0.636	0.973
	3	0.523	0.574	0.716
	4	0.517	0.512	0.715
	5	0.510	0.509	0.662
	6	0.508	0.505	0.614
	7	0.503	0.499	0.610
	8	0.497	0.492	0.609
Chassahowitzka NWA	1	0.215	0.220	0.278
	2	0.207	0.186	0.165
	3	0.187	0.176	0.145
	4	0.155	0.170	0.139
	5	0.141	0.147	0.118
	6	0.140	0.141	0.118
	7	0.138	0.136	0.093
	8	0.133	0.135	0.091

TABLE 3-3
SUMMARY OF BART EXEMPTION MODELING RESULTS, NORMAL OPERATION - NEW IMPROVE ALGORITHM
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA

Class I Area	Distance from Source to Nearest Class I Area Boundary (km)	Number of Days and Receptors with Change in Haze Index > 0.5 dv									22nd Highest Impact (dv) Over 3-Yr Period
		2001			2002			2003			
		No. of Days	No. of Receptors	8th Highest Impact (dv)	No. of Days	No. of Receptors	8th Highest Impact (dv)	No. of Days	No. of Receptors	8th Highest Impact (dv)	
Everglades NP	105	1	NA	0.434	2	NA	0.434	7	NA	0.520	0.445

TABLE 3-4
VISIBILITY IMPACT RANKINGS AT CLASS I AREAS, NORMAL OPERATION
NEW IMPROVE ALGORITHM
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA

Class I Area	Rank	Predicted Change in Visibility Impact (dv) 2001	2002	2003
Everglades NP	1	0.928	0.779	0.993
	2	0.518	0.556	0.834
	3	0.460	0.498	0.640
	4	0.458	0.460	0.604
	5	0.443	0.450	0.597
	6	0.442	0.445	0.553
	7	0.440	0.445	0.533
	8	0.434	0.434	0.520

TABLE 3-5
SUMMARY OF BART EXEMPTION MODELING RESULTS, NO. 6 FUEL OIL FIRING SCENARIO, 1999 IMPROVE ALGORITHM
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA

Class I Area	Distance from Source to Nearest Class I Area Boundary (km)	Number of Days and Receptors with Change in Haze Index > 0.5 dv									22nd Highest Impact (dv) Over 3-Yr Period
		2001			2002			2003			
		No. of Days	No. of Receptors	8th Highest Impact (dv)	No. of Days	No. of Receptors	8th Highest Impact (dv)	No. of Days	No. of Receptors	8th Highest Impact (dv)	
Everglades NP	105	18	839	0.599	22	574	0.691	23	901	0.722	0.691
Chassahowitzka NWA	289	1	37	0.21	2	113	0.34	1	113	0.208	0.260

TABLE 3-6
VISIBILITY IMPACT RANKINGS AT CLASS I AREAS
NO. 6 FUEL OIL FIRING SCENARIO
1999 IMPROVE ALGORITHM
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA

Class I Area	Predicted Change in Visibility Impact (dv)			
	Rank	2001	2002	2003
Everglades NP	1	1.740	1.209	1.426
	2	0.746	0.969	1.150
	3	0.721	0.943	1.080
	4	0.720	0.932	1.063
	5	0.655	0.769	1.002
	6	0.652	0.723	0.905
	7	0.631	0.712	0.806
	8	0.599	0.691	0.722
Chassahowitzka NWA	1	0.528	0.750	0.569
	2	0.325	0.723	0.408
	3	0.309	0.469	0.339
	4	0.299	0.462	0.253
	5	0.280	0.388	0.231
	6	0.278	0.371	0.228
	7	0.250	0.350	0.219
	8	0.210	0.340	0.208

TABLE 3-7
SUMMARY OF BART EXEMPTION MODELING RESULTS, NO. 6 FUEL OIL FIRING SCENARIO - NEW IMPROVE ALGORITHM
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA

Class I Area	Distance from Source to Nearest Class I Area Boundary (km)	Number of Days and Receptors with Change in Haze Index > 0.5 dv									22nd Highest Impact (dv) Over 3-Yr Period
		2001			2002			2003			
		No. of Days	No. of Receptors	8th Highest Impact (dv)	No. of Days	No. of Receptors	8th Highest Impact (dv)	No. of Days	No. of Receptors	8th Highest Impact (dv)	
Everglades NP	105	5	NA	0.502	10	NA	0.553	12	NA	0.578	0.553

TABLE 3-8
VISIBILITY IMPACT RANKINGS AT CLASS I AREAS
NO. 6 FUEL OIL FIRING SCENARIO
NEW IMPROVE ALGORITHM
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA

Class I Area	Predicted Change in Visibility Impact (dv)			
	Rank	2001	2002	2003
Everglades NP	1	1.366	0.936	1.153
	2	0.598	0.804	0.940
	3	0.578	0.750	0.865
	4	0.576	0.720	0.834
	5	0.524	0.598	0.782
	6	0.523	0.590	0.717
	7	0.505	0.563	0.651
	8	0.502	0.553	0.578

TABLE 3-9
CONTRIBUTION OF VISIBILITY IMPAIRING PARTICLE SPECIES TYPES - BAGASSE FIRING ONLY

		Percent Contribution to 8th Highest Visibility Impact (dv)											
		2001				2002				2003			
		Visibility	Contribution of [a]			Visibility	Contribution of [a]			Visibility	Contribution of [a]		
Emission Unit	Unit ID	Impact (dv)	SO_4 (%)	NO_3 (%)	PM_{10} (%)	Impact (dv)	SO_4 (%)	NO_3 (%)	PM_{10} (%)	Impact (dv)	SO_4 (%)	NO_3 (%)	PM_{10} (%)
Boiler No. 1	B1	0.044	20.1	27.5	46.9	0.049	22.1	5.8	64.5	0.059	19.5	35.7	39.3
Boiler No. 2	B2	0.035	31.2	10.2	55.4	0.038	23.7	19.0	52.6	0.043	24.3	14.0	56.2
Boiler No. 4	B4	0.200	11.9	36.9	39.3	0.199	14.5	22.1	49.0	0.233	13.6	27.1	45.6
Boiler No. 5	B5	0.155	20.9	7.4	62.3	0.157	14.0	17.7	56.6	0.195	17.9	14.0	61.7
BART-Eligible Source		0.434	15.9	32.8	44.9	0.434	16.3	32.7	45.0	0.520	14.1	35.4	44.1

[a] Visibility impairing sulfate particles are formed due to SO_2 and H_2SO_4 emissions, nitrate particles are formed due to NO_x emissions, and other non-hygroscopic PM_{10} particles are a result of fine filterable PM_{10}, coarse filterable PM_{10}, elemental carbon, and condensable secondary organic aerosol emissions.

TABLE 3-10
BART ANALYSIS FOR SUGAR CANE GROWERS COOPERATIVE OF FLORIDA
CONTRIBUTION OF VISIBILITY IMPAIRING PARTICLE SPECIES TYPES - BAGASSE AND FUEL OIL FIRING

		Percent Contribution to 8th Highest Visibility Impact (dv)											
		2001				2002				2003			
		Visibility	Contribution of [a]			Visibility	Contribution of [a]			Visibility	Contribution of [a]		
Emission Unit	Unit ID	Impact (dv)	SO_4 (%)	NO_3 (%)	PM_{10} (%)	Impact (dv)	SO_4 (%)	NO_3 (%)	PM_{10} (%)	Impact (dv)	SO_4 (%)	NO_3 (%)	PM_{10} (%)
Boiler No. 1	B1	0.071	64.1	5.0	25.5	0.081	64.0	5.7	22.7	0.086	71.1	11.1	14.2
Boiler No. 2	B2	0.065	72.0	2.7	21.8	0.074	70.7	3.9	20.1	0.081	78.3	1.7	15.5
Boiler No. 4	B4	0.207	35.4	18.5	36.0	0.240	31.5	23.5	37.1	0.284	41.4	16.4	35.6
Boiler No. 5	B5	0.169	35.2	26.5	32.1	0.187	39.1	32.7	24.1	0.216	40.2	13.1	40.7
BART-Eligible Source		0.502	39.7	15.9	36.1	0.553	48.0	27.8	20.1	0.578	48.7	13.8	30.3

[a] Visibility impairing sulfate particles are formed due to SO_2 and H_2SO_4 emissions, nitrate particles are formed due to NOx emissions, and other non-hygroscopic PM_{10} particles are a result of fine filterable PM_{10}, coarse filterable PM_{10}, elemental carbon, and condensable secondary organic aerosol emissions.

4.0 REQUIREMENTS FOR ANALYSIS OF BART CONTROL OPTIONS

The visibility regulations define BART as follows:

> *Best Available Retrofit Technology (BART)* means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by [a BART-eligible source]. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. [FR, Volume 70, pages 39104-9172].

The BART analysis identifies the best system of continuous emission reduction taking into account:

1. The available retrofit control options,
2. Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
3. The costs of compliance with control options,
4. The remaining useful life of the facility,
5. The energy and non-air quality environmental impacts of control options, and
6. The visibility impacts analysis.

Once it is determined that a source is subject to BART for a particular pollutant, then for each affected emissions unit, BART must be established for that pollutant. The BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review.

For volatile organic compounds (VOC) and PM sources subject to maximum achievable control technology (MACT) standards under 40 CFR 63, the analysis may be streamlined (at the discretion of the State) by including a discussion of the MACT controls and whether any major new technologies have been developed subsequent to the MACT standards. There are many VOC and PM sources that are well-controlled because they are regulated by the MACT standards that EPA developed under Clean Air Act (CAA) Section 112. There are also MACT standards that have invoked stringent control measures for SO_2. Any source subject to MACT standards must meet a level that is as stringent as the best-controlled 12 percent of sources in the industry. The EPA believes that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the MACT standards that would lead to cost effective increases in the level of control, EPA believes the State may rely on the MACT standards for purposes of BART [FR, Volume 70, pages 39104-39172].

EPA believes that the same rationale also holds true for emissions standards developed for municipal waste incinerators under CAA Section 111(d), and for many new source review/prevention of significant deterioration (NSR/PSD) determinations and NSR/PSD settlement agreements. However, EPA does not believe that technology determinations from the 1970s or early 1980s, including new source performance standards (NSPS), should be considered to represent best control for existing sources, as best control levels for recent plant retrofits are more stringent than these older levels.

Where the source is relying on these standards to represent a BART level of control, a discussion of whether any new technologies have subsequently become available should be provided.

The five basic steps of a case-by-case BART analysis are:

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, and

STEP 5 — Evaluate Visibility Impacts.

Each of these steps is described briefly in the following sections.

STEP 1 — Identify All Available Retrofit Control Technologies

Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. In identifying "all" options, the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies are identified. It is not necessary to list all permutations of available control levels that exist for a given technology; the list is complete if it includes the maximum level of control each technology is capable of achieving.

Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant. Technologies required as Best Achievable Control Technology (BACT) or lowest achievable emission rate (LAER) are available for BART purposes and must be included as control alternatives. The control alternatives can include not only existing controls for the source category in question but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies that have not yet been applied to (or permitted for) full-scale operations need not be considered as available; as it is not expected that the source owner should purchase or construct a process or control device that has not already been demonstrated in practice.

Where NSPS exist for a source category (as is the case for most of the categories affected by BART), the BART analysis should include a level of control equivalent to the NSPS as one of the control options. The NSPS standards are codified in 40 CFR 60.

Potentially applicable retrofit control alternatives can be categorized in three ways.

- Pollution prevention: use of inherently lower-emitting processes/practices, including the use of control techniques (e.g. low-NO_x burners) and work practices that prevent emissions and result in lower "production-specific" emissions,
- Use of (and where already in place, improvement in the performance of) add-on controls, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced, and
- Combinations of inherently lower-emitting processes and add-on controls.

In the course of the BART review, one or more of the available control options may be eliminated from consideration if demonstrated to be technically infeasible or to have unacceptable energy, cost, or non-air quality environmental impacts on a case-by-case (or site-specific) basis.

The EPA does not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, EPA does not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis.

For emissions units subject to a BART review, there will often be control measures or devices already in place. For such emissions units, it is important to include control options that involve improvements to existing controls and not to limit the control options only to those measures that involve a complete replacement of control devices.

If a BART source has controls already in place that are the most stringent controls available (note that this means all possible improvements to any control devices have been made), it is not necessary to comprehensively complete each following step of the BART analysis. As long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, the remaining analyses may be skipped, including the visibility analysis in Step 5. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses.

STEP 2 — Eliminate Technically Infeasible Options

In Step 2, the source evaluates the technical feasibility of the control options identified in Step 1. The source should document a demonstration of technical infeasibility and should explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option on the emissions unit under review. The source may then eliminate such technically infeasible control options from further consideration in the BART analysis.

Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) they could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." A technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Where it is concluded that a control option identified in Step 1 is technically infeasible, the source should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emissions unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are irresolvable technical difficulties with applying the control to the source (e.g., size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, or adverse side effects on the rest of the facility). Where the resolution of technical difficulties is merely a matter of increased cost, the technology should be considered technically feasible. The cost of a control alternative is considered later in the process.

A possible outcome of the BART procedures discussed in these guidelines is the evaluation of multiple control technology alternatives resulting in essentially equivalent emissions. It is not EPA's intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit (FR, Volume 70, pages 39104-39172). Consequently, one should use judgment in deciding how to conduct an alternative, detailed impacts analysis (Step 4, below). For example, if two or more control techniques result in control levels that are essentially identical, considering the uncertainties of emissions factors and other parameters pertinent to estimating performance, only the less costly of these options need to be evaluated. The scope of the BART analysis should be narrowed in this way only if there is a negligible difference in emissions and energy and non-air quality environmental impacts between control alternatives.

STEP 3 — Evaluate Control Effectiveness of Remaining Control Technologies

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review. Two key issues in this process include:

- Ensuring that the degree of control is expressed using a metric that ensures an "apples to apples" comparison of emissions performance levels among options, and
- Giving appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.

This issue is especially important when comparing inherently lower-polluting processes to one another or to add-on controls. In such cases, it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed. Examples of common metrics are:

- Pounds of SO_2 emissions per million Btu heat input, and
- Pounds of NO_x emissions per ton of black liquor solids burned.

Many control techniques, including both add-on controls and inherently lower polluting processes, can perform at a wide range of levels. Scrubbers and high and low efficiency electrostatic precipitators (ESPs) are two of the many examples of such control techniques that can perform at a wide range of levels. It is not EPA's intent to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options (FR, Volume 70, pages 39104-39172). It is important, however, that in analyzing the technology one take into account the most stringent emission control level that the technology is capable of achieving. Recent regulatory decisions and performance data (e.g., manufacturer's data, engineering estimates, and the experience of other sources) should be considered when identifying an emissions performance level or levels to evaluate.

In assessing the capability of the control alternative, latitude exists to consider special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, the basis for choosing the alternate level (or range) of control in the BART analysis should be explained. Situations may occur where it is preferred or appropriate to evaluate other levels of control in addition to the most stringent level for a given device.

For retrofitting existing sources in addressing BART, the source should consider ways to improve the performance of existing control devices, particularly when a control device is not achieving the level of control that other similar sources are achieving in practice with the same device. For example, improving performance for sources with ESPs that are performing below currently achievable levels should be considered.

STEP 4— Evaluate Impacts and Document the Results

After identifying the available and technically feasible control technology options, the following analyses should be conducted when making the BART determination:

1. Costs of compliance,
2. Energy impacts,
3. Non-air quality environmental impacts, and
4. Remaining useful life.

The source should discuss and, where possible, quantify both beneficial and adverse impacts. In general, the analysis should focus on the direct impact of the control alternative.

Costs of Compliance

To conduct a cost analysis, the following steps are used:

1. Identify the emissions units being controlled,
2. Identify design parameters for emission controls, and
3. Develop cost estimates based upon those design parameters.

It is important to identify clearly the emissions units being controlled, that is, to specify a well-defined area or process segment within the plant. In some cases, multiple emissions units can be controlled jointly. Then, specify the control system design parameters. The value selected for the design parameter should ensure that the control option will achieve the level of emission control being evaluated. The analysis should include documentation of the assumptions regarding design parameters. Examples of supporting references include the *Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual,* Fifth Edition, February 1996, EPA 453/B–96–001, and background information documents used for NSPS and hazardous pollutant emission standards.

Once the control technology alternatives and achievable emissions performance levels have been identified, then the source must develop estimates of capital and annual costs. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the *OAQPS Control Cost Manual*). To maintain and improve consistency, cost estimates should be based on the *OAQPS Control Cost Manual,* where possible. The *OAQPS Control Cost Manual* addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option.

Cost effectiveness, in general, is a criterion used to assess the potential for achieving an objective in the most economical way. For purposes of air pollutant analysis, "effectiveness" is measured in terms of tons of pollutant emissions removed, and "cost" is measured in terms of annualized control costs. The EPA recommends two types of cost effectiveness calculations: average cost effectiveness and incremental cost effectiveness.

Average cost effectiveness means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls). Because costs are calculated in (annualized) dollars per year and emission rates are calculated in TPY, the result is an average cost effectiveness number in (annualized) dollars per ton of pollutant removed.

The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, the anticipated annual emissions will be estimated based upon actual emissions from a baseline period.

When future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) are projected to differ from past practice, and if this projection has a deciding effect in the BART determination, then these parameters or assumptions are to be translated into enforceable limitations. In the absence of enforceable limitations, baseline emissions are calculated based upon continuation of past practice.

In addition to the average cost effectiveness of a control option, the incremental cost effectiveness should also be calculated. The incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction):

$$\text{Incremental Cost effectiveness (dollars per incremental ton removed)} =$$

$$\frac{\text{(Total annualized costs of control option)} - \text{(Total annualized costs of next control option)}}{\text{(Control option annual emissions)} - \text{(Next control option annual emissions)}}$$

Energy Impacts

The energy requirements of the control technology should be analyzed to determine whether the use of that technology results in energy penalties or benefits. If such benefits or penalties exist, they should be quantified to the extent practicable. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impact analysis can, in most cases, simply be factored into the cost impacts analysis.

The energy impact analysis should consider only direct energy consumption and not indirect energy impacts. The energy requirements of the control options should be shown in terms of total (and in certain cases, also incremental) energy costs per ton of pollutant removed. These units can then be converted into dollar costs and, where appropriate, factored into the control cost analysis.

The energy impact analysis may also address concerns over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region. However, in general, a scarce fuel is one that is in short supply locally and can be better used for alternative purposes, or one that may not be reasonably available to the source either at the present time or in the near future.

Non-Air Quality Environmental Impacts

In the non-air quality related environmental impacts portion of the BART analysis, environmental impacts other than air quality due to emissions of the pollutant in question are addressed. Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device.

Any significant or unusual environmental impacts associated with a control alternative, that have the potential to affect the selection or elimination of a control alternative, should be identified. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Alternatively, water availability may affect the feasibility and costs of wet scrubbers. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon.

In general, the analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection of a control alternative, or elimination of a more stringent control alternative. Thus, any important relative environmental impacts (both positive and negative) of alternatives can be compared with each other.

Remaining Useful Life

The requirement to consider the "remaining useful life" of the source for BART determinations may be treated as one element of the overall cost analysis. The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's *OAQPS Control Cost Manual* require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly not exceed this time period, the remaining useful life has an effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations.

The remaining useful life is the difference between:

1. The date that controls will be put in place (capital and other construction costs incurred before controls are put in place can be rolled into the first year, as suggested in EPA's *OAQPS Control Cost Manual*).
2. The date the facility permanently stops operations. Where this affects the BART determination, this date should be assured by a federally- or State-enforceable restriction preventing further operation.

The EPA recognizes that there may be situations where a source operator intends to shut down a source by a given date, but wishes to retain the flexibility to continue operating beyond that date in the event, for example, that market conditions change. Where this is the case, the BART analysis may account for this, but it must maintain consistency with the statutory requirement to install BART within 5 years. Where the source operator chooses not to accept a federally enforceable condition requiring the source to shut down by a given date, it is necessary to determine whether a reduced time period for the remaining useful life changes the level of controls that would have been required as BART.

STEP 5 — Evaluate Visibility Impacts

The following is an approach EPA suggests to determine visibility impacts (the degree of visibility improvement for each source subject to BART) for the BART determination. Once a source has been determined to be subject to BART, a visibility improvement determination for the source must be conducted as part of the BART determination.

The permitting agency has flexibility in making this determination; i.e., in setting absolute thresholds, target levels of improvement, or *de minimis* levels since the visibility improvement must be weighed among the five factors; and the agency is free to determine the weight and significance to be assigned to each factor. For example, a 0.3-dv improvement may merit a stronger weighting in one case versus another, so one "bright line" may not be appropriate.

CALPUFF or another appropriate dispersion model must be used to determine the visibility improvement expected at a Class I area from the potential BART control technology applied to the source. Modeling should be conducted for SO_2, NO_x, and direct PM emissions [PM with an aerodynamic diameter less than or equal to 2.5 microns ($PM_{2.5}$) and/or PM_{10}]. There are several steps for determining the visibility impacts from an individual source using a dispersion model:

- Develop a modeling protocol.
- For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol. Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in dv compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the control efficiency being evaluated is 95 percent and the 24-hr pre-control emission rate is 100 pounds per hour (lb/hr) of SO_2, then the post control rate is 5 lb/hr.
- Make the net visibility improvement determination. Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. Flexibility exists to assess visibility improvements due to BART controls by one or more methods. Factors such as the frequency, magnitude, and duration of components of impairment may be considered. Suggestions for making the determination are:
    - Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g. the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an *x*-percent change in improvement).
    - Compare the 8th-highest days for the pre- and post-control runs.

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

Selecting the "Best" Alternative

From the alternatives evaluated in Step 3, EPA recommends developing a chart (or charts) displaying for each of the alternatives the following:

1. Expected emission rate (TPY, lb/hr);
2. Emissions performance level [e.g., percent pollutant removed, emissions per unit product, lb/MMBtu, parts per million];
3. Expected emissions reductions (TPY);

4. Costs of compliance – total annualized costs ($), cost effectiveness (dollars per ton), incremental cost effectiveness (dollars per ton), and/or any other cost effectiveness measures (such as dollars per dv);
5. Energy impacts;
6. Non-air quality environmental impacts; and
7. Modeled visibility impacts.

The source has the discretion to determine the order in which control options are evaluated for BART. The source should provide a justification for adopting the technology selected as the “best” level of control, including an explanation of the CAA factors that led to the choice of one option over other control levels.

In the case where the source is conducting a BART determination for two regulated pollutants on the same source, if the result is two different BART technologies that do not work well together, a different technology or combination of technologies can be substituted.

Even if the control technology is cost effective, there may be cases where the installation of controls would affect the viability of continued plant operations. There may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include product prices, the market share, and profitability of the source. Where there are such unusual circumstances that are judged to affect plant operations, the source may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations, this may be considered in the selection process, but it may be preferred to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning. Any analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available.

5.0 BART ANALYSIS

5.1 Overall BART Strategy

The overall strategy followed in analyzing the BART control options for the Belle Glade facility BART-eligible source (combination of all BART-eligible emissions units at the facility) was to follow the BART determination guidelines contained in Appendix Y of Title 40, Part 51 of the Code of Federal Regulations (40 CFR 51) in a way that makes the most practical sense, with the overall goal of improving visibility.

Rule 62-296.340, Florida Administrative Code (F.A.C.) requires that BART evaluations be performed in accordance with the criteria of 40 CFR 51.308(e) and the procedures and guidelines in 40 CFR 51, Appendix Y, *Guidelines for BART Determinations Under the Regional Haze Rule.* According to the BART requirements, the degree of visibility improvement that would be achieved as a result of emissions reductions achievable from the BART-eligible source must be considered. Appendix Y describes the five basic steps of a BART analysis, where the fifth and final step is the evaluation of visibility impacts (visibility improvement determination in dv). When making this determination, the permitting authority has flexibility in setting absolute thresholds, target levels of improvement, or *de minimis* levels, since the visibility improvement must be weighed among the five factors. The permitting authority is free to determine the weight and significance to be assigned to each factor [FR, Volume 70, page 39170].

The following overall steps were followed in the BART determination analysis for the SCGCF Belle Glade BART-eligible emissions units:

- Determine the maximum impacts of the individual BART-eligible units and identify the degree of visibility improvement possible from each emissions unit;
- Determine the pollutant contributions to the maximum impact for each BART-eligible emissions unit;
- Focus on the clearly dominant pollutant(s);
- Identify existing and in-use control technologies;
- For the emissions units with significant impacts and for the clearly dominant pollutant(s), conduct full scale top-down BART analysis;
- Select BART and propose emission rates.

The State of Florida has not set a bright line for visibility improvement from individual emissions units. Nonetheless, a reasonable level of visibility improvement should be deemed to be insignificant, not warranting further evaluation. This is particularly important for BART-eligible sources that have many BART-eligible emissions units, in order to reduce the time and expense of performing the full BART control technology evaluation. As described further in this section, SCGCF has concluded that a control technology evaluation is not warranted for certain emissions units due to the insignificant visibility improvement that would result from applying any control technology.

The maximum visibility impacts of the Belle Glade facility as a BART-eligible source are presented in Tables 3-3 and 3-7 for the normal operation scenario and the No. 6 fuel oil firing scenario, respectively. As shown in Table 3-3 (normal operation), the maximum (8th-highest) impact is 0.52 dv at the Everglades NP (highest, 8th-highest impact over a 3-year period), barely over the exemption criteria of 0.5 dv. The individual emissions unit visibility impacts are presented in Tables 3-9 and 3-10 for the normal operation scenario and the No. 6 fuel oil firing scenario, respectively, along with the pollutant contributions. It can be clearly seen from these tables that Boiler Nos. 4 and 5 are the dominating emissions units, contributing more than 80 percent of the BART-eligible source impacts.

Tables 3-9 and 3-10 also show the individual pollutant contributions. For the bagasse-only firing scenario during normal operation, PM_{10} was found to be the most dominating pollutant, contributing to 40 to 60 percent of the highest, 8th-highest impact over the period 2001-2003. NO_x was found to be the second highest contributing pollutant. For the No. 6 fuel oil firing scenario, SO_2 was found to be the most dominating pollutant (see Table 3-10) for visibility impacts from Boiler Nos. 4 and 5 and PM_{10} was found to be the second highest contributor. The BART analyses for the Belle Glade facility BART-eligible source therefore focused on the evaluation of controls for all three pollutants: PM_{10}, SO_2, and NO_x for Boiler Nos. 4 and 5.

The maximum visibility impacts of either Boiler No. 1 or 2 are 0.06 dv (0.09 dv for the No. 6 fuel oil firing scenario) or less. These visibility impacts are considered to be insignificant. Also, any control technology evaluation conducted for Boiler Nos. 4 and 5 are also valid for Boiler Nos. 1 and 2, except that the cost effectiveness will be much higher because of the small visibility improvement possible from Boiler Nos. 1 and 2. Therefore, control technologies for these units were not extensively assessed, and FDEP should not require an extensive evaluation for these units.

5.2 BART for SO_2 Emissions from Boiler Nos. 4 And 5

As shown in Table 3-9, the 8th-highest visibility impact due to Boiler Nos. 4 and 5 for normal operation (bagasse firing only) are 0.233 and 0.195 dv, respectively, which are 45 and 38 percent, respectively, of the total facility impact of 0.52 dv. Based on the individual pollutant contributions shown in Tables 3-9 and 3-10, only 12 to 21 percent of the total visibility impact from either Boiler No. 4 or 5 is due to SO_4 particles during normal operation. Control of SO_2 emissions, therefore, is not expected to offer large visibility improvement benefits during normal operation.

The contribution of SO_4 particles increases to 41 percent during the fuel oil firing scenario, which is not normal operation.

5.2.1 Available Retrofit Control Technologies

As part of the BART analysis, a review was performed of previous SO_2 BACT determinations for boilers in sugar mills listed in the RACT/BACT/LAER Clearinghouse (RBLC) on EPA's webpage. A summary of BACT determinations for industrial boilers from this review is presented in Table 5-1. Determinations issued during the last 10 years are included in the table. From the review of previous BACT determinations, it is evident that SO_2 BACT determinations for large industrial boilers and boilers firing fuel oil and biomass have largely been based on use of low-sulfur fuels. Depending upon the boiler configuration, use of a wet scrubber flue gas desulfurization (FGD) system could also be an option for consideration. BACT determinations for fuel oil-fired industrial boilers are based on No. 2 fuel oil with sulfur content as low as 0.05 percent.

5.2.2 Control Technology Feasibility

The technically feasible SO_2 controls for Boiler Nos. 4 and 5 are shown in Table 5-2. A technology that is available and applicable is technically feasible. As shown, there are three feasible approaches for SO_2 abatement: low sulfur No. 2 fuel oil, reduced sulfur No. 6 fuel oil, and wet or dry scrubbers. Each abatement method is described below.

Low Sulfur No. 2 Fuel Oil

Emissions of SO_2 are directly proportional to fuel oil sulfur content. BACT determinations involving the use of No. 2 fuel oil define low sulfur fuel as having a sulfur content as low as 0.05 percent. The use of ultra-low sulfur No. 2 fuel oil with 0.0015 percent sulfur would result in significantly lower SO_2 emissions. Since Boiler Nos. 4 and 5 burn No. 6 fuel oil, modifications to the existing boilers would be required to accommodate No. 2 fuel oil firing. This would require a new fuel oil storage tank, piping (fuel transport) systems, and new burners. The existing process control systems would likely require upgrading to support the use of No. 2 fuel oil in Boiler Nos. 4 and 5. However, this is considered a technically feasible means of reducing SO_2 emissions and therefore is being evaluated as a potential BART determination for these boilers.

Reduced Sulfur No. 6 Fuel Oil

Reducing the sulfur content of the No. 6 fuel oil combusted in the Boiler Nos. 4 and 5 would reduce SO_2 emissions proportional to the magnitude of the sulfur reduction. Based on information from the Energy Information Administration, low sulfur No. 6 fuel oil is defined as having sulfur content of 1.0 percent or less. Although there is a cost premium for low sulfur No. 6 fuel oil, since the boilers currently burn No. 6 fuel oil with a maximum sulfur content of 2.4 percent, it is considered a technically feasible control technology.

Post-Combustion Controls

Post-combustion SO_2 controls consist primarily of FGD systems or scrubbers. In a wet scrubber, the SO_2-containing flue gas passes through a vessel or tower where it contacts an alkaline slurry, usually in a counter-flow arrangement. The intensive contact between the gas and the liquid droplets ensures rapid and effective reactions that can yield greater than 90 percent SO_2 capture. Conversely, a configuration where the reaction between SO_2 and the sorbent takes place in a dedicated reactor is referred to as a "dry scrubber".. Several configurations are possible based on the temperature window desired. This can occur at furnace (~2,200°F), economizer (800-900°F), or duct (~250°F) temperatures. Dry processes are more compatible with low to medium sulfur coals due to limitations in reaction rates and sorbent handling (MANE-VU, March 2005).

From review of the RBLC, post-combustion controls are typically applied to coal-fired boilers. The application of scrubbing systems to primarily fuel oil and/or carbonaceous fuel-fired boilers is considered cost prohibitive. Boiler Nos. 4 and 5 primarily burn carbonaceous fuel.

The burning of bagasse in Boiler Nos. 4 and 5 already results in inherent SO_2 removal from the exhaust gas stream. This is due to the alkaline nature of the ash from carbonaceous fuels, which acts to absorb SO_2 from the flue gas, and has been well documented by the National Council for Air and Stream Improvement (NCASI) in past studies. This fact further reduces the feasibility of add-on scrubbers as a potential BART technology. However, as a complete analysis, SO_2 scrubbing systems for Boiler Nos. 4 and 5 were further analyzed and cost effectiveness figures were developed.

5.2.3 Control Effectiveness of Options

Each of the above available control techniques is listed in Table 5-2 with its associated control efficiency estimate, and is ranked based on control efficiency.

5.2.4 Impacts of Control Technology Options

Cost of Compliance

To achieve SO_2 emissions below current levels, Boiler Nos. 4 and 5 would require use of lower sulfur fuel oil or a post-combustion control such as a SO_2 scrubber. Two fuel options were identified: low sulfur No. 2 fuel oil and reduced sulfur No. 6 fuel oil.

Based on information provided by SCGCF, the current fuel (2.4 percent sulfur) cost is $88.8 per barrel (bbl) or $2.114 per gallon (gal). The cost of compliance to use reduced sulfur No. 6 fuel oil is represented by the additional cost of the fuel oil versus $2.114/gal for the current 2.4 percent sulfur fuel oil used in the boilers. According to SCGCF, reduced sulfur No. 6 fuel oil with 1.0 percent maximum sulfur costs $90.0/bbl or $2.164/gal.

To convert to reduced sulfur No. 6 fuel oil, the evaluation must include the addition of a new fuel oil storage tank, pumps, piping, etc. To evaluate the cost effectiveness of converting to reduced sulfur No. 6 fuel oil, capital costs of $807,000 for the new storage tank and $1.2 million for other equipment such as pumps, piping, instrumentation, etc. were used (based on data for a new 500,000 gal tank). The total capital investment is estimated at $2.7 million, as shown in Table 5-3.

Annual operating costs were developed considering the annualized capital recovery cost and other direct and indirect operating costs, which are based on standard cost factors and engineering estimates. Capital recovery costs are based on an interest rate of 7 percent and a 15-year equipment (remaining useful) life. Annual operating costs, including the cost differential for the lower sulfur fuel oil, are estimated to be $253,600 per year for the 1.0 percent sulfur option. Total annual costs are estimated at $558,000 per year. The total cost effectiveness is calculated to be approximately $4,000 per ton of SO_2 removed for each boiler. The cost analysis is presented in Table 5-3.

To convert to lower sulfur No. 2 fuel oil, the evaluation must include the addition of a new fuel oil storage tank, pumps, piping, etc., and replacement of the fuel oil burners to accommodate the No. 2 fuel oil, as well as accounting for the lower heating value of No. 2 fuel oil. To evaluate the cost effectiveness of converting to No. 2 fuel oil, capital costs of $807,000 for the new storage tank and

$800,000 for other equipment such as pumps, piping, instrumentation, etc. were estimated. Capital costs also included new burner costs of $175,000.

Annual operating costs, including the cost differential for the lower sulfur No. 2 fuel oil, are estimated to be $661,200 and $680,400 per year, respectively, for 0.0015 percent and 0.05 percent sulfur. Total annual costs are estimated at $939,700 and $958,900 per year, respectively. The total cost effectiveness for 0.0015 percent and 0.05 percent sulfur No. 2 fuel oil was calculated to be $4,960 and $5,120 per ton of SO_2 removed, respectively. The cost analysis is presented in Table 5-3.

The cost analysis to reduce SO_2 emissions by installing a wet SO_2 scrubbing system on each of Boiler Nos. 4 and 5 is presented in Table 5-4. The cost quote was received from Andritz for a similar boiler, and is included in Appendix B. As shown in Table 5-4, the total capital investment of the system in each boiler is more than $4.2 million. The annual costs are slightly more than $1.0 million for each boiler, and the scrubber system cost effectiveness is approximately $6,200 per ton of SO_2 removed for Boiler No. 4 and $7,600 per ton SO_2 removed for Boiler No. 5, which is prohibitively high. This analysis is based on a scrubber with 98-percent SO_2 removal efficiency; however, costs for lower SO_2 removal efficiency would not be substantially different, since the capital costs would not change significantly and most of the annual costs are operating costs.

SCGCF currently has impingement type wet scrubbers for each Boiler No. 4 and 5 to control PM emissions. A cost analysis was developed to use caustic in these scrubbers to control SO_2 emissions and is presented in Table 5-5. The only equipment cost included is for the caustic injection system, which is assumed to be 20 percent of the total cost of the Andritz system. As shown in Table 5-5, the total capital investment of the system is $510,000 and $449,000 for Boiler Nos. 4 and 5, respectively. The annual costs are $528,000 for Boiler No. 4 and $447,000 for Boiler No. 5. Using a 50 percent control efficiency, the cost effectiveness was calculated to be more than $6,100 for either boiler, which is very high.

Energy Impacts

Use of low or reduced sulfur fuel oils causes energy impacts associated with operating the Boiler Nos. 4 and 5, based on the lower heating value of incrementally lower sulfur content fuel oils. The heating value of 2.4 percent sulfur No. 6 fuel oil is approximately 150,000 British thermal units per gallon (Btu/gal), while that of low sulfur No. 2 fuel oil (0.05 percent sulfur) is approximately 135,000 Btu/gal, a 10 percent differential. This would translate into 10 percent additional gallons of

No. 2 fuel oil to provide the same energy input as No. 6 fuel oil. According to the vendor specification, the Andritz SO_2 scrubbing system uses 186 kilowatts of electricity. Therefore, there would be an additional annual electricity cost of approximately $100,000 per boiler at the rate of $0.06 per kilowatt-hour.

Non-Air Quality Environmental Impacts

Use of low or reduced sulfur fuel oils do not result in any non-air quality environmental impacts. Use of caustic would create wastewater impacts and disposal costs.

Remaining Useful Life

SCGCF has no plan to shut down the Belle Glade facility or Boiler Nos. 4 and 5 in the near future. A useful life of 15 years was used to develop the capital recovery cost in estimating the costs of compliance.

5.2.5 Visibility Impacts

The baseline SO_2 emissions used in the determination of the visibility impacts due to the Boiler Nos. 4 and 5 are shown in Table 2-3 of the revised BART modeling protocol. The use of lower sulfur fuel oil would not affect SO_2 emissions during normal operation, which is based on bagasse firing only; therefore, there would be no change in visibility impairment during normal operation. The use of low sulfur fuel oil would affect SO_2 emissions during the maximum fuel oil firing scenario and these emissions rates are summarized in Table 5-10. The use of the scrubber system with 98-percent control efficiency would reduce SO_2 emissions in both the normal operation and maximum fuel oil firing scenarios, and these emissions are also summarized in Table 5-10.

The visibility impacts using the "controlled" SO_2 emission rates were predicted for 2003, the year that produced the highest baseline visibility impacts. The controlled visibility impacts for the different control scenarios considered were compared to the baseline visibility impacts and the reductions in visibility impairment were calculated. Using these reductions in visibility impairment, the visibility cost effectiveness numbers (dollars per dv improvement) were calculated based on the annualized cost for each control option. The visibility cost effectiveness numbers for SO_2 control options are summarized below and are also presented in Tables 5-3 through 5-5.

- Reduced sulfur (1.0 percent sulfur) No. 6 fuel oil – $5.5 million/dv
- Low sulfur (0.05 percent sulfur) No. 2 fuel oil – $7.8 million/dv

- Ultra-low sulfur (0.0015 percent) No. 2 fuel oil – \$7.6 million/dv
- Scrubber system, 98-percent SO_2 removal – \$13 million/dv (Boiler No. 4), \$17.5 million/dv (Boiler No. 5)
- Caustic in existing scrubber system, 50-percent SO_2 removal – \$9.6 million/dv (Boiler No. 4), \$14 million/dv (Boiler No. 5)

For the bagasse only firing scenario, there was very little change in visibility impacts from the scrubber controls and as a result, the visibility cost effectiveness increased to more than a hundred million dollars per dv of visibility improvement.

5.2.6 Selection of BART

As the visibility cost effectiveness values above indicate, the cost of improvement is extremely high for all control options. It is emphasized that the primary fuel for the Boiler Nos. 4 and 5 is carbonaceous fuel. The boilers may operate for days at a time without burning any fuel oil. Therefore, any wet scrubber for SO_2 control would sit idle the majority of the time. It should also be noted that any reduction in the fuel oil sulfur content has no effect on carbonaceous fuel firing SO_2 emissions.

Based on the cost analysis and dv improvement, SCGCF proposes the current operation of the Boiler Nos. 4 and 5 as BART, i.e., use of carbonaceous fuels to the extent practicable, with use of 2.4 percent sulfur No. 6 fuel oil only as necessary to meet steam demands.

5.3 BART For NO_x Emissions from Boiler Nos. 4 and 5

Boiler Nos. 4 and 5 emit modest quantities of NO_x emissions from the combustion of fuel oil and bagasse. As shown in Tables 3-9 and 3-10, NO_x emissions are the second biggest contributor of the maximum visibility impacts and contribute to about 13 to 27 percent of the maximum impact in 2003 for either boiler. However, based on the maximum visibility impact for each boiler and the maximum contribution from NO_x emissions, controlling NO_x emissions would not provide a meaningful reduction in visibility impacts. Total elimination of the NO_x contribution would only reduce visibility impacts by about 0.07 dv for either boiler and because of the small reduction in visibility impairment, the cost effectiveness is also expected to be very high.

To support this theory, detailed cost analysis was conducted using recent quotes from two vendors of NO_x control technology – MobotecUSA and FuelTech Inc. Mobotec provided information associated with the installation of their Rotating Opposed Fired Air (ROFA System) and the ROFA plus urea injection system, known as Rotamix (refer to Appendix B). FuelTech provided information regarding their NO_xOUT SNCR system (refer to Appendix B).

The ROFA system would provide approximately a 45 percent reduction in baseline NO_x emissions, while Rotamix would provide 60 percent reduction. FuelTech's SNCR system is less effective than Mobotec's, only reducing base NO_x emissions by approximately 30 percent.

The cost of implementing the ROFA and ROTAMIX NO_x controls can be found in Tables 5-6 and 5-7 for Boiler Nos. 4 and 5, respectively. The cost for the FuelTech SNCR with NO_xOUT is presented in Table 5-8. The cost effectiveness in dollars per ton of NO_x removed for these control technologies are as follows:

- Mobotec ROFA – \$7,482/ton of NO_x (No. 4); \$11,624/ton of NO_x (No. 5)
- Mobotec ROFA+Rotamix – \$8,784/ton of NO_x (No. 4); \$14,435/ton of NO_x (No. 5)
- FuelTech NO_xOUT – \$9,501/ton of NO_x (No. 4); \$14,483/ton of NO_x (No. 5)

In addition, the cost effectiveness of the NO_x control options with respect to improvement in regional haze impacts are as follows:

- Mobotec ROFA – over \$31 million/dv (No. 4); over \$33 million/dv (No. 5)
- Mobotec ROFA+Rotamix – over \$33 million/dv (No. 4); over \$36 million/dv (No. 5)
- FuelTech NO_xOUT – over \$37 million/dv (No. 4); over \$55 million/dv (No. 5)

As the cost effectiveness calculations indicate, the cost to implement any of the potentially feasible NO_x control systems is prohibitively high. When factoring in the improvement that these costly control systems provide, the costs, which are more than \$31,000,000 per dv of improvement, become impractical. As such, and after evaluation of technically feasible NO_x control options, SCGCF concludes that the cost for the NO_x control systems, especially when viewed from the perspective of the improvement to regional haze, is prohibitively high, and as such, does not propose to implement these options.

5.4 BART for PM_{10} Emissions from Boiler Nos. 4 and 5

As shown in Tables 3-9 and 3-10, PM_{10} emissions are the largest contributor to the maximum visibility impacts for the bagasse-firing normal operation scenario, which contribute to a maximum of 49 percent for Boiler No. 4 and 62 percent for Boiler No. 5. During the maximum fuel oil firing scenario, the PM_{10} contributions are a maximum of 37 and 41 percent for Boiler Nos. 4 and 5, respectively. PM_{10} emissions from Boiler Nos. 4 and 5 are currently controlled by a low efficiency dust collector and two impingement type wet scrubbers. The result is already low emissions of PM_{10}. However, because of the high contribution to visibility impairment, a quote was obtained from PPC Industries for a dry ESP. PPC Industries' ESP is 98.6 percent effective in reducing PM_{10} emissions.

The cost of implementation of the dry ESP system is presented in Table 5-9. The capital cost included an equipment cost of \$1.7 million plus approximately another \$1.1 million in direct installation costs. The total direct capital cost is estimated at \$2.7 million, as shown in Table 5-9. The total capital investment is approximately \$4.3 million.

Annual operating costs were developed considering the annualized capital recovery cost and other direct and indirect operating costs, which are based on standard cost factors and engineering estimates. Capital recovery costs are based on an interest rate of 7 percent and a 15-year equipment life. Annual operating costs are estimated to be \$346,000 per year. Total annual costs are estimated at \$827,000 per year. The total cost effectiveness is calculated to be more than \$8,200 per ton of PM_{10} removed for Boiler No. 4 and more than \$10,500 per ton of PM_{10} removed for Boiler No. 5.

Based on the stack test data from 2001 to present, the current maximum PM emission rates are 0.124 lb/MMBtu and 0.15 lb/MMBtu for Boiler Nos. 4 and 5, respectively. The ESP would reduce PM emissions to 0.02 lb/MMBtu, which is an 84-percent and 87-percent reduction for Boiler Nos. 4 and 5, respectively. Using these additional control efficiencies, controlled emission rates were calculated for Boiler Nos. 4 and 5 based on their baseline emission rates. The baseline emission rates are maximum annual rates from the annual operating reports for the period 2001 to present. These controlled emission rates were modeled to determine the visibility impacts for the controlled scenario. Using the improvement in the visibility impacts, the cost effectiveness of the PM_{10} control options were determined as follows:

- Boiler No. 4 – \$6.27 million/dv (normal operation); \$7.5 million/dv (No. 6 fuel oil scenario)
- Boiler No. 5 – \$6.32 million/dv (normal operation); \$9.6 million/dv (No. 6 fuel oil scenario)

The cost effectiveness calculations presented in Table 5-9 indicate that the cost to implement additional PM_{10} control systems is prohibitively high. When factoring in the visibility improvement that this costly control system provides, the cost is more than $6.2 million/dv for Boiler No. 4 and more than $6.3 million/dv for Boiler No. 5. Because of the high cost effectiveness, SCGCF proposes no additional control for PM_{10} and proposes the existing controls for PM_{10} as the BART.

5.5 Control Technology Modeling

Emission rates were developed for the various control technology options mentioned in Sections 5.2 through 5.4 and modeling was conducted for each of Boiler Nos. 4 and 5 to determine the visibility impairment due to the controlled emission rates. These emission rates and the various control options are summarized in Table 5-10. Modeling results showing the visibility impacts are summarized in Table 5-11.

5.6 Application for BART Determination

The FDEP's Application for Air Permit – Long Form is included in Appendix C to support this BART determination.

TABLE 5-1
SUMMARY OF BACT DETERMINATIONS FOR SULFUR DIOXIDE EMISSIONS FROM LARGE INDUSTRIAL BOILERS

Company Name	State	Permit No./RBLC ID	Permit Issue Date	Throughput	Emission Limit	Control Equipment
COLUMBIA ENERGY CENTER	SC	SC-0091	07/03/2003	550 MMBTU/HR	0.06 lb/MMBTU	LOW SULFUR FUEL OIL (No. 2)
INTERNATIONAL PAPER - MANSFIELD MILL	LA	LA-0122	08/14/2001	645 MMBTU/HR	0.7 %S	REDUCED SULFUR FUEL OIL
GRAYS FERRY COGEN PARTNERSHIP	PA	PA-0187	03/21/2001	1,119 MMBTU/HR	0.2 LB/MMBTU	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL
RAYONIER SPECIALTY PULP PRODUCTS	GA	GA-0084	06/16/1997	338 MMBTU/HR	0.05 %S	LOW SULFUR FUEL OIL
INTERSTATE PAPER, LLC	GA	GA-0097	11/21/2001	300 MMBTU/HR	0.14 LB/MMBTU	CAUSTIC WET SCRUBBER
WEYERHAEUSER CO	FL	PSD-FL-278/FL-0237	02/06/2001	NA NA	0.15 LB/MMBTU	LOW SULFUR FUEL W/ OR W/OUT EMISSION CONTROL
CHAMPION INTERNATIONAL	AL	AL-0112	12/09/1997	710 MMBTU/HR	0.045 LB/MMBTU	WET SCRUBBER WITH SODA ASH
REGENTS OF THE UNIVERSITY OF MICHIGAN	MI	MI-0248	10/06/1998	376 MMBTU/HR	0.3 LB/MMBTU	LOW SULFUR FUEL OIL

Reference: RACT/BACT/LAER Clearinghouse on EPA's Webpage, 2006.

TABLE 5-2
SO_2 CONTROL TECHNOLOGY FEASIBILITY ANALYSIS - BOILER NOS. 4 AND 5

SO_2 Abatement Method	Estimated Efficiency	Technically Feasible and Demonstrated? (Y/N)	Rank Based on Control Efficiency
Low-sulfur (0.5, 0.05, 0.0015%) No. 2 Fuel Oil	98%	Y	1
Reduced sulfur (1%) No. 6 Fuel Oil	60%	Y	4
Wet Scrubbers	>90%	Y	2
Dry Scrubbers	60-95%	N	3

TABLE 5-3

COST-EFFECTIVENESS OF FUEL SWITCHING FOR NO. 4 OR NO. 5 BOILER

Cost Items	Cost Factors	No. 2 Oil (0.0015% S) Cost ($)	No. 2 Oil (0.05% S) Cost ($)	No. 6 Oil (1.0% S) Cost ($)
DIRECT CAPITAL COSTS (DCC):				
(1) Equipment Cost				
(a) New Fuel Oil Storage tank	See Footnote "a"	807,000	807,000	807,000
(b) Pumps, piping, etc.	See Footnote "a"	800,000	800,000	1,200,000
(c) New oil guns/atomizer sprayer plates	Babcock & Wilcox -- excludes installation[b]	175,000	175,000	0
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	111,375	111,375	125,438
Subtotal: Total Equipment Cost (TEC)		1,893,375	1,893,375	2,132,438
(3) Direct Installation Costs	85% of TEC (for new oil guns)	148,750	148,750	0
Total DCC:		2,042,125	2,042,125	2,132,438
INDIRECT CAPITAL COSTS (ICC):[c]				
(1) Indirect Installation Costs	SCGCF estimate	430,000	430,000	640,000
(a) Engineering	10% of TEC (for new oil guns)	17,500	17,500	Included Above
(b) Construction & Field Expenses	10% of TEC (for new oil guns)	17,500	17,500	Included Above
(c) Construction Contractor Fee	10% of TEC (for new oil guns)	17,500	17,500	Included Above
(d) Contingencies	3% of TEC (for new oil guns)	5,250	5,250	Included Above
(2) Other Indirect Costs				
(a) Startup	1% of TEC (for new oil guns)	1,750	1,750	Included Above
(b) Performance Test	3% of TEC (for new oil guns)	5,250	5,250	Included Above
Total ICC:		494,750	494,750	640,000
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	2,536,875	2,536,875	2,772,437.5
DIRECT OPERATING COSTS (DOC):[d]				
(1) Operating Labor				
Operator	1.0 hr/shift, $30/hr, 8760 hrs/yr	32,850	32,850	32,850
Supervisor	15% of operator cost	4,928	4,928	4,928
(2) Maintenance				
Labor	Equivalent to One-Half Operating Labor	16,425	16,425	16,425
Materials	100% of maintenance labor	16,425	16,425	16,425
(3) Utilities				
(4) Fuels				
Existing Fuel Cost (No. 6 fuel oil with 2.4%S)	$2.114/gal, 594,000 gal/yr	1,255,716	1,255,716	1,255,716
Proposed Fuel Cost (fuel with lower sulfur content)	See Footnote "e"	1,702,400	1,721,600	1,285,416
Differential Fuel Cost (Proposed - Existing)	Proposed fuel cost - existing fuel cost	446,684	465,884	29,700
Total DOC:		517,312	536,512	100,328
INDIRECT OPERATING COSTS (IOC):[d]				
(1) Overhead	60% of oper. labor & maintenance	42,377	42,377	42,377
(2) Property Taxes	1% of total capital investment	25,369	25,369	27,724
(3) Insurance	1% of total capital investment	25,369	25,369	27,724
(4) Administration	2% of total capital investment	50,738	50,738	55,449
Total IOC:		143,852	143,852	153,274
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1098 times TCI (15 yrs @ 7%)	278,549	278,549	304,414
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**939,712**	**958,912**	**558,015**
BASELINE SO_2 EMISSIONS (TPY) :	Highest actual emissions in 2001-present (for either Nos. 4 or 5 boiler)	189.5	189.5	189.5
MAX SO_2 EMISSIONS WITH PROPOSED FUEL (TPY):	640K gal/yr 0.05%S or 0.0015%S No. 2 oil or 594K gal/yr 1% S No. 6 Fuel Oil	0.1	2.3	48.7
REDUCTION IN SO_2 EMISSIONS (TPY):		189.5	187.2	140.8
COST EFFECTIVENESS:	$ per ton of SO_2 removed	**4,960**	**5,122**	**3,963**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10	0.284	0.284	0.284
CONTROLLED VISIBILITY IMPACT (dv)	Table 5-11, Lowest impact - Boiler 4 or 5	0.16	0.161	0.183
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.124	0.123	0.101
VISIBILITY COST EFFECTIVENESS ($/dv) :	AC/Reduction in visibility impact	**7,578,322**	**7,796,032**	**5,524,902**

Footnotes:

[a] Based on data for a new 500,000 gallon storage tank, and estimated cost of piping, pumps, etc.

[b] Based on quote of $175,000 additional equipment cost for new atomizers for use of low sulfur No. 2 fuel oil.

[c] All indirect capital costs are included in basic price.

[d] Factors and cost estimates reflect OAQPS Cost Manual, Section 5.

[e] Fuel cost per SCGCF: No. 6 Oil @ 2.4%S - $2.114/gal, No. 6 Oil @ 1%S - $2.164/gal, No. 2 Oil @ 0.0015%S - $2.66/gal, No. 2 Oil @ 0.05%S - $2.69/gal. Fuel oil usage is 594,000 gal/yr based on actual fuel oil usage from the period 2001-2006. 594,000 gal of No. 6 oil is equivalent to 640,000 gal og No. 2 oil based on 151,000 Btu/gal for No. 6 oil and 140,000 Btu/gal for No. 2 oil.

TABLE 5-4
CAPITAL AND ANNUAL COSTS FOR BOILER SO_2 CONTROL USING A SCRUBBER SYSTEM

Cost Items	Cost Factors	Boiler No. 4 Scrubber System Cost ($)	Boiler No. 5 Scrubber System Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Based on Vendor Quote	1,308,535	1,151,086
(a) Separator/Scrubber/Mist Eliminator		included	included
(b) Caustic Injection		included	included
(c) Devices/Instrumentation		included	included
(g) Access & Platform		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	81,783	71,943
(3) Equipment Freight Cost	5% of Equipment Cost	65,427	57,554
Subtotal: Total Equipment Cost (TEC)		1,455,745	1,280,583
(3) Installation Costs [a]			
(a) Vendor Quote - Installation of Equipment and Piping		1,500,000	1,500,000
(b) Foundations, Structural Steel, Lighting	12% of TEC	174,689	153,670
(c) Piping		Included	Included
(d) Drains/Heat Tracing/Insulation	1% of TEC	14,557	12,806
(e) Electrical - Motor Starters/Wiring/DCS	1% of TEC	14,557	12,806
(f) Painting	1% of TEC	14,557	12,806
(g) Documentation/Engineering		included	included
(h) Start-up and Commissioning		included	included
(i) Inlet Ductwork and Connecting Ductwork	Estimate	150,000	150,000
Total DCC:		3,324,106	3,122,671
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) Performance Testing	Typical Value: 1% of Total Equipment Cost	14,557	12,806
(2) Other Indirect Costs (a)			
Engineering	10% of TEC	145,574	128,058
Construction and field expenses	10% of TEC	145,574	128,058
Contractor Fees	10% of TEC	145,574	128,058
Startup & Testing	Typical Value: 1% of TEC	Included	Included
Total ICC:		451,281	396,981
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	755,077	703,930
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	4,530,465	4,223,582
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	1.0 hr/shift, $30/hr, 8760 hrs/yr	32,850	32,850
Supervisor	15% of operator cost	4,928	4,928
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	16,425	16,425
Materials	100% of maintenance labor	16,425	16,425
(3) Operating Material			
Caustic	$400/ton dry caustic [b]	168,207	122,389
Water makeup	$2.36/1000 gal (No. 4 - 56.8 gpm, No. 5 - 43.6 gpm) [c]	70,478	54,127
Solid Waste Disposal	$40/ton [d]	16,821	12,239
(4) Electricity	2x125 hp (2 Queneh pumps), 186 KW, $0.06/KW-hr	97,762	97,762
Total DOC:		423,894	357,145
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	42,377	42,377
(2) Property Taxes	1% of total capital investment	45,305	42,236
(3) Insurance	1% of total capital investment	45,305	42,236
(4) Administration	2% of total capital investment	90,609	84,472
Total IOC:	(1) + (2) + (3) + (4)	223,595	211,320
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1098 times TCI (15 yrs @ 7%)	497,445	463,749
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**1,144,935**	**1,032,214**
BASELINE SO_2 EMISSIONS (TPY) :	Highest actual emissions in 2001-present	189.5	137.9
CONTROLLED SO_2 EMISSIONS (TPY) :	98% Removal by the Scrubber (vendor specification)	3.8	2.8
REDUCTION IN SO_2 EMISSIONS (TPY):	Baseline - Controlled	185.7	135.1
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	**6,164**	**7,638**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.197	0.158
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.087	0.058
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**13,160,167**	**17,796,788**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.231	0.191
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.002	0.004
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**572,467,285**	**258,053,423**

Notes:
(a) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002, Section 5
Vendor quote from Andritz/Envirocare International, received in March 2007.
(b) Caustic requirement calculated from the annual baseline SO_2 emissions using chemical equilibrium equation (2 moles of NaOH per mole of SO_2).
(c) Water makeup calculated from vendor data for inlet condition of 2,200 lb/hr and prorating for SO_2 emission rates of 500 lb/hr and 384 lb/hr, for Nos. 4 and 5, respectively.
(d) Solid waste calculated from annual baseline SO_2 emissions using chemical equilibrium equation. Na_2SO_4 is the end product.

TABLE 5-5
CAPITAL AND ANNUAL COSTS FOR BOILER SO_2 CONTROL USING CAUSTIC IN EXISTING SCRUBBER SYSTEM

Cost Items	Cost Factors	Boiler No. 4 Scrubber System Cost ($)	Boiler No. 5 Scrubber System Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Based on Vendor Quote	0	0
(a) Separator/Scrubber/Mist Eliminator		included	included
(b) Caustic Injection System (tank, pump, control, DCS)	Assumed 20% of Vendor Quote for Total System	261,707	230,217
(c) Devices/Instrumentation		included	included
(g) Access & Platform		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	16,357	14,389
(3) Equipment Freight Cost	5% of Equipment Cost	13,085	11,511
Subtotal: Total Equipment Cost (TEC)		291,149	256,117
(3) Installation Costs [a]			
(a) Vendor Quote - Installation of Equipment and Piping		0	0
(b) Foundations, Structural Steel, Lighting	12% of TEC	34,938	30,734
(c) Piping		Included	Included
(d) Drains/Heat Tracing/Insulation	1% of TEC	2,911	2,561
(e) Electrical - Motor Starters/Wiring/DCS	1% of TEC	2,911	2,561
(f) Painting	1% of TEC	2,911	2,561
(g) Documentation/Engineering		included	included
(h) Start-up and Commissioning		included	included
(i) Inlet Ductwork and Connecting Ductwork	Estimate	0	0
Total DCC:		334,821	294,534
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) Performance Testing	Typical Value: 1% of Total Equipment Cost	2,911	2,561
(2) Other Indirect Costs (a)			
Engineering	10% of TEC	29,115	25,612
Construction and field expenses	10% of TEC	29,115	25,612
Contractor Fees	10% of TEC	29,115	25,612
Startup & Testing	Typical Value: 1% of TEC	Included	Included
Total ICC:		90,256	79,396
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	85,015	74,786
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	510,093	448,716
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	1.0 hr/shift, $30/hr, 8760 hrs/yr	32,850	32,850
Supervisor	15% of operator cost	4,928	4,928
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	16,425	16,425
Materials	100% of maintenance labor	16,425	16,425
(3) Operating Material			
Caustic	$400/ton dry caustic [b]	168,207	122,389
Water makeup	$2.36/1000 gal (No. 4 - 56.8 gpm, No. 5 - 43.6 gpm)[c]	70,478	54,127
Solid Waste Disposal	$40/ton [d]	16,821	12,239
(4) Electricity	2x125 hp (2 Quench pumps), 186 KW, $0.06/KW-hr	97,762	97,762
Total DOC:		423,894	357,145
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	42,377	42,377
(2) Property Taxes	1% of total capital investment	5,101	4,487
(3) Insurance	1% of total capital investment	5,101	4,487
(4) Administration	2% of total capital investment	10,202	8,974
Total IOC:	(1) + (2) + (3) + (4)	62,780	60,325
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1098 times TCI (15 yrs @ 7%)	56,008	49,269
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	542,683	466,739
BASELINE SO_2 EMISSIONS (TPY) :	Highest actual emissions in 2001-present	189.5	137.9
CONTROLLED SO_2 EMISSIONS (TPY) :	50% Removal by Existing Scrubber (assumed)	94.8	69.0
REDUCTION IN SO_2 EMISSIONS (TPY):	Baseline - Controlled	94.8	69.0
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	5,727	6,769
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.229	0.184
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.055	0.032
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**9,866,962**	**14,585,588**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.232	0.192
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.001	0.003
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**542,682,883**	**155,579,603**

Notes:
(a) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002, Section 5
Vendor quote from Andritz/Envirocare International, received in March 2007.
(b) Caustic requirement calculated from the annual baseline SO_2 emissions using chemical equilibrium equation (2 moles of NaOH per mole of SO_2).
(c) Water makeup calculated from vendor data for inlet condition of 2,200 lb/hr and prorating for SO_2 emission rates of 500 lb/hr and 384 lb/hr, for Nos. 4 and 5, respectively.
(d) Solid waste calculated from annual baseline SO_2 emissions using chemical equilibrium equation. Na_2SO_4 is the end product.

TABLE 5-6
COST EFFECTIVENESS OF MOBOTEC FOR NO_x CONTROL, BOILER NO. 4

Cost Items	Cost Factors[a]	NOx Control for Boiler No. 4 ROFA Only Cost ($)	ROFA + ROTAMIX Cost ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	126,590	126,590
ROFA System	Vendor quote[b]	2,330,476	3,317,676
Emissions Monitoring	15% of equipment cost	349,571	497,651
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	186,438	265,414
Freight	5% of Equipment Cost	116,524	165,884
Taxes	Florida sales tax, 6.25%	145,655	207,355
Purchased Equipment Cost (PEC)		3,285,254	4,610,570
ROFA Installataion	Vendor quote[b]	345,250	685,250
Total DCC		3,630,504	5,295,820
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	98,158	98,158
Electrical and Controls	Vendor quote[b]	33,712	33,712
General Facilities	5% of DCC	181,525	264,791
Engineering and home office fees	10% of DCC	363,050	529,582
Process Contingency	5% of DCC	181,525	264,791
Total ICC		857,971	1,191,034
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	897,695	1,297,371
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	5,386,169	7,784,224
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 52 weeks/yr	31,200	31,200
Supervisor	15% of operator cost	4,680	4,680
Maintenance	3% of TCI	161,585	233,527
Electricity	100 kW, $0.05/kW-hr, 80% C.F.	35,040	35,040
Water usage	122 gal/hr; $2.36/1000gal[c]	0	2,519
Urea	20.3 gal/hr X $1.00/gal X 8760 hrs/yr[c]	0	177,903
Total DOC:		232,505	484,868
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	118,479	161,644
Property Taxes	1% of TCI	53,862	77,842
Insurance	1% of TCI	53,862	77,842
Administration	2% of TCI	107,723	155,684
		333,926	473,013
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1098 times TCI (15 yrs @ 7%)	591,401	854,708
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**1,157,832**	**1,812,589**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions in last 5 years	343.9	343.9
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	189.1	137.6
REDUCTION IN NO_x EMISSONS (TPY):		154.8	206.3
COST EFFECTIVENESS:	**$ per ton of NO_x Removed**	**7,482**	**8,784**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.284
CONTROLLED VISIBILITY IMPACT (dv)		0.255	0.246
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.029	0.038
VISIBILITY COST EFFECTIVENESS ($/dv) :		**39,925,252**	**47,699,717**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.233
CONTROLLED VISIBILITY IMPACT (dv)		0.196	0.178
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.037	0.055
VISIBILITY COST EFFECTIVENESS ($/dv) :		**31,292,765**	**32,956,168**

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Cost Control Manual, Sixth Edition (EPA/452/B-02-001, Jan. 2002).

[b] Vendor quote from Mobotec, May and June, 2007, adjusted for specific heat input rate of Boiler No. 4.

[c] Vendor operational parameters of water flow (90 gph) and urea usage (15 gph) adjusted for specific heat input rate of Boiler No. 4.

TABLE 5-7
COST EFFECTIVENESS OF MOBOTEC FOR NO_x CONTROL, BOILER NO. 5

Cost Items	Cost Factors[a]	NOx Control for Boiler No. 5 ROFA Only Cost ($)	ROFA + ROTAMIX Cost ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	97,059	97,059
ROFA System	Vendor quote[b]	1,786,820	2,774,020
Emissions Monitoring	15% of equipment cost	268,023	416,103
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	142,946	221,922
Freight	5% of Equipment Cost	89,341	138,701
Taxes	Florida sales tax, 6.25%	111,676	173,376
Purchased Equipment Cost (PEC)		2,525,865	3,851,181
ROFA Installataion	Vendor quote[b]	345,250	685,250
Total DCC		2,871,115	4,536,431
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	75,259	75,259
Electrical and Controls	Vendor quote[b]	25,848	25,848
General Facilities	5% of DCC	143,556	226,822
Engineering and home office fees	10% of DCC	287,112	453,643
Process Contingency	5% of DCC	143,556	226,822
Total ICC		675,330	1,008,393
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	709,289	1,108,965
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	4,255,734	6,653,789
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 52 weeks/yr	31,200	31,200
Supervisor	15% of operator cost	4,680	4,680
Maintenance	3% of TCI	127,672	199,614
Electricity	100 kW, $0.05/kW-hr, 80% C.F.	35,040	35,040
Water usage	93.4 gal/hr; $2.36/1000gal[c]	0	1,931
Urea	15.6 gal/hr X $1.00/gal X 8760 hrs/yr[c]	0	136,401
Total DOC:		198,592	408,866
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	98,131	141,296
Property Taxes	1% of TCI	42,557	66,538
Insurance	1% of TCI	42,557	66,538
Administration	2% of TCI	85,115	133,076
		268,361	407,448
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1098 times TCI (15 yrs @ 7%)	467,280	730,586
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**934,232**	**1,546,900**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions in last 5 years	178.6	178.6
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	98.2	71.4
REDUCTION IN NO_x EMISSONS (TPY):		80.4	107.2
COST EFFECTIVENESS:	**$ per ton of NO_x Removed**	**11,624**	**14,435**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.216	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.198	0.192
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.018	0.024
VISIBILITY COST EFFECTIVENESS ($/dv) :		**51,901,792**	**64,454,178**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.195	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.167	0.153
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.028	0.042
VISIBILITY COST EFFECTIVENESS ($/dv) :		**33,365,438**	**36,830,959**

Footnotes:

[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Cost Control Manual, Sixth Edition (EPA/452/B-02-001, Jan. 2002).

[b] Vendor quote from Mobotec, May and June, 2007, adjusted for specific heat input rate of Boiler No. 5.

[c] Vendor operational parameters of water flow (90 gph) and urea usage (15 gph) adjusted for specific heat input rate of Boiler No. 5.

TABLE 5-8
COST EFFECTIVENESS OF FUEL TECH FOR NO_x CONTROL, BOILER NOS. 4 AND 5

Cost Items	Cost Factors	SNCR System for Boiler No. 4 Cost ($)	SNCR System for Boiler No. 5 Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Based on Vendor Quote [b]	1,225,708	939,446
(a) NOxOUT SNCR Basic Process		included	included
(b) 8,000 Gallon FRP Storage Tank		included	included
(c) Circulation Module and Enclosure		included	included
(d) Urea and Dilution water Metering Module		included	included
(e) Urea Distribution Module, Injectors, Control Panel		included	included
(f) Temperature Monitoring, Engineering Designs		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	76,607	58,715
(3) Equipment Freight Cost	5% of Equipment Cost	61,285	46,972
Subtotal: Total Equipment Cost (TEC)		1,363,600	1,045,133
(4) Installation Costs [a]			
(a) Vendor quotes for similar boilers (equal to basic process equipment cost)		1,225,708	939,446
(b) Tank Foundation and Structural Support	5% of TEC	68,180	52,257
(c) Piping and Wiring	Engineering Estimate	100,000	100,000
(d) Electrical and Controls	Engineering Estimate	100,000	100,000
(h) NOxOUT Supply - First Fill	No. 4-10,800 gal, No. 5-8,300 gal. 5, $1.00/gal[c]	10,800	8,300
Total DCC:		2,868,288	2,245,136
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) General Facilities	5% of TEC	68,180	52,257
(b) Engineering and Home Office Fees	10% of TEC	136,360	104,513
(c) Process Contingency	5% of TEC	68,180	52,257
(2) Other Indirect Costs			
(a) NO_x, Ammonia, and CO Monitoring	Estimate	20,000	20,000
(b) Performance Testing	Based on historical testing	45,000	45,000
(c) Spare Parts	Engineering Estimate, 2% of TEC	27,272	20,903
(d) Contractor Fees	10% of TEC	136,360	104,513
Total ICC:		501,352	399,443
PROJECT CONTINGENCY (Retrofit installation)	20% of (DCC+ICC)	673,928	528,916
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI)	DCC + ICC+Project Contingency	4,043,568	3,173,494
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	1.0 hr/shift, $30/hr, 7,296 hrs/yr	27,360	27,360
Supervisor	15% of operator cost	4,104	4,104
(2) Maintenance	Engineering estimate, 1.5% of TCI	60,654	47,602
(3) Annual NO_xOut Cost	No. 4-26 gph, No. 5-20 gph, $1.00/gal[c]	191,140	146,551
(4) Electricity	No. 4-47 KW, No. 5 - 36 KW, $0.06/KW-hr[c]	20,744	15,905
(5) Water Consumption	No. 4-15 gpm, No.5-11 gpm, $2.36/1000 gal[c]	15,204	11,657
Total DOC:		319,206	253,180
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	55,271	47,440
(2) Property Taxes	1% of total capital investment	40,436	31,735
(3) Insurance	1% of total capital investment	40,436	31,735
(4) Administration	2% of total capital investment	80,871	63,470
Total IOC:	(1) + (2) + (3) + (4)	217,013	174,380
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1098 times TCI (15 yrs @ 7%)	443,984	348,450
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**980,203**	**776,009**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions from 2001 to present	343.9	178.6
CONTROLLED NO_x EMISSIONS (TPY) :	SNCR NOx Reduction (30%)	240.7	125.0
REDUCTION IN NO_x EMISSIONS (TPY):		103.2	53.6
COST EFFECTIVENESS:	**$ per ton of NOx Removed**	**9,501**	**14,483**
BASELINE VISIBILITY IMPACT	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.265	0.204
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.019	0.012
VISIBILITY COST EFFECTIVENESS ($/dv) :		**51,589,642**	**64,667,399**
BASELINE VISIBILITY IMPACT	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.207	0.181
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.026	0.014
VISIBILITY COST EFFECTIVENESS ($/dv) :		**37,700,123**	**55,429,199**

Notes:

(a) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002, Section 4

(b) Vendor quote from Fuel Tech, Inc., received in March 2007.

(c) Vendor operational parameters of NOxOUT flow (19.35 gph average), dilution water flow (10.87 gpm average), and power requirement (35 kW) adjusted for the specific heat input capacity of Boiler Nos. 4 and 5.

TABLE 5-9
CAPITAL AND ANNUAL COSTS FOR BOILER PM CONTROL USING ESP

Cost Items	Cost Factors	ESP for Boiler No. 4 Cost ($)	ESP for Boiler No. 5 Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) ESP + auxiliary equipment	Based on Vendor Quote	1,657,000	1,657,000
(2) Instrumentation	10% of Equipment Cost	included	included
(3) Sales Tax	3% of Equipment Cost	49,710	49,710
(4) Equipment Freight Cost	5% of Equipment Cost	included	included
Subtotal: Total Equipment Cost (TEC)		1,706,710	1,706,710
(5) Direct Installation Costs [a]			
(a) Vendor Quote - Installation	Described below	0	0
(b) Foundation (Support included)	2% of TEC (4% for foundation & support)	34,134	34,134
(c) Handling & Erection	50% of TEC	853,355	853,355
(d) Electrical	8% of TEC	136,537	136,537
(e) Piping	1% of TEC	17,067	17,067
(f) Painting	2% of TEC	17,067	17,067
(g) Insulation for Ductwork	2% of TEC	included	included
Total DCC:		2,764,870	2,764,870
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Engineering	20% of TEC	341,342	341,342
(2) Construction and field expenses	20% of TEC	341,342	341,342
(3) Contractor Fees	10% of TEC	170,671	170,671
(4) Startup	1% of TEC	17,067	17,067
(5) Performance Test	1% of TEC	17,067	17,067
Total ICC:		887,489	887,489
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	730,472	730,472
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	4,382,831	4,382,831
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Coordinator	25% Time spent on ESP, Annual Salary 70K	17,500	17,500
Operator	1.0 hr/shift, $30/hr, 8760 hrs/yr	32,850	32,850
Supervisor	15% of operator cost	4,928	4,928
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	16,425	16,425
Materials	100% of maintenance labor	16,425	16,425
(3) Operating Material	None	0	0
(4) Electricity	132 KW, $0.06/KW-hr	57,784	57,784
(5) Water Usage	None, dry ESP	0	0
(6) Wastewater Treatment	None, dry ESP	0	0
Total DOC:		128,412	128,412
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	42,377	42,377
(2) Property Taxes	1% of total capital investment	43,828	43,828
(3) Insurance	1% of total capital investment	43,828	43,828
(4) Administration	2% of total capital investment	87,657	87,657
Total IOC:	(1) + (2) + (3) + (4)	217,690	217,690
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.1098 times TCI (15 yrs @ 7%)	481,235	481,235
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**827,336**	**827,336**
BASELINE PM EMISSIONS (TPY) :	Highest actual emissions in 2001-present (from AORs)	118.8	90.0
CONTROLLED PM EMISSIONS (TPY) :	Boiler 4 - 84% reduction, Boiler 5 - 87% reduction	19.0	11.7
REDUCTION IN PM EMISSONS (TPY):	Baseline - Controlled	99.8	78.3
COST EFFECTIVENESS:	$ per ton of PM Removed	**8,291**	**10,566**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.174	0.130
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.110	0.086
VISIBILITY COST EFFECTIVENESS ($/dv) :		**7,521,240**	**9,620,191**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.101	0.064
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.132	0.131
VISIBILITY COST EFFECTIVENESS ($/dv) :		**6,267,700**	**6,315,545**

Notes:
(a) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002, Section 6, Chapter 3 ESP.
Vendor quote from PPC Industries, received in July 2007.

107.8

TABLE 5-10
SUMMARY OF BASELINE AND CONTROLLED 24-HOUR AVERAGE EMISSION RATES

			Baseline Scenario [a]			SO_2 Control Scenarios					NOx Control Scenarios			PM Control Scenario
						No. 6 Oil (1% S Content)	No. 2 Oil (0.05%S)	No. 2 Oil (0.0015%S)	SO_2 Scrubber (98% Control)	Caustic (50% Control)	ROFA (45% Control)	ROFA+ROTAMIX (60% Control)	SNCR (30% Control)	ESP (98.6% Control)
Source	**EU ID**	**Model ID**	**PM_{10} (lb/hr)**	**NO_x (lb/hr)**	**SO_2[a] (lb/hr)**	SO_2 (lb/hr)	SO_2 (lb/hr)	SO_2 (lb/hr)	SO_2 (lb/hr)	SO_2 (lb/hr)	NO_x (lb/hr)	NO_x (lb/hr)	NO_x (lb/hr)	PM_{10} (lb/hr)
ON-CROP SEASON														
Bagasse-Firing Only														
Boiler No. 1	001	SGC1	28.2	52.6	15.1	15.1	15.1	15.1	0.3	7.5	28.9	21.0	36.8	0.4
Boiler No. 2	002	SGC2	22.2	24.9	15.2	15.2	15.2	15.2	0.3	7.6	13.7	10.0	17.4	0.3
Boiler No. 4	003	SGC4	61.6	183.7	30.7	30.7	30.7	30.7	0.61	15.4	101.0	73.5	128.6	0.9
Boiler No. 5	004	SGC5	53.7	102.9	22.2	22.2	22.2	22.2	0.44	11.1	56.6	41.2	72.0	0.8
		Total =	165.6	364.1	83.3	83.3	83.3	83.3	1.7	41.6	200.3	145.6	254.9	2.3
Maximum Fuel Oil w/Remainder Bagasse														
Boiler No. 1	001	SGC1	21.5	59.2	180.9	81.9	14.5	11.3	3.6	90.5	32.6	23.7	41.5	0.3
Boiler No. 2	002	SGC2	17.1	38.8	181.1	82.0	14.7	11.4	3.6	90.5	21.3	15.5	27.1	0.2
Boiler No. 4	003	SGC4	49.3	178.4	314.4	145.0	29.8	24.2	6.3	157.2	98.1	71.4	124.9	0.7
Boiler No. 5	004	SGC5	42.1	105.8	240.2	110.0	21.5	17.2	4.8	120.1	58.2	42.3	74.0	0.6
		Total =	130.1	382.2	916.6	418.9	80.5	64.1	18.3	458.3	210.2	152.9	267.5	1.8
OFF-CROP SEASON														
Bagasse-Firing Only														
Boiler No. 1	001	SGC1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Boiler No. 2	002	SGC2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Boiler No. 4	004	SGC4	58.5	174.5	29.2	29.2	29.2	29.2	0.58	14.6	96.0	69.8	122.2	0.8
Boiler No. 5	005	SGC5	54.0	103.6	22.4	22.4	22.4	22.4	0.45	11.2	57.0	41.4	72.5	0.8
		Total =	112.5	278.1	51.5	51.5	51.5	51.5	1.0	25.8	153.0	111.2	194.7	1.6
Maximum Fuel Oil w/Remainder Bagasse														
Boiler No. 1	001	SGC1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Boiler No. 2	002	SGC2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Boiler No. 4	004	SGC4	38.1	165.7	500.4	219.0	27.6	18.4	10.0	250.2	91.1	66.3	116.0	0.5
Boiler No. 5	005	SGC5	34.9	108.3	384.4	168.2	21.2	14.1	7.7	192.2	59.6	43.3	75.8	0.5
		Total =	72.9	274.0	884.8	387.2	48.7	32.4	17.7	442.4	150.7	109.6	191.8	1.0

[a] Baseline emission rates are from Table 2-3.

TABLE 5-11
SUMMARY OF VISIBILITY IMPACTS AT BASELINE AND CONTROLLED 24-HOUR AVERAGE EMISSION RATES

Source	EU ID	Model ID	Baseline Impacts (dv)	SO_2 Control Scenario Impacts: No. 6 Oil (1% S Content) (dv)	No. 2 Oil (0.05%S) (dv)	No. 2 Oil (0.0015%S) (dv)	SO_2 Scrubber (98% Control) (dv)	Caustic (50% Control) (dv)	NOx Control Scenario Impacts: ROFA (45% Control) (dv)	ROFA+ROTAMIX (60% Control) (dv)	SNCR (30% Control) (dv)	PM Control Impacts: ESP (98.6% Control) (dv)
Bagasse-Firing Only												
Boiler No. 4	004	SGC4	0.233	--	--	--	0.231	0.232	0.196	0.178	0.207	0.101
Boiler No. 5	005	SGC5	0.195	--	--	--	0.191	0.192	0.167	0.153	0.181	0.064
Maximum Fuel Oil w/Remainder Bagasse												
Boiler No. 4	004	SGC4	0.284	0.223	0.198	0.198	0.197	0.229	0.255	0.246	0.265	0.174
Boiler No. 5	005	SGC5	0.216	0.183	0.161	0.160	0.158	0.184	0.198	0.192	0.204	0.130

Note: 8th Highest maximum visibility impacts from 2003.

6.0 REFERENCES

Guidelines for Best Available Retrofit Technology. Federal Register, Volume 70, pages 39104-39172. August 1, 2005.

OAQPS Cost Control Manual, Fifth Edition, EPA-4531B-96-001. February 1996.

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NCASI, 2006. Retrofit Control Technology Assessment for NO_x, SO_2, and PM Emissions from Kraft Pulp and Paper Mill Unit Operation. National Council for Air and Stream Improvement.

APPENDIX A

REVISED
AIR MODELING PROTOCOL
FOR SUGAR CANE GROWERS COOPERATIVE OF FLORIDA
BELLE GLADE, FLORIDA

REVISED
BART MODELING PROTOCOL FOR
SUGAR CANE GROWERS COOPERATIVE OF FLORIDA
BELLE GLADE, FLORIDA

Prepared For:
Sugar Cane Growers Cooperative of Florida, Inc.
Belle Glade Facility
Belle Glade, Florida

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

January 2007

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TABLE OF CONTENTS

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

1.0 INTRODUCTION

1.1 Objectives

Under the regional haze regulations contained in Title 40, Part 51 of the Code of Federal Regulations (40 CFR 51), Subpart P – Protection of Visibility, the U.S. Environmental Protection Agency (EPA) has issued final rules and guidelines, dated July 6, 2005, for Best Available Retrofit Technology (BART) determinations [Federal Register (FR), Volume 70, pages 39104-39172]. BART applies to certain large stationary sources known as BART-eligible sources. Sources are BART-eligible if they meet the following three criteria:

- Contain emissions units that are one of the 26 listed source categories in the guidance;
- Contain emissions units that were put in place between August 7, 1962 and August 7, 1977; and
- Potential emissions from the emissions units of at least 250 tons per year (TPY) of a visibility-impairing pollutant [sulfur dioxide (SO_2), nitrogen oxides (NO_x), and direct particulate matter of equal to or less than 10 microns (PM_{10})].

Sugar Cane Growers Cooperative of Florida's (SCGCF) Belle Glade facility has been identified as a BART-eligible source with multiple BART-eligible emissions units.

The Florida Department of Environmental Protection (FDEP) has proposed to adopt EPA's visibility protection rules and guidelines contained in 40 CFR 51, Subpart P. Final adoption of these rules is expected by the end of this year.

The basic tenet of the regional haze program is the achievement of natural visibility conditions in Prevention of Significant Deterioration (PSD) Class I areas by the year 2064. Florida has four PSD Class I areas while Georgia has two PSD Class I areas that can be affected by Florida sources [i.e., located in Florida or within 300 kilometers (km) of Florida].

BART is required for any BART-eligible source that FDEP determines emits any air pollutant that may "reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area." The BART guidelines establish a threshold value of 0.5 deciview (dv) for any single source for determining whether the source contributes to visibility impairment.

Throughout this protocol the terms "source" and "facility" have the same meanings. The term "BART-eligible emissions unit" is defined as any single emissions unit that meets the criteria described above, except for the 250 TPY criteria, which applies to the entire BART-eligible source. A "BART-eligible source" is defined as the collection of all BART-eligible emissions units at a single facility. If a source has several emissions units, only those that meet the BART-eligible criteria are included in the definition of "BART-eligible source."

The FDEP requires that the California Puff (CALPUFF) modeling system be used to determine visibility impacts from BART-eligible sources at the PSD Class I areas. A source-specific modeling protocol is required to be submitted by the affected sources to FDEP for review and approval. The source-specific modeling must be included in the BART application, due to FDEP no later than January 31, 2007.

This protocol describes the modeling procedures to be followed for performing the air modeling and includes site-specific data for SCGCF's BART-eligible emissions units. The site-specific data includes emissions unit locations, stack parameters, emission rates, and PM_{10} speciation information.

For guidance in preparing the air modeling protocol, the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) has developed a "common" modeling protocol outline that describes the recommended procedures for performing a visibility impairment analysis under the BART regulations [see *Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART)*, December 22, 2005 (Revision 3.2- August 31, 2006)]. The proposed modeling protocol for the SCGCF Belle Glade facility follows the general procedures recommended by VISTAS.

1.2 Location of Source

The SCGCF Belle Glade facility is located in Belle Glade, Palm Beach County, Florida. An area map showing the facility location and PSD Class I areas located within 300 km of the facility is presented in Figure 1-1. The PSD Class I areas and their distances from SCGCF are as follows:

- Everglades National Park (NP) - 105 km, and
- Chassahowitzka National Wilderness Area (NWA) - 289 km.

The Universal Transverse Mercator (UTM) coordinates of the SCGCF facility are approximately 534.9 km East and 2,953.3 km North in UTM Zone 17.

1.3 Source Impact Evaluation Criteria

The common BART modeling protocol describes the application of the CALPUFF modeling system for two purposes:

- Air quality modeling to determine whether a BART-eligible source is "subject to BART" – to evaluate whether a BART-eligible source is exempt from BART controls because it is not reasonably expected to cause or contribute to impairment of visibility in Class I areas, and
- Air quality modeling of emissions from sources that have been found to be subject to BART – to evaluate regional haze benefits of alternative control options and to document the benefits of the preferred option.

The common BART protocol identifies the first activity as the "BART exemption analysis" and the second activity as the "BART control analysis."

The final BART rule (70 FR 39118) states that the proposed threshold at which a source may "contribute" to visibility impairment should not be higher than 0.5 dv. The FDEP is also recommending the criterion of 0.5 dv.

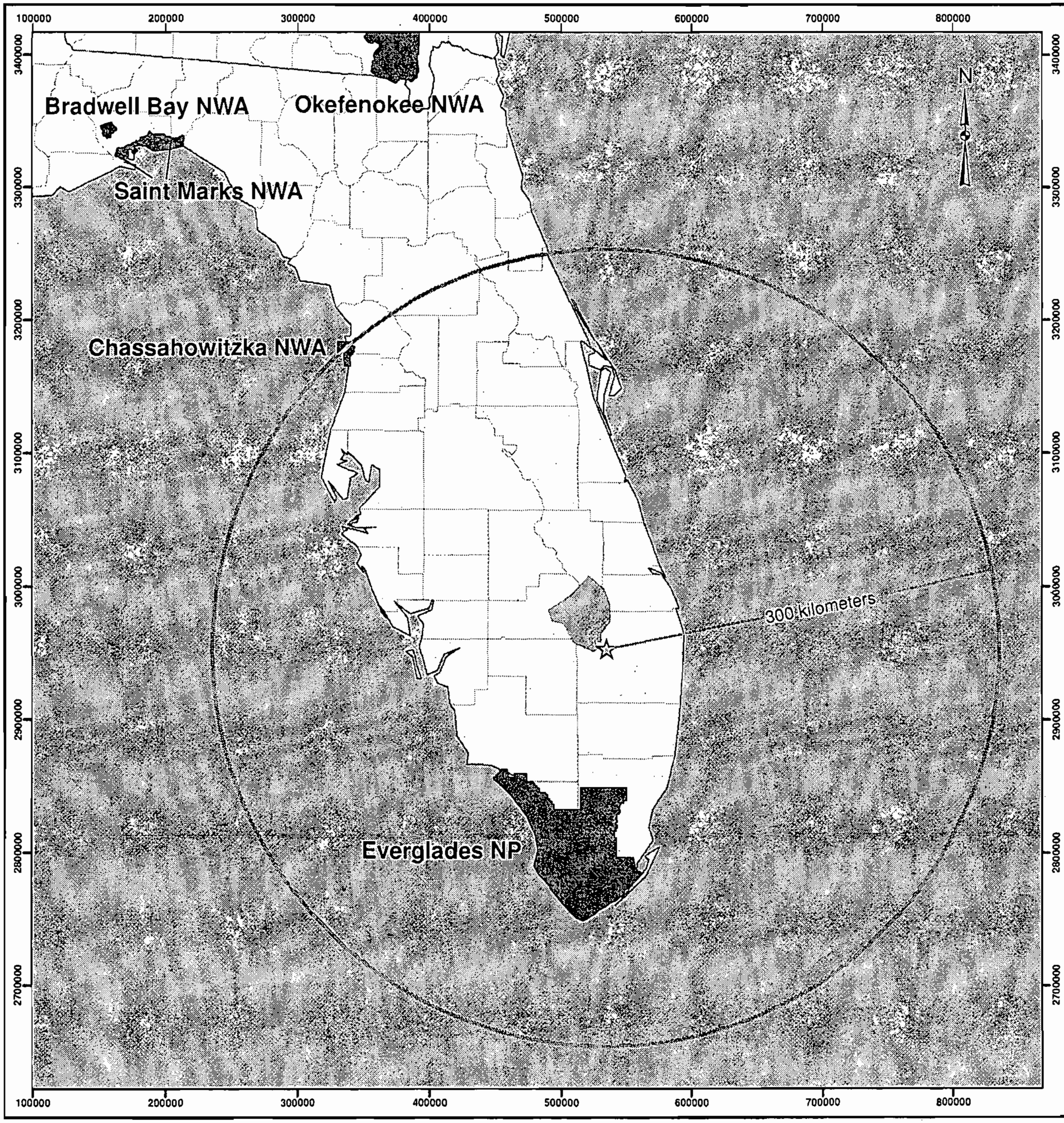
Based on VISTAS recommendations regarding BART exemption analysis, "initial screening" and "refined" analyses can be performed to determine whether a BART-eligible source is subject to or exempt from BART. The initial screening analysis, which is based on a coarse scale 12-km regional VISTAS domain, is optional and answers two questions – whether (a) a particular source may be exempted from further BART analyses and (b) if refined (finer grid) CALPUFF analyses were to be undertaken, which Class I areas should be included.

For the screening analysis, the highest predicted 24-hour impairment value is compared to the 0.5 dv criteria. If the highest predicted impacts are found to be less than 0.5 dv, no further analysis is required. But if the highest impact is predicted to be greater than 0.5 dv, then a refined, finer grid analysis may be performed.

The refined analysis, which is based on a finer grid subregional California Meteorological Model (CALMET) domain, is the definitive test for whether a source is subject to BART. In the refined analysis, the 98th percentile, i.e., the 8th highest 24-hour average visibility impairment value in 1 year or the 22nd highest 24-hour average visibility impairment value over 3 years combined, whichever is higher, is compared to 0.5 dv.

The screening analysis is optional for large sources that will clearly exceed the initial screening thresholds or sources that are very close to the Class I areas, which will be better treated by a finer grid resolution. For the SCGCF Belle Glade Facility BART analyses, only the refined analysis will be performed to determine whether the source is exempt from BART. All Class I areas within 300 km of SCGCF will be included in the refined modeling analysis and modeling results will be presented for each evaluated Class I area.

If the BART exemption analysis reveals that the BART-eligible source is subject to BART control analysis, part of the BART review process involves evaluating the visibility benefits of different BART control measures. These benefits will be determined by the refined analysis, where CALPUFF will be executed with the baseline emission rates and again with emission rates reflective of BART control options.



LEGEND

☆ Facility Location

Class I Areas

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

100,000 0 100,000 Meters

PROJECT

SUGAR CANE GROWERS COOPERATIVE
BART MODELING PROTOCOL

TITLE

Facility Location and PSD Class I areas Within 300 km

Golder Associates
Gainesville, Florida

PROJECT No.			SCALE AS SHOWN	REV. 0
DESIGN	AB	25 Apr. 2006		
GIS	AB	25 Apr. 2006		
CHECK	AB	25 Apr. 2006		
REVIEW	AB	25 Apr. 2006		

FIGURE 1-1

2.0 SOURCE DESCRIPTION

2.1 Source Applicability

SCGCF operates six boilers and a paint spray booth at the Belle Glade facility. The FDEP has published a list of potential BART-eligible sources (updated January 10, 2006), which is based on a survey questionnaire sent by FDEP to selected facilities in Florida on November 4, 2002 and April 18, 2003. FDEP's list contains four potential BART-eligible emissions units located at the SCGCF Belle Glade facility. The SCGCF Belle Glade facility is on the FDEP list since it has emission units in one of the 26 major source categories identified in the BART regulation [fossil-fuel boilers of more than 250 million British thermal units (MMBtu) per hour heat input] and has potential emissions of visibility impairment pollutants (i.e., SO_2, NO_x, and PM_{10}) from its BART-eligible emission units that are greater than 250 TPY.

From detailed information obtained from SCGCF, a BART-eligibility analysis was performed to verify the applicability of the BART rule to the facility as well as the list of BART-eligible units at the facility. This analysis consisted of a three-step procedure.

First, the facility is classified under the source category of fossil-fuel boilers of more than 250 MMBtu per hour heat input.

Second, each emissions unit at the facility was reviewed to determine which units met the date requirements for a BART-eligible unit. For each emissions unit, it was determined which units began operation after August 7, 1962, and also were in existence on August 7, 1977.

Third, if an emissions unit met the date requirements for BART eligibility, the potential emissions of visibility impairing pollutants from each unit were identified. At present, the visibility impairing pollutants include SO_2, NO_x, and PM_{10}. Other potential visibility impairing pollutants, such as volatile organic compounds (VOCs) and ammonia, have been determined by FDEP to have no significant effect on regional haze in Florida.

The results of this analysis are summarized in Table 2-1. As shown in Table 2-1, the potential annual SO_2, NO_x, and PM_{10} emissions from the BART-eligible emissions units total more than 250 TPY for all pollutants. Because the emissions of one or more pollutants are greater than the 250 TPY threshold, all of these pollutants will be included in the visibility impairment assessment for the facility.

Based on this analysis, the final list of BART-eligible, non-fugitive emissions units for SCGCF are as follows:

- Boiler No. 1 (EU001)
- Boiler No. 2 (EU002)
- Boiler No. 4 (EU004)
- Boiler No. 5 (EU005)

Boiler No. 3 (EU003) is excluded from the BART-eligible list as it has a maximum heat input rate less than 250 million British thermal units per hour (MMBtu/hr) and is not an integral part of the plant process. EPA has ruled that any boiler that supplies only heat or steam to a process is not integral to that process.

Based on discussions with FDEP, if a facility is more than 50 km from the nearest PSD Class I area, fugitive particulate matter (PM) emissions from BART-eligible emissions units are not required to undergo BART control evaluation nor need to be included in assessing visibility impairment.

2.2 Stack Parameters

The stack height above ground, stack diameter, exit velocity, and exit temperature for the BART-eligible emissions units at the Belle Glade facility are presented in Table 2-2. For the modeling analysis, all the emissions units will be collocated in the VISTAS domain Lambert Conformal Conic (LCC) coordinate system at (X, Y) = (1,642.612, -1,332.551) km.

2.3 Emission Rates for Visibility Impairment Analyses

The EPA BART guidance indicates that the emission rate to be used for BART modeling is the highest 24-hour actual emission rate representative of normal operations for the modeling period. Depending on the availability of the source data, the source emissions information should be based on the following, in order of priority based on the BART common protocol:

- 24-hour maximum emissions based on continuous emission monitoring (CEM) data for the period 2001-2003,
- Facility stack test emissions,
- Potential to emit,

- Allowable permit limits, and
- AP-42 emission factors.

SCGCF is permitted to operate all boilers during the sugarcane processing season (October through April). The maximum 24-hour average emission rates for the BART-eligible units at SCGCF that will be used in the modeling for the sugarcane processing season are presented in Table 2-3.

Since bagasse-firing and No. 6 fuel oil firing result in different air emissions, two cases were considered in developing the emissions to be used in the visibility modeling. The first case is 100-percent bagasse firing, which is the normal operating case. The second case is maximum No. 6 fuel oil firing, with the remainder of heat input due to bagasse. This second case occurs rarely in practice. Review of fuel oil usage records for the boilers shows that the maximum amount of fuel oil burned in a day in Boiler Nos. 1 through 5 from 2001 to present was 52,000 gallons, except during startup, shutdown, or malfunction conditions. For purposes of BART, this total amount was assumed to be burned in the BART-eligible boilers.

To identify the worst-case actual historic emissions for the BART-eligible boilers, records of daily steam production were reviewed for the period of 2001 through 2005. Analyses of these records showed that the maximum combined daily steam production rate for Boiler Nos. 1, 2, 4, and 5 during the crop season was 724,625 lb/steam, which occurred on January 28, 2004. The actual steam production rate for each boiler occurring on this date was then used in the calculation of the emissions for the BART modeling (refer to Appendix A, Tables A-1 and A-2).

The PM and NO_x emission rates are based on stack test data. The SO_2 emission rates are based on industry test data and assumptions shown in the Title V renewal application for the facility (September 2005). A summary of the stack test data is presented in Appendix A, Table A-8. Emission rate calculations for the SCGCF boilers are presented in Appendix A, Tables A-1 and A-2.

SCGCF is also permitted to operate any three boilers during the off-crop season (May through September), with a total maximum daily steam production rate of 450,000 pounds per hour (lb/hr). No single boiler has a maximum daily steam production rate greater than or equal to 450,000 lb/hr, so two- or three-boiler combinations must be used to achieve the maximum production rate allowed during the off-crop season. Emissions calculations based on different two- and three-boiler combinations are presented in Appendix A, Tables A-3 and A-4. The maximum off-crop season emissions are summarized in Table 2-3.

Based on review of these possible two- or three-boiler combinations, it was determined that using Boiler Nos. 4 and 5, operating at 84.91 percent of their maximum capacity in order to maintain the maximum daily steam production rate under 450,000 lb/hr, would result in the potential worst-case emissions of visibility-impairing pollutants for both fuel firing scenarios.

2.4 PM Speciation

Based on the latest regulatory guidance, PM emissions by size category need to be considered in the appropriate species for the visibility analysis. The effect that each species has on visibility impairment is related to a parameter called the extinction coefficient. The higher the extinction coefficient, the greater the species' affect on visibility. Filterable PM is speciated into coarse (PMC), fine (PMF), and elemental carbon (EC), with default extinction efficiencies of 0.6, 1.0, and 10.0, respectively. PMC is PM with aerodynamic diameter between 10 microns and 2.5 microns. Both EC and PMF have aerodynamic diameters equal to or less than 2.5 microns. Condensable PM is comprised of inorganic PM such as sulfate (SO_4) and organic PM such as secondary organic aerosols (SOA). The extinction efficiencies for these species are 3*f(RH) and 4, respectively, where f(RH) is the relative humidity factor.

The PM emissions from the BART-eligible units at the SCGCF were speciated into the recommended size and species categories using the latest EPA Publication AP-42 emission factors for wood-fired boilers (no species data are available for bagasse-fired boilers) for both bagasse- and maximum fuel oil with remainder bagasse-firing scenarios. The PM emissions from the stack test data were considered as total filterable PM_{10}. Using the AP-42 factors, emission factors for all the filterable species categories were first developed as a fraction of the total filterable PM_{10} and then, using the fraction, the emission rates of the different species were estimated.

Condensable PM emissions were estimated based on AP-42 emission factors and are presented in Tables A-6 and A-7. Since speciation data for condensable PM from wood-fired boilers are not available, the condensable PM emissions were equally divided into organic and inorganic components.

Speciation among the different size categories were also developed based on AP-42 cumulative particle size distribution and size-specific emission factors for wood/bark-fired boilers. Detailed PM speciation summaries are presented in Tables 2-4 through 2-7, which cover the scenarios shown in Table 2-3. Additional size-specific speciation data is presented in Appendix A, Tables A-5.

2.5 Building Dimensions

Based on discussions with FDEP, building downwash effects will not be considered in the modeling because these effects are considered to be minimal in assessing impacts at the distance of the nearest PSD Class I area, which is more than 50 km from the SCGCF Belle Glade facility.

TABLE 2-1
BART ELIGIBILITY ANALYSIS FOR SUGAR CANE GROWERS COOPERATIVE OF FLORIDA - BELLE GLADE FACILITY
(FACILITY ID 0990026)

EU ID	Emission Unit	BART Category [a]	Initial Construction Date	In Existence on 8/7/1977? (Yes/No)	Began Operation After 8/7/1962 ? (Yes/No)	Meets BART Date Criteria ? (Yes/No)	SO_2, NO_x, or PM Source ? (Yes/No)	BART Eligible ? (Yes/No)	Potential Emissions SO_2 (TPY)	Potential Emissions NO_x (TPY)	Potential Emissions PM_{10} (TPY)	Comments
001	Boiler No. 1	22	1963	Yes	Yes	Yes	Yes	Yes	2,196.5	556.5	243.2	
002	Boiler No. 2	22	1963	Yes	Yes	Yes	Yes	Yes	2,190.4	550.6	240.6	
003	Boiler No. 3	None[c]	--	--	--	--	--	--	--	--	--	<250 MMBtu/hr & not integral to process
004	Boiler No. 4	22	1975	Yes	Yes	Yes	Yes	Yes	4,009.8	1,195.1	417.8	
005	Boiler No. 5	22	1968	Yes	Yes	Yes	Yes	Yes	3,079.0	916.2	400.5	
006	Boiler No. 8	22	1982	No	Yes	No	Yes	No	--	--	--	Did not exist on 8/7/77
007	Spray Booth	None[c]	--	--	--	--	--	No	--	--	--	
								Total TPY =	4,256.0 [b]	3,218.4	1,302.1	

[a] BART category 22 is "Fossil-Fuel boilers of more than 250 million BTUs per hour heat input."

[b] Facility has facility-wide cap of 14 ton/day SO_2 emissions.

[c] Unit does not belong to any BART source category.

TABLE 2-2
SUMMARY OF STACK AND OPERATING PARAMETERS AND LOCATIONS FOR THE BART-ELIGIBLE EMISSIONS UNITS, SCGCF

		Stack Parameters[a]				Operating Parameters[a]				
		Height		Diameter		Flow Rate	Exit Temperature		Velocity	
Emission Unit	Model ID	ft	m	ft	m	acfm	°F	K	ft/s	m/s
Boiler No. 1	SGC1	150	45.72	7.0	2.13	114,500	156	342.0	49.6	15.11
Boiler No. 2	SGC2	150	45.72	7.0	2.13	118,000	156	342.0	51.1	15.58
Boiler No. 4	SGC4	180	54.86	8.9	2.72	203,000	162	345.4	54.1	16.50
Boiler No. 5	SGC5	150	45.72	7.0	2.13	178,000	160	344.3	77.1	23.50

[a] Stack and operating parameters from Title V renewal application dated September 2005.

Note: All emissions units will be collocated for the purpose of modeling. The facility coordinates are as follows:

UTM Zone 17: 634.9 km East, 2,953.3 km North.

Lambert Conformal Conic (LCC) coordinate, VISTAS Domain: 1,642.612 km, -1,332.551 km

TABLE 2-3
SUMMARY OF MAXIMUM 24-HOUR AVERAGE EMISSION RATES
FOR THE BART-ELIGIBLE EMISSIONS UNITS, SCGCF

Source	EU ID	Model ID	PM_{10} (lb/hr)	NO_x (lb/hr)	SO_2[a] (lb/hr)
ON-CROP SEASON					
Bagasse-Firing Only					
Boiler No. 1	001	SGC1	28.2	52.6	15.1
Boiler No. 2	002	SGC2	22.2	24.9	15.2
Boiler No. 4	003	SGC4	61.6	183.7	30.7
Boiler No. 5	004	SGC5	53.7	102.9	22.2
		Total =	165.6	364.1	83.3
Maximum Fuel Oil w/Remainder Bagasse					
Boiler No. 1	001	SGC1	21.5	59.2	180.9
Boiler No. 2	002	SGC2	17.1	38.8	181.1
Boiler No. 4	003	SGC4	49.3	178.4	314.4
Boiler No. 5	004	SGC5	42.1	105.8	240.2
		Total =	130.1	382.2	916.6
OFF-CROP SEASON[b]					
Bagasse-Firing Only					
Boiler No. 1	001	SGC1	0.0	0.0	0.0
Boiler No. 2	002	SGC2	0.0	0.0	0.0
Boiler No. 4	004	SGC4	58.5	174.5	29.2
Boiler No. 5	005	SGC5	54.0	103.6	22.4
		Total =	112.5	278.1	51.5
Maximum Fuel Oil w/Remainder Bagasse					
Boiler No. 1	001	SGC1	0.0	0.0	0.0
Boiler No. 2	002	SGC2	0.0	0.0	0.0
Boiler No. 4	004	SGC4	38.1	165.7	500.4
Boiler No. 5	005	SGC5	34.9	108.3	384.4
		Total =	72.9	274.0	884.8

Refer to Appendix A for basis of emissions.

[a] Total emissions of SO_2 from all operating boilers shall not exceed 14 tons per day (1166.7 pounds per day).

[b] Up to three boilers can be operating during the off-crop season. For the purposes of exemption modeling, Boiler Nos. 4 and 5 will be modeled operating at 84.91% of their maximum capacity in order to maintain the maximum daily steam production rate under 450,000 lb/hr during off-crop season in the bagasse-firing only scenario (Scenario C in Appendix A, Table A-3), as well as in the maximum fuel oil w/ remainder bagasse firing scenario (Scenario C in Appendix A, Table A-4). These firing scenarios represent potential worst-case emissions of visibility-impairing pollutants for both fuel firing scenarios. Off-crop season is May through September.

TABLE 2-4
PM SPECIATION SUMMARY - SCGCF
BAGASSE-FIRING ONLY SCENARIO, ON-CROP SEASON

PM	Source	Rate (lb/hr)	Coarse PM	Soil (Fine PM)	Elemental Carbon	H_2SO_4	Organic
Filterable PM_{10}[a]	Boiler 1	28.2	0.00	25.53	2.62		
	Boiler 2	22.2	0.00	20.11	2.06		
	Boiler 4	61.6	0.00	55.84	5.73		
	Boiler 5	53.7	0.00	48.70	4.99		
Condensable[b]	Boiler 1	4.28				2.14	2.14
	Boiler 2	4.32				2.16	2.16
	Boiler 4	8.70				4.35	4.35
	Boiler 5	6.30				3.15	3.15
Total PM_{10} (filterable+condensable)	Boiler 1	32.4	0.00	25.53	2.62	2.14	2.14
	Boiler 2	26.5	0.00	20.11	2.06	2.16	2.16
	Boiler 4	70.3	0.00	55.84	5.73	4.35	4.35
	Boiler 5	60.0	0.00	48.70	4.99	3.15	3.15
PM Speciation (% Filterable)[c]		100.0%	0.0%	90.7%	9.3%		
PM Speciation (% Condensable)[d]		100.0%				50.0%	50.0%
Total PM_{10} (filterable+Organic Condensable PM)	Boiler 1	30.3					
	Boiler 2	24.3					
	Boiler 4	65.9					
	Boiler 5	56.8					
Modeled PM Speciation % (SO_4 modeled separately)	Boiler 1	100.0%	0.0%	84.3%	8.6%	0.0%	7.1%
	Boiler 2	100.0%	0.0%	82.7%	8.5%	0.0%	8.9%
	Boiler 4	100.0%	0.0%	84.7%	8.7%	0.0%	6.6%
	Boiler 5	100.0%	0.0%	85.7%	8.8%	0.0%	5.5%

PM Particle Size Distribution for CALPUFF Assessment

Species Name	Geometric Mass (microns)	Size Distribution by Category (%): Filterable[e] (%)	Organic Condensable	Emission Rate (lb/hr): Boiler 1 Filterable	Organic Condensable	Total	Emission Rate (lb/hr): Boiler 2 Filterable	Organic Condensable	Total	Emission Rate (lb/hr): Boiler 4 Filterable	Organic Condensable	Total	Emission Rate (lb/hr): Boiler 5 Filterable	Organic Condensable	Total
Total PM_{10}				28.2	2.1	30.3	22.2	2.2	24.3	61.6	4.4	65.9	53.7	3.1	56.8
PM0063	0.63	51.0%	50.0%	14.4	1.1	15.4	11.3	1.1	12.4	31.4	2.2	33.6	27.4	1.6	29.0
PM0100	1	45.9%	50.0%	12.9	1.1	14.0	10.2	1.1	11.3	28.3	2.2	30.4	24.7	1.6	26.2
PM0125	1.25	3.1%	0	0.9	0.0	0.9	0.7	0.0	0.7	1.9	0.0	1.9	1.6	0.0	1.6
PM0250	2.5	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM0600	6	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM1000	10	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals		100.0%	100.0%	28.2	2.1	30.3	22.2	2.2	24.3	61.6	4.4	65.9	53.7	3.1	56.8
				Total Modeled PM_{10}		30.3	Total Modeled PM_{10}		24.3	Total Modeled PM_{10}		65.9	Total Modeled PM_{10}		56.8

[a] From Table 2-3.
[b] From Table A-6.
[c] From Table 1.6-1 of AP-42, September 2003: $PM_{2.5}$ is 100% of PM_{10}, therefore, 0% Coarse PM. From Table 6 of EPA's January 2002 DRAFT "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon": 9.3% of $PM_{2.5}$ is EC.
[d] Fifty-percent of condensable PM is assumed to be inorganic condensable PM.
[e] From Table A-5.

TABLE 2-5
PM SPECIATION SUMMARY - SCGCF
MAXIMUM FUEL OIL W/ REMAINDER BAGASSE FIRING SCENARIO, ON-CROP SEASON

PM	Source	Rate (lb/hr)	Coarse PM	Soil (Fine PM)	Elemental Carbon	H_2SO_4	Organic
Filterable PM_{10}[a]	Boiler 1	21.5	0.00	19.51	2.00		
	Boiler 2	17.1	0.00	15.54	1.59		
	Boiler 4	49.3	0.00	44.70	4.58		
	Boiler 5	42.1	0.00	38.22	3.92		
Condensable[b]	Boiler 1	3.82				1.91	1.91
	Boiler 2	3.86				1.93	1.93
	Boiler 4	7.92				3.96	3.96
	Boiler 5	5.69				2.85	2.85
Total PM_{10} (filterable+condensable)	Boiler 1	25.3	0.00	19.51	2.00	1.91	1.91
	Boiler 2	21.0	0.00	15.54	1.59	1.93	1.93
	Boiler 4	57.2	0.00	44.70	4.58	3.96	3.96
	Boiler 5	47.8	0.00	38.22	3.92	2.85	2.85
PM Speciation (% Filterable)[c]		100.0%	0.0%	90.7%	9.3%		
PM Speciation (% Condensable)[d]		100.0%				50.0%	50.0%
Total PM_{10} (filterable+Organic Condensable PM)	Boiler 1	23.4					
	Boiler 2	19.1					
	Boiler 4	53.2					
	Boiler 5	45.0					
Modeled PM Speciation % (SO_4 modeled separately)	Boiler 1	100.0%	0.0%	83.3%	8.5%	0.0%	8.1%
	Boiler 2	100.0%	0.0%	81.5%	8.4%	0.0%	10.1%
	Boiler 4	100.0%	0.0%	84.0%	8.6%	0.0%	7.4%
	Boiler 5	100.0%	0.0%	85.0%	8.7%	0.0%	6.3%

PM Particle Size Distribution for CALPUFF Assessment

Species	Geometric Size Distribution by Category (%)			Emission Rate (lb/hr): Boiler 1			Emission Rate (lb/hr): Boiler 2			Emission Rate (lb/hr): Boiler 4			Emission Rate (lb/hr): Boiler 5		
Name	Mass (microns)	Filterable[e] (%)	Organic Condensable	Filterable	Organic Condensable	Total	Filterable	Organic Condensable	Total	Filterable	Organic Condensable	Total	Filterable	Organic Condensable	Total
Total PM_{10}				21.5	1.9	23.4	17.1	1.9	19.1	49.3	4.0	53.2	42.1	2.8	45.0
PM0063	0.63	51.0%	50.0%	11.0	1.0	11.9	8.7	1.0	9.7	25.1	2.0	27.1	21.5	1.4	22.9
PM0100	1	45.9%	50.0%	9.9	1.0	10.8	7.9	1.0	8.8	22.6	2.0	24.6	19.4	1.4	20.8
PM0125	1.25	3.1%	0	0.7	0.0	0.7	0.5	0.0	0.5	1.5	0.0	1.5	1.3	0.0	1.3
PM0250	2.5	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM0600	6	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM1000	10	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals		100.0%	100.0%	21.5	1.9	23.4	17.1	1.9	19.1	49.3	4.0	53.2	42.1	2.8	45.0
					Total Modeled PM_{10}	23.4		Total Modeled PM_{10}	19.1		Total Modeled PM_{10}	53.2		Total Modeled PM_{10}	45.0

[a] From Table 2-3.

[b] From Table A-6.

[c] From Table 1.6-1 of AP-42, September 2003: $PM_{2.5}$ is 100% of PM_{10}, therefore, 0% Coarse PM. From Table 6 of EPA's January 2002 DRAFT "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon": 9.3% of $PM_{2.5}$ is EC

[d] Fifty-percent of condensable PM is assumed to be inorganic condensable PM.

[e] From Table A-5.

TABLE 2-6
PM SPECIATION SUMMARY - SCGCF
BAGASSE-FIRING ONLY SCENARIO, OFF-CROP SEASON

PM	Source	Rate (lb/hr)	Coarse PM	Soil (Fine PM)	Elemental Carbon	H_2SO_4	Organic
Filterable PM_{10} [a]	Boiler 1	0.0	0.00	0.00	0.00		
	Boiler 2	0.0	0.00	0.00	0.00		
	Boiler 4	58.5	0.00	53.04	5.44		
	Boiler 5	54.0	0.00	49.02	5.03		
Condensable [b]	Boiler 1	0.00				0.00	0.00
	Boiler 2	0.00				0.00	0.00
	Boiler 4	8.27				4.13	4.13
	Boiler 5	6.34				3.17	3.17
Total PM_{10} (filterable+condensable)	Boiler 1	0.0	0.00	0.00	0.00	0.00	0.00
	Boiler 2	0.0	0.00	0.00	0.00	0.00	0.00
	Boiler 4	66.7	0.00	53.04	5.44	4.13	4.13
	Boiler 5	60.4	0.00	49.02	5.03	3.17	3.17
PM Speciation (% Filterable) [c]		100.0%	0.0%	90.7%	9.3%		
PM Speciation (% Condensable) [d]		100.0%				50.0%	50.0%
Total PM_{10} (filterable+Organic Condensable PM)	Boiler 1	0.0					
	Boiler 2	0.0					
	Boiler 4	62.6					
	Boiler 5	57.2					
Modeled PM Speciation % (SO_4 modeled separately)	Boiler 1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Boiler 2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Boiler 4	100.0%	0.0%	84.7%	8.7%	0.0%	6.6%
	Boiler 5	100.0%	0.0%	85.7%	8.8%	0.0%	5.5%

PM Particle Size Distribution for CALPUFF Assessment

Species	Geometric Size Distribution by Category (%)			Emission Rate (lb/hr): Boiler 1			Emission Rate (lb/hr): Boiler 2			Emission Rate (lb/hr): Boiler 4			Emission Rate (lb/hr): Boiler 5		
Name	Mass (microns)	Filterable [e] (%)	Organic Condensable	Filterable	Organic Condensable	Total	Filterable	Organic Condensable	Total	Filterable	Organic Condensable	Total	Filterable	Organic Condensable	Total
Total PM_{10}				0.0	0.0	0.0	0.0	0.0	0.0	58.5	4.1	62.6	54.0	3.2	57.2
PM0063	0.63	51.0%	50.0%	0.0	0.0	0.0	0.0	0.0	0.0	29.8	2.1	31.9	27.6	1.6	29.2
PM0100	1	45.9%	50.0%	0.0	0.0	0.0	0.0	0.0	0.0	26.9	2.1	28.9	24.8	1.6	26.4
PM0125	1.25	3.1%	0	0.0	0.0	0.0	0.0	0.0	0.0	1.8	0.0	1.8	1.7	0.0	1.7
PM0250	2.5	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM0600	6	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM1000	10	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals		100.0%	100.0%	0.0	0.0	0.0	0.0	0.0	0.0	58.5	4.1	62.6	54.0	3.2	57.2
				Total Modeled PM_{10}		0.0	Total Modeled PM_{10}		0.0	Total Modeled PM_{10}		62.6	Total Modeled PM_{10}		57.2

[a] From Table 2-3.
[b] From Table A-6.
[c] From Table 1.6-1 of AP-42, September 2003: $PM_{2.5}$ is 100% of PM_{10}, therefore, 0% Coarse PM. From Table 6 of EPA's January 2002 DRAFT "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon": 9.3% of $PM_{2.5}$ is EC
[d] Fifty-percent of condensable PM is assumed to be inorganic condensable PM.
[e] From Table A-5.

TABLE 2-7
PM SPECIATION SUMMARY - SCGCF
MAXIMUM FUEL OIL W/ REMAINDER BAGASSE FIRING SCENARIO, OFF-CROP SEASON

PM	Source	Rate (lb/hr)	Coarse PM	Soil (Fine PM)	Elemental Carbon	H_2SO_4	Organic
Filterable PM_{10}[a]	Boiler 1	0.0	0.00	0.00	0.00		
	Boiler 2	0.0	0.00	0.00	0.00		
	Boiler 4	38.1	0.00	34.54	3.54		
	Boiler 5	34.9	0.00	31.62	3.24		
Condensable[b]	Boiler 1	0.00				0.00	0.00
	Boiler 2	0.00				0.00	0.00
	Boiler 4	6.96				3.48	3.48
	Boiler 5	5.33				2.67	2.67
Total PM_{10} (filterable+condensable)	Boiler 1	0.0	0.00	0.00	0.00	0.00	0.00
	Boiler 2	0.0	0.00	0.00	0.00	0.00	0.00
	Boiler 4	45.0	0.00	34.54	3.54	3.48	3.48
	Boiler 5	40.2	0.00	31.62	3.24	2.67	2.67
PM Speciation (% Filterable)[c]		100.0%	0.0%	90.7%	9.3%		
PM Speciation (% Condensable)[d]		100.0%				50.0%	50.0%
Total PM_{10} (filterable+Organic Condensable PM)	Boiler 1	0.0					
	Boiler 2	0.0					
	Boiler 4	41.6					
	Boiler 5	37.5					
Modeled PM Speciation % (SO_4 modeled separately)	Boiler 1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Boiler 2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Boiler 4	100.0%	0.0%	83.1%	8.5%	0.0%	8.4%
	Boiler 5	100.0%	0.0%	84.3%	8.6%	0.0%	7.1%

PM Particle Size Distribution for CALPUFF Assessment

Species	Geometric Size Distribution by Category (%)			Emission Rate (lb/hr): Boiler 1			Emission Rate (lb/hr): Boiler 2			Emission Rate (lb/hr): Boiler 4			Emission Rate (lb/hr): Boiler 5		
Name	Mass (microns)	Filterable[e] (%)	Organic Condensable	Filterable	Organic Condensable	Total	Filterable	Organic Condensable	Total	Filterable	Organic Condensable	Total	Filterable	Organic Condensable	Total
Total PM_{10}				0.0	0.0	0.0	0.0	0.0	0.0	38.1	3.5	41.6	34.9	2.7	37.5
PM0063	0.63	51.0%	50.0%	0.0	0.0	0.0	0.0	0.0	0.0	19.4	1.7	21.2	17.8	1.3	19.1
PM0100	1	45.9%	50.0%	0.0	0.0	0.0	0.0	0.0	0.0	17.5	1.7	19.2	16.0	1.3	17.3
PM0125	1.25	3.1%	0	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	1.2	1.1	0.0	1.1
PM0250	2.5	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM0600	6	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PM1000	10	0.0%	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals		100.0%	100.0%	0.0	0.0	0.0	0.0	0.0	0.0	38.1	3.5	41.6	34.9	2.7	37.5
				Total Modeled PM_{10}		0.0	Total Modeled PM_{10}		0.0	Total Modeled PM_{10}		41.6	Total Modeled PM_{10}		37.5

[a] From Table 2-3.

[b] From Table A-6.

[c] From Table 1.6-1 of AP-42, September 2003: $PM_{2.5}$ is 100% of PM_{10}, therefore, 0% Coarse PM. From Table 6 of EPA's January 2002 DRAFT "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon": 9.3% of $PM_{2.5}$ is EC

[d] Fifty-percent of condensable PM is assumed to be inorganic condensable PM.

[e] From Table A-5.

3.0 GEOPHYSICAL AND METEOROLOGICAL DATA

3.1 Modeling Domain and Terrain

CALMET data sets have been developed by EarthTech, Inc., which are based on the following 3 years of Fifth Generation Mesoscale Model (MM5) meteorological data assembled by VISTAS:

- 2001 MM5 data set at 12 km grid (developed by EPA),
- 2002 MM5 data set at 12 km grid (developed by VISTAS), and
- 2003 MM5 data set at 36 km grid (developed by Midwest Regional Planning Organization).

For the finer grid modeling analysis (refined analysis), the 4-km spacing Florida CALMET domain will be used. VISTAS has prepared a total of five sub-regional 4-km spacing CALMET domains. Domain 2 covers all Florida sources and Class I areas that can be potentially affected by the Florida sources.

Golder Associates Inc. (Golder) obtained these data sets from FDEP. As indicated in Section 1.3, for this protocol, the exemption modeling will be based on the finer grid modeling since the SCGCF Belle Glade facility is a large source that is likely to exceed the initial screening thresholds.

3.2 Land Use and Meteorological Database

The CALMET meteorological domains to be used in the exemption modeling have been supplied by VISTAS.

3.3 Air Quality Database

3.3.1 Ozone Concentrations

For these analyses, observed ozone data for 2001-2003 from CASTNet and Aerometric Information Retrieval System (AIRS) stations will be used. These data sets have been obtained from EarthTech's website as recommended by FDEP.

3.3.2 Ammonia Concentrations

A fixed monthly background ammonia concentration of 0.5 parts per billion (ppb) will be used based on FDEP's recommendation.

3.4 Natural Conditions at Class I Area

Based on VISTAS' recommendation, Visibility Method 6 will be used in all BART-related modeling, which will compute extinction coefficients for hygroscopic species (modeled and background) using a monthly f(RH) in lieu of calculating hourly RH factors. Monthly RH values from Table A-3 of EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule* (Haze Guideline) will be used. Monthly RH factors for the Class I areas within 300 km of the SCGCF facility are as follows:

Month	Chassahowitzka NWA	Everglades NP
January	3.8	2.7
February	3.5	2.6
March	3.4	2.6
April	3.2	2.4
May	3.3	2.4
June	3.9	2.7
July	3.9	2.6
August	4.2	2.9
September	4.1	3.0
October	3.9	2.8
November	3.7	2.6
December	3.9	2.7

Method 6 requires input of natural background (BK) concentrations of ammonium sulfate ($BKSO_4$), ammonium nitrate ($BKNO_3$), coarse particulates (BKPMC), organic carbon (BKOC), soil (BKSOIL), and elemental carbon (BKEC) in micrograms per cubic meter ($\mu g/m^3$). The model then calculates the natural background light extinction and haze index based on these values.

According to VISTAS and FDEP recommendations, the natural background light extinction may be based on haze index (HI) values (in dv) for either the annual average or the 20 percent best visibility days provided by EPA in Appendix B of the Haze Guidance document (using the 10^{th} percentile HI value). For SCGCF's BART analysis, the annual average HI values will be used to determine natural background light extinction of the Class I areas. The light extinction coefficient in inverse megameters (Mm^{-1}) is based on the concentration of the visibility impairing components and the extinction efficiency, in square meters per gram (m^2/g), for each component.

Per VISTAS and FDEP recommendations, the natural background light extinction that is equivalent to the EPA-provided background HI for each Class I area, based on the annual average, will be estimated using the following background values:

- Rayleigh scattering = 10 Mm^{-1};
- Concentrations of $BKSO_4$, $BKNO_3$, BKPMC, BKEC, and BKEC = 0.0; and
- BKSOIL concentration, which is estimated from the extinction coefficient that corresponds to EPA's HI value (corresponding to annual average) and then subtracting the Rayleigh scattering of 10 Mm^{-1} (assumes that the extinction efficiency of soil is 1 m^2/g).

According to Appendix B of the Haze Guideline document, the annual average background light extinction coefficient for each PSD Class I area and corresponding calculated BKSOIL concentrations are as follows:

- Chassahowitzka NWA – 21.45 Mm^{-1} (equivalent to 7.63 dv); 11.45 $\mu g/m^3$
- Everglades NP – 20.77 Mm^{-1} (equivalent to 7.61 dv); 10.77 $\mu g/m^3$

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the EPA under the 1999 Regional Haze Rule (RHR). This algorithm for estimating light extinction from particle speciation data tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the sea coasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from particulate matter component concentrations, which provides a better correspondence between measured visibility and that calculated from particulate matter component concentrations.

The new algorithm splits the total sulfate, nitrate, and organic carbon compound concentrations into two fractions, representing small and large size distributions of those compounds. New terms added to the algorithm are light absorption by NO_2 gas and light scattering due to fine sea salt accompanied by its own hygroscopic scattering enhancement factor and Class I area specific Rayleigh scattering values rounded off to the nearest whole number. The U.S. Environmental Protection Agency (EPA) and the Federal Land Managers (FLMs) from the National Park Service (NPS) and the U.S. Fish and Wildlife Service have determined that adding site-specific data (e.g., sea salt and site-specific Rayleigh scattering) to the old IMPROVE algorithm, for a hybrid approach, is not recommended and is allowing the optional use of the new IMPROVE algorithm.

As one or more of the Class I areas within 300 km of the SCGCF facility are located near the sea coast, the new IMPROVE algorithm may additionally be used to calculate the natural background at these Class I areas. The new IMPROVE algorithm accounts for the background sea-salt concentrations and site-specific Rayleigh scattering. Since the new IMPROVE equation cannot be directly implemented using the existing version of the CALPUFF model without additional post-processing or model revision, VISTAS has developed a methodology for implementing the new IMPROVE equation using existing CALPUFF/CALPOST output in a spreadsheet. This spreadsheet, known as the CALPOST-IMPROVE Processor will be used to re-calculate visibility impacts due to SCGCF's BART-eligible units in addition to the visibility impacts determined using the old IMPROVE equation.

It is assumed that ambient NO_2 concentrations due to SCGCF's BART eligible unit would be very small as to cause negligible light absorption, so light absorption by NO_2 gas, which is a new term, added to the new IMPROVE algorithm, will not be considered for SCGCF's BART modeling analysis. The following Class I area specific Rayleigh scattering (in Mm^{-1}) and sea salt concentrations (in $\mu g/m^3$) values will be used to evaluate the visibility impacts using the new CALPOST-IMPROVE Processor:

- Chassahowitzka NWA – 11 Mm^{-1} ; 0.08 $\mu g/m^3$
- Everglades NP – 11 Mm^{-1} ; 0.31 $\mu g/m^3$

4.0 AIR QUALITY MODELING METHODOLOGY

For predicting maximum visibility impairment at the Class I Area, the CALPUFF modeling system will be used. For BART-related visibility impact assessments, the CALPUFF model, Version 5.756 (060725), is recommended for use by the EPA and VISTAS. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The CALPUFF model is a non-steady-state long-range transport Lagrangian puff dispersion model applicable for estimating visibility impacts. The methods and assumptions used in the CALPUFF model will be based on the latest recommendations for CALPUFF analysis as presented in the VISTAS modeling protocol, Interagency Workgroup on Air Quality Models (IWAQM) Phase 2 Summary Report and the Federal Land Managers' Air Quality Related Values Work Group (FLAG) document. This model is also maintained by the EPA on the Support Center for Regulatory Air Models (SCRAM) website.

4.1 Modeling Domain Configuration

The 4-km spacing Florida domain will be used for the BART exemption modeling and if required, modeling to evaluate visibility benefits of different BART control measures. VISTAS has prepared five sub-regional 4-km spacing CALMET domains. Domain 2 of these domains cover sources in Florida and Class I areas that are affected by the sources in Florida.

4.2 CALMET Meteorological Domain

The refined CALMET domain, to be used for SCGCF's BART modeling has been provided by FDEP. The major features used in preparing these CALMET data have been described in Section 4.0 of the VISTAS BART modeling protocol.

4.3 CALPUFF Computational Domain and Receptors

The computational domain to be used for the refined modeling will be equal to the full extent of the meteorological domain. Visibility impacts will be predicted at each PSD Class I area using receptor locations provided by the Federal Land Managers. The receptors to be used for each of the PSD Class I areas are presented in Figures 4-1 and 4-2.

4.4 CALPUFF Modeling Options

The major CALPUFF modeling options recommended in the IWAQM guidance (EPA, 1988; Pages B-1 through B-8), in addition to the recommendations in Section 4.3.3 of the VISTAS BART modeling protocol, will be used.

4.5 Light Extinction and Haze Impact Calculations

The CALPOST program will be used to calculate the light extinction and the haze impact. The Method 6 technique, which is recommended by the BART guidance, will be used to compute change in light extinction.

4.6 Quality Assurance and Quality Control (QA/QC)

Quality assurance procedures will be established to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program. The meteorological datasets to be used in the modeling were developed and provided by VISTAS and therefore, no further QA will be required for these.

The CALPUFF modeling options are described in Section 4.4. The site-specific source data will be independently confirmed by an independent modeler not involved in the initial setup of the modeling files. The verification will encompass the following:

- Units of measure;
- Verification of the correct source and receptor locations;
- Including datum and projection;
- Confirmation of the switch selections relative to modeling guidance;
- Checks of the program switches and file names of the various processing steps; and
- Confirmation of the use of the proper version and level of each model program.

In addition, all the data and program files needed to reproduce the modeling results will be supplied with the modeling report.

The source and emission data will be independently verified by Golder and SCGCF. The source coordinates and related projection/datum parameters will be checked using the CALPUFF GUI's COORDS software and other comparable coordinate translation software such as CORPSCON and National Park Services Conversion Utilities software.

The POSTUTIL and CALPOST post-processor input files will be carefully checked to make sure of the following:

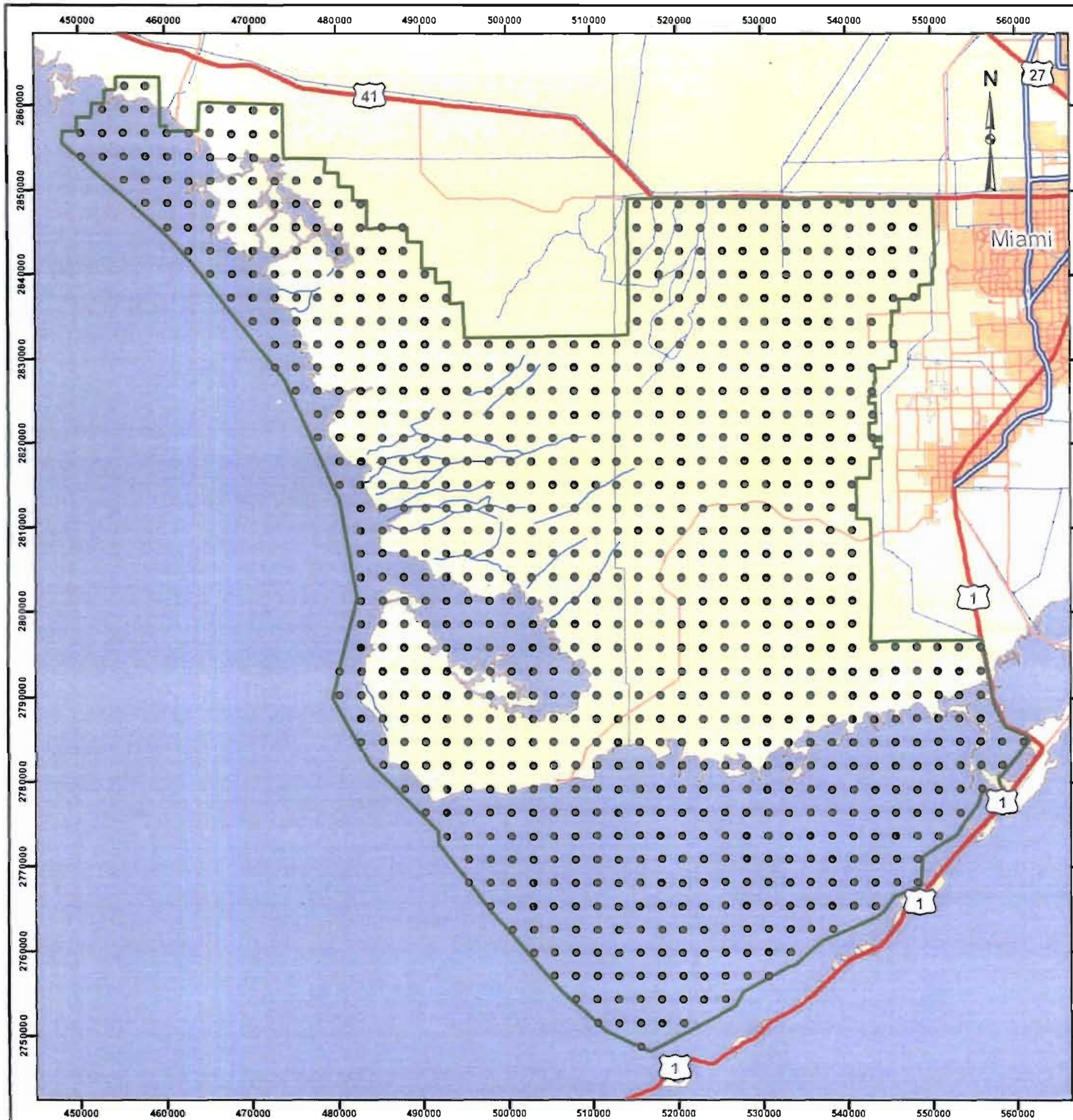
- Appropriate CALPUFF concentrations files are used in the POSTUTIL run;
- The PM species categories are computed using the appropriate fractions;
- Background light extinction computation method selected as Method 6;
- Correct monthly relative humidity adjustment factors used for the appropriate Class I area;
- Background light extinction values as described in Section 3.4 of this protocol;
- Appropriate species names for coarse and fine PM;
- Appropriate Rayleigh scattering term used; and
- Appropriate Class I receptors selected for each Class I area-specific CALPOST run.

4.7 Modeling Report

A modeling report will be submitted containing the following information:

- Map of source location and Class I areas within 300 km of the source;
- Table showing visibility impacts at each Class I area within 300 km of the source; and
- For the refined modeling analysis, a table showing the eight highest visibility impairment values ranked in a descending order for the prime Class I area(s) of interest.

The predicted visibility impairment results for the base emission case and all evaluated BART emission scenarios will be included in the report to show the affect on visibility for each proposed control technology. Final recommendations for BART will also be presented, based on the analysis results of the five evaluation criteria presented in the regulation.



LEGEND

Everglades NP

- 901 Receptor Grid
- Class I Boundary

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

15,000 0 15,000 Meters

PROJECT

SUGAR CANE GROWERS COOPERATIVE
BART MODELING PROTOCOL

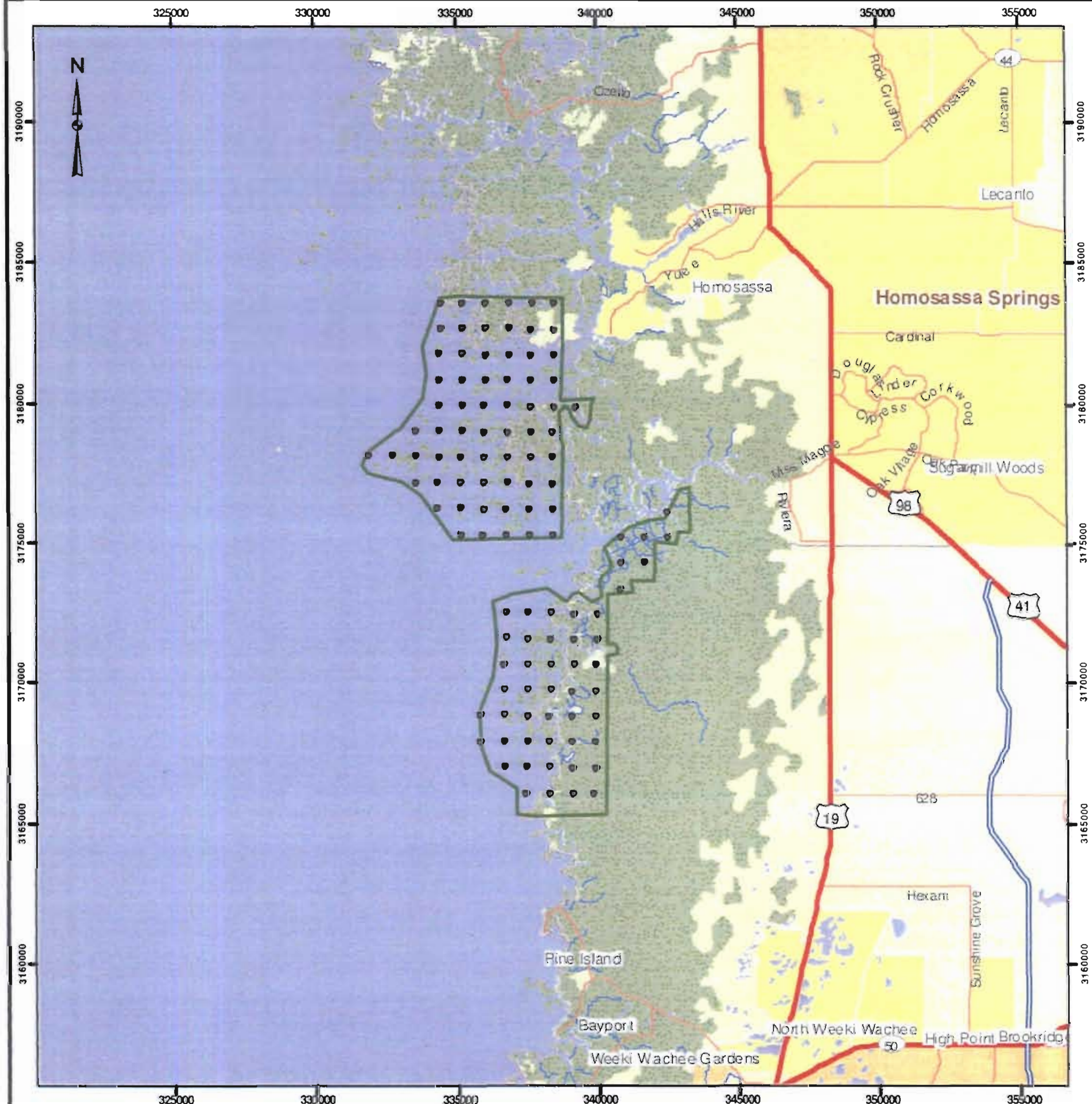
TITLE

Everglades NP Receptor Grid

Golder Associates, Gainesville, Florida

PROJECT No.			SCALE AS SHOWN	REV 0
DESIGN	AB	25 Apr 2006		
GIS	AB	25 Apr 2006		

FIGURE 4-1



LEGEND

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

5,000 0 5,000 Meters

PROJECT
SUGAR CANE GROWERS COOPERATIVE
BART MODELING PROTOCOL

TITLE
Chassahowitzka NWA Receptor Grid

Golder Associates

FIGURE 4-2

APPENDIX A

DETAILED EMISSION CALCULATION, PM SPECIATION, AND STACK TEST DATA

TABLE A-1
EMISSIONS FOR ON-CROP SEASON OPERATION, SCGCF
BAGASSE-FIRING ONLY (24-HR AVERAGING TIME)

Boiler	Maximum Steam Rate (lb/hr)	Maximum Heat Input (MMBtu/hr)[a]	Rates for Scenario[b] Percent Capacity	Steam (lb/hr)	Heat Input (MMBtu/hr)	SO_2 Emissions Factor (lb/MMBtu)[c]	Total (lb/hr)	NO_X Emissions Factor (MMBtu/hr)	Total (lb/hr)	PM_{10} Emissions Factor (MMBtu/hr)[d]	Total (lb/hr)
001	139,700	266.7	94%	131,750	251.5	0.06	15.1	0.209 [e]	52.6	0.112 [e]	28.2
002	138,514	269.0	94%	130,708	253.8	0.06	15.2	0.098 [f]	24.9	0.087 [f]	22.2
004	300,000	572.7	89%	268,167	511.9	0.06	30.7	0.359 [g]	183.7	0.120 [g]	61.6
005	230,000	439.1	84%	194,000	370.4	0.06	22.2	0.278 [g]	102.9	0.145 [g]	53.7
Totals	808,214	1,547.5		724,625	1,387.7		83.3		364.1		165.6

[a] Maximum heat input rate is based on maximum 24-hour heat input rate in Permit No. 0990026-012-AV.

[b] Based highest combined daily steam production for Boiler Nos. 1, 2, 4 and 5 occurring during 2001-2005 (Jan. 28, 2004).

[c] Based on industry test data.

[d] Based on AP-42 Table 1.8-1, Bagasse Firing, with wet scrubber control where 97% of PM is PM_{10}.

[e] Highest emission factor from last 2 years of stack testing (since new water-cooled, pinhole grate was installed).

[f] Highest emission factor from last 1 year of stack testing (since new water-cooled, pinhole grate was installed).

[g] Highest emission factor from last 5 years of stack testing.

Unless otherwise specified, heating values for each fuel are used as follows:

3,600 Btu/lb for wet bagasse, 8,000 Btu/lb dry bagasse, and 151,000 Btu/gal for No. 6 fuel oil.

TABLE A-2
EMISSIONS FOR ON-CROP SEASON OPERATION, SCGCF
MAXIMUM FUEL OIL W/ REMAINDER BAGASSE FIRING (24-HR AVERAGING TIME)

Boiler	Maximum Steam Rate (lb/hr)	Maximum Heat Input (MMBtu/hr)[a]	Maximum Heat Input From Fuel Oil (MMBtu/hr)[a]	Rates for Scenario: Percent Capacity	Steam[b] (lb/hr)	Percent Oil	Total (MMBtu/hr)	Fuel Oil (MMBtu/hr)	Bagasse (MMBtu/hr)	SO_2 Emissions[b]: Fuel Oil (lb/hr)[c]	Bagasse (lb/hr)[d]	Total (lb/hr)	NO_X Emissions: Fuel Oil (lb/hr)[e]	Bag. Factor (lb/MMBtu)	Bagasse (lb/hr)	Total (lb/hr)	PM_{10} Emissions: Fuel Oil (lb/hr)[f]	Bagasse Factor (lb/MMBtu)[g]	Bagasse (lb/hr)	Total (lb/hr)
001	139,700	266.7	229.7	94%	131,750	24.41%	251.5	65.1	186.4	169.7	11.2	180.9	20.3	0.209 [h]	39.0	59.2	0.7	0.112 [h]	20.9	21.5
002	138,514	269.0	229.7	94%	130,708	24.20%	253.8	65.1	188.7	169.7	11.3	181.1	20.3	0.098 [i]	18.5	38.8	0.7	0.087 [i]	16.5	17.1
004	300,000	572.7	392.9	89%	268,167	19.45%	511.9	111.4	400.6	290.3	24.0	314.4	34.7	0.359 [j]	143.8	178.4	1.1	0.120 [j]	48.2	49.3
005	230,000	439.1	301.9	84%	194,000	19.49%	370.4	85.6	284.8	223.1	17.1	240.2	26.6	0.278 [j]	79.1	105.8	0.9	0.145 [j]	41.3	42.1
Totals	808,214	1,547.5	1,154.2		724,625		1,387.7	327.2	1,060.5	852.9	63.6	916.6	101.8		280.4	382.2	3.3		126.8	130.1

[a] Maximum heat input rate is based on maximum 24-hour heat input rate in Permit No. 0990026-012-AV.

[b] Total emissions of SO_2 from all operating boilers based on 52,000 gal/day (7,852 MMBtu/day) (max 24-hr period from 2001 to present), prorated to individual boilers based on maximum fuel oil capacity.

[c] Emission factor of 2.607 lb/MMBtu based on maximum 2.4% fuel sulfur content. No. 6 fuel oil has a heating value of 151,000 Btu/gal and density of 8.2 lb/gal. No SO_2 removal in web scrubber assumed.

[d] Emission factor of 0.06 lb/MMBtu used based on industry test data.

[e] Emission factor of 0.31 lb/MMBtu used based on factor of 47 lb per 1,000 gallon for NO_X due to fuel oil firing, from AP-42 Table 13.1: 47 lb/1,000 gal ÷ 151,000 Btu/gal * 10^6 Btu/MMBtu = 0.31 MMBtu

[f] Emission factor of 0.010 lb/MMBtu used based on AP-42, Table 1.3-4, for No. 6 fuel oil combustion controlled by a wet scrubber. $PM_{10} = 0.5*((1.12*2.4)+0.37)$ lb/1,000 gal.

[g] Based on AP-42 Table 1.8-1, Bagasse Firing, with wet scrubber control where 97% of PM is PM_{10}.

[h] Highest emission factor from last 2 years of stack testing (since new water-cooled, pinhole grate was installed).

[i] Highest emission factor from last 1 year of stack testing (since new water-cooled, pinhole grate was installed).

[j] Highest emission factor from last 5 years of stack testing.

Unless otherwise specified, heating values for each fuel are used as follows:
3,600 Btu/lb for wet bagasse, 8,000 Btu/lb dry bagasse, and 151,000 Btu/gal for No. 6 fuel oil.

TABLE A-3
EMISSIONS - FUTURE OFF-CROP SEASON OPERATION, SCGCF
BAGASSE-FIRING ONLY (24-HR AVERAGING TIME)

Boiler	Maximum Steam Rate (lb/hr)	Maximum Heat Input (MMBtu/hr)	Rates for Scenario: Percent Capacity[a]	Rates for Scenario: Steam Rate (lb/hr)[b]	Rates for Scenario: Heat Input (MMBtu/hr)	SO_2 Emissions: Factor[c] (lb/MMBtu)	SO_2 Emissions: Total (lb/hr)	NO_X Emissions: Factor[d] (MMBtu/hr)	NO_X Emissions: Total (lb/hr)	PM_{10} Emissions: Factor[d] (MMBtu/hr)	PM_{10} Emissions: Total (lb/hr)
Scenario A											
001	139,700	266.7	100%	139,700	266.7	0.06	16.0	0.209	55.8	0.112	29.8
002	138,514	269.0	0%	0	0.0	0.06	0.0	0.098	0.0	0.087	0.0
004	300,000	572.7	100%	300,000	572.7	0.06	34.4	0.359	205.5	0.120	68.9
005	230,000	439.1	0%	0	0.0	0.06	0.0	0.278	0.0	0.145	0.0
Totals	808,214	1547.5		439,700	839.4		50.4		261.3		98.7
Scenario B											
001	139,700	266.7	0%	0	0.0	0.06	0.0	0.209	0.0	0.112	0.0
002	138,514	269.0	100%	138,514	269.0	0.06	16.1	0.098	26.4	0.087	23.5
004	300,000	572.7	100%	300,000	572.7	0.06	34.4	0.359	205.5	0.120	68.9
005	230,000	439.1	0%	0	0.0	0.06	0.0	0.278	0.0	0.145	0.0
Totals	808,214	1547.5		438,514	841.7		50.5		231.9		92.4
Scenario C											
001	139,700	266.7	0%	0	0.0	0.06	0.0	0.209	0.0	0.112	0.0
002	138,514	269.0	0%	0	0.0	0.06	0.0	0.098	0.0	0.087	0.0
004	300,000	572.7	84.91%	254,717	486.3	0.06	29.2	0.359	174.5	0.120	58.5
005	230,000	439.1	84.91%	195,283	372.8	0.06	22.4	0.278	103.6	0.145	54.0
Totals	808,214	1547.5		450,000	859.1		51.5		278.1		112.5
Scenario D											
001	139,700	266.7	77.83%	108,723	207.6	0.06	12.5	0.209	43.4	0.112	23.2
002	138,514	269.0	77.83%	107,800	209.4	0.06	12.6	0.098	20.5	0.087	18.3
004	300,000	572.7	77.83%	233,478	445.7	0.06	26.7	0.359	160.0	0.120	53.6
005	230,000	439.1	0%	0	0.0	0.06	0.0	0.278	0.0	0.145	0.0
Totals	808,214	1547.5		450,000	862.6		51.8		223.9		95.1
Scenario E											
001	139,700	266.7	88.55%	123,698	236.2	0.06	14.2	0.209	49.4	0.112	26.4
002	138,514	269.0	88.55%	122,648	238.2	0.06	14.3	0.098	23.4	0.087	20.8
004	300,000	572.7	0%	0	0.0	0.06	0.0	0.359	0.0	0.120	0.0
005	230,000	439.1	88.55%	203,654	388.8	0.06	23.3	0.278	108.0	0.145	56.4
Totals	808,214	1547.5		450,000	863.1		51.8		180.7		103.6

[a] Scenarios with the boilers operating below 75% of the maximum capacity were considered economically infeasible.

[b] The maximum steam rate is limited to 450,000 lb/hr total for any three out of the four boilers operating during the off-crop season.

[c] Emission factors based on industry test data, representing worst-case maximum.

[d] Emission factors based on test data (refer to Appendix A, Table A-1).

TABLE A-4
EMISSIONS - FUTURE OFF-CROP SEASON OPERATION, SCGCF
MAXIMUM FUEL OIL W/ REMAINDER BAGASSE FIRING (24-HR AVERAGING TIME)

Boiler	Maximum Steam Rate (lb/hr)	Maximum Heat Input (MMBtu/hr)	Maximum Heat Input From Fuel Oil (MMBtu/hr)	Rates for Scenario: Percent Capacity[a]	Rates for Scenario: Steam Rate (lb/hr)[b]	Rates for Scenario: Percent Oil	Rates for Scenario: Fuel Oil (MMBtu/hr)	Rates for Scenario: Bagasse (MMBtu/hr)	SO_2 Emissions[c]: Fuel Oil (lb/hr)[d]	SO_2 Emissions[c]: Bagasse (lb/hr)[d]	SO_2 Emissions[c]: Total (lb/hr)	NO_X Emissions: Fuel Oil (lb/hr)[g]	NO_X Emissions: Bagasse Factor (lb/MMBtu)[e]	NO_X Emissions: Bagasse (lb/hr)	NO_X Emissions: Total (lb/hr)	PM_{10} Emissions: Fuel Oil (lb/hr)[f]	PM_{10} Emissions: Bagasse Factor (lb/MMBtu)[e]	PM_{10} Emissions: Bagasse (lb/hr)	PM_{10} Emissions: Total (lb/hr)
Scenario A																			
001	139,700	266.7	229.7	100%	139,700	54.63%	120.7	146.0	314.7	8.8	323.4	37.6	0.209	30.5	68.1	1.2	0.112	16.3	17.5
002	138,514	269.0	229.7	0%	0	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.098	0.0	0.0	0.0	0.087	0.0	0.0
004	300,000	572.7	392.9	100%	300,000	54.63%	206.5	366.2	538.2	22.0	560.2	64.3	0.359	131.4	195.7	2.1	0.120	44.0	46.1
005	230,000	439.1	301.9	0%	0	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.278	0.0	0.0	0.0	0.145	0.0	0.0
Totals	808,214	1,547.5	1,154.2		439,700		327.2	512.2	852.9	30.7	883.7	101.8		162.0	263.8	3.3		60.4	63.7
Scenario B																			
001	139,700	266.7	229.7	0%	0	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.209	0.0	0.0	0.0	0.112	0.0	0.0
002	138,514	269.0	229.7	100%	138,514	52.07%	120.7	148.3	314.7	8.9	323.6	37.6	0.098	14.5	52.1	1.2	0.087	13.0	14.2
004	300,000	572.7	392.9	100%	300,000	52.07%	206.5	366.2	538.2	22.0	560.2	64.3	0.359	131.4	195.7	2.1	0.120	44.0	46.1
005	230,000	439.1	301.9	0%	0	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.278	0.0	0.0	0.0	0.145	0.0	0.0
Totals	808,214	1,547.5	1,154.2		438,514		327.2	514.5	852.9	30.9	883.8	101.8		146.0	247.8	3.3		57.0	60.3
Scenario C																			
001	139,700	266.7	229.7	0%	0	0.00%	0.0	0.0	-0.0	0.0	0.0	0.0	0.209	0.0	0.0	0.0	0.112	0.0	0.0
002	138,514	269.0	229.7	0%	0	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.098	0.0	0.0	0.0	0.087	0.0	0.0
004	300,000	572.7	392.9	84.91%	254,717	50.97%	185.0	301.2	482.3	18.1	500.4	57.6	0.359	108.1	165.7	1.9	0.120	36.2	38.1
005	230,000	439.1	301.9	84.91%	195,283	50.97%	142.2	230.7	370.6	13.8	384.4	44.2	0.278	64.1	108.3	1.4	0.145	33.4	34.9
Totals	808,214	1,547.5	1,154.2		450,000		327.2	531.9	852.9	31.9	884.8	101.8		172.2	274.0	3.3		69.7	72.9
Scenario D																			
001	139,700	266.7	229.7	77.83%	108,723	50.75%	88.2	119.4	229.9	7.2	237.0	27.4	0.209	25.0	52.4	0.9	0.112	13.4	14.2
002	138,514	269.0	229.7	77.83%	107,800	50.75%	88.2	121.2	229.9	7.3	237.1	27.4	0.098	11.9	39.3	0.9	0.087	10.6	11.5
004	300,000	572.7	392.9	77.83%	233,478	50.75%	150.8	294.9	393.2	17.7	410.9	46.9	0.359	105.8	152.8	1.5	0.120	35.5	37.0
005	230,000	439.1	301.9	0%	0	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.278	0.0	0.0	0.0	0.145	0.0	0.0
Totals	808,214	1,547.5	1,154.2		450,000		327.2	535.5	852.9	32.1	885.1	101.8		142.7	244.5	3.3		59.4	62.7
Scenario E																			
001	139,700	266.7	229.7	88.55%	123,698	64.96%	98.7	137.4	257.3	8.2	265.6	30.7	0.209	28.7	59.5	1.0	0.112	15.4	16.4
002	138,514	263.8	229.7	88.55%	122,648	64.96%	98.7	134.9	257.3	8.1	265.4	30.7	0.098	13.2	43.9	1.0	0.087	11.8	12.8
004	300,000	572.7	392.9	0%	0	0.00%	0.0	0.0	0.0	0.0	0.0	0.0	0.359	0.0	0.0	0.0	0.120	0.0	0.0
005	230,000	439.1	301.9	88.5%	203,654	64.96%	129.7	259.1	338.2	15.5	353.8	40.4	0.278	72.0	112.4	1.3	0.145	37.6	38.9
Totals	808,214	1,542.3	1,154.2		450,000		327.2	531.4	852.9	31.9	884.8	101.8		113.9	215.8	3.3		64.7	68.0

[a] Scenarios with the boilers operating below 75% of the maximum capacity were considered economically infeasible.

[b] The maximum steam rate is limited to 450,000 lb/hr for any three out of the four boilers operating during the off-crop season.

[c] Total emissions of SO_2 from all operating boilers based on 52,000 gal/day (7,852 MMBtu/day) (max 24-hr period from 2001 to present), prorated to individual boilers based on maximum fuel oil capacity.

[d] Based on 0.06 lb/MMBtu for bagasse firing based on industry data, and 2.607 lb/MMBtu for fuel oil firing from AP-42 with sulfur content equal to 2.4 percent.

[e] Emission factors based on test data (refer to Appendix A, Table A-2).

[f] Based on 0.01 lb/MMBtu for fuel oil firing from AP-42 Table 1.3-4.

[g] Based on 0.31 lb/MMBtu for fuel oil firing from AP-42 Table 1.3-1.

TABLE A-5
FRACTION OF PM EMISSIONS IN DIFFERENT SIZE CATEGORIES

Wood/Bark-fired Boilers with Scrubber Control
from AP-42 Table 1.6-5

Particle Size Range (µm)	% Of Filterable PM (%)	Particle Size Range (µm)	% of Filterable PM (%)	% of Filterable PM_{10} (%)
<15.0	98			
<10.0	98	10-6	0.0	0.0%
<6.0	98	6-2.5	0.0	0.0%
<2.5	98	2.5-1.25	0.0	0.0%
<1.25	98	1.25-1.0	3.0	3.1%
<1.0	95	1.0-625	45.0	45.9%
<0.625	50	0.625-0	50.0	51.0%
				100.0%

TABLE A-6
POTENTIAL CONDENSABLE PM EMISSIONS FOR SCGCF BOILERS, ON-CROP SEASON

Source	Emission Unit ID	Model ID	Condensable PM Emission Factor		Ref.	Activity Factor[a]		CPM Emissions (lb/hr)	CPM Emissions (TPY)
Bagasse-Firing									
Boiler No. 1 - Bagassee	001	SCGCB1	0.017	lb/MMBtu	1	251.5	MMBtu/hr	4.28	15.60
Boiler No. 2 - Bagassee	002	SCGCB2	0.017	lb/MMBtu	1	253.8	MMBtu/hr	4.32	15.74
Boiler No. 4 - Bagassee	004	SCGCB4	0.017	lb/MMBtu	1	511.9	MMBtu/hr	8.70	31.75
Boiler No. 5 - Bagassee	005	SCGCB5	0.017	lb/MMBtu	1	370.4	MMBtu/hr	6.30	22.97
Max Fuel Oil + Bagasse-Firing									
Boiler No. 1 - No. 6 Oil	001	SCGCB1	1.5	lb/1,000 gal	2	431	gal/hr	0.65	2.36
Boiler No. 1 - Bagassee	001	SCGCB1	0.017	lb/MMBtu	1	186.4	MMBtu/hr	3.17	11.56
								3.82	
Boiler No. 2 - No. 6 Oil	002	SCGCB2	1.5	lb/1,000 gal	2	431	gal/hr	0.65	2.36
Boiler No. 2 - Bagassee	002	SCGCB2	0.017	lb/MMBtu	1	188.7	MMBtu/hr	3.21	11.70
								3.86	
Boiler No. 4 - No. 6 Oil	004	SCGCB4	1.5	lb/1,000 gal	2	738	gal/hr	1.11	4.04
Boiler No. 4 - Bagassee	004	SCGCB4	0.017	lb/MMBtu	1	400.6	MMBtu/hr	6.81	24.84
								7.92	
Boiler No. 5 - No. 6 Oil	005	SCGCB5	1.5	lb/1,000 gal	2	567	gal/hr	0.85	3.10
Boiler No. 5 - Bagassee	005	SCGCB5	0.017	lb/MMBtu	1	284.8	MMBtu/hr	4.84	17.66
								5.69	

Footnotes:

[a] Based on permitted rates in Permit No. 0990026-012-AV.

References:

1. AP-42, Table 1.6-1.
2. AP-42, Table 1.3-2.

TABLE A-7
POTENTIAL CONDENSABLE PM EMISSIONS FOR SCGCF BOILERS, OFF-CROP SEASON

Source	Emission Unit ID	Model ID	Condensable PM Emission Factor		Ref.	Activity Factor[a]		CPM Emissions (lb/hr)	CPM Emissions (TPY)
Bagasse-Firing									
Boiler No. 1 - Bagassee	001	SCGCB1	0.017	lb/MMBtu	1	-	MMBtu/hr	0.00	0.00
Boiler No. 2 - Bagassee	002	SCGCB2	0.017	lb/MMBtu	1	-	MMBtu/hr	0.00	0.00
Boiler No. 4 - Bagassee	004	SCGCB4	0.017	lb/MMBtu	1	486.3	MMBtu/hr	8.27	30.16
Boiler No. 5 - Bagassee	005	SCGCB5	0.017	lb/MMBtu	1	372.8	MMBtu/hr	6.34	23.12
Max Fuel Oil + Bagasse-Firing									
Boiler No. 1 - No. 6 Oil	001	SCGCB1	1.5	lb/1,000 gal	2	-	gal/hr	0.00	0.00
Boiler No. 1 - Bagassee	001	SCGCB1	0.017	lb/MMBtu	1	-	MMBtu/hr	0.00	0.00
								0.00	
Boiler No. 2 - No. 6 Oil	002	SCGCB2	1.5	lb/1,000 gal	2	-	gal/hr	0.00	0.00
Boiler No. 2 - Bagassee	002	SCGCB2	0.017	lb/MMBtu	1	-	MMBtu/hr	0.00	0.00
								0.00	
Boiler No. 4 - No. 6 Oil	004	SCGCB4	1.5	lb/1,000 gal	2	1,225	gal/hr	1.84	6.70
Boiler No. 4 - Bagassee	004	SCGCB4	0.017	lb/MMBtu	1	301.2	MMBtu/hr	5.12	18.68
								6.96	
Boiler No. 5 - No. 6 Oil	005	SCGCB5	1.5	lb/1,000 gal	2	941	gal/hr	1.41	5.15
Boiler No. 5 - Bagassee	005	SCGCB5	0.017	lb/MMBtu	1	230.7	MMBtu/hr	3.92	14.30
								5.33	

Footnotes:

[a] Based on permitted rates in Permit No. 0990026-012-AV times 84.91 percent operating capacity.

References:

1. AP-42, Table 1.6-1.
2. AP-42, Table 1.3-2.

TABLE A-8
SUMMARY OF RECENT EMISSION TESTS AT THE SCGCF

Test Date	Unit	Average Heat Input Rate (MMBtu/hr)	PM Average (lb/hr)	PM Average (lb/MMBtu)	NO_x Average (lb/hr)	NO_x Average (lb/MMBtu)
Boiler No. 1						
12/15/2004	EU001	247.8	28.6	0.115	51.8	0.209
1/13/2006	EU001	281.2	22.9	0.081	35.3	0.125
Boiler No. 2						
1/17/2006	EU002	275.6	24.8	0.090	27.0	0.098
Boiler No. 4						
11/21/2001	EU004	484.5	53.7	0.111	55.6	0.115
11/25/2002	EU004	508.3	42.3	0.083	131.5	0.259
1/14/2004	EU004	515.8	64.0	0.124	185.1	0.359
1/13/2005	EU004	512.1	53.2	0.104	125.2	0.245
12/7/2005	EU004	514.1	37.2	0.072	122.8	0.239
Boiler No. 5						
12/5/2001	EU005	383.5	34.7	0.090	80.6	0.210
11/26/2002	EU005	358.9	38.9	0.108	86.1	0.240
1/16/2004	EU005	370.6	50.7	0.137	92.9	0.251
1/12/2005	EU005	388.2	58.0	0.149	93.8	0.242
12/9/2005	EU005	355.8	22.2	0.063	98.9	0.278

APPENDIX B

EXAMPLE CALPUFF INPUT FILE

```
EXAMPLE FACILITY - CALPUFF  10/16/06
LINE 2
LINE 3
---------------- Run title (3 lines) ------------------------------------------

                    CALPUFF MODEL CONTROL FILE
                    --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names

--------------
Default Name  Type          File Name
------------  ----          ---------
CALMET.DAT    input    * METDAT =              *
    or
ISCMET.DAT    input    * ISCDAT =              *
    or
PLMMET.DAT    input    * PLMDAT =              *
    or
PROFILE.DAT   input    * PRFDAT =              *
SURFACE.DAT   input    * SFCDAT =              *
RESTARTB.DAT  input    * RSTARTB=              *
--------------------------------------------------------------------------------
CALPUFF.LST   output   ! PUFLST = PUFFSCGC1.LST !
CONC.DAT      output   ! CONDAT = PUFFSCGC1.CON !
DFLX.DAT      output   * DFDAT  =              *
WFLX.DAT      output   * WFDAT  =              *

VISB.DAT      output   * VISDAT = VISB.DAT     *
TK2D.DAT      output   * T2DDAT =              *
RHO2D.DAT     output   * RHODAT =              *
RESTARTE.DAT  output   * RSTARTE=              *
--------------------------------------------------------------------------------
Emission Files
--------------
PTEMARB.DAT   input    * PTDAT  =              *
VOLEMARB.DAT  input    * VOLDAT =              *
BAEMARB.DAT   input    * ARDAT  =              *
LNEMARB.DAT   input    * LNDAT  =              *
--------------------------------------------------------------------------------
Other Files
-----------
OZONE.DAT     input    ! OZDAT  =C:\BARTHRO3\2001FLOz.DAT !
VD.DAT        input    * VDDAT  =              *
CHEM.DAT      input    * CHEMDAT=              *
H2O2.DAT      input    * H2O2DAT=              *
HILL.DAT      input    * HILDAT=              *
HILLRCT.DAT   input    * RCTDAT=              *
COASTLN.DAT   input    * CSTDAT=              *
FLUXBDY.DAT   input    * BDYDAT=              *
BCON.DAT      input    * BCNDAT=              *
DEBUG.DAT     output   * DEBUG =              *
MASSFLX.DAT   output   * FLXDAT=              *
MASSBAL.DAT   output   * BALDAT=              *
FOG.DAT       output   * FOGDAT=              *
--------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
         T = lower case      ! LCFILES = T !
         F = UPPER CASE
NOTE: (1) file/path names can be up to 70 characters in length


Provision for multiple input files
----------------------------------

     Number of CALMET.DAT files for run (NMETDAT)
                                Default: 1       ! NMETDAT =   36  !
```

```
     Number of PTEMARB.DAT files for run (NPTDAT)
                                    Default: 0       ! NPTDAT =  0  !

     Number of BAEMARB.DAT files for run (NARDAT)
                                    Default: 0       ! NARDAT =  0  !

     Number of VOLEMARB.DAT files for run (NVOLDAT)
                                    Default: 0       ! NVOLDAT =  0  !

!END!

-------------
Subgroup (0a)
-------------

  The following CALMET.DAT filenames are processed in sequence if NMETDAT>1

Default Name  Type          File Name
------------  ----          ---------
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-01A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-01B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-01C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-02A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-02B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-02C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-03A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-03B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-03C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-04A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-04B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-04C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-05A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-05B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-05C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-06A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-06B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-06C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-07A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-07B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-07C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-08A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-08B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-08C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-09A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-09B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-09C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-10A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-10B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-10C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-11A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-11B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-11C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-12A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-12B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-12C.DAT ! !END!
--------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------

    Option to run all periods found
    in the met. file     (METRUN)   Default: 0       ! METRUN =   0  !

         METRUN = 0 - Run period explicitly defined below
         METRUN = 1 - Run all periods in met. file

     Starting date:   Year (IBYR) -- No default       ! IBYR =  2001  !
     (used only if   Month (IBMO) -- No default       ! IBMO =  1  !
      METRUN = 0)      Day (IBDY) -- No default       ! IBDY =  1  !
                      Hour (IBHR) -- No default       ! IBHR =  1  !
```

```
     Base time zone         (XBTZ) -- No default       ! XBTZ = 5.0  !
        PST = 8., MST = 7.
        CST = 6., EST = 5.

     Length of run (hours) (IRLG) -- No default        ! IRLG = 8760 !

     Number of chemical species (NSPEC)
                                      Default: 5       ! NSPEC = 11   !

     Number of chemical species
     to be emitted  (NSE)             Default: 3       ! NSE = 9   !

     Flag to stop run after
     SETUP phase (ITEST)              Default: 2       ! ITEST =  2   !
     (Used to allow checking
     of the model inputs, files, etc.)
           ITEST = 1 - STOPS program after SETUP phase
           ITEST = 2 - Continues with execution of program
                       after SETUP

     Restart Configuration:

        Control flag (MRESTART)       Default: 0       ! MRESTART =  0   !

           0 = Do not read or write a restart file
           1 = Read a restart file at the beginning of
               the run
           2 = Write a restart file during run
           3 = Read a restart file at beginning of run
               and write a restart file during run

        Number of periods in Restart
        output cycle (NRESPD)         Default: 0       ! NRESPD =  0   !

           0 = File written only at last period
          >0 = File updated every NRESPD periods

     Meteorological Data Format (METFM)
                                      Default: 1       ! METFM =  1   !

           METFM = 1 - CALMET binary file (CALMET.MET)
           METFM = 2 - ISC ASCII file (ISCMET.MET)
           METFM = 3 - AUSPLUME ASCII file (PLMMET.MET)
           METFM = 4 - CTDM plus tower file (PROFILE.DAT) and
                       surface parameters file (SURFACE.DAT)

     PG sigma-y is adjusted by the factor (AVET/PGTIME)**0.2
     Averaging Time (minutes) (AVET)
                                      Default: 60.0    ! AVET = 60. !
     PG Averaging Time (minutes) (PGTIME)
                                      Default: 60.0    ! PGTIME = 60. !


!END!

-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Technical options
--------------


     Vertical distribution used in the
     near field (MGAUSS)                    Default: 1     ! MGAUSS =  1   !
        0 = uniform
        1 = Gaussian

     Terrain adjustment method
     (MCTADJ)                               Default: 3     ! MCTADJ =  3   !
        0 = no adjustment
        1 = ISC-type of terrain adjustment
```

```
   2 = simple, CALPUFF-type of terrain
       adjustment
   3 = partial plume path adjustment

Subgrid-scale complex terrain
flag (MCTSG)                         Default: 0      ! MCTSG =  0   !
   0 = not modeled
   1 = modeled

Near-field puffs modeled as
elongated 0 (MSLUG)                  Default: 0      ! MSLUG =  0   !
   0 = no
   1 = yes (slug model used)

Transitional plume rise modeled ?
(MTRANS)                             Default: 1      ! MTRANS =  1   !
   0 = no  (i.e., final rise only)
   1 = yes (i.e., transitional rise computed)

Stack tip downwash? (MTIP)           Default: 1      ! MTIP =  1  !
   0 = no  (i.e., no stack tip downwash)
   1 = yes (i.e., use stack tip downwash)

Vertical wind shear modeled above
stack top? (MSHEAR)                  Default: 0      ! MSHEAR =  0  !
   0 = no  (i.e., vertical wind shear not modeled)
   1 = yes (i.e., vertical wind shear modeled)

Puff splitting allowed? (MSPLIT)     Default: 0      ! MSPLIT =  0  !
   0 = no (i.e., puffs not split)
   1 = yes (i.e., puffs are split)

Chemical mechanism flag (MCHEM)      Default: 1      ! MCHEM =  1   !
   0 = chemical transformation not
       modeled
   1 = transformation rates computed
       internally (MESOPUFF II scheme)
   2 = user-specified transformation
       rates used
   3 = transformation rates computed
       internally (RIVAD/ARM3 scheme)
   4 = secondary organic aerosol formation
       computed (MESOPUFF II scheme for OH)

Aqueous phase transformation flag (MAQCHEM)
(Used only if MCHEM = 1, or 3)       Default: 0      ! MAQCHEM =  0   !
   0 = aqueous phase transformation
       not modeled
   1 = transformation rates adjusted
       for aqueous phase reactions

Wet removal modeled ? (MWET)         Default: 1      ! MWET =  1   !
   0 = no
   1 = yes

Dry deposition modeled ? (MDRY)      Default: 1      ! MDRY =  1   !
   0 = no
   1 = yes
   (dry deposition method specified
    for each species in Input Group 3)

Method used to compute dispersion
coefficients (MDISP)                 Default: 3      ! MDISP =  3   !

   1 = dispersion coefficients computed from measured values
       of turbulence, sigma v, sigma w
   2 = dispersion coefficients from internally calculated
       sigma v, sigma w using micrometeorological variables
       (u*, w*, L, etc.)
   3 = PG dispersion coefficients for RURAL areas (computed using
       the ISCST multi-segment approximation) and MP coefficients in
```

```
        urban areas
   4 = same as 3 except PG coefficients computed using
        the MESOPUFF II eqns.
   5 = CTDM sigmas used for stable and neutral conditions.
        For unstable conditions, sigmas are computed as in
        MDISP = 3, described above.  MDISP = 5 assumes that
        measured values are read

Sigma-v/sigma-theta, sigma-w measurements used? (MTURBVW)
(Used only if MDISP = 1 or 5)          Default: 3     ! MTURBVW =  3  !
   1 = use sigma-v or sigma-theta measurements
        from PROFILE.DAT to compute sigma-y
        (valid for METFM = 1, 2, 3, 4)
   2 = use sigma-w measurements
        from PROFILE.DAT to compute sigma-z
        (valid for METFM = 1, 2, 3, 4)
   3 = use both sigma-(v/theta) and sigma-w
        from PROFILE.DAT to compute sigma-y and sigma-z
        (valid for METFM = 1, 2, 3, 4)
   4 = use sigma-theta measurements
        from PLMMET.DAT to compute sigma-y
        (valid only if METFM = 3)

Back-up method used to compute dispersion
when measured turbulence data are
missing (MDISP2)                       Default: 3     ! MDISP2 =  3  !
(used only if MDISP = 1 or 5)
   2 = dispersion coefficients from internally calculated
        sigma v, sigma w using micrometeorological variables
        (u*, w*, L, etc.)
   3 = PG dispersion coefficients for RURAL areas (computed using
        the ISCST multi-segment approximation) and MP coefficients in
        urban areas
   4 = same as 3 except PG coefficients computed using
        the MESOPUFF II eqns.

PG sigma-y,z adj. for roughness?       Default: 0     ! MROUGH = 0  !
(MROUGH)
   0 = no
   1 = yes

Partial plume penetration of           Default: 1     ! MPARTL =  1  !
elevated inversion?
(MPARTL)
   0 = no
   1 = yes

Strength of temperature inversion      Default: 0     ! MTINV =  0  !
provided in PROFILE.DAT extended records?
(MTINV)
   0 = no (computed from measured/default gradients)
   1 = yes

PDF used for dispersion under convective conditions?
                                       Default: 0     ! MPDF =  0  !
(MPDF)
   0 = no
   1 = yes

Sub-Grid TIBL module used for shore line?
                                       Default: 0     ! MSGTIBL = 0  !
(MSGTIBL)
   0 = no
   1 = yes

Boundary conditions (concentration) modeled?
                                       Default: 0     ! MBCON = 0  !
(MBCON)
   0 = no
   1 = yes
```

```
      Analyses of fogging and icing impacts due to emissions from
      arrays of mechanically-forced cooling towers can be performed
      using CALPUFF in conjunction with a cooling tower emissions
      processor (CTEMISS) and its associated postprocessors.  Hourly
      emissions of water vapor and temperature from each cooling tower
      cell are computed for the current cell configuration and ambient
      conditions by CTEMISS. CALPUFF models the dispersion of these
      emissions and provides cloud information in a specialized format
      for further analysis. Output to FOG.DAT is provided in either
      'plume mode' or 'receptor mode' format.

      Configure for FOG Model output?
                                             Default: 0      ! MFOG =  0   !
      (MFOG)
         0 = no
         1 = yes  - report results in PLUME Mode format
         2 = yes  - report results in RECEPTOR Mode format


      Test options specified to see if
      they conform to regulatory
      values? (MREG)                         Default: 1      ! MREG =  1   !

         0 = NO checks are made
         1 = Technical options must conform to USEPA
             Long Range Transport (LRT) guidance
                        METFM    1 or 2
                        AVET     60. (min)
                        PGTIME   60. (min)
                        MGAUSS   1
                        MCTADJ   3
                        MTRANS   1
                        MTIP     1
                        MCHEM    1 or 3 (if modeling SOx, NOx)
                        MWET     1
                        MDRY     1
                        MDISP    2 or 3
                        MPDF     0 if MDISP=3
                                 1 if MDISP=2
                        MROUGH   0
                        MPARTL   1
                        SYTDEP   550. (m)
                        MHFTSZ   0

 !END!

 --------------------------------------------------------------------------------

 INPUT GROUP: 3a, 3b -- Species list
 -------------------

 ------------
 Subgroup (3a)
 ------------

   The following species are modeled:

 ! CSPEC =          SO2 !          !END!
 ! CSPEC =          SO4 !          !END!
 ! CSPEC =          NOX !          !END!
 ! CSPEC =         HNO3 !          !END!
 ! CSPEC =          NO3 !          !END!
 ! CSPEC =       PM0063 !          !END!
 ! CSPEC =       PM0100 !          !END!
 ! CSPEC =       PM0125 !          !END!
 ! CSPEC =       PM0250 !          !END!
 ! CSPEC =       PM0600 !          !END!
 ! CSPEC =       PM1000 !          !END!
```

```
                                                               Dry                 OUTPUT GROUP
   SPECIES          MODELED          EMITTED          DEPOSITED                NUMBER
    NAME         (0=NO, 1=YES)    (0=NO, 1=YES)    (0=NO,                    (0=NONE,
   (Limit: 12                                       1=COMPUTED-GAS            1=1st CGRUP,
    Characters                                      2=COMPUTED-PARTICLE       2=2nd CGRUP,
    in length)                                      3=USER-SPECIFIED)         3= etc.)

!         SO2   =           1,               1,           1,                  0    !
!         SO4   =           1,               1,           2,                  0    !
!         NOX   =           1,               1,           1,                  0    !
!        HNO3   =           1,               0,           1,                  0    !
!         NO3   =           1,               0,           2,                  0    !
!      PM0063   =           1,               1,           2,                  1    !
!      PM0100   =           1,               1,           2,                  1    !
!      PM0125   =           1,               1,           2,                  1    !
!      PM0250   =           1,               1,           2,                  1    !
!      PM0600   =           1,               1,           2,                  1    !
!      PM1000   =           1,               1,           2,                  1    !

!END!

-------------
Subgroup (3b)
-------------
  The following names are used for Species-Groups in which results
  for certain species are combined (added) prior to output.  The
  CGRUP name will be used as the species name in output files.
  Use this feature to model specific particle-size distributions
  by treating each size-range as a separate species.
  Order must be consistent with 3(a) above.

! CGRUP =          PM10 !      !END!

INPUT GROUP: 4 -- Map Projection and Grid control parameters
--------------

     Projection for all (X,Y):
     -------------------------

     Map projection
     (PMAP)                     Default: UTM     ! PMAP = LCC   !

         UTM :  Universal Transverse Mercator
         TTM :  Tangential Transverse Mercator
         LCC :  Lambert Conformal Conic
          PS :  Polar Stereographic
          EM :  Equatorial Mercator
        LAZA :  Lambert Azimuthal Equal Area

     False Easting and Northing (km) at the projection origin
     (Used only if PMAP= TTM, LCC, or LAZA)
     (FEAST)                    Default=0.0      ! FEAST  = 0.000  !
     (FNORTH)                   Default=0.0      ! FNORTH = 0.000  !

     UTM zone (1 to 60)
     (Used only if PMAP=UTM)
     (IUTMZN)                   No Default       ! IUTMZN =   0 !

     Hemisphere for UTM projection?
     (Used only if PMAP=UTM)
     (UTMHEM)                   Default: N       ! UTMHEM = N   !
         N    :  Northern hemisphere projection
         S    :  Southern hemisphere projection

     Latitude and Longitude (decimal degrees) of projection origin
     (Used only if PMAP= TTM, LCC, PS, EM, or LAZA)
     (RLAT0)                    No Default       ! RLAT0 =  40N !
     (RLON0)                    No Default       ! RLON0 =  97W !

         TTM :  RLON0 identifies central (true N/S) meridian of projection
```

```
               RLAT0 selected for convenience
        LCC :  RLON0 identifies central (true N/S) meridian of projection
               RLAT0 selected for convenience
        PS  :  RLON0 identifies central (grid N/S) meridian of projection
               RLAT0 selected for convenience
        EM  :  RLON0 identifies central meridian of projection
               RLAT0 is REPLACED by 0.0N (Equator)
        LAZA:  RLON0 identifies longitude of tangent-point of mapping plane
               RLAT0 identifies latitude of tangent-point of mapping plane

    Matching parallel(s) of latitude (decimal degrees) for projection
    (Used only if PMAP= LCC or PS)
    (XLAT1)                    No Default      ! XLAT1 = 33N  !
    (XLAT2)                    No Default      ! XLAT2 = 45N  !

        LCC :  Projection cone slices through Earth's surface at XLAT1 and XLAT2
        PS  :  Projection plane slices through Earth at XLAT1
               (XLAT2 is not used)

    ----------
    Note: Latitudes and longitudes should be positive, and include a
          letter N,S,E, or W indicating north or south latitude, and
          east or west longitude.  For example,
          35.9  N Latitude  =  35.9N
          118.7 E Longitude = 118.7E


    Datum-region
    ------------

    The Datum-Region for the coordinates is identified by a character
    string.  Many mapping products currently available use the model of the
    Earth known as the World Geodetic System 1984 (WGS-84).  Other local
    models may be in use, and their selection in CALMET will make its output
    consistent with local mapping products.  The list of Datum-Regions with
    official transformation parameters is provided by the National Imagery and
    Mapping Agency (NIMA).

    NIMA Datum - Regions(Examples)
    ------------------------------------------------------------------------------
    WGS-84    WGS-84 Reference Ellipsoid and Geoid, Global coverage (WGS84)
    NAS-C     NORTH AMERICAN 1927 Clarke 1866 Spheroid, MEAN FOR CONUS (NAD27)
    NAR-C     NORTH AMERICAN 1983 GRS 80 Spheroid, MEAN FOR CONUS (NAD83)
    NWS-84    NWS 6370KM Radius, Sphere
    ESR-S     ESRI REFERENCE 6371KM Radius, Sphere

    Datum-region for output coordinates
    (DATUM)                    Default: WGS-G     ! DATUM = NWS-84 !


METEOROLOGICAL Grid:

    Rectangular grid defined for projection PMAP,
    with X the Easting and Y the Northing coordinate

           No. X grid cells (NX)      No default     ! NX = 263    !
           No. Y grid cells (NY)      No default     ! NY = 206     !
        No. vertical layers (NZ)      No default     ! NZ =  10    !

          Grid spacing (DGRIDKM)      No default     ! DGRIDKM = 4. !
                                      Units: km

               Cell face heights
                   (ZFACE(nz+1))      No defaults
                                      Units: m
   ! ZFACE = 0.,20.,40.,80.,160.,320.,640.,1200.,2000.,3000.,4000. !

           Reference Coordinates
         of SOUTHWEST corner of
                grid cell(1, 1):
```

```
          X coordinate (XORIGKM)       No default      ! XORIGKM =  721.995 !
          Y coordinate (YORIGKM)       No default      ! YORIGKM = -1598.000 !
                                     Units: km


COMPUTATIONAL Grid:

     The computational grid is identical to or a subset of the MET. grid.
     The lower left (LL) corner of the computational grid is at grid point
     (IBCOMP, JBCOMP) of the MET. grid.  The upper right (UR) corner of the
     computational grid is at grid point (IECOMP, JECOMP) of the MET. grid.
     The grid spacing of the computational grid is the same as the MET. grid.

        X index of LL corner (IBCOMP)      No default      ! IBCOMP =  1  !
                  (1 <= IBCOMP <= NX)

        Y index of LL corner (JBCOMP)      No default      ! JBCOMP =  1  !
                  (1 <= JBCOMP <= NY)


        X index of UR corner (IECOMP)      No default      ! IECOMP = 263 !
                  (1 <= IECOMP <= NX)

        Y index of UR corner (JECOMP)      No default      ! JECOMP = 206 !
                  (1 <= JECOMP <= NY)


SAMPLING Grid (GRIDDED RECEPTORS):

     The lower left (LL) corner of the sampling grid is at grid point
     (IBSAMP, JBSAMP) of the MET. grid.  The upper right (UR) corner of the
     sampling grid is at grid point (IESAMP, JESAMP) of the MET. grid.
     The sampling grid must be identical to or a subset of the computational
     grid.  It may be a nested grid inside the computational grid.
     The grid spacing of the sampling grid is DGRIDKM/MESHDN.

        Logical flag indicating if gridded
        receptors are used (LSAMP)         Default: T      ! LSAMP = F !
        (T=yes, F=no)

        X index of LL corner (IBSAMP)      No default      ! IBSAMP =  1    !
         (IBCOMP <= IBSAMP <= IECOMP)

        Y index of LL corner (JBSAMP)      No default      ! JBSAMP =  1    !
         (JBCOMP <= JBSAMP <= JECOMP)


        X index of UR corner (IESAMP)      No default      ! IESAMP =  263 !
         (IBCOMP <= IESAMP <= IECOMP)

        Y index of UR corner (JESAMP)      No default      ! JESAMP =  206  !
         (JBCOMP <= JESAMP <= JECOMP)


       Nesting factor of the sampling
        grid (MESHDN)                      Default: 1      ! MESHDN =  1  !
        (MESHDN is an integer >= 1)

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 5 -- Output Options
--------------
                                                   *                          *
     FILE                       DEFAULT VALUE             VALUE THIS RUN
     ----                       -------------             --------------
```

```
Concentrations (ICON)              1                    !  ICON =  1   !
Dry Fluxes (IDRY)                  1                    !  IDRY =  0   !
Wet Fluxes (IWET)                  1                    !  IWET =  0   !
Relative Humidity (IVIS)           1                    !  IVIS =  0   !
 (relative humidity file is
  required for visibility
  analysis)
Use data compression option in output file?
(LCOMPRS)                           Default: T          ! LCOMPRS = T !

*
 0 = Do not create file, 1 = create file


 DIAGNOSTIC MASS FLUX OUTPUT OPTIONS:

    Mass flux across specified boundaries
    for selected species reported hourly?
    (IMFLX)                         Default: 0          ! IMFLX =  0  !
      0 = no
      1 = yes (FLUXBDY.DAT and MASSFLX.DAT filenames
               are specified in Input Group 0)

    Mass balance for each species
    reported hourly?
    (IMBAL)                         Default: 0          ! IMBAL =  0  !
      0 = no
      1 = yes (MASSBAL.DAT filename is
           specified in Input Group 0)


 LINE PRINTER OUTPUT OPTIONS:

    Print concentrations (ICPRT)    Default: 0          ! ICPRT =  0   !
    Print dry fluxes (IDPRT)        Default: 0          ! IDPRT =  0   !
    Print wet fluxes (IWPRT)        Default: 0          ! IWPRT =  0   !
    (0 = Do not print, 1 = Print)

    Concentration print interval
    (ICFRQ) in hours                Default: 1          ! ICFRQ =  24  !
    Dry flux print interval
    (IDFRQ) in hours                Default: 1          ! IDFRQ =  1   !
    Wet flux print interval
    (IWFRQ) in hours                Default: 1          ! IWFRQ =  1   !

    Units for Line Printer Output
    (IPRTU)                         Default: 1          ! IPRTU =  3   !
                    for            for
              Concentration    Deposition
        1 =       g/m**3        g/m**2/s
        2 =      mg/m**3       mg/m**2/s
        3 =      ug/m**3       ug/m**2/s
        4 =      ng/m**3       ng/m**2/s
        5 =     Odour Units

    Messages tracking progress of run
    written to the screen ?
    (IMESG)                         Default: 2          ! IMESG =  2   !
      0 = no
      1 = yes (advection step, puff ID)
      2 = yes (YYYYJJJHH, # old puffs, # emitted puffs)


  SPECIES (or GROUP for combined species) LIST FOR OUTPUT OPTIONS

                ---- CONCENTRATIONS ----   ------ DRY FLUXES ------   ------ WET FLUXES ----
--    -- MASS FLUX --
   SPECIES
   /GROUP        PRINTED?  SAVED ON DISK?   PRINTED?  SAVED ON DISK?   PRINTED?  SAVED ON
DISK?   SAVED ON DISK?
```

```
       -------      -------------------------    ------------------------    ---------------------
--    ---------------
!           SO2  =      0,           1,           0,           1,           0,           1,
0    !
!           SO4  =      0,           1,           0,           1,           0,           1,
0    !
!           NOX  =      0,           1,           0,           1,           0,           1,
0    !
!          HNO3  =      0,           1,           0,           1,           0,           1,
0    !
!           NO3  =      0,           1,           0,           1,           0,           1,
0    !
!          PM10  =      0,           1,           0,           1,           0,           1,
0    !

     OPTIONS FOR PRINTING "DEBUG" QUANTITIES (much output)

       Logical for debug output
       (LDEBUG)                                 Default: F      ! LDEBUG = F !

       First puff to track
       (IPFDEB)                                 Default: 1      ! IPFDEB =  1   !

       Number of puffs to track
       (NPFDEB)                                 Default: 1      ! NPFDEB =  1   !

       Met. period to start output
       (NN1)                                    Default: 1      ! NN1 =  1    !

       Met. period to end output
       (NN2)                                    Default: 10     ! NN2 =  10   !

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 6a, 6b, & 6c -- Subgrid scale complex terrain inputs
-------------------------


---------------
Subgroup (6a)
---------------
       Number of terrain features (NHILL)       Default: 0      ! NHILL =  0    !

       Number of special complex terrain
       receptors  (NCTREC)                      Default: 0      ! NCTREC =  0    !

       Terrain and CTSG Receptor data for
       CTSG hills input in CTDM format ?
       (MHILL)                                  No Default      ! MHILL =  2    !
       1 = Hill and Receptor data created
           by CTDM processors & read from
           HILL.DAT and HILLRCT.DAT files
       2 = Hill data created by OPTHILL &
           input below in Subgroup (6b);
           Receptor data in Subgroup (6c)

       Factor to convert horizontal dimensions  Default: 1.0    ! XHILL2M = 1. !
       to meters (MHILL=1)

       Factor to convert vertical dimensions    Default: 1.0    ! ZHILL2M = 1. !
       to meters (MHILL=1)

       X-origin of CTDM system relative to      No Default      ! XCTDMKM = 0.0E00 !
       CALPUFF coordinate system, in Kilometers (MHILL=1)

       Y-origin of CTDM system relative to      No Default      ! YCTDMKM = 0.0E00 !
       CALPUFF coordinate system, in Kilometers (MHILL=1)
```

```
! END !

---------------
Subgroup (6b)
---------------

                   1 **
     HILL information


HILL          XC         YC       THETAH  ZGRID  RELIEF    EXPO 1    EXPO 2    SCALE 1
SCALE 2    AMAX1      AMAX2
 NO.          (km)       (km)       (deg.)   (m)     (m)       (m)       (m)        (m)
(m)        (m)        (m)
----          ----       ----       ------  -----  ------    ------    ------    -------    ----
---    -----      -----

---------------
Subgroup (6c)
---------------

    COMPLEX TERRAIN RECEPTOR INFORMATION

                      XRCT          YRCT          ZRCT          XHH
                      (km)          (km)           (m)
                     ------         -----         ------        ----


-------------------
1
     Description of Complex Terrain Variables:
          XC, YC   = Coordinates of center of hill
          THETAH   = Orientation of major axis of hill (clockwise from
                     North)
          ZGRID    = Height of the  0  of the grid above mean sea
                     level
          RELIEF   = Height of the crest of the hill above the grid elevation
          EXPO 1   = Hill-shape exponent for the major axis
          EXPO 2   = Hill-shape exponent for the major axis
          SCALE 1 = Horizontal length scale along the major axis
          SCALE 2 = Horizontal length scale along the minor axis
          AMAX     = Maximum allowed axis length for the major axis
          BMAX     = Maximum allowed axis length for the major axis

          XRCT, YRCT = Coordinates of the complex terrain receptors
          ZRCT     = Height of the ground (MSL) at the complex terrain
                     Receptor
          XHH      = Hill number associated with each complex terrain receptor
                      (NOTE: MUST BE ENTERED AS A REAL NUMBER)

   **
     NOTE: DATA for each hill and CTSG receptor are treated as a separate
           input subgroup and therefore must end with an input group terminator.

--------------------------------------------------------------------------------


INPUT GROUP: 7 -- Chemical parameters for dry deposition of gases
--------------

      SPECIES     DIFFUSIVITY      ALPHA STAR      REACTIVITY    MESOPHYLL RESISTANCE
HENRY'S LAW COEFFICIENT
       NAME         (cm**2/s)                                            (s/cm)
(dimensionless)
      -------     -----------      ----------      ----------    --------------------    ---
--------------------

!          SO2 =      0.1509,          1000,            8,                 0,
0.04 !
!          NOX =      0.1656,             1,            8,                 5,
3.5 !
```

```
!        HNO3 =      0.1628,             1,             18,                  0,
0.00000008 !

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 8 -- Size parameters for dry deposition of particles
--------------

     For SINGLE SPECIES, the mean and standard deviation are used to
     compute a deposition velocity for NINT (see group 9) size-ranges,
     and these are then averaged to obtain a mean deposition velocity.

     For GROUPED SPECIES, the size distribution should be explicitly
     specified (by the 'species' in the group), and the standard deviation
     for each should be entered as 0.  The model will then use the
     deposition velocity for the stated mean diameter.

      SPECIES       GEOMETRIC MASS MEAN        GEOMETRIC STANDARD
       NAME              DIAMETER                   DEVIATION
                         (microns)                  (microns)
      -------       -------------------        ------------------
!          SO4 =          0.48,                      2.   !
!          NO3 =          0.48,                      2.   !
!       PM0063 =          0.63,                      0.   !
!       PM0100 =          1.00,                      0.   !
!       PM0125 =          1.25,                      0.   !
!       PM0250 =          2.50,                      0.   !
!       PM0600 =          6.00,                      0.   !
!       PM1000 =         10.00,                      0.   !

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 9 -- Miscellaneous dry deposition parameters
--------------

     Reference cuticle resistance (s/cm)
     (RCUTR)                           Default: 30     !  RCUTR = 30.0 !
     Reference ground resistance  (s/cm)
     (RGR)                             Default: 10     !    RGR = 10.0 !
     Reference pollutant reactivity
     (REACTR)                          Default: 8      ! REACTR = 8.0 !

     Number of particle-size intervals used to
     evaluate effective particle deposition velocity
     (NINT)                            Default: 9      !   NINT =  9   !

     Vegetation state in unirrigated areas
     (IVEG)                            Default: 1      !   IVEG =  1    !
        IVEG=1 for active and unstressed vegetation
        IVEG=2 for active and stressed vegetation
        IVEG=3 for inactive vegetation

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 10 -- Wet Deposition Parameters
---------------

                      Scavenging Coefficient -- Units: (sec)**(-1)
```

```
       Pollutant      Liquid Precip.       Frozen Precip.
       ---------      --------------       --------------
!         SO2  =          3.0E-05,             0.0E00  !
!         SO4  =          1.0E-04,             3.0E-05 !
!        HNO3  =          6.0E-05,             0.0E00  !
!         NO3  =          1.0E-04,             3.0E-05 !
!      PM0063  =          1.0E-04,             3.0E-05 !
!      PM0100  =          1.0E-04,             3.0E-05 !
!      PM0125  =          1.0E-04,             3.0E-05 !
!      PM0250  =          1.0E-04,             3.0E-05 !
!      PM0600  =          1.0E-04,             3.0E-05 !
!      PM1000  =          1.0E-04,             3.0E-05 !

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 11 -- Chemistry Parameters
---------------

     Ozone data input option (MOZ)     Default: 1             ! MOZ =  1   !
     (Used only if MCHEM = 1, 3, or 4)
        0 = use a monthly background ozone value
        1 = read hourly ozone concentrations from
            the OZONE.DAT data file

     Monthly ozone concentrations
     (Used only if MCHEM = 1, 3, or 4 and
      MOZ = 0 or MOZ = 1 and all hourly O3 data missing)
     (BCKO3) in ppb                    Default: 12*80.
     !  BCKO3 = 12*50. !

     Monthly ammonia concentrations
     (Used only if MCHEM = 1, or 3)
     (BCKNH3) in ppb                   Default: 12*10.
     !  BCKNH3 = 12*0.5 !

     Nighttime SO2 loss rate (RNITE1)
     in percent/hour                   Default: 0.2           ! RNITE1 = .2 !

     Nighttime NOx loss rate (RNITE2)
     in percent/hour                   Default: 2.0           ! RNITE2 = 2.0 !

     Nighttime HNO3 formation rate (RNITE3)
     in percent/hour                   Default: 2.0           ! RNITE3 = 2.0 !

     H2O2 data input option (MH2O2)    Default: 1             ! MH2O2 =  1   !
     (Used only if MAQCHEM = 1)
        0 = use a monthly background H2O2 value
        1 = read hourly H2O2 concentrations from
            the H2O2.DAT data file

     Monthly H2O2 concentrations
     (Used only if MQACHEM = 1 and
      MH2O2 = 0 or MH2O2 = 1 and all hourly H2O2 data missing)
     (BCKH2O2) in ppb                  Default: 12*1.
     !  BCKH2O2 = 12*1 !

 --- Data for SECONDARY ORGANIC AEROSOL (SOA) Option
     (used only if MCHEM = 4)

     The SOA module uses monthly values of:
          Fine particulate concentration in ug/m^3 (BCKPMF)
          Organic fraction of fine particulate     (OFRAC)
          VOC / NOX ratio (after reaction)         (VCNX)
     to characterize the air mass when computing
     the formation of SOA from VOC emissions.
```

```
     Typical values for several distinct air mass types are:

        Month    1    2    3    4    5    6    7    8    9   10   11   12
                Jan  Feb  Mar  Apr  May  Jun  Jul  Aug  Sep  Oct  Nov  Dec

     Clean Continental
        BCKPMF   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.
        OFRAC  .15  .15  .20  .20  .20  .20  .20  .20  .20  .20  .20  .15
        VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

     Clean Marine (surface)
        BCKPMF  .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5
        OFRAC  .25  .25  .30  .30  .30  .30  .30  .30  .30  .30  .30  .25
        VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

     Urban - low biogenic (controls present)
        BCKPMF  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.
        OFRAC  .20  .20  .25  .25  .25  .25  .25  .25  .20  .20  .20  .20
        VCNX     4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.

     Urban - high biogenic (controls present)
        BCKPMF  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.
        OFRAC  .25  .25  .30  .30  .30  .55  .55  .55  .35  .35  .35  .25
        VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

     Regional Plume
        BCKPMF  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.
        OFRAC  .20  .20  .25  .35  .25  .40  .40  .40  .30  .30  .30  .20
        VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

     Urban - no controls present
        BCKPMF 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100.
        OFRAC  .30  .30  .35  .35  .35  .55  .55  .55  .35  .35  .35  .30
        VCNX     2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.

     Default: Clean Continental
     !  BCKPMF = 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00 !
     !  OFRAC  = 0.15, 0.15, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.15 !
     !  VCNX   = 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00,
50.00 !


!END!


-------------------------------------------------------------------------------


INPUT GROUP: 12 -- Misc. Dispersion and Computational Parameters
---------------

     Horizontal size of puff (m) beyond which
     time-dependent dispersion equations (Heffter)
     are used to determine sigma-y and
     sigma-z (SYTDEP)                           Default: 550.    ! SYTDEP = 5.5E02 !

     Switch for using Heffter equation for sigma z
     as above (0 = Not use Heffter; 1 = use Heffter
     (MHFTSZ)                                   Default: 0       ! MHFTSZ =  0    !

     Stability class used to determine plume
     growth rates for puffs above the boundary
     layer (JSUP)                               Default: 5       ! JSUP =  5    !

     Vertical dispersion constant for stable
     conditions (k1 in Eqn. 2.7-3)  (CONK1)     Default: 0.01    ! CONK1 = .01 !

     Vertical dispersion constant for neutral/
     unstable conditions (k2 in Eqn. 2.7-4)
     (CONK2)                                    Default: 0.1     ! CONK2 = .1 !
```

```
Factor for determining Transition-point from
Schulman-Scire to Huber-Snyder Building Downwash
scheme (SS used for Hs < Hb + TBD * HL)
(TBD)                                        Default: 0.5     ! TBD = .5 !
   TBD < 0   ==> always use Huber-Snyder
   TBD = 1.5 ==> always use Schulman-Scire
   TBD = 0.5 ==> ISC Transition-point

Range of land use categories for which
urban dispersion is assumed
(IURB1, IURB2)                               Default: 10      ! IURB1 =  10  !
                                                      19      ! IURB2 =  19  !

Site characterization parameters for single-point Met data files ---------
(needed for METFM = 2,3,4)

   Land use category for modeling domain
   (ILANDUIN)                                Default: 20      ! ILANDUIN =  20  !

   Roughness length (m) for modeling domain
   (Z0IN)                                    Default: 0.25    ! Z0IN = .25 !

   Leaf area index for modeling domain
   (XLAIIN)                                  Default: 3.0     ! XLAIIN = 3.0 !

   Elevation above sea level (m)
   (ELEVIN)                                  Default: 0.0     ! ELEVIN = .0 !

   Latitude (degrees) for met location
   (XLATIN)                                  Default: -999.   ! XLATIN = -999.0 !

   Longitude (degrees) for met location
   (XLONIN)                                  Default: -999.   ! XLONIN = -999.0 !

Specialized information for interpreting single-point Met data files -----

   Anemometer height (m) (Used only if METFM = 2,3)
   (ANEMHT)                                  Default: 10.     ! ANEMHT = 10.0 !

   Form of lateral turbulance data in PROFILE.DAT file
   (Used only if METFM = 4 or MTURBVW = 1 or 3)
   (ISIGMAV)                                 Default: 1       ! ISIGMAV =  1  !
       0 = read sigma-theta
       1 = read sigma-v

   Choice of mixing heights (Used only if METFM = 4)
   (IMIXCTDM)                                Default: 0       ! IMIXCTDM =  0  !
       0 = read PREDICTED mixing heights
       1 = read OBSERVED mixing heights

Maximum length of a slug (met. grid units)
(XMXLEN)                                     Default: 1.0     ! XMXLEN = 1.0 !

Maximum travel distance of a puff/slug (in
grid units) during one sampling step
(XSAMLEN)                                    Default: 1.0     ! XSAMLEN = 1.0 !

Maximum Number of slugs/puffs release from
one source during one time step
(MXNEW)                                      Default: 99      ! MXNEW =  99   !

Maximum Number of sampling steps for
one puff/slug during one time step
(MXSAM)                                      Default: 99      ! MXSAM =  99   !

Number of iterations used when computing
the transport wind for a sampling step
that includes gradual rise (for CALMET
and PROFILE winds)
(NCOUNT)                                     Default: 2       ! NCOUNT =  2   !
```

```
     Minimum sigma y for a new puff/slug (m)
     (SYMIN)                                        Default: 1.0     ! SYMIN = 1.0   !

     Minimum sigma z for a new puff/slug (m)
     (SZMIN)                                        Default: 1.0     ! SZMIN = 1.0   !

     Default minimum turbulence velocities sigma-v and sigma-w
     for each stability class over land and over water (m/s)
     (SVMIN(12) and SWMIN(12))

                        ---------- LAND ----------         --------- WATER ----------
        Stab Class :  A    B    C    D    E    F         A    B    C    D    E    F
                     ---  ---  ---  ---  ---  ---       ---  ---  ---  ---  ---  ---
     Default SVMIN : .50, .50, .50, .50, .50, .50,       .37, .37, .37, .37, .37, .37
     Default SWMIN : .20, .12, .08, .06, .03, .016,      .20, .12, .08, .06, .03, .016

          ! SVMIN = 0.500, 0.500, 0.500, 0.500, 0.500, 0.500, 0.370, 0.370, 0.370, 0.370,
0.370, 0.370!
          ! SWMIN = 0.200, 0.120, 0.080, 0.060, 0.030, 0.016, 0.200, 0.120, 0.080, 0.060,
0.030, 0.016!

     Divergence criterion for dw/dz across puff
     used to initiate adjustment for horizontal
     convergence (1/s)
     Partial adjustment starts at CDIV(1), and
     full adjustment is reached at CDIV(2)
     (CDIV(2))                                      Default: 0.0,0.0  ! CDIV = .0, .0 !

     Minimum wind speed (m/s) allowed for
     non-calm conditions. Also used as minimum
     speed returned when using power-law
     extrapolation toward surface
     (WSCALM)                                       Default: 0.5     ! WSCALM = .5 !

     Maximum mixing height (m)
     (XMAXZI)                                       Default: 3000.   ! XMAXZI = 3000.0 !

     Minimum mixing height (m)
     (XMINZI)                                       Default: 50.     ! XMINZI = 50.0 !

     Default wind speed classes --
     5 upper bounds (m/s) are entered;
     the 6th class has no upper limit
     (WSCAT(5))                         Default    :
                                        ISC RURAL : 1.54, 3.09, 5.14, 8.23, 10.8 (10.8+)

                             Wind Speed Class :  1    2    3    4    5
                                                ---  ---  ---  ---  ---
                                    ! WSCAT = 1.54, 3.09, 5.14, 8.23, 10.80 !

     Default wind speed profile power-law
     exponents for stabilities 1-6
     (PLX0(6))                          Default    : ISC RURAL values
                                        ISC RURAL : .07, .07, .10, .15, .35, .55
                                        ISC URBAN : .15, .15, .20, .25, .30, .30

                              Stability Class :  A    B    C    D    E    F
                                                ---  ---  ---  ---  ---  ---
                                     ! PLX0 = 0.07, 0.07, 0.10, 0.15, 0.35, 0.55 !

     Default potential temperature gradient
     for stable classes E, F (degK/m)
     (PTG0(2))                          Default: 0.020, 0.035
                                           ! PTG0 = 0.020,   0.035 !

     Default plume path coefficients for
     each stability class (used when option
     for partial plume height terrain adjustment
     is selected -- MCTADJ=3)
     (PPC(6))                     Stability Class :  A     B     C     D     E     F
                                    Default  PPC : .50,  .50,  .50,  .50,  .35,  .35
```

```
                                       ---   ---   ---   ---   ---   ---
                                   !  PPC = 0.50, 0.50, 0.50, 0.50, 0.35, 0.35 !

Slug-to-puff transition criterion factor
equal to sigma-y/length of slug
(SL2PF)                            Default: 10.       ! SL2PF = 10.0 !

Puff-splitting control variables ------------------------

  VERTICAL SPLIT
  --------------

  Number of puffs that result every time a puff
  is split - nsplit=2 means that 1 puff splits
  into 2
  (NSPLIT)                           Default:   3       ! NSPLIT =  3  !

  Time(s) of a day when split puffs are eligible to
  be split once again; this is typically set once
  per day, around sunset before nocturnal shear develops.
  24 values: 0 is midnight (00:00) and 23 is 11 PM (23:00)
  0=do not re-split    1=eligible for re-split
  (IRESPLIT(24))                     Default:  Hour 17 = 1
  !  IRESPLIT = 0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0 !

  Split is allowed only if last hour's mixing
  height (m) exceeds a minimum value
  (ZISPLIT)                          Default: 100.      ! ZISPLIT = 100.0 !

  Split is allowed only if ratio of last hour's
  mixing ht to the maximum mixing ht experienced
  by the puff is less than a maximum value (this
  postpones a split until a nocturnal layer develops)
  (ROLDMAX)                          Default: 0.25      ! ROLDMAX = 0.25 !


  HORIZONTAL SPLIT
  ----------------

  Number of puffs that result every time a puff
  is split - nsplith=5 means that 1 puff splits
  into 5
  (NSPLITH)                          Default:   5       ! NSPLITH =  5  !

  Minimum sigma-y (Grid Cells Units) of puff
  before it may be split
  (SYSPLITH)                         Default:  1.0      ! SYSPLITH = 1.0 !

  Minimum puff elongation rate (SYSPLITH/hr) due to
  wind shear, before it may be split
  (SHSPLITH)                         Default:  2.       ! SHSPLITH = 2.0 !

  Minimum concentration (g/m^3) of each
  species in puff before it may be split
  Enter array of NSPEC values; if a single value is
  entered, it will be used for ALL species
  (CNSPLITH)                         Default:  1.0E-07  ! CNSPLITH = 1.0E-07 !

Integration control variables ------------------------

  Fractional convergence criterion for numerical SLUG
  sampling integration
  (EPSSLUG)                          Default:   1.0e-04 ! EPSSLUG = 1.0E-04 !

  Fractional convergence criterion for numerical AREA
  source integration
  (EPSAREA)                          Default:   1.0e-06 ! EPSAREA = 1.0E-06 !

  Trajectory step-length (m) used for numerical rise
  integration
  (DSRISE)                           Default:   1.0     ! DSRISE = 1.0 !
```

```
!END!

-------------------------------------------------------------------------------

INPUT GROUPS: 13a, 13b, 13c, 13d -- Point source parameters
--------------------------------

---------------
Subgroup (13a)
---------------

     Number of point sources with
     parameters provided below      (NPT1)  No default   !  NPT1 =   6 !

     Units used for point source
     emissions below                (IPTU)  Default: 1   !  IPTU =    3   !
           1 =        g/s
           2 =       kg/hr
           3 =       lb/hr
           4 =     tons/yr
           5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =     Odour Unit * m**3/min
           7 =     metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (13d)        (NSPT1) Default: 0   !  NSPT1 = 6   !

     Number of point sources with
     variable emission parameters
     provided in external file      (NPT2)  No default   !  NPT2 =   0   !

     (If NPT2 > 0, these point
     source emissions are read from
     the file: PTEMARB.DAT)

!END!

---------------
Subgroup (13b)
---------------
                                            a
          POINT SOURCE: CONSTANT DATA
          -----------------------------
                                                                                  b          c
  Source       X          Y       Stack    Base     Stack    Exit  Exit     Bldg.  Emission
   No.     Coordinate Coordinate Height Elevation Diameter  Vel.  Temp.    Dwash   Rates
              (km)       (km)      (m)      (m)       (m)   (m/s) (deg. K)
  ------   ---------- ---------- ------  ------   -------- ----- -------- ----- --------

****************    EMISSION RATES ARE IN LB/HR
****************SO2****SO4***NOX****HNO3**NO3**PM10
1 !SRCNAM = EXAMPLE !
1 !X = 1000.000, -1000.000, 10.00, 1.0, 1.00, 10.00, 100.0, 0, 10.0, 1.00, 10.0, 0.0,
0.0,10.0,10.0,1.0, 0.0, 0.0, 0.0 ! !END!

--------

    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

     SRCNAM  is a 12-character name for a source
             (No default)
     X       is an array holding the source data listed by the column headings
             (No default)
     SIGYZI  is an array holding the initial sigma-y and sigma-z (m)
```

```
        (Default: 0.,0.)
FMFAC   is a vertical momentum flux factor (0. or 1.0) used to represent
        the effect of rain-caps or other physical configurations that
        reduce momentum rise associated with the actual exit velocity.
        (Default: 1.0  -- full momentum used)

 b
 0. = No building downwash modeled, 1. = downwash modeled
 NOTE: must be entered as a REAL number (i.e., with decimal point)

 c
 An emission rate must be entered for every pollutant modeled.
 Enter emission rate of zero for secondary pollutants that are
 modeled, but not emitted.  Units are specified by IPTU
 (e.g. 1 for g/s).

---------------
Subgroup (13c)
---------------

           BUILDING DIMENSION DATA FOR SOURCES SUBJECT TO DOWNWASH
           -------------------------------------------------------
Source                                                                  a
 No.       Effective building width and height (in meters) every 10 degrees
------     ----------------------------------------------------------------


--------

 a
 Each pair of width and height values is treated as a separate input
 subgroup and therefore must end with an input group terminator.

---------------
Subgroup (13d)
---------------
                                                a
          POINT SOURCE: VARIABLE EMISSIONS DATA
          ---------------------------------------

 Use this subgroup to describe temporal variations in the emission
 rates given in 13b.  Factors entered multiply the rates in 13b.
 Skip sources here that have constant emissions.  For more elaborate
 variation in source parameters, use PTEMARB.DAT and NPT2 > 0.

 IVARY determines the type of variation, and is source-specific:
 (IVARY)                                Default: 0
       0 =       Constant
       1 =       Diurnal cycle (24 scaling factors: hours 1-24)
       2 =       Monthly cycle (12 scaling factors: months 1-12)
       3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                where first group is DEC-JAN-FEB)
       4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                first group is Stability Class A,
                                and the speed classes have upper
                                bounds (m/s) defined in Group 12
       5 =       Temperature   (12 scaling factors, where temperature
                                classes have upper bounds (C) of:
                                0, 5, 10, 15, 20, 25, 30, 35, 40,
                                45, 50, 50+)


--------
 a
 Data for each species are treated as a separate input subgroup
 and therefore must end with an input group terminator.

-------------------------------------------------------------------------------
```

```
INPUT GROUPS: 14a, 14b, 14c, 14d -- Area source parameters
---------------------------------

---------------
Subgroup (14a)
---------------

     Number of polygon area sources with
     parameters specified below (NAR1)       No default  !  NAR1 =  0   !

     Units used for area source
     emissions below            (IARU)       Default: 1  !  IARU =   1  !
           1 =         g/m**2/s
           2 =        kg/m**2/hr
           3 =        lb/m**2/hr
           4 =      tons/m**2/yr
           5 =      Odour Unit * m/s  (vol. flux/m**2 of odour compound)
           6 =      Odour Unit * m/min
           7 =      metric tons/m**2/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (14d)        (NSAR1) Default: 0  !  NSAR1 =  0  !

     Number of buoyant polygon area sources
     with variable location and emission
     parameters (NAR2)                      No default  !  NAR2 =  0   !
     (If NAR2 > 0, ALL parameter data for
     these sources are read from the file: BAEMARB.DAT)

!END!

---------------
Subgroup (14b)
---------------
                                           a
          AREA SOURCE: CONSTANT DATA
          ----------------------------
                                                                b
Source           Effect.   Base       Initial    Emission
 No.             Height   Elevation   Sigma z     Rates
                  (m)       (m)         (m)
-------          ------    ------     --------   ---------

--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.
    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by IARU
     (e.g. 1 for g/m**2/s).

---------------
Subgroup (14c)
---------------

           COORDINATES (UTM-km) FOR EACH VERTEX(4) OF EACH POLYGON
           --------------------------------------------------------
Source                                                                a
 No.       Ordered list of X followed by list of Y, grouped by source
------     ------------------------------------------------------------

--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.
```

```
---------------
Subgroup (14d)
---------------
                                                   a
          AREA SOURCE: VARIABLE EMISSIONS DATA
          ------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 14b.  Factors entered multiply the rates in 14b.
     Skip sources here that have constant emissions.  For more elaborate
     variation in source parameters, use BAEMARB.DAT and NAR2 > 0.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                                Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
           4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                    first group is Stability Class A,
                                    and the speed classes have upper
                                    bounds (m/s) defined in Group 12
           5 =       Temperature   (12 scaling factors, where temperature
                                    classes have upper bounds (C) of:
                                    0, 5, 10, 15, 20, 25, 30, 35, 40,
                                    45, 50, 50+)


--------
    a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


-------------------------------------------------------------------------------

INPUT GROUPS: 15a, 15b, 15c -- Line source parameters
---------------------------

---------------
Subgroup (15a)
---------------

     Number of buoyant line sources
     with variable location and emission
     parameters (NLN2)                              No default  !  NLN2 =  0   !

     (If NLN2 > 0, ALL parameter data for
      these sources are read from the file: LNEMARB.DAT)

     Number of buoyant line sources (NLINES)        No default   ! NLINES =  0  !

     Units used for line source
     emissions below                (ILNU)          Default: 1  !  ILNU =   1  !
           1 =        g/s
           2 =        kg/hr
           3 =        lb/hr
           4 =      tons/yr
           5 =      Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =      Odour Unit * m**3/min
           7 =      metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (15c)        (NSLN1) Default: 0  !  NSLN1 =  0  !
```

```
     Maximum number of segments used to model
     each line (MXNSEG)                               Default: 7    ! MXNSEG =  7  !

     The following variables are required only if NLINES > 0.  They are
     used in the buoyant line source plume rise calculations.

        Number of distances at which                  Default: 6    ! NLRISE =  6  !
        transitional rise is computed

        Average building length (XL)                  No default    ! XL = .0 !
                                                      (in meters)

        Average building height (HBL)                 No default    ! HBL = .0 !
                                                      (in meters)

        Average building width (WBL)                  No default    ! WBL = .0 !
                                                      (in meters)

        Average line source width (WML)               No default    ! WML = .0 !
                                                      (in meters)

        Average separation between buildings (DXL)    No default    ! DXL = .0 !
                                                      (in meters)

        Average buoyancy parameter (FPRIMEL)          No default    ! FPRIMEL = .0 !
                                                      (in m**4/s**3)

!END!

---------------
Subgroup (15b)
---------------

          BUOYANT LINE SOURCE: CONSTANT DATA
          ----------------------------------
                                                                                 a
Source     Beg. X      Beg. Y      End. X     End. Y    Release    Base         Emission
 No.     Coordinate  Coordinate  Coordinate Coordinate  Height   Elevation       Rates
            (km)        (km)        (km)       (km)       (m)       (m)
------   ----------  ----------  ---------  ----------  -------  ---------    ---------

--------

    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by ILNTU
     (e.g. 1 for g/s).

---------------
Subgroup (15c)
---------------
                                                           a
          BUOYANT LINE SOURCE: VARIABLE EMISSIONS DATA
          --------------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 15b.  Factors entered multiply the rates in 15b.
     Skip sources here that have constant emissions.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                                 Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
```

```
        4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                 first group is Stability Class A,
                                 and the speed classes have upper
                                 bounds (m/s) defined in Group 12
        5 =       Temperature   (12 scaling factors, where temperature
                                 classes have upper bounds (C) of:
                                 0, 5, 10, 15, 20, 25, 30, 35, 40,
                                 45, 50, 50+)
--------
    a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


--------------------------------------------------------------------------------


INPUT GROUPS: 16a, 16b, 16c -- Volume source parameters
---------------------------

---------------
Subgroup (16a)
---------------

     Number of volume sources with
     parameters provided in 16b,c (NVL1)     No default  !  NVL1 =  0   !

     Units used for volume source
     emissions below in 16b       (IVLU)     Default: 1  !  IVLU =   1  !
           1 =         g/s
           2 =        kg/hr
           3 =        lb/hr
           4 =       tons/yr
           5 =       Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =       Odour Unit * m**3/min
           7 =       metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (16c)      (NSVL1)    Default: 0  !  NSVL1 =  0  !

     Number of volume sources with
     variable location and emission
     parameters                   (NVL2)     No default  !  NVL2 =   0   !

     (If NVL2 > 0, ALL parameter data for
      these sources are read from the VOLEMARB.DAT file(s) )

!END!

---------------
Subgroup (16b)
---------------
                                            a
           VOLUME SOURCE: CONSTANT DATA
           ------------------------------
                                                                           b
       X UTM     Y UTM     Effect.   Base     Initial    Initial    Emission
     Coordinate Coordinate Height  Elevation  Sigma y    Sigma z     Rates
       (km)       (km)       (m)      (m)       (m)        (m)
     ---------- ----------  ------   ------   --------   --------   --------


--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

    b
     An emission rate must be entered for every pollutant modeled.
```

Enter emission rate of zero for secondary pollutants that are modeled, but not emitted. Units are specified by IVLU (e.g. 1 for g/s).

Subgroup (16c)

VOLUME SOURCE: VARIABLE EMISSIONS DATA[a]

Use this subgroup to describe temporal variations in the emission rates given in 16b. Factors entered multiply the rates in 16b. Skip sources here that have constant emissions. For more elaborate variation in source parameters, use VOLEMARB.DAT and NVL2 > 0.

IVARY determines the type of variation, and is source-specific:
(IVARY)   Default: 0

```
      0 =       Constant
      1 =       Diurnal cycle (24 scaling factors: hours 1-24)
      2 =       Monthly cycle (12 scaling factors: months 1-12)
      3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                               where first group is DEC-JAN-FEB)
      4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                               first group is Stability Class A,
                               and the speed classes have upper
                               bounds (m/s) defined in Group 12
      5 =       Temperature   (12 scaling factors, where temperature
                               classes have upper bounds (C) of:
                               0, 5, 10, 15, 20, 25, 30, 35, 40,
                               45, 50, 50+)
```

----
[a] Data for each species are treated as a separate input subgroup and therefore must end with an input group terminator.

INPUT GROUPS: 17a & 17b -- Non-gridded (discrete) receptor information

----
Subgroup (17a)

Number of non-gridded receptors (NREC)   No default   ! NREC = 364 !

!END!

Subgroup (17b)

NON-GRIDDED (DISCRETE) RECEPTOR DATA[a]

```
                    X            Y           Ground        Height   b
Receptor       Coordinate   Coordinate    Elevation    Above Ground
  No.             (km)         (km)          (m)            (m)
--------       ----------   ----------    ---------    ------------
RECEPTORS OBTAINED FROM THE NPS/FWS EXTRACTION PROGRAM
ALL RECEPTORS ARE LCC (KM)

1 EXAPLE RECEPTOR
     1 ! X =      1000.000,  -1000.000,        0,        0.000!   !END!
```

a

Data for each receptor are treated as a separate input subgroup and therefore must end with an input group terminator.

b

Receptor height above ground is optional. If no value is entered, the receptor is placed on the ground.

```
EXAMPLE FACILITY - CALPUFF  10/16/06
LINE 2
LINE 3
---------------- Run title (3 lines) ------------------------------------------

                     CALPUFF MODEL CONTROL FILE
                     --------------------------

-------------------------------------------------------------------------------

INPUT GROUP: 0 -- Input and Output File Names

--------------
Default Name  Type          File Name
------------  ----          ---------
CALMET.DAT    input    * METDAT =           *
    or
ISCMET.DAT    input    * ISCDAT =           *
    or
PLMMET.DAT    input    * PLMDAT =           *
    or
PROFILE.DAT   input    * PRFDAT =           *
SURFACE.DAT   input    * SFCDAT =           *
RESTARTB.DAT  input    * RSTARTB=           *
--------------------------------------------------------------------------------
CALPUFF.LST   output   ! PUFLST = PUFFSCGC1.LST !
CONC.DAT      output   ! CONDAT = PUFFSCGC1.CON !
DFLX.DAT      output   * DFDAT  =           *
WFLX.DAT      output   * WFDAT  =           *

VISB.DAT      output   * VISDAT = VISB.DAT    *
TK2D.DAT      output   * T2DDAT =           *
RHO2D.DAT     output   * RHODAT =           *
RESTARTE.DAT  output   * RSTARTE=           *
--------------------------------------------------------------------------------
Emission Files
--------------
PTEMARB.DAT   input    * PTDAT  =           *
VOLEMARB.DAT  input    * VOLDAT =           *
BAEMARB.DAT   input    * ARDAT  =           *
LNEMARB.DAT   input    * LNDAT  =           *
--------------------------------------------------------------------------------
Other Files
-----------
OZONE.DAT     input    ! OZDAT  =C:\BARTHRO3\2001FLOz.DAT !
VD.DAT        input    * VDDAT  =           *
CHEM.DAT      input    * CHEMDAT=           *
H2O2.DAT      input    * H2O2DAT=           *
HILL.DAT      input    * HILDAT=          *
HILLRCT.DAT   input    * RCTDAT=          *
COASTLN.DAT   input    * CSTDAT=          *
FLUXBDY.DAT   input    * BDYDAT=          *
BCON.DAT      input    * BCNDAT=          *
DEBUG.DAT     output   * DEBUG =          *
MASSFLX.DAT   output   * FLXDAT=          *
MASSBAL.DAT   output   * BALDAT=          *
FOG.DAT       output   * FOGDAT=          *
--------------------------------------------------------------------------------
All file names will be converted to lower case if LCFILES = T
Otherwise, if LCFILES = F, file names will be converted to UPPER CASE
         T = lower case      ! LCFILES = T !
         F = UPPER CASE
NOTE: (1) file/path names can be up to 70 characters in length


Provision for multiple input files
----------------------------------

     Number of CALMET.DAT files for run (NMETDAT)
                                Default: 1       ! NMETDAT =   36  !
```

```
     Number of PTEMARB.DAT files for run (NPTDAT)
                                        Default: 0       ! NPTDAT =  0  !

     Number of BAEMARB.DAT files for run (NARDAT)
                                        Default: 0       ! NARDAT =  0  !

     Number of VOLEMARB.DAT files for run (NVOLDAT)
                                        Default: 0       ! NVOLDAT =  0  !

!END!

-------------
Subgroup (0a)
-------------

  The following CALMET.DAT filenames are processed in sequence if NMETDAT>1

Default Name  Type          File Name
------------  ----          ---------
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-01A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-01B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-01C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-02A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-02B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-02C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-03A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-03B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-03C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-04A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-04B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-04C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-05A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-05B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-05C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-06A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-06B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-06C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-07A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-07B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-07C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-08A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-08B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-08C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-09A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-09B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-09C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-10A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-10B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-10C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-11A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-11B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-11C.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-12A.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-12B.DAT ! !END!
CALMET.DAT    input    ! METDAT =D:\FLA4KM\2001\MET2001-DOM2-12C.DAT ! !END!
-------------------------------------------------------------------------------

INPUT GROUP: 1 -- General run control parameters
--------------

    Option to run all periods found
    in the met. file     (METRUN)   Default: 0       ! METRUN =   0  !

         METRUN = 0 - Run period explicitly defined below
         METRUN = 1 - Run all periods in met. file

     Starting date:    Year (IBYR) -- No default       ! IBYR =  2001  !
     (used only if    Month (IBMO) -- No default       ! IBMO =  1  !
      METRUN = 0)       Day (IBDY) -- No default       ! IBDY =  1  !
                       Hour (IBHR) -- No default       ! IBHR =  1  !
```

```
     Base time zone        (XBTZ) -- No default       ! XBTZ = 5.0  !
        PST = 8., MST = 7.
        CST = 6., EST = 5.

     Length of run (hours) (IRLG) -- No default       ! IRLG = 8760 !

     Number of chemical species (NSPEC)
                                      Default: 5      ! NSPEC = 11   !

     Number of chemical species
     to be emitted  (NSE)             Default: 3      ! NSE = 9   !

     Flag to stop run after
     SETUP phase (ITEST)              Default: 2      ! ITEST =  2   !
     (Used to allow checking
     of the model inputs, files, etc.)
           ITEST = 1 - STOPS program after SETUP phase
           ITEST = 2 - Continues with execution of program
                       after SETUP

     Restart Configuration:

        Control flag (MRESTART)       Default: 0      ! MRESTART =  0   !

           0 = Do not read or write a restart file
           1 = Read a restart file at the beginning of
               the run
           2 = Write a restart file during run
           3 = Read a restart file at beginning of run
               and write a restart file during run

        Number of periods in Restart
        output cycle (NRESPD)         Default: 0      ! NRESPD =  0   !

           0 = File written only at last period
          >0 = File updated every NRESPD periods

     Meteorological Data Format (METFM)
                                      Default: 1      ! METFM =  1   !

           METFM = 1 - CALMET binary file (CALMET.MET)
           METFM = 2 - ISC ASCII file (ISCMET.MET)
           METFM = 3 - AUSPLUME ASCII file (PLMMET.MET)
           METFM = 4 - CTDM plus tower file (PROFILE.DAT) and
                       surface parameters file (SURFACE.DAT)

     PG sigma-y is adjusted by the factor (AVET/PGTIME)**0.2
     Averaging Time (minutes) (AVET)
                                      Default: 60.0    ! AVET = 60.  !
     PG Averaging Time (minutes) (PGTIME)
                                      Default: 60.0    ! PGTIME = 60.  !


!END!

-------------------------------------------------------------------------------

INPUT GROUP: 2 -- Technical options
--------------


     Vertical distribution used in the
     near field (MGAUSS)                    Default: 1     ! MGAUSS =  1   !
        0 = uniform
        1 = Gaussian

     Terrain adjustment method
     (MCTADJ)                               Default: 3     ! MCTADJ =  3   !
        0 = no adjustment
        1 = ISC-type of terrain adjustment
```

```
   2 = simple, CALPUFF-type of terrain
       adjustment
   3 = partial plume path adjustment

Subgrid-scale complex terrain
flag (MCTSG)                         Default: 0     ! MCTSG =  0   !
   0 = not modeled
   1 = modeled

Near-field puffs modeled as
elongated 0 (MSLUG)                  Default: 0     ! MSLUG =  0   !
   0 = no
   1 = yes (slug model used)

Transitional plume rise modeled ?
(MTRANS)                             Default: 1     ! MTRANS =  1   !
   0 = no  (i.e., final rise only)
   1 = yes (i.e., transitional rise computed)

Stack tip downwash? (MTIP)           Default: 1     ! MTIP =  1  !
   0 = no  (i.e., no stack tip downwash)
   1 = yes (i.e., use stack tip downwash)

Vertical wind shear modeled above
stack top? (MSHEAR)                  Default: 0     ! MSHEAR =  0  !
   0 = no  (i.e., vertical wind shear not modeled)
   1 = yes (i.e., vertical wind shear modeled)

Puff splitting allowed? (MSPLIT)     Default: 0     ! MSPLIT =  0  !
   0 = no (i.e., puffs not split)
   1 = yes (i.e., puffs are split)

Chemical mechanism flag (MCHEM)      Default: 1     ! MCHEM =  1   !
   0 = chemical transformation not
       modeled
   1 = transformation rates computed
       internally (MESOPUFF II scheme)
   2 = user-specified transformation
       rates used
   3 = transformation rates computed
       internally (RIVAD/ARM3 scheme)
   4 = secondary organic aerosol formation
       computed (MESOPUFF II scheme for OH)

Aqueous phase transformation flag (MAQCHEM)
(Used only if MCHEM = 1, or 3)       Default: 0     ! MAQCHEM =  0   !
   0 = aqueous phase transformation
       not modeled
   1 = transformation rates adjusted
       for aqueous phase reactions

Wet removal modeled ? (MWET)         Default: 1     ! MWET =  1   !
   0 = no
   1 = yes

Dry deposition modeled ? (MDRY)      Default: 1     ! MDRY =  1   !
   0 = no
   1 = yes
   (dry deposition method specified
    for each species in Input Group 3)

Method used to compute dispersion
coefficients (MDISP)                 Default: 3     ! MDISP =  3   !

   1 = dispersion coefficients computed from measured values
       of turbulence, sigma v, sigma w
   2 = dispersion coefficients from internally calculated
       sigma v, sigma w using micrometeorological variables
       (u*, w*, L, etc.)
   3 = PG dispersion coefficients for RURAL areas (computed using
       the ISCST multi-segment approximation) and MP coefficients in
```

```
        urban areas
    4 = same as 3 except PG coefficients computed using
        the MESOPUFF II eqns.
    5 = CTDM sigmas used for stable and neutral conditions.
        For unstable conditions, sigmas are computed as in
        MDISP = 3, described above.  MDISP = 5 assumes that
        measured values are read

Sigma-v/sigma-theta, sigma-w measurements used? (MTURBVW)
(Used only if MDISP = 1 or 5)          Default: 3      ! MTURBVW =  3  !
    1 = use sigma-v or sigma-theta measurements
        from PROFILE.DAT to compute sigma-y
        (valid for METFM = 1, 2, 3, 4)
    2 = use sigma-w measurements
        from PROFILE.DAT to compute sigma-z
        (valid for METFM = 1, 2, 3, 4)
    3 = use both sigma-(v/theta) and sigma-w
        from PROFILE.DAT to compute sigma-y and sigma-z
        (valid for METFM = 1, 2, 3, 4)
    4 = use sigma-theta measurements
        from PLMMET.DAT to compute sigma-y
        (valid only if METFM = 3)

Back-up method used to compute dispersion
when measured turbulence data are
missing (MDISP2)                       Default: 3      ! MDISP2 =  3  !
(used only if MDISP = 1 or 5)
    2 = dispersion coefficients from internally calculated
        sigma v, sigma w using micrometeorological variables
        (u*, w*, L, etc.)
    3 = PG dispersion coefficients for RURAL areas (computed using
        the ISCST multi-segment approximation) and MP coefficients in
        urban areas
    4 = same as 3 except PG coefficients computed using
        the MESOPUFF II eqns.

PG sigma-y,z adj. for roughness?       Default: 0      ! MROUGH =  0  !
(MROUGH)
    0 = no
    1 = yes

Partial plume penetration of           Default: 1      ! MPARTL =  1  !
elevated inversion?
(MPARTL)
    0 = no
    1 = yes

Strength of temperature inversion      Default: 0      ! MTINV =  0  !
provided in PROFILE.DAT extended records?
(MTINV)
    0 = no (computed from measured/default gradients)
    1 = yes

PDF used for dispersion under convective conditions?
                                       Default: 0      ! MPDF =  0  !
(MPDF)
    0 = no
    1 = yes

Sub-Grid TIBL module used for shore line?
                                       Default: 0      ! MSGTIBL = 0  !
(MSGTIBL)
    0 = no
    1 = yes

Boundary conditions (concentration) modeled?
                                       Default: 0      ! MBCON = 0  !
(MBCON)
    0 = no
    1 = yes
```

```
Analyses of fogging and icing impacts due to emissions from
arrays of mechanically-forced cooling towers can be performed
using CALPUFF in conjunction with a cooling tower emissions
processor (CTEMISS) and its associated postprocessors.  Hourly
emissions of water vapor and temperature from each cooling tower
cell are computed for the current cell configuration and ambient
conditions by CTEMISS. CALPUFF models the dispersion of these
emissions and provides cloud information in a specialized format
for further analysis. Output to FOG.DAT is provided in either
'plume mode' or 'receptor mode' format.

Configure for FOG Model output?
                                          Default: 0     ! MFOG =  0   !
(MFOG)
   0 = no
   1 = yes  - report results in PLUME Mode format
   2 = yes  - report results in RECEPTOR Mode format


Test options specified to see if
they conform to regulatory
values? (MREG)                            Default: 1     ! MREG =  1   !

   0 = NO checks are made
   1 = Technical options must conform to USEPA
       Long Range Transport (LRT) guidance
                  METFM    1 or 2
                  AVET     60. (min)
                  PGTIME   60. (min)
                  MGAUSS   1
                  MCTADJ   3
                  MTRANS   1
                  MTIP     1
                  MCHEM    1 or 3 (if modeling SOx, NOx)
                  MWET     1
                  MDRY     1
                  MDISP    2 or 3
                  MPDF     0 if MDISP=3
                           1 if MDISP=2
                  MROUGH   0
                  MPARTL   1
                  SYTDEP   550. (m)
                  MHFTSZ   0

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 3a, 3b -- Species list
-------------------

------------
Subgroup (3a)
------------

  The following species are modeled:

! CSPEC =          SO2 !         !END!
! CSPEC =          SO4 !         !END!
! CSPEC =          NOX !         !END!
! CSPEC =         HNO3 !         !END!
! CSPEC =          NO3 !         !END!
! CSPEC =       PM0063 !         !END!
! CSPEC =       PM0100 !         !END!
! CSPEC =       PM0125 !         !END!
! CSPEC =       PM0250 !         !END!
! CSPEC =       PM0600 !         !END!
! CSPEC =       PM1000 !         !END!
```

```
                                                              Dry                   OUTPUT GROUP
    SPECIES          MODELED          EMITTED           DEPOSITED                  NUMBER
     NAME        (0=NO, 1=YES)     (0=NO, 1=YES)      (0=NO,                    (0=NONE,
   (Limit: 12                                          1=COMPUTED-GAS           1=1st CGRUP,
    Characters                                         2=COMPUTED-PARTICLE      2=2nd CGRUP,
    in length)                                         3=USER-SPECIFIED)        3= etc.)

!          SO2   =           1,              1,             1,                  0    !
!          SO4   =           1,              1,             2,                  0    !
!          NOX   =           1,              1,             1,                  0    !
!         HNO3   =           1,              0,             1,                  0    !
!          NO3   =           1,              0,             2,                  0    !
!      PM0063    =           1,              1,             2,                  1    !
!      PM0100    =           1,              1,             2,                  1    !
!      PM0125    =           1,              1,             2,                  1    !
!      PM0250    =           1,              1,             2,                  1    !
!      PM0600    =           1,              1,             2,                  1    !
!      PM1000    =           1,              1,             2,                  1    !

!END!

-------------
Subgroup (3b)
-------------
  The following names are used for Species-Groups in which results
  for certain species are combined (added) prior to output.  The
  CGRUP name will be used as the species name in output files.
  Use this feature to model specific particle-size distributions
  by treating each size-range as a separate species.
  Order must be consistent with 3(a) above.

! CGRUP =          PM10 !       !END!

INPUT GROUP: 4 -- Map Projection and Grid control parameters
-------------

     Projection for all (X,Y):
     -------------------------

     Map projection
     (PMAP)                       Default: UTM     ! PMAP = LCC   !

         UTM :  Universal Transverse Mercator
         TTM :  Tangential Transverse Mercator
         LCC :  Lambert Conformal Conic
          PS :  Polar Stereographic
          EM :  Equatorial Mercator
        LAZA :  Lambert Azimuthal Equal Area

     False Easting and Northing (km) at the projection origin
     (Used only if PMAP= TTM, LCC, or LAZA)
     (FEAST)                      Default=0.0      ! FEAST  = 0.000  !
     (FNORTH)                     Default=0.0      ! FNORTH = 0.000  !

     UTM zone (1 to 60)
     (Used only if PMAP=UTM)
     (IUTMZN)                     No Default       ! IUTMZN =  0 !

     Hemisphere for UTM projection?
     (Used only if PMAP=UTM)
     (UTMHEM)                     Default: N       ! UTMHEM = N  !
         N   :  Northern hemisphere projection
         S   :  Southern hemisphere projection

     Latitude and Longitude (decimal degrees) of projection origin
     (Used only if PMAP= TTM, LCC, PS, EM, or LAZA)
     (RLAT0)                      No Default       ! RLAT0 =  40N !
     (RLON0)                      No Default       ! RLON0 =  97W !

         TTM :  RLON0 identifies central (true N/S) meridian of projection
```

```
              RLAT0 selected for convenience
       LCC :  RLON0 identifies central (true N/S) meridian of projection
              RLAT0 selected for convenience
       PS  :  RLON0 identifies central (grid N/S) meridian of projection
              RLAT0 selected for convenience
       EM  :  RLON0 identifies central meridian of projection
              RLAT0 is REPLACED by 0.0N (Equator)
       LAZA:  RLON0 identifies longitude of tangent-point of mapping plane
              RLAT0 identifies latitude of tangent-point of mapping plane

   Matching parallel(s) of latitude (decimal degrees) for projection
   (Used only if PMAP= LCC or PS)
   (XLAT1)                    No Default      ! XLAT1 = 33N  !
   (XLAT2)                    No Default      ! XLAT2 = 45N  !

       LCC :  Projection cone slices through Earth's surface at XLAT1 and XLAT2
       PS  :  Projection plane slices through Earth at XLAT1
              (XLAT2 is not used)

   ----------
   Note:  Latitudes and longitudes should be positive, and include a
          letter N,S,E, or W indicating north or south latitude, and
          east or west longitude.  For example,
          35.9  N Latitude  =  35.9N
          118.7 E Longitude = 118.7E


   Datum-region
   ------------

   The Datum-Region for the coordinates is identified by a character
   string.  Many mapping products currently available use the model of the
   Earth known as the World Geodetic System 1984 (WGS-84).  Other local
   models may be in use, and their selection in CALMET will make its output
   consistent with local mapping products.  The list of Datum-Regions with
   official transformation parameters is provided by the National Imagery and
   Mapping Agency (NIMA).

   NIMA Datum - Regions(Examples)
   ------------------------------------------------------------------------------
   WGS-84    WGS-84 Reference Ellipsoid and Geoid, Global coverage (WGS84)
   NAS-C     NORTH AMERICAN 1927 Clarke 1866 Spheroid, MEAN FOR CONUS (NAD27)
   NAR-C     NORTH AMERICAN 1983 GRS 80 Spheroid, MEAN FOR CONUS (NAD83)
   NWS-84    NWS 6370KM Radius, Sphere
   ESR-S     ESRI REFERENCE 6371KM Radius, Sphere

   Datum-region for output coordinates
   (DATUM)                    Default: WGS-G     ! DATUM = NWS-84 !


METEOROLOGICAL Grid:

   Rectangular grid defined for projection PMAP,
   with X the Easting and Y the Northing coordinate

          No. X grid cells (NX)      No default     ! NX = 263   !
          No. Y grid cells (NY)      No default     ! NY = 206    !
       No. vertical layers (NZ)      No default     ! NZ =  10   !

         Grid spacing (DGRIDKM)      No default     ! DGRIDKM = 4. !
                                     Units: km

              Cell face heights
                  (ZFACE(nz+1))      No defaults
                                     Units: m
      ! ZFACE = 0.,20.,40.,80.,160.,320.,640.,1200.,2000.,3000.,4000. !

          Reference Coordinates
         of SOUTHWEST corner of
               grid cell(1, 1):
```

```
          X coordinate (XORIGKM)       No default      ! XORIGKM =  721.995 !
          Y coordinate (YORIGKM)       No default      ! YORIGKM = -1598.000 !
                                      Units: km


COMPUTATIONAL Grid:

     The computational grid is identical to or a subset of the MET. grid.
     The lower left (LL) corner of the computational grid is at grid point
     (IBCOMP, JBCOMP) of the MET. grid.  The upper right (UR) corner of the
     computational grid is at grid point (IECOMP, JECOMP) of the MET. grid.
     The grid spacing of the computational grid is the same as the MET. grid.

        X index of LL corner (IBCOMP)       No default     ! IBCOMP =  1  !
                  (1 <= IBCOMP <= NX)

        Y index of LL corner (JBCOMP)       No default     ! JBCOMP =  1  !
                  (1 <= JBCOMP <= NY)


        X index of UR corner (IECOMP)       No default     ! IECOMP = 263 !
                  (1 <= IECOMP <= NX)

        Y index of UR corner (JECOMP)       No default     ! JECOMP = 206 !
                  (1 <= JECOMP <= NY)


SAMPLING Grid (GRIDDED RECEPTORS):

     The lower left (LL) corner of the sampling grid is at grid point
     (IBSAMP, JBSAMP) of the MET. grid.  The upper right (UR) corner of the
     sampling grid is at grid point (IESAMP, JESAMP) of the MET. grid.
     The sampling grid must be identical to or a subset of the computational
     grid.  It may be a nested grid inside the computational grid.
     The grid spacing of the sampling grid is DGRIDKM/MESHDN.

        Logical flag indicating if gridded
        receptors are used (LSAMP)          Default: T     ! LSAMP = F !
        (T=yes, F=no)

        X index of LL corner (IBSAMP)       No default     ! IBSAMP =  1   !
         (IBCOMP <= IBSAMP <= IECOMP)

        Y index of LL corner (JBSAMP)       No default     ! JBSAMP =  1   !
         (JBCOMP <= JBSAMP <= JECOMP)


        X index of UR corner (IESAMP)       No default     ! IESAMP =  263 !
         (IBCOMP <= IESAMP <= IECOMP)

        Y index of UR corner (JESAMP)       No default     ! JESAMP =  206  !
         (JBCOMP <= JESAMP <= JECOMP)


       Nesting factor of the sampling
        grid (MESHDN)                       Default: 1     ! MESHDN =  1  !
        (MESHDN is an integer >= 1)

!END!


-------------------------------------------------------------------------------


INPUT GROUP: 5 -- Output Options
--------------
                                                  *                          *
     FILE                      DEFAULT VALUE             VALUE THIS RUN
     ----                      -------------             --------------
```

```
Concentrations (ICON)              1                 !  ICON =  1   !
Dry Fluxes (IDRY)                  1                 !  IDRY =  0   !
Wet Fluxes (IWET)                  1                 !  IWET =  0   !
Relative Humidity (IVIS)           1                 !  IVIS =  0   !
 (relative humidity file is
  required for visibility
  analysis)
Use data compression option in output file?
(LCOMPRS)                           Default: T        ! LCOMPRS = T !

*
 0 = Do not create file, 1 = create file


 DIAGNOSTIC MASS FLUX OUTPUT OPTIONS:

    Mass flux across specified boundaries
    for selected species reported hourly?
    (IMFLX)                         Default: 0        ! IMFLX =  0  !
      0 = no
      1 = yes (FLUXBDY.DAT and MASSFLX.DAT filenames
               are specified in Input Group 0)

    Mass balance for each species
    reported hourly?
    (IMBAL)                         Default: 0        ! IMBAL =  0  !
      0 = no
      1 = yes (MASSBAL.DAT filename is
            specified in Input Group 0)


 LINE PRINTER OUTPUT OPTIONS:

    Print concentrations (ICPRT)    Default: 0        ! ICPRT =  0   !
    Print dry fluxes (IDPRT)        Default: 0        ! IDPRT =  0   !
    Print wet fluxes (IWPRT)        Default: 0        ! IWPRT =  0   !
    (0 = Do not print, 1 = Print)

    Concentration print interval
    (ICFRQ) in hours                Default: 1        ! ICFRQ =  24  !
    Dry flux print interval
    (IDFRQ) in hours                Default: 1        ! IDFRQ =  1   !
    Wet flux print interval
    (IWFRQ) in hours                Default: 1        ! IWFRQ =  1   !

    Units for Line Printer Output
    (IPRTU)                         Default: 1        ! IPRTU =  3   !
                    for            for
               Concentration   Deposition
       1 =         g/m**3        g/m**2/s
       2 =        mg/m**3       mg/m**2/s
       3 =        ug/m**3       ug/m**2/s
       4 =        ng/m**3       ng/m**2/s
       5 =       Odour Units

    Messages tracking progress of run
    written to the screen ?
    (IMESG)                         Default: 2        ! IMESG =  2   !
      0 = no
      1 = yes (advection step, puff ID)
      2 = yes (YYYYJJJHH, # old puffs, # emitted puffs)


  SPECIES (or GROUP for combined species) LIST FOR OUTPUT OPTIONS

                ---- CONCENTRATIONS ----    ------ DRY FLUXES ------    ------ WET FLUXES ----
--    -- MASS FLUX --
   SPECIES
   /GROUP         PRINTED?  SAVED ON DISK?    PRINTED?  SAVED ON DISK?    PRINTED?  SAVED ON
DISK?   SAVED ON DISK?
```

```
    -------     -----------------------    ----------------------    ---------------------
--   ---------------
!          SO2 =      0,            1,            0,            1,            0,            1,
0    !
!          SO4 =      0,            1,            0,            1,            0,            1,
0    !
!          NOX =      0,            1,            0,            1,            0,            1,
0    !
!         HNO3 =      0,            1,            0,            1,            0,            1,
0    !
!          NO3 =      0,            1,            0,            1,            0,            1,
0    !
!         PM10 =      0,            1,            0,            1,            0,            1,
0    !

     OPTIONS FOR PRINTING "DEBUG" QUANTITIES (much output)

       Logical for debug output
       (LDEBUG)                                 Default: F      ! LDEBUG = F !

       First puff to track
       (IPFDEB)                                 Default: 1      ! IPFDEB =  1  !

       Number of puffs to track
       (NPFDEB)                                 Default: 1      ! NPFDEB =  1  !

       Met. period to start output
       (NN1)                                    Default: 1      ! NN1 =  1   !

       Met. period to end output
       (NN2)                                    Default: 10     ! NN2 =  10  !

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 6a, 6b, & 6c -- Subgrid scale complex terrain inputs
-------------------------

---------------
Subgroup (6a)
---------------
       Number of terrain features (NHILL)       Default: 0      ! NHILL =  0   !

       Number of special complex terrain
       receptors  (NCTREC)                      Default: 0      ! NCTREC =  0   !

       Terrain and CTSG Receptor data for
       CTSG hills input in CTDM format ?
       (MHILL)                                  No Default      ! MHILL =  2   !
       1 = Hill and Receptor data created
           by CTDM processors & read from
           HILL.DAT and HILLRCT.DAT files
       2 = Hill data created by OPTHILL &
           input below in Subgroup (6b);
           Receptor data in Subgroup (6c)

       Factor to convert horizontal dimensions  Default: 1.0    ! XHILL2M = 1. !
       to meters (MHILL=1)

       Factor to convert vertical dimensions    Default: 1.0    ! ZHILL2M = 1. !
       to meters (MHILL=1)

       X-origin of CTDM system relative to      No Default      ! XCTDMKM = 0.0E00 !
       CALPUFF coordinate system, in Kilometers (MHILL=1)

       Y-origin of CTDM system relative to      No Default      ! YCTDMKM = 0.0E00 !
       CALPUFF coordinate system, in Kilometers (MHILL=1)
```

```
! END !

---------------
Subgroup (6b)
---------------

                      1 **
     HILL information


HILL           XC         YC        THETAH  ZGRID  RELIEF    EXPO 1    EXPO 2   SCALE 1
SCALE 2    AMAX1      AMAX2
 NO.          (km)       (km)       (deg.)    (m)      (m)       (m)       (m)       (m)
(m)        (m)        (m)
----          ----       ----       ------  -----  ------    ------    ------   -------    ----
---    -----      -----


---------------
Subgroup (6c)
---------------

    COMPLEX TERRAIN RECEPTOR INFORMATION

                      XRCT          YRCT        ZRCT          XHH
                      (km)          (km)         (m)
                     ------        -----       ------         ----


-------------------
1
     Description of Complex Terrain Variables:
          XC, YC  = Coordinates of center of hill
          THETAH  = Orientation of major axis of hill (clockwise from
                    North)
          ZGRID   = Height of the  0  of the grid above mean sea
                    level
          RELIEF  = Height of the crest of the hill above the grid elevation
          EXPO 1  = Hill-shape exponent for the major axis
          EXPO 2  = Hill-shape exponent for the major axis
          SCALE 1 = Horizontal length scale along the major axis
          SCALE 2 = Horizontal length scale along the minor axis
          AMAX    = Maximum allowed axis length for the major axis
          BMAX    = Maximum allowed axis length for the major axis

          XRCT, YRCT = Coordinates of the complex terrain receptors
          ZRCT    = Height of the ground (MSL) at the complex terrain
                    Receptor
          XHH     = Hill number associated with each complex terrain receptor
                    (NOTE: MUST BE ENTERED AS A REAL NUMBER)

   **
     NOTE: DATA for each hill and CTSG receptor are treated as a separate
           input subgroup and therefore must end with an input group terminator.

------------------------------------------------------------------------------


INPUT GROUP: 7 -- Chemical parameters for dry deposition of gases
--------------

      SPECIES     DIFFUSIVITY      ALPHA STAR      REACTIVITY    MESOPHYLL RESISTANCE
HENRY'S LAW COEFFICIENT
       NAME        (cm**2/s)                                             (s/cm)
(dimensionless)
      -------     -----------      ----------      ----------    --------------------    ---
--------------------


!          SO2 =       0.1509,          1000,             8,                  0,
0.04 !
!          NOX =       0.1656,             1,             8,                  5,
3.5 !
```

```
!        HNO3 =     0.1628,           1,          18,             0,
0.00000008 !

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 8 -- Size parameters for dry deposition of particles
--------------

     For SINGLE SPECIES, the mean and standard deviation are used to
     compute a deposition velocity for NINT (see group 9) size-ranges,
     and these are then averaged to obtain a mean deposition velocity.

     For GROUPED SPECIES, the size distribution should be explicitly
     specified (by the 'species' in the group), and the standard deviation
     for each should be entered as 0.  The model will then use the
     deposition velocity for the stated mean diameter.

      SPECIES       GEOMETRIC MASS MEAN        GEOMETRIC STANDARD
       NAME              DIAMETER                   DEVIATION
                         (microns)                  (microns)
      -------       -------------------        ------------------
!         SO4 =          0.48,                      2.    !
!         NO3 =          0.48,                      2.    !
!      PM0063 =          0.63,                      0.    !
!      PM0100 =          1.00,                      0.    !
!      PM0125 =          1.25,                      0.    !
!      PM0250 =          2.50,                      0.    !
!      PM0600 =          6.00,                      0.    !
!      PM1000 =         10.00,                      0.    !

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 9 -- Miscellaneous dry deposition parameters
--------------

     Reference cuticle resistance (s/cm)
     (RCUTR)                           Default: 30     !  RCUTR = 30.0 !
     Reference ground resistance  (s/cm)
     (RGR)                             Default: 10     !    RGR = 10.0 !
     Reference pollutant reactivity
     (REACTR)                          Default: 8      ! REACTR = 8.0 !

     Number of particle-size intervals used to
     evaluate effective particle deposition velocity
     (NINT)                            Default: 9      !   NINT =  9   !

     Vegetation state in unirrigated areas
     (IVEG)                            Default: 1      !   IVEG =  1    !
        IVEG=1 for active and unstressed vegetation
        IVEG=2 for active and stressed vegetation
        IVEG=3 for inactive vegetation

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 10 -- Wet Deposition Parameters
---------------

                      Scavenging Coefficient -- Units: (sec)**(-1)
```

```
       Pollutant      Liquid Precip.       Frozen Precip.
       ---------      --------------       --------------
!          SO2 =          3.0E-05,              0.0E00 !
!          SO4 =          1.0E-04,              3.0E-05 !
!         HNO3 =          6.0E-05,              0.0E00 !
!          NO3 =          1.0E-04,              3.0E-05 !
!       PM0063 =          1.0E-04,              3.0E-05 !
!       PM0100 =          1.0E-04,              3.0E-05 !
!       PM0125 =          1.0E-04,              3.0E-05 !
!       PM0250 =          1.0E-04,              3.0E-05 !
!       PM0600 =          1.0E-04,              3.0E-05 !
!       PM1000 =          1.0E-04,              3.0E-05 !

!END!

-------------------------------------------------------------------------------

INPUT GROUP: 11 -- Chemistry Parameters
---------------

     Ozone data input option (MOZ)     Default: 1            ! MOZ =  1   !
     (Used only if MCHEM = 1, 3, or 4)
        0 = use a monthly background ozone value
        1 = read hourly ozone concentrations from
            the OZONE.DAT data file

     Monthly ozone concentrations
     (Used only if MCHEM = 1, 3, or 4 and
      MOZ = 0 or MOZ = 1 and all hourly O3 data missing)
     (BCKO3) in ppb                    Default: 12*80.
     !  BCKO3 = 12*50. !

     Monthly ammonia concentrations
     (Used only if MCHEM = 1, or 3)
     (BCKNH3) in ppb                   Default: 12*10.
     !  BCKNH3 = 12*0.5 !

     Nighttime SO2 loss rate (RNITE1)
     in percent/hour                   Default: 0.2          ! RNITE1 = .2 !

     Nighttime NOx loss rate (RNITE2)
     in percent/hour                   Default: 2.0          ! RNITE2 = 2.0 !

     Nighttime HNO3 formation rate (RNITE3)
     in percent/hour                   Default: 2.0          ! RNITE3 = 2.0 !

     H2O2 data input option (MH2O2)    Default: 1            ! MH2O2 =  1   !
     (Used only if MAQCHEM = 1)
        0 = use a monthly background H2O2 value
        1 = read hourly H2O2 concentrations from
            the H2O2.DAT data file

     Monthly H2O2 concentrations
     (Used only if MQACHEM = 1 and
      MH2O2 = 0 or MH2O2 = 1 and all hourly H2O2 data missing)
     (BCKH2O2) in ppb                  Default: 12*1.
     !  BCKH2O2 = 12*1 !

 --- Data for SECONDARY ORGANIC AEROSOL (SOA) Option
     (used only if MCHEM = 4)

     The SOA module uses monthly values of:
          Fine particulate concentration in ug/m^3 (BCKPMF)
          Organic fraction of fine particulate     (OFRAC)
          VOC / NOX ratio (after reaction)         (VCNX)
     to characterize the air mass when computing
     the formation of SOA from VOC emissions.
```

```
     Typical values for several distinct air mass types are:

        Month    1    2    3    4    5    6    7    8    9    10   11   12
                Jan  Feb  Mar  Apr  May  Jun  Jul  Aug  Sep  Oct  Nov  Dec

     Clean Continental
        BCKPMF   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.   1.
        OFRAC  .15  .15  .20  .20  .20  .20  .20  .20  .20  .20  .20  .15
        VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

     Clean Marine (surface)
        BCKPMF  .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5   .5
        OFRAC  .25  .25  .30  .30  .30  .30  .30  .30  .30  .30  .30  .25
        VCNX    50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.  50.

     Urban - low biogenic (controls present)
        BCKPMF  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.  30.
        OFRAC  .20  .20  .25  .25  .25  .25  .25  .25  .20  .20  .20  .20
        VCNX     4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.   4.

     Urban - high biogenic (controls present)
        BCKPMF  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.  60.
        OFRAC  .25  .25  .30  .30  .30  .55  .55  .55  .35  .35  .35  .25
        VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

     Regional Plume
        BCKPMF  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.  20.
        OFRAC  .20  .20  .25  .35  .25  .40  .40  .40  .30  .30  .30  .20
        VCNX    15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.  15.

     Urban - no controls present
        BCKPMF 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100. 100.
        OFRAC  .30  .30  .35  .35  .35  .55  .55  .55  .35  .35  .35  .30
        VCNX     2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.   2.

     Default: Clean Continental
     !  BCKPMF = 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00, 1.00 !
     !  OFRAC  = 0.15, 0.15, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.20, 0.15 !
     !  VCNX   = 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00, 50.00,
50.00 !

!END!

--------------------------------------------------------------------------------

INPUT GROUP: 12 -- Misc. Dispersion and Computational Parameters
---------------

     Horizontal size of puff (m) beyond which
     time-dependent dispersion equations (Heffter)
     are used to determine sigma-y and
     sigma-z (SYTDEP)                           Default: 550.    ! SYTDEP = 5.5E02 !

     Switch for using Heffter equation for sigma z
     as above (0 = Not use Heffter; 1 = use Heffter
     (MHFTSZ)                                   Default: 0       ! MHFTSZ =  0   !

     Stability class used to determine plume
     growth rates for puffs above the boundary
     layer (JSUP)                               Default: 5       ! JSUP =  5   !

     Vertical dispersion constant for stable
     conditions (k1 in Eqn. 2.7-3)  (CONK1)     Default: 0.01    ! CONK1 = .01 !

     Vertical dispersion constant for neutral/
     unstable conditions (k2 in Eqn. 2.7-4)
     (CONK2)                                    Default: 0.1     ! CONK2 = .1 !
```

```
Factor for determining Transition-point from
Schulman-Scire to Huber-Snyder Building Downwash
scheme (SS used for Hs < Hb + TBD * HL)
(TBD)                                          Default: 0.5    ! TBD = .5 !
   TBD < 0   ==> always use Huber-Snyder
   TBD = 1.5 ==> always use Schulman-Scire
   TBD = 0.5 ==> ISC Transition-point

Range of land use categories for which
urban dispersion is assumed
(IURB1, IURB2)                                 Default: 10     ! IURB1 =  10  !
                                                        19     ! IURB2 =  19  !

Site characterization parameters for single-point Met data files ---------
(needed for METFM = 2,3,4)

   Land use category for modeling domain
   (ILANDUIN)                                  Default: 20     ! ILANDUIN =  20  !

   Roughness length (m) for modeling domain
   (Z0IN)                                      Default: 0.25   ! Z0IN = .25 !

   Leaf area index for modeling domain
   (XLAIIN)                                    Default: 3.0    ! XLAIIN = 3.0 !

   Elevation above sea level (m)
   (ELEVIN)                                    Default: 0.0    ! ELEVIN = .0 !

   Latitude (degrees) for met location
   (XLATIN)                                    Default: -999.  ! XLATIN = -999.0 !

   Longitude (degrees) for met location
   (XLONIN)                                    Default: -999.  ! XLONIN = -999.0 !

Specialized information for interpreting single-point Met data files -----

   Anemometer height (m) (Used only if METFM = 2,3)
   (ANEMHT)                                    Default: 10.    ! ANEMHT = 10.0 !

   Form of lateral turbulance data in PROFILE.DAT file
   (Used only if METFM = 4 or MTURBVW = 1 or 3)
   (ISIGMAV)                                   Default: 1      ! ISIGMAV =  1  !
       0 = read sigma-theta
       1 = read sigma-v

   Choice of mixing heights (Used only if METFM = 4)
   (IMIXCTDM)                                  Default: 0      ! IMIXCTDM =  0  !
       0 = read PREDICTED mixing heights
       1 = read OBSERVED mixing heights

Maximum length of a slug (met. grid units)
(XMXLEN)                                       Default: 1.0    ! XMXLEN = 1.0 !

Maximum travel distance of a puff/slug (in
grid units) during one sampling step
(XSAMLEN)                                      Default: 1.0    ! XSAMLEN = 1.0 !

Maximum Number of slugs/puffs release from
one source during one time step
(MXNEW)                                        Default: 99     ! MXNEW =  99   !

Maximum Number of sampling steps for
one puff/slug during one time step
(MXSAM)                                        Default: 99     ! MXSAM =  99   !

Number of iterations used when computing
the transport wind for a sampling step
that includes gradual rise (for CALMET
and PROFILE winds)
(NCOUNT)                                       Default: 2      ! NCOUNT =  2   !
```

```
Minimum sigma y for a new puff/slug (m)
(SYMIN)                                     Default: 1.0    ! SYMIN = 1.0   !

Minimum sigma z for a new puff/slug (m)
(SZMIN)                                     Default: 1.0    ! SZMIN = 1.0   !

Default minimum turbulence velocities sigma-v and sigma-w
for each stability class over land and over water (m/s)
(SVMIN(12) and SWMIN(12))

                ---------- LAND ----------         --------- WATER ----------
   Stab Class :  A    B    C    D    E    F        A    B    C    D    E    F
                ---  ---  ---  ---  ---  ---      ---  ---  ---  ---  ---  ---
Default SVMIN : .50, .50, .50, .50, .50, .50,     .37, .37, .37, .37, .37, .37
Default SWMIN : .20, .12, .08, .06, .03, .016,    .20, .12, .08, .06, .03, .016

      ! SVMIN = 0.500, 0.500, 0.500, 0.500, 0.500, 0.500, 0.370, 0.370, 0.370, 0.370,
0.370, 0.370!
      ! SWMIN = 0.200, 0.120, 0.080, 0.060, 0.030, 0.016, 0.200, 0.120, 0.080, 0.060,
0.030, 0.016!

Divergence criterion for dw/dz across puff
used to initiate adjustment for horizontal
convergence (1/s)
Partial adjustment starts at CDIV(1), and
full adjustment is reached at CDIV(2)
(CDIV(2))                                   Default: 0.0,0.0  ! CDIV = .0, .0 !

Minimum wind speed (m/s) allowed for
non-calm conditions. Also used as minimum
speed returned when using power-law
extrapolation toward surface
(WSCALM)                                    Default: 0.5    ! WSCALM = .5 !

Maximum mixing height (m)
(XMAXZI)                                    Default: 3000.  ! XMAXZI = 3000.0 !

Minimum mixing height (m)
(XMINZI)                                    Default: 50.    ! XMINZI = 50.0 !

Default wind speed classes --
5 upper bounds (m/s) are entered;
the 6th class has no upper limit
(WSCAT(5))                     Default    :
                               ISC RURAL : 1.54, 3.09, 5.14, 8.23, 10.8 (10.8+)

                    Wind Speed Class :  1     2     3     4     5
                                       ---   ---   ---   ---   ---
                           ! WSCAT = 1.54, 3.09, 5.14, 8.23, 10.80 !

Default wind speed profile power-law
exponents for stabilities 1-6
(PLX0(6))                      Default    : ISC RURAL values
                               ISC RURAL : .07, .07, .10, .15, .35, .55
                               ISC URBAN : .15, .15, .20, .25, .30, .30

                     Stability Class :  A     B     C     D     E     F
                                       ---   ---   ---   ---   ---   ---
                            ! PLX0 = 0.07, 0.07, 0.10, 0.15, 0.35, 0.55 !

Default potential temperature gradient
for stable classes E, F (degK/m)
(PTG0(2))                      Default: 0.020, 0.035
                                  ! PTG0 = 0.020,   0.035 !

Default plume path coefficients for
each stability class (used when option
for partial plume height terrain adjustment
is selected -- MCTADJ=3)
(PPC(6))                 Stability Class :  A     B     C     D     E     F
                            Default  PPC : .50,  .50,  .50,  .50,  .35,  .35
```

```
                                          ---   ---   ---   ---   ---   ---
                                ! PPC = 0.50, 0.50, 0.50, 0.50, 0.35, 0.35 !

Slug-to-puff transition criterion factor
equal to sigma-y/length of slug
(SL2PF)                              Default: 10.        ! SL2PF = 10.0 !

Puff-splitting control variables ------------------------

  VERTICAL SPLIT
  --------------

  Number of puffs that result every time a puff
  is split - nsplit=2 means that 1 puff splits
  into 2
  (NSPLIT)                           Default:   3        ! NSPLIT =  3  !

  Time(s) of a day when split puffs are eligible to
  be split once again; this is typically set once
  per day, around sunset before nocturnal shear develops.
  24 values: 0 is midnight (00:00) and 23 is 11 PM (23:00)
  0=do not re-split    1=eligible for re-split
  (IRESPLIT(24))                     Default:  Hour 17 = 1
  !  IRESPLIT = 0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,0,1,0,0,0,0,0,0 !

  Split is allowed only if last hour's mixing
  height (m) exceeds a minimum value
  (ZISPLIT)                          Default: 100.       ! ZISPLIT = 100.0 !

  Split is allowed only if ratio of last hour's
  mixing ht to the maximum mixing ht experienced
  by the puff is less than a maximum value (this
  postpones a split until a nocturnal layer develops)
  (ROLDMAX)                          Default: 0.25       ! ROLDMAX = 0.25 !


  HORIZONTAL SPLIT
  ----------------

  Number of puffs that result every time a puff
  is split - nsplith=5 means that 1 puff splits
  into 5
  (NSPLITH)                          Default:   5        ! NSPLITH =  5  !

  Minimum sigma-y (Grid Cells Units) of puff
  before it may be split
  (SYSPLITH)                         Default:  1.0       ! SYSPLITH = 1.0 !

  Minimum puff elongation rate (SYSPLITH/hr) due to
  wind shear, before it may be split
  (SHSPLITH)                         Default:  2.        ! SHSPLITH = 2.0 !

  Minimum concentration (g/m^3) of each
  species in puff before it may be split
  Enter array of NSPEC values; if a single value is
  entered, it will be used for ALL species
  (CNSPLITH)                         Default:  1.0E-07   ! CNSPLITH = 1.0E-07 !

Integration control variables ------------------------

  Fractional convergence criterion for numerical SLUG
  sampling integration
  (EPSSLUG)                          Default:   1.0e-04  ! EPSSLUG = 1.0E-04 !

  Fractional convergence criterion for numerical AREA
  source integration
  (EPSAREA)                          Default:   1.0e-06  ! EPSAREA = 1.0E-06 !

  Trajectory step-length (m) used for numerical rise
  integration
  (DSRISE)                           Default:   1.0      ! DSRISE = 1.0 !
```

```
!END!

--------------------------------------------------------------------------------

INPUT GROUPS: 13a, 13b, 13c, 13d -- Point source parameters
--------------------------------

---------------
Subgroup (13a)
---------------

     Number of point sources with
     parameters provided below      (NPT1)  No default  !  NPT1 =  6 !

     Units used for point source
     emissions below                (IPTU)  Default: 1  !  IPTU =   3  !
           1 =        g/s
           2 =       kg/hr
           3 =       lb/hr
           4 =     tons/yr
           5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =     Odour Unit * m**3/min
           7 =     metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (13d)        (NSPT1) Default: 0  !  NSPT1 = 6  !

     Number of point sources with
     variable emission parameters
     provided in external file      (NPT2)  No default  !  NPT2 =  0  !

     (If NPT2 > 0, these point
     source emissions are read from
     the file: PTEMARB.DAT)

!END!

---------------
Subgroup (13b)
---------------
                                         a
          POINT SOURCE: CONSTANT DATA
          -----------------------------
                                                                                    b           c
  Source       X           Y        Stack     Base      Stack     Exit  Exit      Bldg.  Emission
   No.     Coordinate  Coordinate  Height  Elevation  Diameter   Vel.  Temp.     Dwash   Rates
              (km)        (km)       (m)      (m)        (m)    (m/s) (deg. K)
  ------   ----------  ----------  ------   ------   --------  ----- --------  -----  --------

****************   EMISSION RATES ARE IN LB/HR
****************SO2****SO4***NOX****HNO3**NO3**PM10
1 !SRCNAM = EXAMPLE !
1 !X = 1000.000, -1000.000, 10.00, 1.0, 1.00, 10.00, 100.0, 0, 10.0, 1.00, 10.0, 0.0,
0.0,10.0,10.0,1.0, 0.0, 0.0, 0.0 ! !END!

--------

    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

     SRCNAM  is a 12-character name for a source
             (No default)
     X       is an array holding the source data listed by the column headings
             (No default)
     SIGYZI  is an array holding the initial sigma-y and sigma-z (m)
```

```
         (Default: 0.,0.)
FMFAC    is a vertical momentum flux factor (0. or 1.0) used to represent
         the effect of rain-caps or other physical configurations that
         reduce momentum rise associated with the actual exit velocity.
         (Default: 1.0  -- full momentum used)
```

[b]
0. = No building downwash modeled, 1. = downwash modeled
NOTE: must be entered as a REAL number (i.e., with decimal point)

[c]
An emission rate must be entered for every pollutant modeled.
Enter emission rate of zero for secondary pollutants that are
modeled, but not emitted. Units are specified by IPTU
(e.g. 1 for g/s).

Subgroup (13c)

BUILDING DIMENSION DATA FOR SOURCES SUBJECT TO DOWNWASH

Source No.	Effective building width and height (in meters) every 10 degrees[a]

---

[a]
Each pair of width and height values is treated as a separate input
subgroup and therefore must end with an input group terminator.

Subgroup (13d)

POINT SOURCE: VARIABLE EMISSIONS DATA[a]

Use this subgroup to describe temporal variations in the emission
rates given in 13b. Factors entered multiply the rates in 13b.
Skip sources here that have constant emissions. For more elaborate
variation in source parameters, use PTEMARB.DAT and NPT2 > 0.

```
IVARY determines the type of variation, and is source-specific:
(IVARY)                              Default: 0
     0 =       Constant
     1 =       Diurnal cycle (24 scaling factors: hours 1-24)
     2 =       Monthly cycle (12 scaling factors: months 1-12)
     3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                              where first group is DEC-JAN-FEB)
     4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                              first group is Stability Class A,
                              and the speed classes have upper
                              bounds (m/s) defined in Group 12
     5 =       Temperature   (12 scaling factors, where temperature
                              classes have upper bounds (C) of:
                              0, 5, 10, 15, 20, 25, 30, 35, 40,
                              45, 50, 50+)
```

---

[a]
Data for each species are treated as a separate input subgroup
and therefore must end with an input group terminator.

```
INPUT GROUPS: 14a, 14b, 14c, 14d -- Area source parameters
--------------------------------

---------------
Subgroup (14a)
---------------

     Number of polygon area sources with
     parameters specified below (NAR1)       No default  !  NAR1 =  0   !

     Units used for area source
     emissions below            (IARU)       Default: 1  !  IARU =   1  !
          1 =        g/m**2/s
          2 =       kg/m**2/hr
          3 =       lb/m**2/hr
          4 =     tons/m**2/yr
          5 =     Odour Unit * m/s  (vol. flux/m**2 of odour compound)
          6 =     Odour Unit * m/min
          7 =     metric tons/m**2/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (14d)        (NSAR1) Default: 0  !  NSAR1 =  0   !

     Number of buoyant polygon area sources
     with variable location and emission
     parameters (NAR2)                      No default  !  NAR2 =  0    !
     (If NAR2 > 0, ALL parameter data for
     these sources are read from the file: BAEMARB.DAT)

!END!

---------------
Subgroup (14b)
---------------
                                           a
          AREA SOURCE: CONSTANT DATA
          ----------------------------
                                                              b
Source           Effect.   Base      Initial    Emission
 No.             Height  Elevation   Sigma z     Rates
                  (m)       (m)        (m)
-------          ------  ------      --------   ---------


--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.
    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by IARU
     (e.g. 1 for g/m**2/s).

---------------
Subgroup (14c)
---------------

           COORDINATES (UTM-km) FOR EACH VERTEX(4) OF EACH POLYGON
           --------------------------------------------------------
Source                                                               a
 No.       Ordered list of X followed by list of Y, grouped by source
------     ------------------------------------------------------------


--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.
```

```
---------------
Subgroup (14d)
---------------
                                              a
      AREA SOURCE: VARIABLE EMISSIONS DATA
      ------------------------------------

   Use this subgroup to describe temporal variations in the emission
   rates given in 14b.  Factors entered multiply the rates in 14b.
   Skip sources here that have constant emissions.  For more elaborate
   variation in source parameters, use BAEMARB.DAT and NAR2 > 0.

   IVARY determines the type of variation, and is source-specific:
   (IVARY)                                Default: 0
         0 =       Constant
         1 =       Diurnal cycle (24 scaling factors: hours 1-24)
         2 =       Monthly cycle (12 scaling factors: months 1-12)
         3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                  where first group is DEC-JAN-FEB)
         4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                  first group is Stability Class A,
                                  and the speed classes have upper
                                  bounds (m/s) defined in Group 12
         5 =       Temperature   (12 scaling factors, where temperature
                                  classes have upper bounds (C) of:
                                  0, 5, 10, 15, 20, 25, 30, 35, 40,
                                  45, 50, 50+)


--------
  a
   Data for each species are treated as a separate input subgroup
   and therefore must end with an input group terminator.

-------------------------------------------------------------------------------

INPUT GROUPS: 15a, 15b, 15c -- Line source parameters
---------------------------

---------------
Subgroup (15a)
---------------

   Number of buoyant line sources
   with variable location and emission
   parameters (NLN2)                              No default  !  NLN2 =  0   !

   (If NLN2 > 0, ALL parameter data for
    these sources are read from the file: LNEMARB.DAT)

   Number of buoyant line sources (NLINES)        No default   ! NLINES =  0  !

   Units used for line source
   emissions below                (ILNU)          Default: 1  !  ILNU =   1  !
         1 =         g/s
         2 =        kg/hr
         3 =        lb/hr
         4 =      tons/yr
         5 =      Odour Unit * m**3/s  (vol. flux of odour compound)
         6 =      Odour Unit * m**3/min
         7 =      metric tons/yr

   Number of source-species
   combinations with variable
   emissions scaling factors
   provided below in (15c)        (NSLN1) Default: 0  !  NSLN1 =  0  !
```

```
Maximum number of segments used to model
each line (MXNSEG)                                     Default: 7    ! MXNSEG =  7  !

The following variables are required only if NLINES > 0.  They are
used in the buoyant line source plume rise calculations.

   Number of distances at which                        Default: 6    ! NLRISE =  6  !
   transitional rise is computed

   Average building length (XL)                        No default    ! XL = .0 !
                                                       (in meters)

   Average building height (HBL)                       No default    ! HBL = .0 !
                                                       (in meters)

   Average building width (WBL)                        No default    ! WBL = .0 !
                                                       (in meters)

   Average line source width (WML)                     No default    ! WML = .0 !
                                                       (in meters)

   Average separation between buildings (DXL)          No default    ! DXL = .0 !
                                                       (in meters)

   Average buoyancy parameter (FPRIMEL)                No default    ! FPRIMEL = .0 !
                                                       (in m**4/s**3)

!END!

---------------
Subgroup (15b)
---------------

          BUOYANT LINE SOURCE: CONSTANT DATA
          ----------------------------------
                                                                                        a
Source    Beg. X      Beg. Y      End. X     End. Y     Release     Base          Emission
 No.     Coordinate  Coordinate  Coordinate Coordinate  Height    Elevation        Rates
           (km)        (km)        (km)       (km)        (m)        (m)
------   ----------  ----------  ---------  ----------  -------   ---------      ---------

--------

    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

    b
     An emission rate must be entered for every pollutant modeled.
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by ILNTU
     (e.g. 1 for g/s).

---------------
Subgroup (15c)
---------------
                                                          a
          BUOYANT LINE SOURCE: VARIABLE EMISSIONS DATA
          --------------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 15b.  Factors entered multiply the rates in 15b.
     Skip sources here that have constant emissions.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                                 Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
```

```
          4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                   first group is Stability Class A,
                                   and the speed classes have upper
                                   bounds (m/s) defined in Group 12
          5 =       Temperature   (12 scaling factors, where temperature
                                   classes have upper bounds (C) of:
                                   0, 5, 10, 15, 20, 25, 30, 35, 40,
                                   45, 50, 50+)
--------
    a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


-------------------------------------------------------------------------------


INPUT GROUPS: 16a, 16b, 16c -- Volume source parameters
---------------------------

---------------
Subgroup (16a)
---------------

     Number of volume sources with
     parameters provided in 16b,c (NVL1)     No default  !  NVL1 =  0   !

     Units used for volume source
     emissions below in 16b       (IVLU)     Default: 1  !  IVLU =   1  !
           1 =        g/s
           2 =       kg/hr
           3 =       lb/hr
           4 =     tons/yr
           5 =     Odour Unit * m**3/s  (vol. flux of odour compound)
           6 =     Odour Unit * m**3/min
           7 =     metric tons/yr

     Number of source-species
     combinations with variable
     emissions scaling factors
     provided below in (16c)      (NSVL1)    Default: 0  !  NSVL1 =  0  !

     Number of volume sources with
     variable location and emission
     parameters                   (NVL2)     No default  !  NVL2 =   0   !

     (If NVL2 > 0, ALL parameter data for
      these sources are read from the VOLEMARB.DAT file(s) )

!END!

---------------
Subgroup (16b)
---------------
                                                 a
          VOLUME SOURCE: CONSTANT DATA
          ------------------------------
                                                                              b
        X UTM      Y UTM      Effect.    Base     Initial    Initial    Emission
     Coordinate Coordinate   Height   Elevation   Sigma y    Sigma z     Rates
        (km)       (km)        (m)       (m)        (m)        (m)
     ---------- ----------   ------    ------    --------   --------   --------


--------
    a
     Data for each source are treated as a separate input subgroup
     and therefore must end with an input group terminator.

    b
     An emission rate must be entered for every pollutant modeled.
```

```
     Enter emission rate of zero for secondary pollutants that are
     modeled, but not emitted.  Units are specified by IVLU
     (e.g. 1 for g/s).

---------------
Subgroup (16c)
---------------
                                                    a
          VOLUME SOURCE: VARIABLE EMISSIONS DATA
          ----------------------------------------

     Use this subgroup to describe temporal variations in the emission
     rates given in 16b.  Factors entered multiply the rates in 16b.
     Skip sources here that have constant emissions.  For more elaborate
     variation in source parameters, use VOLEMARB.DAT and NVL2 > 0.

     IVARY determines the type of variation, and is source-specific:
     (IVARY)                                Default: 0
           0 =       Constant
           1 =       Diurnal cycle (24 scaling factors: hours 1-24)
           2 =       Monthly cycle (12 scaling factors: months 1-12)
           3 =       Hour & Season (4 groups of 24 hourly scaling factors,
                                    where first group is DEC-JAN-FEB)
           4 =       Speed & Stab. (6 groups of 6 scaling factors, where
                                    first group is Stability Class A,
                                    and the speed classes have upper
                                    bounds (m/s) defined in Group 12
           5 =       Temperature   (12 scaling factors, where temperature
                                    classes have upper bounds (C) of:
                                    0, 5, 10, 15, 20, 25, 30, 35, 40,
                                    45, 50, 50+)


--------
     a
     Data for each species are treated as a separate input subgroup
     and therefore must end with an input group terminator.


--------------------------------------------------------------------------------

INPUT GROUPS: 17a & 17b -- Non-gridded (discrete) receptor information
----------------------

---------------
Subgroup (17a)
---------------

     Number of non-gridded receptors (NREC)  No default  !  NREC = 364 !

!END!

---------------
Subgroup (17b)
---------------
                                                  a
           NON-GRIDDED (DISCRETE) RECEPTOR DATA
           ------------------------------------

                    X            Y          Ground        Height    b
Receptor        Coordinate   Coordinate   Elevation   Above Ground
  No.              (km)         (km)         (m)           (m)
--------        ----------   ----------   ---------   ------------
RECEPTORS OBTAINED FROM THE NPS/FWS EXTRACTION PROGRAM
ALL RECEPTORS ARE LCC (KM)

1 EXAPLE RECEPTOR
     1 ! X =     1000.000,   -1000.000,         0,         0.000!   !END!

     a
```

Data for each receptor are treated as a separate input subgroup and therefore must end with an input group terminator.

b
Receptor height above ground is optional. If no value is entered, the receptor is placed on the ground.

APPENDIX B

VENDOR LETTERS

The Babcock & Wilcox Company
a McDermott company
2302 Parklake Drive Suite 300 • Atlanta, GA 30345 • (770)-939-6292 • www.babcock.com

VIA EMAIL

March 5, 2007

Smurfit-Stone Corporation
Fernandina Beach, FL

Attention: Ms. Rachel Davis, PMP
Environmental Engineer

Reference: Addition of low-S light oil capability
No. 5 Power Boiler, S-10222
Proposal Reference, P-7991

Dear Rachel:

In follow up to your request, this is to advise a material only budgetary estimate to add light oil capabilities to each of the current six (6) oil burners on the mill's No. 5 Power Boiler. The material scope of this estimate includes:

- six (6) new oil guns with atomizer sprayer plates sized for the light oil to be specified
- six (6) new light oil valve racks
- local control cabinets with PLCs and BMS logic to tie into existing DCS system
- installation and start up Technical Assistance

Not included is all piping, electrical, installation, or any other material not included in our scope of supply. This would the mill's responsibility to estimate based on previous similar self-performed projects or from a contractor who typically performs such projects.

Our material supply only estimate for your planning purposes is $175,000.

Following your review of this information, let me know should you have any questions.

Sincerely,

THE BABCOCK & WILCOX COMPANY

Rich Mattie

R. J. Mattie, District Sales Manager

cc: Tom Keenan—SSCC, Fernandina
Byron Pikula—SSCC, Fernanina
Dave Kittel---B&W, St. Marys
Bentley Sherlock—B&W, Atlanta

Fuel Storage Tank

Buff, Dave

From: Davis, Rachel G. [RGDAVIS@SMURFIT.COM]
Sent: Thursday, May 31, 2007 1:00 PM
To: Buff, Dave
Subject: FW: BART fuel tank estimate

Final Tank Estimate below - please use in cost estimates for 5PB

From: Keenan, Tom
Sent: Thursday, May 31, 2007 12:52 PM
To: Davis, Rachel G.
Cc: Crews, Bill
Subject: BART fuel tank estimate

The proposed project scope of work includes the following major aspects:

- New Barge Unloading Station
- New Piping to the new fuel oil storage tank
- New Tanker Truck Unloading Station
- New No. 6 Fuel Oil Storage Tank
- Modifications to the Existing Spill Containment Area (Now 3 Tanks)
- Existing Pump House Expansion
- New Piping from the New Storage Tank to an Existing Day Tank
- Modifications to the Existing Fuel Oil Day Tanks Piping
- New Steam Trace Piping
- New Structural Requirements (Tank foundation)
- Electrical and Process Control Facilities

An SSCC Phase 2 Cost Estimate (a one-page Summary Spreadsheet) and the basis of this estimate is included within Section 4.0. Based upon the preliminary proposed scope of work, as described herein, the target estimate accuracy is +/- 25 percent.

The major scope groupings contributing to this estimated cost are:
Field-Erected Tank, Piling and Concrete Foundations $ 807,000 (No. 6 oil)
Process Piping Requirements $ 767,450
Spill Containment Structures $ 113,000
Electrical and Instrumentation $ 166,206
Other Direct Costs $ 189,740
Subtotal $ **2,043,396**
Indirect costs, By SSCC, Etc. $ 640,000
Total $ **2,683,396**

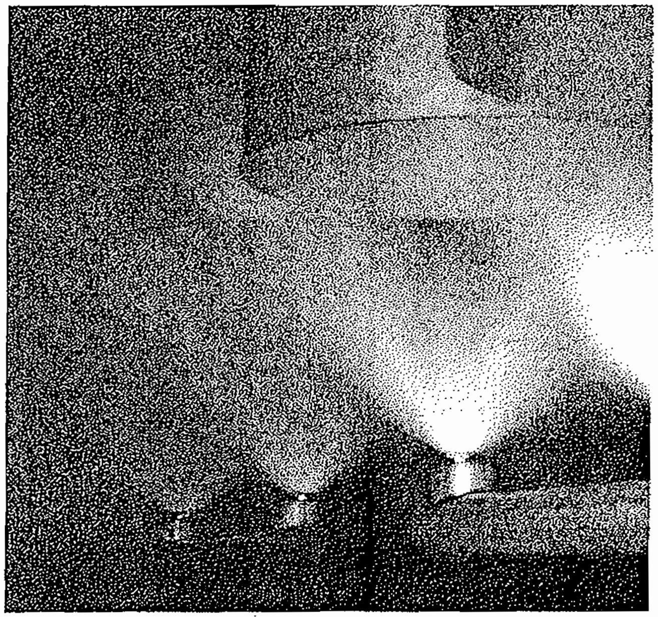
Option 2 (No. 2 Fuel Oil – Diesel)
For the proposed BACT retrofit of the existing No. 5 Power Boiler, the Base Case Scope of Work & Cost Estimate has been developed using the SSCC direction to replace the existing supplemental oil (No. 6 fuel oil with an approximate 2.5% sulfur content) with low sulfur

(approx. 1%) No. 6 Fuel Oil as the new "alternative fuel". However, with the Base Case cost estimate being higher than expected during project conception, Mustang was asked to revisit the cost estimate to use No. 2 Fuel Oil (Diesel) as the new "alternative fuel". The Option 2 impacts to the proposed project scope and estimate are as follows: The viscosity and flow characteristics of the diesel oil will permit the oil to be stored, pumped, and piped without the requirement for steam tracing. This scope reduction results in the following project savings:

Delete steam supply piping $ 48,061
Delete steam trace piping, materials & labor $135,483 No. 2 O.I
Delete the associated piping insulation $196,869
Delete the heater unit (HX at the tank's suction nozzle) $ 15487
(Equipment and installation)
These combined savings result in a total cost reduction of ... **$ 396,260.**
Applying these combined savings to the Base Case total installed cost (TIC) results in the following Option 2 impacts:
Base Case TIC Estimated Cost $ 2,683,396
Option 2 Combined Savings ($ 396,260)
Option 2 TIC Estimated Cost $ 2,287,136

Tom Keenan
Engineering Manager
Smurfit Stone
Fernandina Beach Mill
904-277-7732

ANDRITZ



Proposal
For

EnviroCare International

Power Boiler Scrubber Alternatives

Smurfit Stone Container
Fernandina Beach, FL

March 15, 2007

Budget Proposal Q70644

ANDRITZ

<u>ANDRITZ AND ENVIROCARE INTERNATIONAL</u>
PARTNERS IN AIR POLLUTION CONTROL SERVICES
TO THE PULP & PAPER INDUSTRY

March 15, 2007

Smurfit Stone Container Corp,
North 8th Street
Fernandina Beach FL 32034
Attention: Ms. Rachel Davis
Tel.: 904-277-7718
E-Mail: rg.davis@smurfit.com

Subject: **Andritz/EnviroCare Power Boiler Scrubber**
Budgetary Proposal No. Q70644 Rev. 0

Dear Ms. Davis,

Following your inquiry and discussions with Magnus Rundqwist, we have assembled this budgetary proposal for a SO2 scrubber system for your Fernandina Beach mill power boiler.

We have proceeded under the assumption that the ESP will remain in service and that SO2 is the main target emission for the addition of a scrubber. With no or little "sunk cost", the scrubber can be upgraded at a later date incorporating additional stages to further accommodate any future emission requirements. We have also assumed that we will not require a new stack or ID fan. All this will be verified as we further define the scope of supply.

As you are probably aware, we are in the construction phase of a large PM/SO2 scrubber system at the SSCC West Point facility. The startup of this system is scheduled for this autumn. We would like to arrange a mill visit to meet with you and discuss our experience with Power Boiler Scrubbers and your options. The mill visit would also give us an opportunity to see the site which would make it possible to improve this budgetary quote. We are available at your convenience.

Please contact me (770-640-2539) or Magnus Rundqwist (678-714-8065) if you need more information or have any questions.

Regards,

Kimmo Peltonen, Andritz Inc.
cc: Magnus Rundqwist, EnviroCare International

INTRODUCTION

The design proposed is a customized Andritz/EnviroCare scrubber comprised of a SpiralMist™ Quench section followed by Dual Orifice Impingement Tray Removal stage and High Efficient Mist Eliminator stage. The stages/equipment is described in more detail under scope of supply.

The advantages of making the following upgrade include:

-High SO2 removal efficiency
-Use of caustic is minimized

SYSTEM DESCRIPTION - OVERVIEW

EnviroCare research into conventional scrubber designs has led to the development of the *MicroMist™ wet* scrubber technology. This unique approach to wet scrubbing utilizes a multi-tube venturi stage where each venturi tube is preceded by a *MicroMist™* atomizer. *MicroMist™* scrubbing is characterized by extreme relative motion between the injected micro-fine scrubbing droplets and the sub-micron particles, resulting in exceptionally high capture efficiencies at all gas flow rates. EnviroCare's *MicroMist™* wet scrubbers incorporate the latest technological advances in wet scrubbing and atomization technologies and are protected under U.S. Patent Nos. 5,279,646, 5,512,085, 5,759,233, 6,383,260 and 6,719,829 (other U.S. and foreign patents pending). Each component is designed for durability and is integrated into a state-of-the-art air pollution control system.

Outstanding features of the EnviroCare MicroMist™ venturi system:

- Maximum achievable capture efficiency.
- Best available turndown ratio.
- Low-pressure drop for improved operating economy.
- Pre-piped, pre-wired skid mounted scrubber liquor Booster Pump for lower installation and commissioning costs.
- Highest quality, low maintenance components.

THE SPIRALMIST™ DESIGN FOR SMURFIT STONE CONTAINER, FERNANDINA BEACH, FLORIDA

Separator/Scrubber

A complete Vessel will be supplied with access man-ways where necessary. The scrubber will be ~20ft in diameter and about 40ft tall. The shell will be made of 304L steel and key internals will be made of 316L or higher grade. A special inlet flange will be designed to minimize the risk for build-ups in the dry-wet interface

The scrubber can be designed to accommodate a top mounted or a free standing stack (stack by others).

Andritz will provide load-range diagrams but civil design and foundation design supply by the Mill.

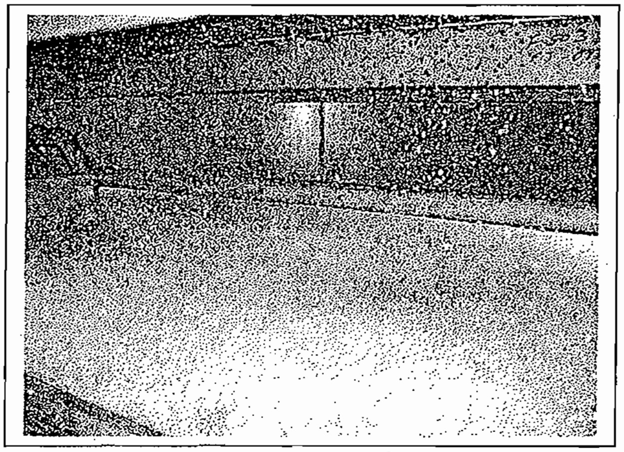
Stage 1 -Quench stage

The design would include a SpiralMist™ quench and SO2 removal section in the lower part of the separator. Water is pumped to the SpiralMist™ nozzles from the circulation tank located in the base. In addition, through the quenching, generation of fine droplets and creation of relative droplet/particle motion, results in saturation of the gas and removal of the vast majority of coarse particles from the flue gas stream.

Make-up water is provided from overflow from the tray and mist eliminator.
The systems blow down is taken from the bottom of the tank. Note that no or low pressure drop is taken across the quench stage.

Stage 2 – Dual-Orifice Impingement Tray

A single Dual-Orifice™ impingement tray is located just downstream of the quench section. The impingement trays further reduce the particulate loading in the gas stream. The impingement tray is, in turn, followed by a high efficiency mist eliminator pack designed to collect all droplet carryover from the MicroMist scrubber.



The flue gases passing through the D-O Tray followed by the Mist Eliminator

Stage 3 – Mist Eliminator

The MicroMist™ venturi stage is followed by a high-efficiency mist eliminator section. New lances with specially design to eliminate/minimize break-through (wet stack) are supplied. Make-up water branch off from the tray water supply will spray the mist eliminator intermittently to wash out any dirty particles. The mist eliminator areas sprayed will be divided in 2 circuits.

This back wash spray water is also part of the scrubber systems make-up water source.

Stage 6 – Caustic Injection – Neutralization

The tray stage captures any residual SO_2 and some of the H_2SO_4. Therefore the drain of the tray stage will be acidic unless caustic is added to keep the pH near neutral. The drain liquid pH is measured to immediately gauge the caustic requirement and to keep the pH probe in the 'cleanest' near acidic/non-scaling environment.

The caustic is added through a 'quill' in a flowing pipe (for mixing) after measurement of the pH but before the going to the recycle tank (this portion goes directly to the suction of the recirculation pumps). This prevents scale deposits by preventing the high concentration caustic from contacting sensitive surfaces like pump impellers or pH probes before it is thoroughly mixed and diluted.

The overflow solution tray stage is directed to the Quench pumps. It mixes with recycled liquid from the lower recycle tank/loop and is injected into the hot inlet gases through the quench nozzles. The residual caustic present is consumed in the neutralization of absorbed SO_2 gas and some condensed H_2SO_4 present on the larger flyash particles (>2 micron Ø) captured by the quencher stage. Any alkalinity in the captured flyash particles also neutralizes the captured SO_2 and H_2SO_4 in the recycled scrubbing liquids. The drain pH of the lower/primary recycle tank BD from the quencher recycle loop is dependent on the equilibrium of inlet SO_2/SO_3 and the alkalinity in coal flyash but it is usually near neutral or slightly acidic (pH=6-7).

This strategy uses the lowest possible pH for the recirculation loops to achieve the required outlet SO_2 emissions. Therefore the use of caustic is minimized by maximizing the effectiveness of the flyash alkalinity to neutralize the captured SO_2/SO_3 at low pH.

DESIGN NOTE: **MAKE-UP WATER AND BLOW DOWN RATE:**

The future SOx load into the scrubber is going to govern the Make-up water requirement rate. The make-up rate should at all time result in a blow-down rate containing <6% dissolved solids, plus making up for evaporated water.
(S.S. Suspended Solids (PM/Dust), D.S. Dissolved Solids ($CaSO_4$,Na_2SO_4 etc))

MAKE-UP WATER QUALITY (Typical)

Below are the typical quality parameters required for the make-up water system of the Andritz/EnviroCare scrubber. If any numbers exceed the listed, further review and consideration in the design would be required. Anytime we add caustic we need to specify maximum hardness of the makeup water to prevent scaling issues from elevated pH and/or heating.

MAKE-UP WATER REQUIREMENT

		Total (Mg/L)
Chloride ion	Cl	< 20
Magnesium+Calcium ions	Mg+Ca	< 28
pH @ 25°C		6.0 - 8.0
Suspended Solids		< 100
Dissolved Solids		< 500
Hardness (as CaCO3)		< 80
Maximum Solid Size[1]		< 1/32"
Organics (HPC[2]/ml)		< 100

[1] EnviroCare M.E. lances for chevron M.E.s are usually equipped with 1/16" inch Ø perf. s/s strainer baskets.
[1] EnviroCare M.E. lances for mesh M.E.s are usually equipped with 1/32" inch Ø perf. s/s strainer baskets.
[2] HPC = Heterotrophic Plate Count

GENERAL PLANT DATA

Plant Elevation: 100 feet M.S.L.
Power Requirement: 480/3/60 Hz volts, 110/1/60 Hz control voltage
Plant Water Pressure: 55 PSIG, 3.8 Bar (at grade)

APPROXIMATE DESIGN OPERATING CONDITIONS — INLET

	Operating	Max. Design
Volume Wet (Approx.):	284,000 ACFM (@-1"W.C.) 163,050 SCFM (w)	
Temperature:	~462°F	600°F
Gas Analysis (% vol.):	(TBD)	
N2:	56%	
H2O:	30.0%	
O2:	5.0%	
CO2:	8.87%	
SO2:	0.13%	

SYSTEM REQUIREMENTS:	Operating	Max. Design
Water Requirement	250 gpm	See Note on page 6
OUTLET GAS CONDITIONS:		
PM:	TBD	
H2SO4:	TBD	
SO2:	>98% removal	

PERFORMANCE GUARANTEE (TBD)

Outlet gas condition		
PM:	TBD	Using EPA Method 5B
H2SO4:	TBD	
SO2:	TBD >98% removal	

SCOPE OF SUPPLY & RESPONSIBILITY MATRIX -PRELIMINARY

Andritz/EnviroCare proposes to furnish equipment and services in accordance with the description outlined in the matrix below. For more detail refer to attached color coded P&ID for more complete information. For firm price proposal a complete more detailed matrix will be generated.

A/E: Andritz/EnviroCare
BC: By Customer – Smurfit

Item No	*SCOPE OF SUPPLY*	Eng. Design	Equip. Supply	Install by	Description/Comments
1.0	***SEPARATOR***	A/E	A/E		20'6"diam. ~40 ft effective height Complete SS304L Shell, all internals SS316 No shell thickness < 3/16" Shell will be shipped in as few pieces to accommodate fast installation. Weight ~35,000lbs
1.0	***STAGE 1 QUENCH SYSTEM***				
	(1) Quench Spiral Mist Spray Grid with internal header	A/E	A/E		SS316, Complete with EnviroCare's proprietary nozzles, PI's, Y-strainers, ball valves and hardware
	(2) Quench Lance Header	A/E	A/E		One pipe/connecting point to Quench
	(1) Recirculation tank	A/E	A/E		Internal, base of scrubber vessel ~6,000 gallons
	(2) Quench Pump Skid & Motors -Complete System (see P&ID)	A/E	A/E		Sulzer or Goulds 2 x 2000 gpm @ 60 psig/1.15SF One operating, One stand-by ~2x150 Hp/1800rpm
	STAGE 2 DUAL ORIFICE STAGE				
	(1)Dual Orifice Tray EnviroCare's proprietary Dual Orifice Impingement tray section	A/E	A/E	*In vessel*	Surface ~350 sq.ft Material: SS316,
	TRAY up-wash spray grid	A/E	A/E		SS316, Complete with EnviroCare's proprietary nozzles, PI's, y-strainers, valves

Item No	Scope of Supply	Eng. Design	Equip. Supply	Install By	Description/Comments
	STAGE 3 ***MIST ELIMINATOR***				
	Mist Eliminator Complete	A/E	A/E		Surface ~350 sq.ft SS316 Chevron style
	Mist Eliminator/Tray supply spray grid	A/E	A/E		SS316, Complete with EnviroCare's proprietary nozzles, solenoids, PI's, y-strainers, ball valves etc.
	Mist Eliminator back wash spray grid	A/E	A/E		SS316, Complete with EnviroCare's proprietary nozzles, solenoids, PI's, y-strainers, ball valves etc.
	(1) Spool piece with PRV & y-strainer	A/E	A/E		
	STAGE 4 ***CAUSTIC INJECTION***				
	SO2 & SAM control/ Caustic Injection System -Caustic "buffer" tank -Dosage/control system -Dual pH probe/transmitters	A/E	A/E		By A/E to be optimized with existing mill caustic system
	DUCT & STACK				
	Inlet duct (ESP to Scrubber)	BC	BC		
	Stack (top mount or free standing)	BC	BC		
	PIPING	A/E	A		**A/E will provide detailed P&ID's**
	Drains	BC	BC		
	Heat Tracing	BC	BC		
	Insulation	BC	BC		
	FOUNDATION AND ANCHORING	BC	BC		**A/E will provide loads Foundation design, grouting and anchoring by others**
	ELECTRICAL	A/E	BC		**A/E will provide Electrical drawings and provide local JB's Termination & wiring by others**
	Motorstarters/MCC	BC	BC		
	Wiring	BC	BC		
	DCS	BC	BC		

Item No	Scope of Supply	Eng. Design	Equip. Supply	Install by	Description/Comments
9.0	**DEVICES/ INSTRUMENTATION**				Other than local gauges SEE P&ID
	FIT Quench Flow	A/E	A/E		Rosemount,
	FE Tray Flow	A/E	A/E		Local FE
	DPIT Scrubber Overall	A/E	A/E		Re-pipe to measure inlet to outlet
	LIT – Recirc tank	A/E	A/E		Rosemount or done by limit switches
	CV – Demister Spray	A/E	A/E		In valve rack Solenoid valves Open/Close for timed intermittent spray
	(2) AIT – pH Probe	A/E	A/E		Includes "well"
10.0	**ACCESS & PLATFORM**	A/E	BC		A/E will submit recommendations
11.0	**DEMOLITION**				
	Demolition of existing equipment	N/A			If applicable

Item No	Scope of Supply	Eng. Design	Equip. Supply	Install by	Description/Comments
11.0	**DOCUMENTATION /ENGINEERING**	A/E			
	Drawings	A/E	**Prior to Installation** Andritz/EnviroCare will provide an execution plan along with General arrangement and engineering drawings Note: All Drawings will be drawin in VectorWorks but saved and transmitted as .dxf files **Installation** Andritz/EnviroCare will provide engineering and drawings necessary to implement Andritz/EnviroCare equipment within plant and incorporate with customer supplied and existing equipment. It will also include all controls and monitoring logic required to program and operate the new scrubber system through existing mill DCS.			
	Documents Supplied -Equipment List -Process & Instrument Diagrams (P&ID) -Flow diagram (included on P&ID) -Utility List -Control Description	A/E	A/E	N/A	The control description will be detailed for programming/screen work by Smurfit/3rd or party
	On-site engineering -Kick off meeting -Engineering Documents Review Meeting (one meeting) -Progress meetings				
	O&M manuals	A/E	A/E	N/A	2 hard copies + CD -rom
12.0	**Start-up and Commissioning**				Andritz/EnviroCare will have a representative on site for Start-up and training of Smurfit personnel 5 days on site are included.

SCHEDULE - Typical

Firm Proposal	**3 Weeks on Request** "after complete scope definition" & site visit
ENGINEERING and DESIGN **Submittal of Drawings for Approval**	**8-10 Weeks** ARO, including drawings of existing equipment, mill specifications, and field verification
FABRICATION	**6-15 Weeks** Will start 1-2 weeks after approved drawings (Note: We assume 2 weeks for approval of drawing submittals)
SHIPMENT OF EQUIPMENT	**2-4 Weeks** Prior to installation
SITE PREPARATION	**4 weeks**
INSTALLATION	**14 days**
COMMISSIONING	**~5 days**
Project Execution From Date of Order to Compliance	**~26-28 Weeks**

PRICING SCHEDULE

BASE PRICE

The BUDGET PRICE for the proposed equipment as described:

EQUIPMENT PRICE, FOB Job Site: **$1,235,000**

ERECTION PRICE *ROUGH BUDGET*,installation of equipment and Piping...**$1,500,000**

Note 1: this erection estimate is based on a similar (except completely EPC) project currently being constructed in Virginia. The erection price above consists only of erection of supplied equipment and piping. Electrical, structural, civil work and foundations are by others. No stack is included in this price. Your site requirements, etc will have a significant impact on a complete system EPC price estimate so we will be able to submit a much better estimate once we decide on a potential scope and visit the mill with a contractor.
Note: A rough guess for the EPC price for a complete system including new stainless stack, significant ductwork, structural steel, electrical, etc is in the range of $4 million to $5 million.

Note 2:
Price is based on today's stainless steel price (There is approx. 30,000 lbs of 304L and 316 steel in this quotation). The contract price will be adjusted for current stainless steel pricing at the time of order.

TERMS OF PAYMENT

PAYMENT SCHEDULE

% of Order Value	Description
10%	On Order
20%	Approval Drawings
60%	Delivery of equipment
10%	Start Up

ANDRITZ 2007 SERVICE RATES

The 2007 rate for Field Service Representatives is as follows:

Daily Rate:	$1,300.00 USD - / 8 Hour Day
Overtime:	One and one half (1½) times daily hourly rate over eight (8) hour day
Saturday:	One and one half (1½) times the daily rate.
Sunday & Holidays:	Two (2) times the daily rate.
Travel Time:	Considered working time. Straight time rates.
Expenses:	Meals are billed at cost or $40 per day. Other expenses are billed at cost plus a 10% handling fee.
Trip Report:	Trip reports are at $ 85 hr.
Air Travel:	Coach class wherever possible in the USA and Canada. For international flights over 5 hours, business class air-fare will apply.
Meetings:	Standard Rates for meetings and safety orientation.
Standby:	Standby rate will be $85.00 per hour, up to 8 hours a day, Saturdays & Sundays included. This rate is valid for standby time away from the jobsite (hotel, etc.).

Limit of Liability:

In no event shall ANDRITZ be liable for special, incidental or consequential damages including, but not limited to loss of use, profits or revenue, losses by reason of plant shutdown or increased expenses of plant operation. The liability of ANDRITZ for other damages shall not exceed the value of the service purchase order.

General Terms and Conditions
for Projects Involving Equipment and Field Labor

THE SALE OF ANY GOODS AND SERVICES ordered by the Customer (the "Work") is expressly conditioned upon the terms and conditions contained herein. Any additional or different terms and conditions set forth in the Customer's purchase order or similar communication are objected to and will not be binding upon ANDRITZ INC., (hereinafter "Andritz ") unless specifically assented to in writing by Andritz's authorized representative.

1: Payment

All payments are due 30 days after receipt of invoice. Late payment will be assessed a penalty of prime rate plus 2% per annum.

2. Sales and Similar Taxes

In addition to the price specified herein, the Customer shall pay, or reimburse Andritz for, the gross amount of any present or future sales, use, excise, value-added or other similar tax applicable to the price, sale or furnishing of any services or goods hereunder, or to their use by Andritz or the Customer, or the Customer shall provide Andritz with evidence of exemption acceptable to the taxing authorities.

3. Schedule

Andritz shall provide an estimated time schedule for Work, but is not responsible for late completion unless otherwise agreed in writing, and then only to the extent the schedule is exceeded beyond any allowed or excusable delay period.

4. Changes, Deletions and Extra Work

The Customer, without invalidating the contract, may make changes by altering, adding to or deducting from the general scope of the work by written change order, the contract price being adjusted accordingly by mutual agreement. All such work shall be executed under the conditions of the contract except that any claim for extension of time caused thereby shall be adjusted at the time of ordering such change. If the change impairs Andritz's ability to satisfy any of its obligations to Customer, the change order will include appropriate modifications to the Contract. If after the date of this Contract, new or revised governmental requirements should require a change in the goods or services, the change will be subject to this paragraph.

5. Delivery and Title Passage

Delivery of goods will be made F.O.B. Customer's job site. Title to each piece of equipment shall pass to the Customer when such equipment is delivered. It is expressly understood and agreed, however, that the passage of title shall not be construed by Andritz as a release from Andritz's responsibility to fully carry out its obligations under the contract.

6. Warranty

(a) Andritz warrants to Customer that the goods and services will be delivered free from defects in material and workmanship. This warranty shall commence upon delivery of the goods and services and shall expire on the earlier to occur of 12 months from initial operation of the goods and services and 18 months from delivery thereof (the "Warranty Period"). If during the Warranty Period the Customer discovers a defect in material or workmanship and gives Andritz written notice thereof within 10 days of such discovery, Andritz will, at its option, either deliver to Customer, F.O.B., mill site, a replacement part or repair the defect in place. Andritz will have no warranty obligations under this paragraph (a): (i) if Customer fails to ensure that the equipment is operated and maintained in accordance with generally approved industry practice and with Andritz's specific written instructions; (ii) if the equipment is used in connection with any mixture or substance or operating condition other than that for which they were designed; (iii) if Customer fails to give Andritz such written 10 day notice; (iv) if the equipment is repaired by someone other than Andritz or has been intentionally or accidentally damaged, (v) for corrosion, erosion, ordinary wear and tear or in respect of any parts which by their nature are exposed to severe wear and tear or are considered expendable; or (vi) for any defects arising out of materials provided, or designs stipulated in whole or in part, by Customer;

(b) Any replacement parts furnished pursuant to this warranty are warranted against defects in material and workmanship for one period of twelve (12) months from the date of installation, but such replacement does not extend Andritz's warranty on the rest of the parts and equipment.

(c) **THE EXPRESS WARRANTIES ANDRITZ MAKES IN THIS PARAGRAPH _ ARE THE ONLY WARRANTIES IT WILL MAKE. THERE ARE NO OTHER WARRANTIES, WHETHER STATUTORY, ORAL, EXPRESS OR IMPLIED.**

IN PARTICULAR, THERE ARE NO IMPLIED WARRANTIES OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

(d) The repair or replace remedy provided in above shall be Customer's exclusive remedy for breach of warranty and Supplier shall not be liable for any loss of use or any production losses whatsoever.

7. Limitation of Liability

Notwithstanding any other provision in this Contract, the following limitations of liability shall apply:

(a) In no event, whether as a result of contract, tort (including negligence), strict liability or otherwise, shall Andritz, its employees, subcontractors or suppliers be liable for special, incidental, indirect, consequential, or punitive damages of any nature including, but not limited to, loss of use, profits or revenue, loss by reasons of plant shutdowns, the inability to operate any facility at full capacity or increased expense of plant operations.

(b) The aggregate liability of Andritz to Customer arising out of the manufacture, sale, delivery, use or resale of the equipment under this Contract, whether based on warranty, contract, tort (including negligence), strict liability or otherwise, shall not exceed fifty percent (50%) of the contract price.

(c) All liability of Andritz to Customer whatsoever, arising out of this Contract, shall terminate at the expiration of the warranty period. The remedies provided in this Contract are the Customer's exclusive remedies.

(d) In no event shall Andritz be liable for any loss or damage whatsoever arising from its failure to discover or repair latent defects or defects inherent in the design of goods serviced (unless such discovery or repair is normally discoverable by tests expressly specified in the scope of work under this contract) or caused by the use of goods by the Customer against the advice of Andritz. If Andritz furnishes the Customer with advice or assistance concerning any products or systems which is not required pursuant to the contract, the furnishing of such advice or assistance will not subject Andritz to any liability whether in contract, indemnity, warranty, tort (including negligence), strict liability or otherwise.

8. Indemnification

Andritz agrees to defend and indemnify Customer from and against any third-party claim for personal injury or physical property damage ("Loss") arising in connection with the goods provided by Andritz hereunder or the work performed by Andritz hereunder, but only to the extent such Loss has been caused by the negligence or willful misconduct ("Fault") of Andritz. Where such Loss results from the Fault of both Andritz and Customer or a third party, then Andritz's defense and indemnity obligation shall be limited to the proportion of the Loss that Andritz's Fault bears to the total Loss.

9. Insurance

Andritz shall provide bodily injury liability insurance for claims arising out of the Work with limits of $2,000,000 per occurrence and in the aggregate for injury or death, and property damage liability insurance for $2,000,000 per occurrence and in the aggregate. Andritz shall also provide workers' compensation insurance as required by the laws of the State or Province where the Work will be performed, and owned and non-owned auto liability insurance.

10. Force Majeure

For the purpose of this Contract "Force Majeure" means all unforeseeable events, beyond the reasonable control of either party that affect the performance of this Contract, including, without limitation, acts of God; acts of governmental authority, laws or regulations; strikes, lockout or other industrial disturbances; delays in transportation or material lost in transit; unavailability of materials from suppliers; rejection of custom produced materials, such as main forgings and castings; inability to obtain labor or material from usual sources; serious accidents involving the work of suppliers or sub-suppliers; thefts; explosions; lack of available shipping by land, sea or air; lack of dock lighterage or loading or unloading facilities; acts of public enemies; declared or undeclared acts of war; acts of terrorism; insurrections; riots; lightning; earthquakes; fires; storms; sever weather; floods; sabotage; or any other event or cause not within either party's reasonable control. In the event that by reason of Force Majeure Andritz or the Customer is unable to carry out its obligations under this Contract, other than the obligation to make payments due hereunder, and the party affected promptly notifies the other of such delay, then such obligations that are affected by Force Majeure will be suspended or reduced for the period of Force Majeure and for such additional time as is required to resume normal operations, and the delivery schedule will be adjusted to account for the delay. If the period of suspension or reduction of operations will extend for more than four (4) consecutive months or periods of suspension or reduction total more than six (6) months in any twelve (12) month period, then either the Customer or Andritz may terminate this agreement.

11. Termination

An order once placed by Customer and accepted by Andritz may not be canceled except with Andritz's consent and the payment of a cancellation charge by the Customer, to cover Andritz's out of pocket costs and expenses if applicable. Andritz has the right to suspend and/or terminate its obligations under the contract, if payment is not received within 30 days of due date.

12. Site Risks

(a.) **Subsurface / Concealed Conditions**

Andritz and Customer acknowledge and agree that as to subsurface or other concealed conditions Andritz is relying upon information provided by Customer, and that any costs or schedule extensions due to changes in subsurface or other concealed conditions from those indicated in the materials provided by Customer, shall be to Customer's account. Customer shall hold Andritz harmless for increased costs and grant any necessary schedule extensions if any concealed or hazardous conditions are found.

(b.) **Environmental Remediation**

Customer acknowledges that Andritz is not an expert in environmental remediation and shall not be directed by change order or otherwise to perform any environmental remediation as part of the work, including but not limited to asbestos and lead paint removal. If any environmental remediation becomes necessary, Customer will contract directly with a qualified third party to perform such work.

13. Governing Law

All provisions of this Contract shall be governed by the laws of the State of New York.

14. Assignment

The delegation or assignment by either party of any or all of its duties or rights hereunder without the other party's written consent shall be void, provided, however, Andritz may subcontract work to one or more subcontractors.

15. Confidentiality

Any information, suggestions or ideas transmitted by the Customer to Andritz are not to be regarded as secret or submitted in confidence except as may be otherwise provided in a writing signed by a duly authorized representative of Andritz.

Customer acknowledges that the information, which Andritz submits to Customer in connection with this quotation or acknowledgment, includes Andritz's confidential and proprietary information, both of a technical and commercial nature. Customer agrees not to disclose such information to third parties without Andritz's prior written consent. Customer further agrees not to permit any third party to fabricate any equipment from Andritz's drawings or to use the drawing other than in connection with this specific quotation or order. Customer will defend and indemnify Andritz from any claim, suit, or liability based on personal injury (including death) or property damage related to any Product or part thereof which is fabricated by a third party without Andritz's prior written consent and from and against related costs, charges and expenses (including attorneys fees). All copies of Andritz's drawings shall remain Andritz's property and may be reclaimed by Andritz at any time.

16. Compliance with Laws

Andritz shall comply with all applicable state and federal laws, including but not limited to, the Fair Labor Standards Act of 1938, as amended, the Occupational Safety and Health Act of 1970 (OSHA), laws related to nonsegregated facilities and equal employment opportunity and all standard, rules, regulations, and orders issued pursuant to such state and federal laws.

17. Special Conditions

For Installation /Repair /Maintenance ("Work") involving Work on existing pressure vessels, piping and equipment add the following:

(a) Unless otherwise agreed and stated in the purchase order, Customer shall be responsible for: (i) physically disconnecting and isolating vessels and equipment being repaired from existing piping and electrical power before Andritz or any of its subcontractors start the Work, and take adequate precautions that re-connection and resumption of use does not take place until the Work is completed, and (ii) emptying the vessels and piping and freeing them from any toxic or harmful substances before the Work begins so that the vessels and piping are safe for Work to begin. Customer shall maintain the area entirely free of combustible, toxic and asphyxiant substances and provide fire protection service until the Work is completed;

(b) If the Work is on an existing vessel or existing piping, the Customer is responsible for determining the prior condition of the portion of the vessel or piping not involved in the Work, and its ability to withstand the Work and any tests that may be necessary;

(c) Customer shall also be responsible for evaluating the effects of prior use of the vessel or piping upon structural adequacy, and the suitability of the vessel or piping for the service intended when the Work is completed;

(d) Andritz has no obligation to provide any inspections or tests, and Customer takes full responsibility for all necessary inspections and tests, including but not limited to, selection of testing personnel, type, location, frequency, and severity of any inspections and tests and all test results at any stage of the Work;

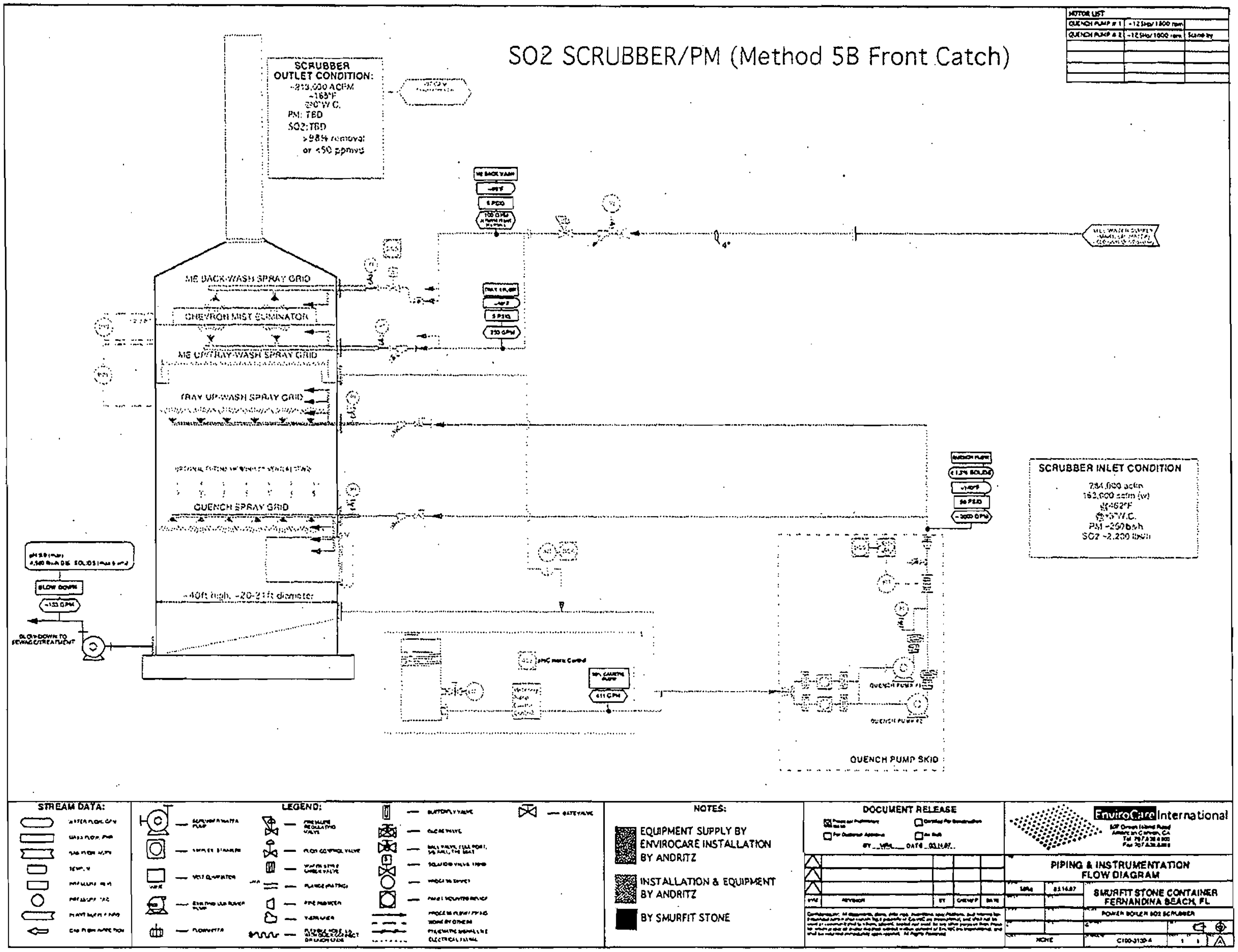
(e) Upon request of Andritz, Customer shall provide Andritz with the history of the vessel, a statement of the tests to be performed and a statement of the proposed use of the vessel after completion of the Work, and

(f) If repairs are required: (i) Customer will provide an Authorized Inspector ("AI") who will determine the scope of the Work to be done; (ii) Andritz will provide Customer with a proposed Quality Control ("QC") package specifying the methods and procedures that Andritz will follow in performing the Work specified by the Customer; (iii) the proposed QC package is subject to approval by the Customer, and such approval must be provided before Work commences; (iv) after approval of the QC package, the Work shall be done in accordance with the QC package. At the option of the AI, hold points may be established for inspection during the course of the Work; and (v) upon completion of the Vessel repair Work, the AI shall inspect the Work and provide a signed acceptance that it has been completed in accordance with the QC package. Such acceptance by the AI shall establish completion of the Work.

18. **Entire Agreement**

This Agreement contains the entire and only agreement between the parties with respect to the subject matter hereof and supersedes all prior oral and written understandings between Customer and Andritz concerning the equipment and/or service specified herein, and any prior course of dealings or usage of the trade not expressly incorporated herein.

BEST AVAILABLE COPY



COMBUSTION IMPROVEMENT
MOBOTECUSA
MULTI-POLLUTANT REDUCTION

SMURFIT STONE CONTAINER CORP.
FERNANDINA BEACH MILL
BOILER #5

PROPOSAL # 07-0361
MobotecSystem™
BUDGETARY PROPOSAL FOR THE ADDITION OF THE MOBOTEC ROTAMIX SYSTEM (SNCR) FOR NOX REDUCTION AND FSI SYSTEM (FURNACE SORBENT INJECTION) FOR SO2 REDUCTION

PREPARED BY: EDWIN HADDAD, MOBOTEC USA 6/11/2007
SUBMITTED TO: RACHEL DAVIS, SMURFIT STONE CONTAINER CORP.

Rachel Davis
Environmental Engineer
Smurfit Stone Container Corporation
Fernandina Beach Mill
Fernandina Beach, Florida
Tel 904-277-7718
RGDAVIS@SMURFIT.COM

Ms. Davis:

The following is submitted as per your request for a budgetary estimate for the Mobotec ROTAMIX (SNCR) and FSI (Furnace sorbent injection) for boiler # 5 at the Fernandina Beach Mill.

	MOBOTEC SUPPLY	LABOR ESTIMATE
ROTAMIX	$ 987,200	$ 340,000
FSI	$ 877,400	$ 210,000

With ROTAMIX we will get an incremental reduction in NOx, over ROFA by about 30%, that is, if we get 50% reduction with ROFA, then we will get a 65% reduction with ROFA and ROTAMIX.

At maximum load, the urea consumption would be about 0.25 gpm, demineralised water about 0.29 gpm and service water about 1.25 gpm.

With FSI we expect a reduction in SO2 between 50 and 60% with a consumption of limestone of about 1,200 lbs/hr.
In the CFD study we would evaluate the impact of this amount of sorbent on the performance of the ESP.

I trust this gives you the necessary information for your BART analysis.

Please call me or Jaye Locke if you have any questions,

Regards,

EdwinEHaddad

Edwin E. Haddad
Vice President, Sales and Marketing

Cc: A. Robb, J. Crilley, H. Nalan, J. Fessenden, J. Locke, Jaye Locke

Mobotec USA
Ph: 925.935.2500
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Physical Address:
2540 Camino Diablo Boulevard, Suite 200
Walnut Creek, California 94597-3933

Mailing Address:
Post Office Box 2025
Orinda, California 94563

MOBOTEC

Smurfit Stone Container Corp.

Fernandina Beach Mill
Power Boiler No. 5

Budgetary Proposal No. 07-0361

MobotecSystem™
for combustion improvement and multi-pollutant reduction

Rachel Davis
Environmental Engineer
Smurfit Stone Container Corporation
Fernandina Beach Mill
Fernandina, Florida
Tel 904-277-7718
Email-RGDAVIS@SMURFIT.COM

Subject: Proposal to furnish the MobotecSystem for combustion improvement and multi-pollutant reduction at Smurfit Stone's Fernandina Beach Mill, Power Boiler #5.

Ms. Davis:

Mobotec USA is pleased to present Smurfit Stone with this proposal and budgetary estimate for engineering, design, procurement and installation of the MobotecSystem for combustion improvements and multi-pollutant reduction at Smurfit Stone's paper mill in Fernandina, Florida. This proposal is based on the information in your Email dated May 9, 2007 sent to me and information received from Jack and Jaye Locke after their meeting in your offices.

The following summarizes Mobotec's understanding of Smurfit Stone's project objectives at Fernandina Beach Mill
:

- Modify the combustion air system and / or burners on the boiler to improve boiler operation and to prepare for BART compliance strategy
- Reduce unburned carbon levels
- Reduce particulate matter emissions
- Reduce NOx
- Eliminate boiler "smoking" at high loads
- Raise cold-end average temperature at the air heater to reduce acidic condensation and corrosion

Mobotec proposes the following staged approach, which we believe to be the best way to achieve these objectives at Fernandina Beach:

1. Create a CFD model of the Fernandina Beach boiler #5
2. Gather additional site data and perform preliminary engineering of the modified combustion air system
3. Install Mobotec's Rotating Opposed-Fire Air (ROFA) system
4. Modify the existing combustion controls including fuel biasing and distribution of air flow to windbox, undergrate, overfire air ports and new ROFA ports.
5. Tune the new combustion control system for optimum performance

This proposal discusses each of these phases as they apply to Fernandina Beach:

Mobotec is confident that we have the best technology to help Smurfit Stone meet these operational objectives on boiler #5 at Fernandina Beach paper mill. Please contact any of the following if you have questions about this proposal:

Jaye Locke: 770-595-5694
Myself: 508-872-1610

Best Regards,
Mobotec USA, Inc.

EdwinEHaddad

Edwin E. Haddad
Vice President, Sales and marketing

Description of Mobotec's Proposed Multi-Phase approach

1. CFD modeling of the furnace
   As described in our brochure, Mobotec USA possesses state-of-the-art computer systems and staff expertise that allow us to create detailed computational fluid dynamics (CFD) models of industrial furnaces. The models are used to select the ideal size, location and design of the MobotecSystem components such as ROFA ports and reagent injection devices. For Fernandina Beach the CFD will include modeling of the air distribution to the windbox, undergrate, OFA and ROFA locations. The modeling results will be of significant technical benefit in finalizing the design for the modified combustion system on these boilers. Mobotec's deliverables include a detailed report of the CFD results.

2. Preliminary Engineering
   Before beginning detail design and material procurement Mobotec would perform a preliminary engineering phase. This phase would include the following:
   - Design kickoff meeting with Smurfit Stone personnel
   - Detail data gathering at site
   - Interview of boiler operators and observation of current boiler operation
   - Determination of new or modified equipment, ductwork, dampers and actuators, flow measurement, etc. required
   - P&IDs and system sizing calculations
   - System design description
   - Summary of predicted operating conditions with modified system
   - Determination of new control system I/O required
   - Written control narrative for the new combustion control scheme

   Mobotec proposes that the preliminary engineering phase be executed concurrently with the CFD modeling phase.

3. ROFA – rotating opposed-fire air
   Mobotec's patented ROFA system serves as the foundation of our combustion improvement and emissions reduction technology. Developed in Sweden in 1991, ROFA advances the concept of staged combustion beyond that of conventional overfire air systems. A booster fan is used to redirect combustion air away from the primary combustion zone to the upper part of the furnace. The bulk flow upward through the furnace is set in rotation using custom-designed asymmetrically placed air nozzles. The overall effect is combustion staging along with turbulent mixing and bulk rotation in the entire furnace. The results of ROFA operation include:
   - Reduced NOx formation in the primary combustion zone
   - Elimination of fuel-rich pockets through improved mixing of fuel and air
   - Increased residence time in the combustion zone
   - Reduced unburned carbon
   - More uniform temperature distribution

Mobotec's preliminary analysis of the Fernandina Beach boiler indicates that this unit is well-suited to combustion improvements using ROFA. The ROFA system includes one new ROFA fan (estimated 300 – 400 hp) per boiler drawing air from the discharge of the existing FD fan. The boosted air is then distributed to four new ROFA boxes to be installed in the upper furnace region. The boxes are placed asymmetrically on opposite sides of the furnace and contain nozzles specially designed to produce the optimal mass flow, velocity and direction as determined by the CFD model. Each box includes a motor-operated modulating damper and a pressure transmitter for adjusting the distribution of ROFA air as boiler load changes.

A preliminary layout of the ROFA boxes for the Fernandina Beach boiler is depicted in the figures included. The layout will be finalized based on the results of the CFD.

Summary of Existing Unit

Fernandina Beach Power Boiler #5

Item	Characteristics		
Manufacturer	Babcock & Wilcox		
Year	1969		
Type	Combined stoker-fired bark plus non condensable gases from pulping process plus No. 6 Fuel Oil 2.5% S max.		
Fuel	Approximate average blend (Btu basis): 40% bark, 60% oil		
		Bark est.	Oil
	Moisture	41.29%	
	Ash	1.43%	
	Carbon	30.52%	
	Hydrogen	3.21%	
	Oxygen	23.35%	
	Nitrogen	0.34%	1.00 est.
	Sulfur	0.01%	2.50%
	HHV	4,500 Btu/lb	18,540 Btu/lb
Unit rating	MCR: 500 kpph steam, 875 psig, 825 degF (Approximately 46 MWe equivalent per boiler)		
Fuel Flow	Typical: 900 tons/day bark; 180 barrels/day oil		
Attemperation Spray	?		
Air leaving air heater:	638 to 688 kpph, 360 to 400 degF		
Secondary (overfire) air	?		
O_2	4 to 10% at full load		
SO_2	0.075 lb of SO2/ton of bark, 1,734 lbs/hr for oil & bark		
NO_x	1.5 lbs NOx/ton of bark, 47 lbs of NOx/Kgal of oil		
Unburned carbon	40% to 70%		
Furnace dimensions	29-1/4' D x 20' W x 81' H; 46,500 cu. ft.		
Height from grate to nose	About 50 ft.		
Height from top burner to nose	About 25 ft.		
Effective combustion volume	About 12,000 cu.ft.		

Item	Characteristics
Calculated retention time in combustion zone	1.1 seconds
Wing walls	None in combustion zone
Downcomers	None

Performance targets, guaranteed and expected

The following performance targets, guaranteed and expected, are based on Mobotec's understanding of the equipment and current operating conditions at Cedar Springs as defined previously under "summary of existing units".

	Baseline	Predicted result
Total unburned carbon	40+%	**Guaranteed ≤ 10%** [1]
PM emissions at air heater outlet	10+ lbs/mmBtu	**Guaranteed ≤ 6.5 lbs/mmBtu** [1]
Opacity at CEMS	"smoking"	Smoking eliminated [2]
NOx at CEMS (ROFA only)	n/a	Expect 45% - 60% reduction
ROFA + ROTAMIX	n/a	Expect 45% - 75% reduction
SO_2 at CEMS (ROFA + FSI) [3]	n/a	Expect 50% - 60% reduction

Mobotec's understanding
Notes:

1. ***Unburned carbon and PM emissions guarantees are based on boiler operating at MCR with 40% bark heat input (Btu basis). As discussed, once guaranteed results are achieved Mobotec will work with plant personnel to obtain lower LOI levels.***
2. ***Mobotec will hold the boiler exit O2 to 2% or greater so as to assure proper boiler, ROFA and ancillary systems operation coupled with "smoking elimination".***
3. Rotamix and FSI predicted results are listed for future reference only. The pricing given in this proposal does not include the Rotamix or FSI system.
4. ***Mobotec reserves the right to conduct baseline testing at contract commencement and to adjust performance guarantees according to the results.***
5. ***FSI is the Mobotec system for SO2 reduction and stands for furnace sorbent injection which involves the injection of limestone in the furnace***

Mobotec USA Table of Deliverables

Item	Description	Furnished by
CFD Study		
	Perform site data gathering	**Mobotec**
	Prepare CFD model	**Mobotec**
	Submit CFD report	**Mobotec**
Preliminary Engineering		
	Site investigation, interviews, data gathering	**Mobotec**
	Design description	**Mobotec**
	Preliminary P&ID	**Mobotec**
	Major equipment specifications	**Mobotec**
	Duct sizing	**Mobotec**
	ROFA port locations	**Mobotec**
	Control description	**Mobotec**
	I/O list	**Mobotec**
Detailed Engineering		
	Equipment arrangement drawings	**Mobotec**
	Tube bend assembly fabrication and installation details	**Mobotec**
	Duct routing drawings	**Mobotec**
	Duct support details	**Mobotec**
	Equipment foundation details	**Mobotec**
	Revise existing SAMA functional diagrams	**Mobotec**
	Generate new SAMA functional diagrams	**Mobotec**
	Instrument data sheets	**Mobotec**
	Instrument installation details	**Mobotec**
	Equipment electrical requirements	**Mobotec**
	Operating procedures	**Mobotec**
	Burner modification details	**Mobotec**
	Electrical single-line diagrams	**Mobotec**
	Motor control schematics	**Mobotec**
	Revise existing P&IDs	**Mobotec**
	Generate new P&IDs for ROFA system	**Mobotec**
	Revise existing loop diagrams	**Mobotec**
	System O&M manuals	**Mobotec**

Item	Description	Furnished by
ROFA Equipment		
	One ROFA fan, 300 - 400 HP, ambient air	**Mobotec**
	One modulating damper with motor-actuator for ROFA fan inlet	**Mobotec**
	Fan & motor bearing temperature and vibration sensors	**Mobotec**
	Duct, expansion joints, supports	**Mobotec**
	Structural steel additions needed to support ROFA ductwork	**Mobotec**
	Four ROFA ports	**Mobotec**
	Boiler tube bend assemblies, one per ROFA box	**Mobotec**
	Modulating damper with motor-actuator, one per ROFA box	**Mobotec**
	Pressure transmitters, one per ROFA box plus one on ROFA duct	**Mobotec**
	ROFA air flow element and transmitter	**Mobotec**
Burner Modifications		
	Refractory modifications to narrow throat on existing burners if needed	Others
Combustion system modifications		
	Evaluate existing combustion control system with owner assistance	**Mobotec**
	Troubleshoot and calibrate existing combustion air flow meter	**Mobotec**
	Revise existing SAMA logic diagrams	**Mobotec**
	Consult with and assist owner's DCS programmer	**Mobotec**
	Control system checkout	**Mobotec**
Mechanical installation		
	Install ROFA fan foundation (fan assumed to be installed at grade)	**Others**
	Install ROFA fan	**Others**
	Install additional structural members as needed for ROFA ductwork	**Others**
	Install ROFA ductwork, dampers, expansion joints, hangers	**Others**
	Relocate boiler downcomers as required for ROFA port accessibility	**Others**
	Install ROFA port waterwall penetrations	**Others**
	Install new instrumentation	**Others**
	Plug existing overfire air ports (if necessary)	**Others**
	Remediate interferences (allowance)	**Others**
Electrical Installation		
	Install rigid steel conduit	**Others**
	Pull and terminate power and control circuits	**Others**
	Megger-test power cables	**Others**

Item	Description	Furnished by
Onsite support		
	Job trailer onsite (57-weeks)	**Mobotec**
	Construction manager onsite (18-weeks per boiler)	**Mobotec**
	Engineering support during equipment startup (2-weeks per boiler)	**Mobotec**
	Tune new combustion controls with ROFA (5-weeks per boiler)	**Mobotec**
	Tuner assistance during performance testing (1-week per boiler)	**Mobotec**
	Operations and maintenance training (4 sessions, 4-shifts, 1-day each, each shift in a different week)	**Mobotec**
	Follow-up training, post-startup, 1-day	**Mobotec**
Items furnished by others (not included in Mobotec's budget numbers)		
	Assist Mobotec in site data gathering during CFD study phase	Smurfit Stone
	Geotechnical engineering for fan foundation work	Others
	Flue gas analyzers: NOx, CO, O2, PM, unburned carbon, opacity**	Others
	Bearing vibration and temperature monitoring system	Others
	Motor starter for ROFA fan: 4160VAC, 400 HP	Others
	Qty. 2 480VAC 50-amp feeds to new distribution panels	Others
	Modifications to power system if required to accommodate new motor	Others
	Interior boiler scaffolding or hanging work platforms	Others
	Hazardous material removal / abatement / disposal	Others
	Assist combustion control evaluation	Smurfit Stone
	New DCS hardware and internal DCS cabling & plc as required	Others
	DCS I/O & plc termination information for loop diagrams	Others
	DCS & plc configuration and programming	Others
	Programmer assistance during control system checkout	Others
	Contract 3rd-party testing firm for performance testing	Others
	Provide site area for equipment storage	Smurfit Stone
	Touch-up paint after installation	Others

Benefits to Smurfit Stone of the MobotecSystem

1. **Reduced unburned carbon**
   Mobotec guarantees that the combustion improvements brought about with the installation of ROFA, burner modifications and combustion control improvements will result in unburned carbon levels of less than 7%.

2. **Reduced particulate matter emissions**
   The combustion improvements brought about with the proposed system will result in reduced particulate matter emissions. Mobotec expects that PM will be reduced from the current level to less than 4.5 lbs/mmBtu.

3. **Reduced cinder carry-over**
   The installation of ROFA along with the combustion air modifications described herein will reduce the air velocity under the stoker grate and in the lower furnace region, and increase the residence time in the mid and upper furnace. Mobotec expects these changes to result in substantial reduction of the carry-over of products of incomplete combustion (cinder and char) through the furnace exit.

4. **Combustion stability**
   Adding ROFA and modifying the air distribution control system will eliminate boiler puffs and furnace pressure instability.

5. **Increased air heater cold-end-average temperature**
   By bypassing the air heater with a portion of the combustion air the cold-end average air heater temperature will rise. This rise will reduce the formation of acidic condensate currently causing air heater corrosion.

6. **Significant NOx reduction**
   ROFA operation results in better combustion with less unburned carbon and CO while simultaneously reducing the formation of NOx in the burner zone. This unique combination results from ROFA's staged combustion with turbulent rotation in the secondary zone NOx credits in the cap and trade market are currently selling for $2,400 per ton. As regulatory limits become tighter the demand for and price of NOx credits will rise.

7. **Improved boiler efficiency and safety**
   Improved combustion, reduce unburned carbon and better temperature distribution lead to increased boiler efficiency and safer boiler operation. Mobotec has typically seen efficiency improvements on the order of 1% with the installation of ROFA on this type of boiler. We predict this much improvement or more at Fernandina Beach due to the significant reduction of unburned carbon loss expected on these boilers.

8. **Additional low-cost NO_x reduction with Rotamix**
   Recent installations of our latest generation Rotamix system have yielded excellent results, as much as *35%* NO_x reduction in addition to the ROFA reduction.

9. **Affordable SO_2 reduction with Furnace Sorbent Injection**
   Adding ROFA to the boiler makes possible the effective use of sorbent injection for the reduction of SO_2 emissions. The combination of ROFA and limestone injection has resulted in as much as 90% reduction in SO_2 emissions. The cost of SO_2 credits on the cap and trade market has risen steadily over the past several months. As SO_2 regulatory limits become more stringent, the market for SO_2 credits will tighten. Boiler operators with SO_2 abatement systems in place will be at a distinct advantage.

10. **Low life-cycle costs**
    Operation and maintenance of the MobotecSystem is simpler and less expensive than that of other emissions reduction technologies such as back-end catalysts and scrubber systems.

11. **Low-risk, proven technology**
    The MobotecSystem has been installed and successfully operated on nearly fifty units in the U.S. and Europe since 1991. We have an excellent track record of meeting our performance targets, with particularly impressive results on smaller units such as those at Cedar Springs. Mobotec has a reputation of standing behind our commitments and doing what it takes to meet our performance targets.

System Costs

Mobotec USA offers the following budgetary pricing for the MobotecSystem for combustion improvements and emissions reduction at the Cedar Springs paper mill. Pricing is subject to all terms listed in the "Proposal Notes" section that follows.

	Power Boiler #1
CFD Study	$ 93,500
Engineering	$ 781,105
Equipment and Startup	$ 722,200
Mechanical installation budget	Others
Mobotec G&A – mechanical installation	$ 72,500
Electrical installation budget	Others
Mobotec G&A – electrical installation	$ 24,900
Burner modifications	Others
Combustion system improvements	$ 218,000
Allowance for closing OFA ports if needed	Others
Furnish new actuated under-grate air dampers if required	$ 38,900
Totals	**$ 1,951,105**
Allowance for recommended spare parts	$36,152
Allowance for addressing construction interferences	Others

Notes:
Resolution of construction interferences will be performed on a time and material basis.

Performance penalty:

Mobotec will deduct the following amounts from the contract value as a financial penalty in the event the system does not meet the performance guarantees specified herein.

Total unburned carbon

	Performance test result	Penalty (% of base contract)
Guarantee level	$\leq$ 10%	0%
Penalty level 1	10% - 30%	**0 – 5%**
Penalty level 2	> 30%	10%
Baseline	About 40%	-

PM emissions at air heater outlet

	Performance test result	Penalty (% of base contract)
Guarantee level	$\leq$ 6.5 lb/MMBtu	0%
Penalty level 1	6.6 – 10.0 lb/MMBtu	**0 - 5%**
Penalty level 2	> 10.0 lb/MMBtu	10%
Baseline	10.0 lb/MMBtu	-

ECONOMICS:

The Mobotec system should reduce oil consumption by about 30%.
Annual oil consumption is 180 barrels/day or 65,700 barrels per year.

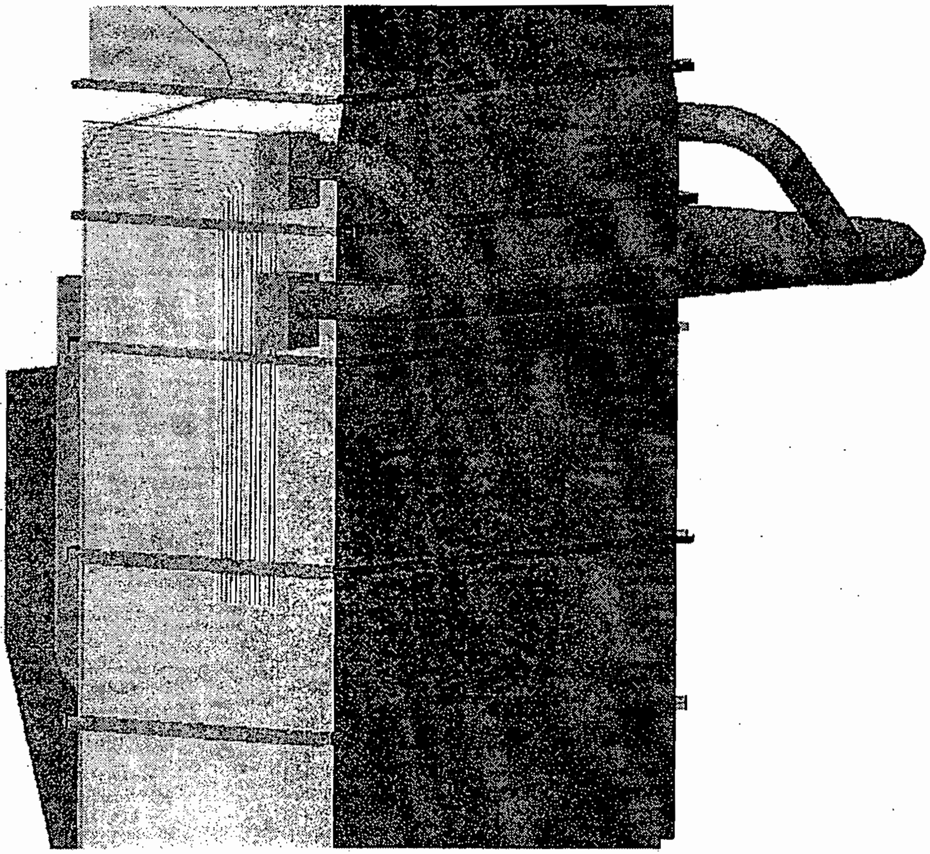
30% reduction is 19,710 barrels per year at $ 85/barrel amounts to an annual savings of:

$ 1,951,105

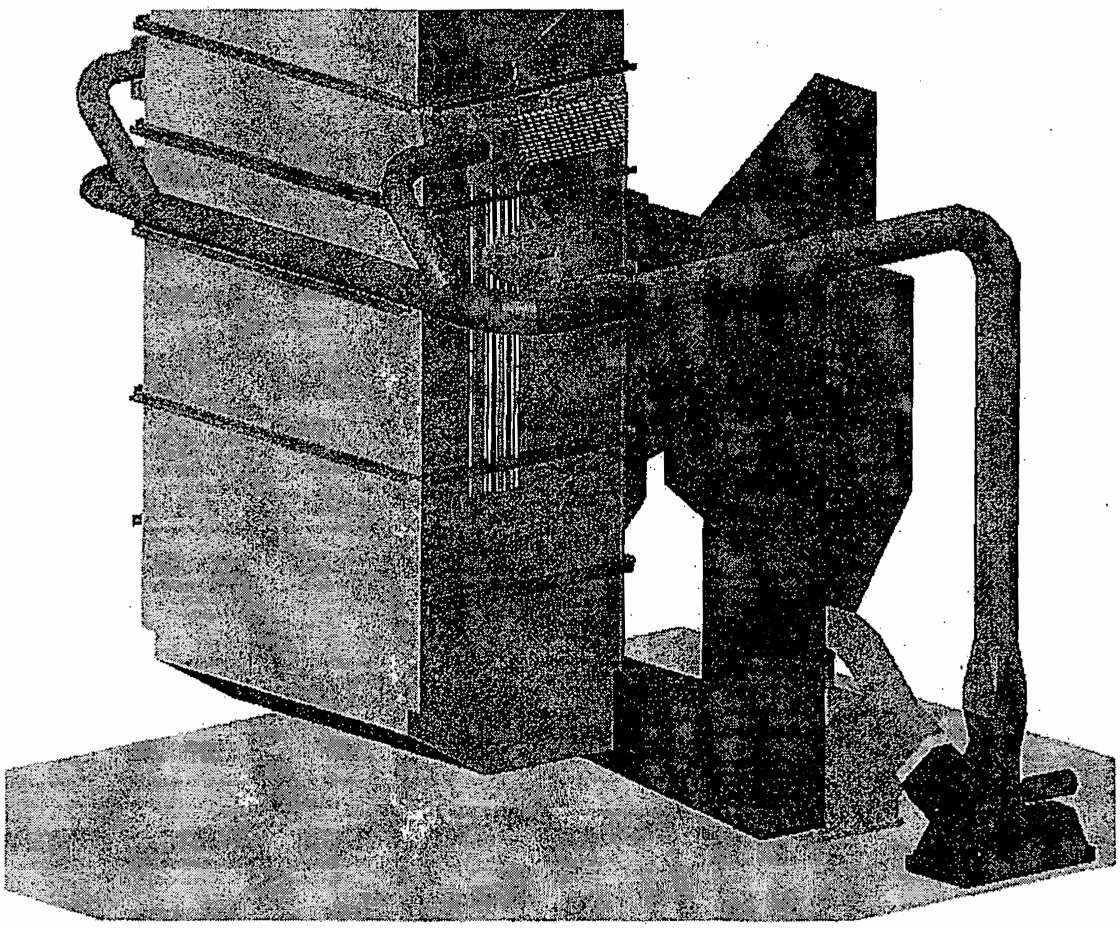
This means a payback of less than 2 years.

Exhibit 2: Fernandina Beach ROFA System isometric renderings

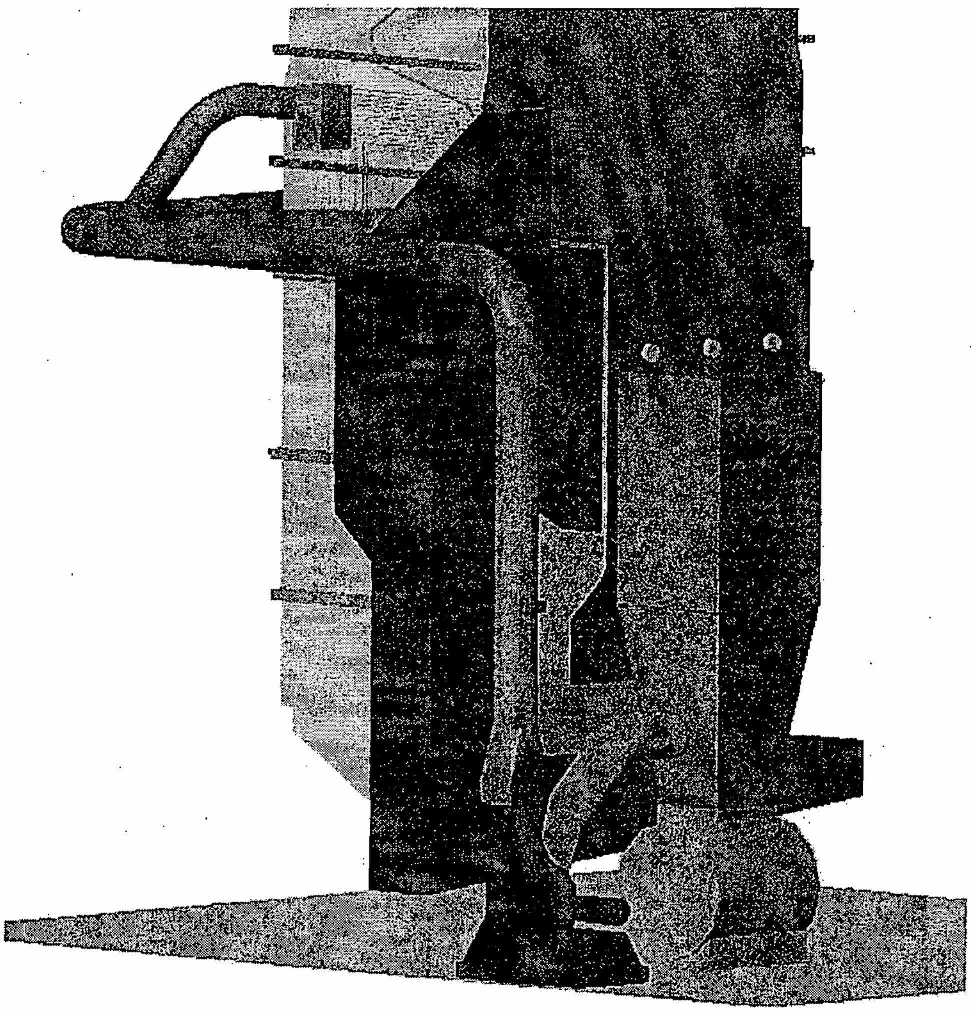
The following 3-D isometric renderings show preliminary box locations and duct routing for the ROFA system at Fernandina Beach.



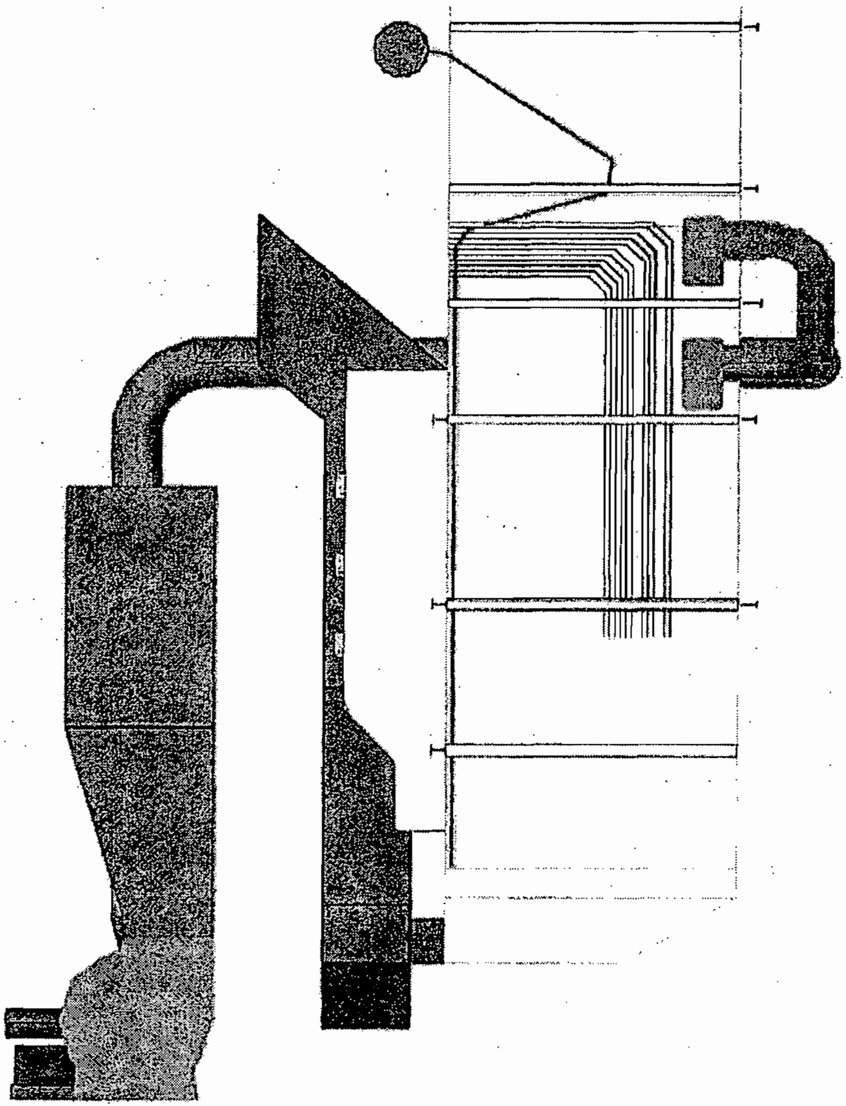
Fernandina Beach isometric rendering – view 1



Fernandina Beach isometric rendering – view 2

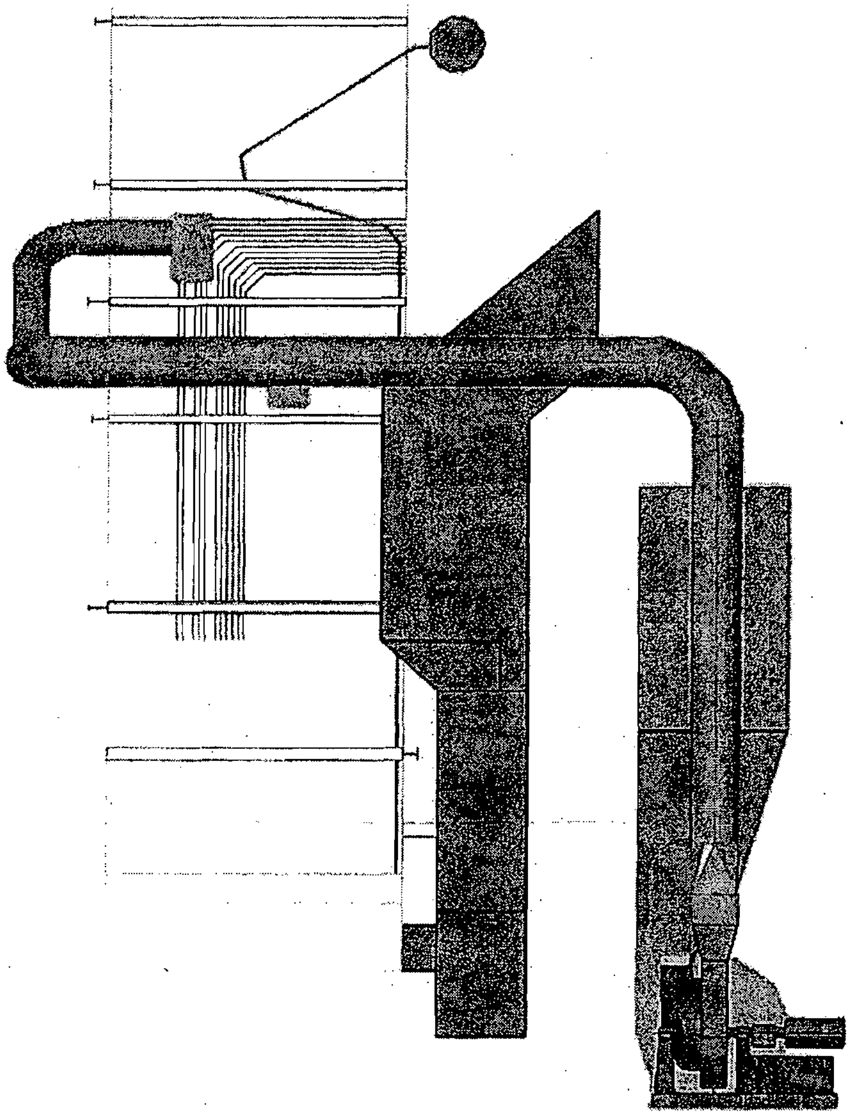


Fernandina Beach isometric rendering – view 3



Fernandina Beach isometric rendering – view 4

Mobotec USA, Inc. *PO Box 2025 Orinda, CA. 94563 USA* *Physical – 3468 Mount Diablo Blvd., Suite B100, Lafayette, CA. 94549 USA*
Phone – 925-962-9040 *Fax – 925-962-9044*



Fernandina Beach isometric rendering – view 5

Ecotube Quote

Buff, Dave

From: Buckley,William [bbuckley@Synterprise.com]
Sent: Friday, June 01, 2007 8:23 PM
To: Davis, Rachel G.
Subject: Smurfit Stone - FL BART - Integrated Technology Budgetary Response 6-1-07
Importance: High

Rachel: Thank you so much again for your interest in an Ecotube based technology solution and its potential application in your Fernandina Beach, Florida operation. I understand you are in the early stages of the BART process and desire a budgetary estimate for a system for initial consideration.

Following preliminary engineering review of your information, it appears that an integrated solution combining both the Ecotube technology and Synterprise's proprietary EcoJet technology would be very appropriate to consider as a foundational element for your application. Each system has the capability to operate as a standalone system and can be integrated together to create an extremely robust, capable and cost effective solution for larger boilers.

I understand you are familiar with the Ecotube system but you may not be aware of the EcoJet technology. The EcoJet System is an advanced, separated over-fired air system, capable of integrating reagent injection delivery, designed to dramatically improve combustion and reduce emissions in utility and industrial boilers. The EcoJet System consists of multiple rows of variable direction, tunable secondary "high energy" air injection wallports staged in the boiler on several elevations above the primary combustion zone. The EcoJet technology package creates several distinct combustion environments within the boiler: an aggressive "advanced thermal conversion zone" lower in the furnace primary firing area and a secondary "gasification and volatilization" combustion area just above the lower boiler "primary firing zone".

Given the physical size of your boiler, it appears that a system consisting of two Ecotube assemblies (positioned in an offset configuration at an upper boiler elevation) integrated with a custom designed network of EcoJet wallports at strategic locations would be appropriate for your Fernandina Beach boiler. With that basis in mind, our engineering team has developed a "draft budgetary" estimate of $2,600,000 USD (+/- 20%) for an "air only" system based on two Ecotubes with an associated network of EcoJet wall ports. This is an installed "turnkey" estimate where Synterprise will engineer, design, supply and provide field construction of the system. The client is responsible for providing source points for electrical service, cooling water supply and drain sources, acquiring necessary permits and several other items similar in nature. An "air only" system of this general architecture and design typically has the potential to reduce NOx emissions by a minimum of 20% and a CO reduction of 60-70% can be achieved. Actual results have ranged close to 40% for NOx reduction and 90% for CO reduction in certain applications. As you probably also know, the integrated Ecotube/EcoJet technology package also differentiates itself from many of the other "parasitic" emission reduction systems because it offers combustion optimization value as well.

If reagent is added to the Integrated System for purposes of further enhanced NOx reduction, a minimum NOx reduction of 60% should be attainable. Actual results have indicated that NOx reduction with reagent may approach 70-75% in certain cases. The "ballpark" added cost for a NOx reagent storage and delivery system with controls integrated into the system would be around $975K for a budgetary view.

If deeper levels of NOx reduction are desired (or reduction of other pollutants), Synterprise can install further remediation equipment such as a "polishing" SCR or Low Temperature Oxidation System. Additional system needs could only be determined through "detailed engineering" work.

As we've discussed, as a foundational element to further identify the nature and scope of initial Ecotube/EcoJet integrated system requirements going forward, an on-site engineering study is necessary to get an accurate sense of furnace temperature profiles which will help us determine the optimum elevation(s) for the actual Ecotube penetrations and Ecojet wall ports locations, obtain a more accurate estimate of integrated project costs and performance benefits. Obviously, that location will determine the extent of structural steel support that might be required, obstacle clearance issues that must be addressed and things of that nature. In addition, the pre-engineering study will generally consist of the following scope:

Synterprise Associate(s) will work closely with client personnel to:

- Schedule, coordinate and perform the required Engineering testing and site assessment activities
- Collect all plant operating, general equipment and electrical/mechanical design information necessary for an Integrated Ecotube/EcoJet system installation
- Analyze all collected operating and design information
- Prepare recommendations, identify system value points and develop a more accurate estimate of the integrated Ecotube/EcoJet cost.

Some of the more specific value points of the Engineering Study process include:

A. Boiler performance measurements and variance analysis will provide the client, and Synterprise Solutions, with a better understanding of current boiler operational modes
   - Boiler flame pattern analysis of combustion conditions (Video analysis) with consultant on-site discussion with site personnel
   - Furnace gas temperatures (Multiple tests with optical pyrometer) with temperature data summary discussion with on site personnel
   - Boiler operational data review and analysis –
     - Primary and secondary air systems
     - Over fired air
     - Total Excess air
     - Capacity factor
     - O2 % at boiler exit
     - Air heater exit gas temp.
     - Air heater air inlet temp.
     - Reheat spray flow lb/hr [if applicable]
     - Cost of fuel $/ton
     - Seasonal variations in load, fuel, steam generation capability
     - Review of operational and combustion issues
     - Review of potential areas of improvement potential
   - Review of original boiler design acceptance test information and any additional performance analysis data that may be available

B. Provide projected operational performance improvement based on implementation of an Integrated Combustion Improvement system solution providing the client with boiler performance improvement potential
   - Boiler performance assessment and projected improvement opportunity identification will be forwarded by email after review by central engineering
   - Projected financial performance improvement potential associated with the combustion system and related / affected systems [fuel handling, bottom ash, fly ash, primary and secondary air, controls, etc]

C. Provide an equipment configuration arrangement and a project plan
   - Integrated Combustion Improvement system project equipment configuration plan developed to obtain projected performance objectives
   - Project plan developed to install the required Integrated Combustion Improvement system lance assemblies and wall boxes as required
   - Potential site location assessment of equipment, platforms (if required), and control equipment
   - Air and source of cooling water requirements will be defined

D. Provide a cost estimate [+/- 10%] for the proposed Integrated Combustion Improvement system solutions

Our clients (even those that have not elected to go forward with projects) have found significant value in the Pre-Engineering Studies. Typical pricing for a study is over $20,000 but I expect to have a team in the southeast region in mid to late July so, if you're interested, Synterprise will offer to perform the study on your Fernandina

Beach boiler for around $10,000 during that period which will keep the potential project moving forward.

Again Rachel, thank you very much for your interest in Synterprise's products and professional services and we'll look forward to your feedback. Please advise if you wish to proceed directly with a Pre-Engineering Study and I'll get a proposal to you right away to initiate that effort.

Very Best Regards,
Bill

William J Buckley
Vice President Engineering and Construction
Synterprise Global Consulting
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Fax - 423-265-2350
www.synterprise.com

FUEL TECH®

Technologies to enable clean efficient energy™

Proposal No. 07-B-023, Rev 1
NOxOUT® SNCR NOx Reduction

For

Smurfit-Stone Container
Fernandina Beach, Florida

No. 5 Power Boiler
BART Study

March 28, 2007

PROPOSAL SUMMARY

Based on the preliminary drawings and design information provided by Smurfit-Stone and the additional data obtained during our mill visit on 3/6/2007, Fuel Tech, Inc. (FTI) is pleased to submit our revised budgetary proposal covering the design, supply, fabrication, delivery, personnel training and commissioning of one (1) NOxOUT® SNCR NOx reduction system for the bark- and oil-fired No. 5 Power Boiler at the Fernandina Beach, FL facility.

NOxOUT® SNCR Process Description

NOxOUT® SNCR is a patented in-furnace, post-combustion NOx reduction technology that relies on the finely controlled distribution of urea to effect a selective reaction of gas-phase ammonia with NOx within a specific temperature region in the upper furnace. The urea is delivered and stored as a 50% aqueous solution that is continuously circulated through the stainless steel SNCR system piping loop. Using plant service water, a metering module located near the injection elevation further dilutes the reagent to a predetermined concentration and precisely controls the flow of diluted reagent to distribution modules located at each injection elevation. The distribution modules provide the final control of diluted reagent and atomizing (plant) air being delivered to each injector, where droplet size and trajectory for each injector have been determined through advanced computer modeling. The final spray characteristics and flow rate of diluted reagent for each injector are fine-tuned during system optimization and startup to correspond to specific boiler operating loads and NOx concentrations.

Using feedback NOx emission signals from the CEMS (if available) and these optimized settings, the SNCR system runs in the background under the control of an on-board Allen-Bradley SLC 500 Series PLC and is transparent to the other plant operations. For this project, communication between the NOxOUT system PLCs and the boiler ControlLogix controls will be over the data highway (DH+).

FTI Scope of Supply

The Fuel Tech Equipment Scope of Supply detailed in this proposal includes:

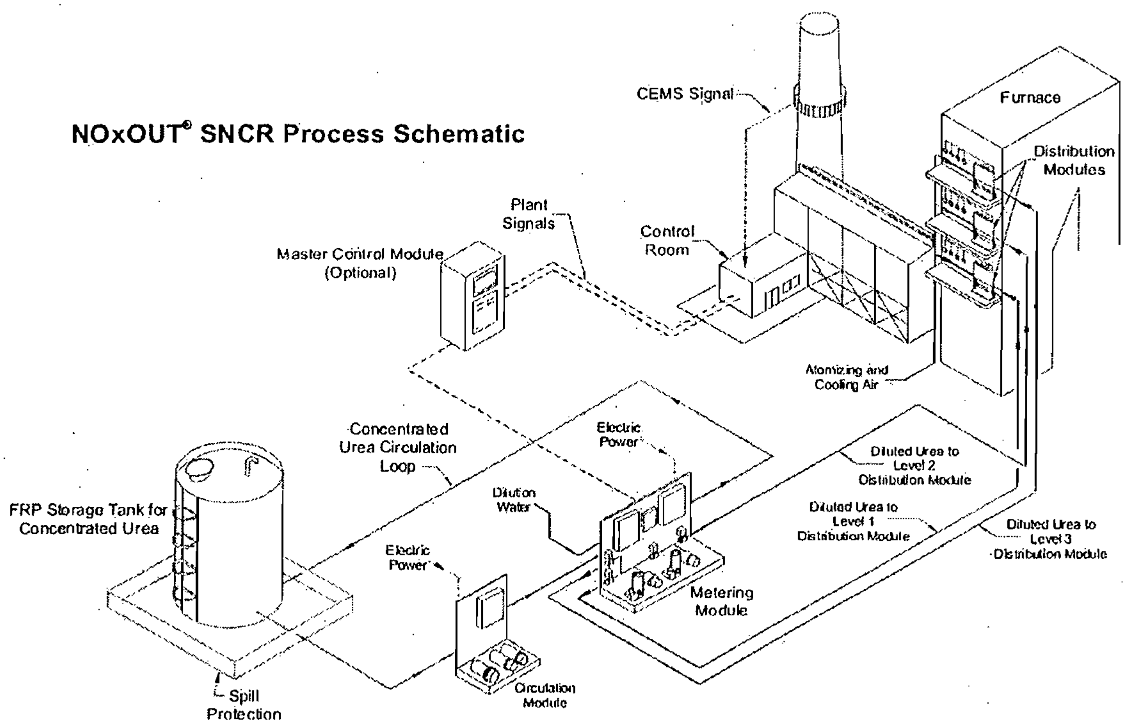
- One (1) double-wall FRP reagent storage tank with all required appurtenances,
- One (1) enclosed reagent circulation module to provide a continuous flow of the reagent to the circulation loop piping – the temperature of the concentrated reagent must be maintained at a sufficient level to minimize the potential for crystallization, generally requiring that this loop be heat traced and possibly insulated,
- Multiple-level, Independent Level Control (ILC) Metering module with an on-board water boost pump (WBP) to control the reagent and dilution water flow rates and deliver a consistent urea droplet concentration to the distribution modules and injectors, and
- Distribution modules to provide fine, individual control of the diluted and atomized reagent being delivered into the boiler via the wall-mounted injectors.

PROPOSAL SUMMARY
(Continued...)

Descriptions of the individuals components identified in the FTI Equipment Scope of Supply summaries, including the module descriptions, estimated module weights and dimensions, are provided later in this Proposal. Expected system utility requirements such as dilution water flow rates, atomizing/cooling air flow rates, and electric power consumption also are provided.

The proposed equipment for this project would be configured very closely to what is illustrated below in the SNCR Process Schematic, with the exception that the SNCR system would have only two (2) levels of diluted urea injection.

NOxOUT® SNCR Process Schematic



PROCESS DESIGN TABLE

Smurfit-Stone – Fernandina Beach, FL No. 5 PB

Design Case		Bark		Bark/Oil
Load Range (% MCR)	(Assumed)	65-100		65-100
Maximum Heat Input	(MMBtu/hr)	423.0		657.8
Uncontrolled NOx	(lb/MMBtu)	0.170		0.245
	(lb/hr)	71.9		161.2
SNCR NOx Reduction	(%)	32.5%		27.5%
Controlled NOx	(lb/MMBtu)	0.115		0.178
	(lb/hr)	48.5		116.9
SNCR NOx Removed	(lb/hr)	23.4		44.3
Expected Temperature at Bullnose Elevation	(°F)	1750-1850		1900-2000
Expected NOxOUT® A Consumption @ MCR	(gph) 50% by weight	12.3		26.4
NH³ Slip Average, Uncorrected @ Stack	ppmd	20		10 (at boiler outlet)
Furnace CO Limit at Bullnose Elevation	(ppm)	700		100
Reagent Distribution Strategy	Level 1	Six (6) Wall-mounted Injectors with Automatic Retract Mechanism		
	Level 2	Five (5) Wall-mounted Fixed Position Injectors		

Process Design Comments

- The GHI for the Bark only case has been recalculated based on the maximum throughput of 47 ton/hr as indicated in the February 2007 %Load data provided for PB5.

- The CO at the stack for the Bark only case has been provided as 435 ppm (at 9.42% O2) suggesting that it will be much higher in the furnace where the O2 is only 5.42% based on 34% excess air and, therefore, still not fully oxidized.

- The February 2007 %Load Data for PB5 indicated that for the Bark/Oil co-firing, the maximum GHI will be under 51% oil and 49% bark. The Baseline NOx for this case was calculated on this basis.
- Since on a weight basis, the majority of the fuel is Bark, the overall sulfur content should be less than 1% and the NH3 can be relaxed to 10 ppm. We will require an actual fuel analysis and GHI to refine our estimates in the future.
- The width of the unit is still not known but I has been estimated as 18' – τηε number of injectors may change once detailed drawings become available.

FTI EQUIPMENT SCOPE OF SUPPLY SUMMARY

	No. 5 Power Boiler at Fernandina Beach, FL
NOxOUT Design Option	NOxOUT® SNCR
8,000 gallon FRP Storage Tank	1
SLP3-C Circulation Module	1
FRP Circulation Module Enclosure	1
	Urea & Dilution Water Metering Independent Level Control
SLP3-M-ILC	1
	Diluted Urea & Atomizing/Cooling Air Distribution Lower Level of Wall Injectors
SLP3-D-6 Distribution Module	1
Wall-mounted Injector with Auto Retract	6
Retract Control Panel	1
	Diluted Urea & Atomizing/Cooling Air Distribution Upper Level of Wall Injectors
SLP3-D-5 Distribution Module	1
Wall-mounted, Fixed Position Injector	5
Retract Control Panel	Not Required
	Additional Equipment and Services
Temperature Monitor, Optical Pyrometer	1
Process Design Modeling	As Required
Project Engineering and CAD Drawings	As Required
PLC Controls & Interface Support	1
Startup, Optimization, and Training	30 Man-days

FUEL TECH EQUIPMENT SCOPE OF SUPPLY

FRP NOxOUT®A UREA STORAGE TANK

Made of Fiberglass Reinforced Plastic (FRP) with Premium Grade Vinylester Resin. Fabricated per ASTM D3299-88 where applicable, 1.5 Specific Gravity, heating package to maintain 80°F, site specific variables include seismic zone, wind load, snow load, and temperature variance.

Also includes heat trace and insulation with thermostat control, level transmitter, manway, vent, internal downpipe, external fill pipe, thermocouple, ladder, hold down and lifting lugs, FRP flanges for inlet and outlet, and fill and circulation line valves for suction isolation, drain, and return control.
8,000 Gallon: 10' OD × 13'-10" Shell Height; Approx. Empty Weight: 3,400 lbs.
Reference FTI Drawing C-1

SLP3-C CIRCULATION MODULE

The Circulation Module is designed for the continuous circulation and heating of the NOxOUT® A chemical and the supplied feed of the reagent into the Metering Module(s). The NOxOUT® tank level indication and alarms will be mounted on this module adjacent to the local control panel.

The Circulation Module includes: Complete assembly and testing, local control panel (NEMA 4X), redundant SS centrifugal pumps with auto switch, TEFC motors, motor starters, stainless steel skid with basin, 3 kW electric heater, duplex strainer for chemical, flow sensor and indicator for NOxOUT® A reagent, reagent temperature indicator, tank level indication, and all necessary SS components, piping, (Schedule 40 socket welded), and fittings.
Typical size: (4' W × 7' L × 6' H); Approximate Weight: 1,500 lbs.
Reference FTI Drawing D-1

CIRCULATION MODULE ENCLOSURE

Fuel Tech provides Switzer 9000 Series modular enclosures to house certain system modules. The enclosures are constructed of fiberglass reinforced isopthalic plastic resin and molded-in color gel coat with ultraviolet inhibitors. Each building is specifically designed for the individual application with reinforced walls and flooring. Lifting lugs and structural design and analysis is performed where needed.

The enclosure includes the pre-installed Circulation Module, two (2) large service doors, heater, electrical outlets, lighting, electrical breaker panel with circuits and transformer specifically sized for application, and steel flooring system. All utility connections will be made to exterior of the enclosure.
Reference FTI Drawing A-22, J-9

FUEL TECH EQUIPMENT SCOPE OF SUPPLY
(Continued…)

SLP3-M-ILC METERING MODULE

This module is designed for Independent Level Control, which permits a biasing of the chemical to each injection level that is in use. The Metering Module provides flow and pressure control of the fluids used in the NOxOUT® Process – NOxOUT® urea and Dilution Water. The water supply will be adjusted, via a regulator, to a set pressure that will allow for proper flow to each Distribution Module. The proper amount of NOxOUT® is then fed, by use of a metering pump and a digital indicating controller, into the dilution water discharge line and through a static mixer. The water/boost pump is supplied to power the mixed chemical up to each injector level at the proper pressures and flow rates. The local control panel on this module can operate in local or remote mode. In the remote mode, the plant DCS or FTI-supplied PLC can automatically feed the optimized amount of NOxOUT® reagent water pressure through the use of a 4-20 mA signal. Automatic flushing of the system is also provided to clear chemical from the lines prior to shutdown.

Also includes complete assembly and testing, two (2) local control panels with PLC (NEMA 4X), two (2) SS metering pumps with AC motors and drive controllers, two (2) turbine/boost pumps with TEFC motors and motor starters, stainless steel skids with basin, two (2) static mixers, two (2) magnetic flow meters with digital indicating controllers to electronically indicate and control the precise chemical flow, two (2) magnetic flow meters, pressure control valves, pressure transmitters and indicator for controlling water flows, motor operated ball valves for chemical and water inlet, duplex strainer for water, air pressure switch, regulators for water inlet chemical calibration columns, and all necessary components, SS Schedule 40 socket-welded piping, SS butt-welded tubing, and fittings.
Typical Size: 4' W × 10' L × 6' H – Approximate Weight: 2,400 lbs.
Reference FTI Drawing E-5

FUEL TECH EQUIPMENT SCOPE OF SUPPLY
(Continued...)

SLP3-D-X DISTRIBUTION MODULE

The Distribution Modules are placed just prior to the injectors (typically at the same elevation) and are used as a guide and check for proper injector performance. Air for atomization and cooling is introduced through this module. One panel pair, controlling the atomizing/cooling air pressure and the flow of diluted urea, is supplied for each injector. They are grouped and pipe-manifolded together for ease of installation.

Complete assembly and testing, flow and pressure indication with regulators for chemical and atomizing air. Each panel will be mounted to a freestanding stainless steel base and a pipe-manifold assembled for easy flow accessibility.

Note: Depending on the outcome of an ongoing cost reduction program which may affect Fuel Tech's ability to cost-effectively combine the metering module and distribution modules for this project, the Distribution Modules may not be integrated into the Metering Module. Regardless of the final determination, there will be no impact on the quoted price.
Typical Size: (SLP3-D-6) 2' W × 6.6' L x 6' H; Approximate weight: 600 lbs.
Typical Size: (SLP3-D-5) 2' W × 5.5' L x 6' H; Approximate weight: 500 lbs.
Reference FTI Drawings F-2 and F-6

SLP3-I-NFTL INJECTOR ASSEMBLY

The urea injector assemblies are installed at the furnace elevation determined by our process modeling with each appropriately sized and characterized for proper flows and pressures required to achieve the necessary NOx reductions. The injectors are constructed entirely of 316L stainless steel. The nozzle tip is a ceramic-coated 316L stainless steel. The cooling shield is typically 3/4" Inconel tubing or 316 stainless steel with ceramic coating (0.750" OD and 0.065" wall thickness). The inner atomization tube is typically 3/8" tubing with an adapter to accept different injector tips, with a standard length of 2.5 feet.

Each assembly includes Fuel Tech air atomized injector, adapter for insertion adjustment, coupler to attach to boiler support, quick-connects and 6' long steel-braided flex hoses for both the chemical and atomizing air connections.
Reference FTI Drawing G-1

FUEL TECH EQUIPMENT SCOPE OF SUPPLY
(Continued...)

SLP3-AR-P INJECTOR W/ AUTOMATIC RETRACT SYSTEM

The injector automatic retract device is an offset design and mounts on the standard/ recommended 1¼" Schedule 40 boiler penetration. The retract mechanism is an air-over-spring device of a hollow shaft design which operates and inserts the NOxOUT injector into the furnace when the atomizing/ cooling air is on. When the injector is fully inserted into the boiler a contact arm actuates a spool valve which starts the NOxOUT reagent flow to the injector. When required, the injector will automatically retract (using the compressed spring as the motive force) and chemical flow will be shut-off. The advantages of the retract system include:

- Complete automation and control room indication of the NOxOUT Injection System,
- Improved system operation and chemical utilization,
- Reduced manpower requirements,
- Improved wear life of the injector,
- Feedback control to ensure the presence of atomizing/ cooling air when the reagent starts to flow, and
- Reduction in system operating costs by eliminating cooling air flow for retracted injector lances.

Each Injector Retract includes a specially designed 33" air-over-spring cylinder with non-rotating shaft, boiler penetration adapter flange (1" Schedule 40 MNPT), stainless steel chemical valve and actuator arm, injector position proximity switch, ceramic-coated shield extension, flex hoses, local control 3-way solenoid, safety guard and assembly of NOxOUT Injector and associated tubing into the auto-retract device.

An Injector **Retract Local Panel** is included for each retract system level to show local indication and act as a junction box to feed retract "inserted/ retracted" signals to the main remote control module. This panel will also be used to control the valve actuators that dictate the injector levels in-service. One retract panel per wall injector level will be provided.
Reference FTI Drawing G-2

FUEL TECH EQUIPMENT SCOPE OF SUPPLY
(Continued...)

TEMPERATURE MONITORING SYSTEM

The temperature monitoring system supplied by Fuel Tech is an optical pyrometer designed to continuously monitor the furnace flue gas temperature. The temperature monitor senses the visible light from the ash particles to determine the flue gas temperature. Temperature readings are not biased by unit wall temperatures and can provide temperature readings for units firing coal, wood waste, municipal solid waste, refuse derived fuels, heavy oil or any other fuel which produce glowing particles during combustion.

The temperature sensed by the monitor will be utilized in determining the proper zone of injection for the NOxOUT process. By properly selecting the zone of injection based on flue gas temperature, the NOxOUT process can be optimized with regard to NOx reduction, chemical flows, and ammonia slip. This temperature control signal allows the Fuel Tech engineers to optimize the system operation and provide the best available SNCR system. The temperature monitor will require the following utilities and connections in order to be installed and operate properly:

- 3" threaded pipe nipple extending 4-6 inches outside the boiler wall
- 110 VAC power
- 60 to 80 psig plant air
- Structural support of the unit (approximately 100 lbs)

Reference FTI Drawing G-11 and G-15

CONTROL ROOM INTERFACE

Control of the ILC Metering Module is facilitated by a PLC-based control system utilizing an Allen-Bradley SLC 500 Series. Communication with the plant DCS can be accomplished via a Data Highway (DH+) or Ethernet connection. As an option, the on-board PLC can control the entire NOx reduction process. This is accomplished by routing to the PLC the required boiler parameters such as NOx, Oxygen, and Boiler Load. The PLC is programmed during the initial phases of the equipment construction and then tuned during the start-up testing to react to specific unit conditions.

Operator interface at the Metering Module is handled by an Allen-Bradley PanelView 550 (or 1000). This unit is a digital display which acts as the operator's window to unit operation and control. From the PanelView, the operator can monitor all of the system performance as well as control the system and adjust the automatic operation at the various load conditions. This is accomplished through the use of the display screen and the integrated keypad.

FUEL TECH SCOPE OF SUPPLY
(Continued...)

ENGINEERING

Fuel Tech will provide Project and Process Engineering and the following drawings and information:

- P&IDs
- Skid Arrangements
- Foundation Loads
- Injector Locations
- Electrical Drawings and Bill of Materials
- Pump Performance Curves

ENGINEERING SERVICES

- Computational Fluid Dynamics and Kinetic Modeling
- Project Engineering
- Start-up and Optimization Service (30 Man-days)
- Operation and Maintenance Manuals (5)

SCOPE OF SUPPLY BY OTHERS

1. Installation of Fuel Tech, Inc. Supplied Equipment.

2. Interconnecting Piping and Wiring of Fuel Tech, Inc. Supplied Equipment.

3. Tank Foundation and Structural Support for System Modules.

4. NOxOUT System Utility Estimates.

Summary of Estimated Utilities NOxOUT SNCR	Plant Air (scfm)	Instrument Air (scfm)	Reagent Flow (gph)	Dilution Water Flow (gpm)	MNL Cooling Water (gpm)	480V Power (kW)	220V Power (kW)	110V Power (kW)
Bark Firing Case	168	36	12.3	10.92	0.0	35	0	0
Bark/Oil Firing Case	168	36	26.4	10.62	0.0	35	0	0
	Note 1	Note 2	Note 3	Note 4		Note 5		

Note 1: These estimates assume that all levels of Injectors are in service, each consuming 12 scfm of plant air for urea atomization and 3 scfm injector tip cooling, which could be considered as "worst case". The actual number of injectors in service, as well as the flow of plant air and dilution water will depend on the boiler operating conditions and which levels of injectors are in and which are out of service.

Note 2: These estimates include 1 × 35 scfm required to cool the temperature monitor optics and approximately 1 scfm for the Metering Module control valves.

Note 3: These urea consumption projections will be verified during the modeling phase of the project, but this volume of concentrated urea would be distributed amongst all injectors that are in service.

Note 4: These estimates are based on the assumption that the total flow (concentrated urea + dilution water) per injector is 1.0 gpm. A higher design flow rate is recommended for pipe sizing purposes but the actual dilution water flow rate will depend on the number of injectors in service at a given load and firing condition.

Note 5: These estimates assume that 480V power is being fed into an FTI-supplied step-down transformer in the proposed Circulation Module Enclosure and the power requirements are routed from there to the remaining SNCR equipment.

5. Chemical Supply: NOxOUT® Quality Licensed Reagent (50% Solution).

6. Implement Control Logic Schemes into Plant Controls System.

7. NOx, Ammonia, and CO Monitoring Equipment, if Required.

8. Required Penetrations for Injector Wall Sleeves and Mounting.

9. Asbestos Abatement, if Required.

10. System Performance Testing.

11. Spare Parts.

FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

For the Engineering, Equipment, and Services identified in this proposal, we quote the following budgetary price, FOB Jobsite:

NOxOUT® SNCR	NINE HUNDRED AND FIVE THOUSAND DOLLARS	$905,000.00

Price includes the stated number of start-up and optimization services man-days, with travel and living expenses included. Please see our Field Service Pricing Schedule, Exhibit C1, dated January 2007, for per diem service rates. A copy is included with this proposal.

TERMS OF PAYMENT

10% Upon Receipt of Letter of Intent, Purchase Order, or Contract
20% Upon Submittal of Drawings to the Buyer for Approval
20% Upon Buyer's Release for Equipment Fabrication
10% Upon Submittal of Certified Drawings to the Buyer
30% Upon Date of Shipment of Equipment, or Thirty Days after Notification to Buyer that Equipment is Ready to Ship, whichever Occurs First.
10% After Successful Completion of Acceptance Test or Six (6) Months after Receipt of Equipment, whichever Occurs First.

All invoices are payable net thirty (30) days from invoice date. Buyer shall pay interest at the rate of ten percent (10%) per annum on all overdue amounts. Buyer shall pay all Sales Tax, Use Tax, Excise Tax, or other similar taxes.

PRELIMINARY PROJECT SCHEDULE

EVENT	RESPONSIBILITY	WEEKS FROM ORDER DATE
Receipt of Order	Smurfit-Stone	0
Begin Project Design	Fuel Tech	1
Submit Preliminary P&ID Drawings	Fuel Tech	4
Customer Drawing Comments Received	Smurfit-Stone	6
Complete Process Modeling	Fuel Tech	10
Submit Mechanical & Electrical Drawings	Fuel Tech	10
Customer Drawing Comments Received/Release for Procurement and Fabrication	Smurfit-Stone	12
Begin Equipment Fabrication	Fuel Tech	14
Equipment Shipment	Fuel Tech	32
Equipment Delivery	Fuel Tech	33
Complete Equipment Installation	Smurfit-Stone	TBD
Begin Start-Up & Testing	Fuel Tech	1-2 weeks after completion of installation
Begin Optimization	Fuel Tech	2-4 weeks
Compliance Testing	Smurfit-Stone	TBD

EXHIBIT C3
FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

These terms and conditions shall be part of the attached proposal and shall become part of the contract entered into between FUEL TECH, INC. (Fuel Tech), and the Buyer. Deviations from these terms and conditions must be agreed to in a writing signed by Fuel Tech and the Buyer. Fuel Tech hereby gives notice of its objection to any different or additional terms or conditions unless such different or additional terms or conditions are agreed to in a writing signed by Fuel Tech and Buyer.

1. TERMS OF PAYMENT:
   All invoices are payable net thirty (30) days from date of invoice. Buyer shall pay interest at the rate of ten percent (10%) per annum on all overdue amounts. Buyer shall pay all sales tax, use tax, excise tax, or other similar taxes.

2. DELAYS:
   If shipments are delayed by Buyer, payment shall be due on and warranty coverage shall begin to run from thirty days after the original shipment date specified in the contract or thirty (30) days after notification to Buyer that equipment is ready to ship, whichever is earlier. Risk of loss shall pass to Buyer at the time that equipment is identified, and any costs caused by such delay shall be borne by Buyer.

   If shipments are delayed by Buyer, Fuel Tech will ship the equipment no later than sixty (60) days after initial notification to the Buyer that the equipment is ready for shipment. Buyer agrees either (1) to provide Fuel Tech an appropriate "ship to" address and to accept delivery or (2) pay reasonable storage charges for the equipment beginning sixty (60) days after initial notification to Buyer that equipment is ready to ship.

3. PERFORMANCE GUARANTEE:
   Buyer warrants that the operating conditions of the Unit are those specified in the Process Design Table. Buyer is solely responsible for the accuracy of that operating condition information, and all performance guarantees and equipment warranties granted by Fuel Tech shall be void if that operating condition information is inaccurate or is not met. All performance guarantees and equipment warranties are conditioned on Buyer timely providing all of the equipment, materials, chemicals, utilities, and services that it has agreed to provide, on operating the Unit within the operating conditions specified in the Process Design Table, and on using reagent of license grade quality in the operation of the Unit.

EXHIBIT C3
FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

4. EQUIPMENT WARRANTY:

   Fuel Tech warrants that the equipment it provides shall be free from defects in design, workmanship, and material at the time the equipment is delivered and for a period of twelve (12) months after initial operation, or eighteen (18) months from shipment of equipment, whichever occurs first. Fuel Tech does not warrant wear parts such as injection tips, cooling shields, pump diaphragms, check valves, solenoids, pump impellers, pump wear rings, pump seals, valve packing, and valve seats.

   All warranties made by the manufacturer of the equipment (if that manufacturer is any entity other than Fuel Tech) shall be assigned by Fuel Tech to the Buyer, if such assignment is permissible by law and contract. Warranty coverage starts at shipment of equipment or thirty (30) days after notification to Buyer that equipment is ready to ship.

5. DISCLAIMER OF WARRANTIES:

   Fuel Tech warrants its equipment and the performance of its equipment solely in accordance with the equipment warranty and performance guarantee contained in this proposal and makes no other representations or warranties of any other kind, express or implied, by fact or by law. All warranties other than those specifically set forth in this proposal are expressly disclaimed. **FUEL TECH SPECIFICALLY DISCLAIMS ALL OTHER WARRANTIES, EXPRESS OR IMPLIED, AND DISLCAIMS THE IMPLIED WARRANTY OF MERCHANTABILITY, THE IMPLIED WARRANTY OF FITNESS FOR A PARTICULAR PURPOSE, AND ANY OTHER IMPLIED WARRANTIES OF DESIGN, CAPACITY, OR PERFORMANCE RELATING TO THE EQUIPMENT.**

6. LIMITATION OF LIABILITY:

   Buyer's sole remedy under the equipment warranty and the performance guarantee shall be to allow Fuel Tech, at Fuel Tech's option, either to repair, replace, or supplement the equipment to meet the performance guarantee, or, in the event that those options are not feasible, to remove the Equipment and refund the contract price to Buyer. NOTWITHSTANDING ANYTHING TO THE CONTRARY, FUEL TECH'S TOTAL LIMIT OF LIABILITY ON ANY CLAIM, WHETHER FOR BREACH OF CONTRACT, BREACH OF WARRANTY, TORT, NEGLIGENCE, STRICT LIABILITY, OR ANY OTHER LEGAL THEORY, FOR ANY LOSS OR DAMAGE ARISING OUT OF, OR CONNECTED TO, OR RESULTING FROM THIS AGREEMENT, INCLUDING WITHOUT LIMITATION AMOUNTS INCURRED BY FUEL TECH OR BUYER IN ATTEMPTING TO REPAIR, REPLACE, OR SUPPLEMENT THE EQUIPMENT OR MEET THE PERFORMANCE GUARANTEE, SHALL BE LIMITED TO THE CONTRACT PRICE TO BE PAID BY BUYER PURSUANT TO THE CONTRACT.

EXHIBIT C3

FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

7. EXCLUSION OF CONSEQUENTIAL DAMAGES:
   NOTWITHSTANDING ANYTHING TO THE CONTRARY, IN NO EVENT SHALL FUEL TECH BE LIABLE FOR ANY INDIRECT, CONSEQUENTIAL, INCIDENTAL, SPECIAL, OR PUNITIVE DAMAGES, INCLUDING BUT NOT LIMITED TO LOSS OF CAPITAL, LOSS OF REVENUES, LOSS OF PROFITS, LOSS OF ANTICIPATORY PROFITS, LOSS OF BUSINESS OPPORTUNITY, DAMAGE TO EQUIPMENT OR FACILITIES, COST OF SUBSTITUTE NOx REDUCTION SYSTEMS, DOWNTIME COSTS, GOVERNMENT FINES, OR CLAIMS OF CUSTOMERS, EVEN IF ADVISED OF THE POSSIBILITY OF SUCH DAMAGES.

8. RESPONSIBILITY FOR THIRD PARTIES
   Buyer shall at all times be responsible for the acts and omissions of its subcontractors and of any other third parties hired or retained or contracted by Buyer to perform work or provide equipment related to the system provided by Fuel Tech, including but not limited to third party design, systems integration, equipment tie-in, or process design changes. Fuel Tech shall have no responsibility for ensuring the accuracy of any such work or the performance of any equipment provided by subcontractors or third parties hired or retained or contracted by Buyer, and Buyer assumes all liability for any such work or equipment and for any failures in Fuel Tech's equipment caused by any such subcontractors or third parties hired or retained or contracted by Buyer. Buyer agrees to indemnify, hold harmless, and defend Fuel Tech from any claims, losses, damages, injuries, or failures caused by any such subcontractors or third parties.

9. CONFIDENTIALITY:
   Buyer agrees that it shall hold Confidential Information received from Fuel Tech in the strictest confidence, shall not use the Confidential Information for its own benefit except as necessary to fulfill the terms of the agreement between the parties, shall disclose the Confidential Information only to employees, agents, or representatives who have a need to know the Confidential Information, shall not disclose the Confidential Information to any third party, shall not copy the Confidential Information, shall not disassemble, decompile, or otherwise reverse engineer the Confidential Information and any inventions, processes, or products disclosed by Fuel Tech, and, in preventing disclosure of Confidential Information to third parties, shall use the same degree of care as for its own information of similar importance, but no less than reasonable care.

10. LICENSE AGREEMENT AND OTHER TERMS:

    Sale is subject to agreement on other terms and conditions, including a Sale of Equipment with License Agreement.

EXHIBIT C3
FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

11. INDEMNIFICATION:
Each Party shall defend, indemnify, and hold harmless the other Party and its employees, agents, and representatives from any claims, liabilities, lawsuits, costs, losses, or damages that arise out of or result from any negligent or willful acts or omissions of the indemnifying Party's employees, agents, or representatives. Where such claims, liabilities, lawsuits, costs, losses, or damages are the result of the joint or concurrent negligence or willful misconduct of the Parties or their respective agents, employees, representatives, subcontractors, or any third party, each Party's duty of indemnification shall be in the same proportion that the negligence or willful misconduct of such Party, its agents, employees, representatives, or subcontractors contributed thereto. The Party entitled to indemnity under this Agreement shall promptly notify the indemnifying Party of any indemnifiable claim, liability, lawsuit, cost, loss, or damage. The Party responsible for indemnification under this Agreement shall conduct and control the defense of the indemnified claim, liability, lawsuit, cost, loss, or damage. The Parties shall use their best efforts to cooperate in all aspects of the defense of any such claim, liability, lawsuit, cost, loss, or damage. The indemnifying Party shall not be bound by any compromise or settlement made without its prior written consent.

12. FORCE MAJEURE
The Parties shall be excused from liability for delays in manufacture, delivery, or performance due to any events beyond the reasonable control of the Parties, including but not limited to acts of God, war, national defense requirements, riot, sabotage, governmental law, ordinance, rule, or regulation (whether valid or invalid), orders of injunction, explosion, strikes, concerted acts of workers, fire, flood, storm, failure of or accidents involving either Party's plant, or shortage of or inability to obtain necessary labor, raw materials, or transportation ("Force Majeure"). Any delay in the performance by either party under this Agreement shall be excused if and to the extent the delay is caused by the occurrence of a Force Majeure, provided that the affected party shall promptly give written notice to the other party of the occurrence of a Force Majeure, specifying the nature of the delay, and the probable extent of the delay, if determinable.

Following the receipt of any written notice of the occurrence of a Force Majeure, the parties shall immediately attempt to determine what fair and reasonable extension for the time of performance may be necessary. The parties agree to use reasonable commercial efforts to mitigate the effects of events of Force Majeure.

No liabilities of any party that arose before the occurrence of the Force Majeure event shall be excused except to the extent affected by such subsequent Force Majeure.

EXHIBIT C3
FUEL TECH, INC. STANDARD TERMS AND CONDITIONS

13. GOVERNING LAW

This Agreement shall be governed by and interpreted in accordance with the laws of the State of Illinois, excluding its choice of laws rules. The parties shall attempt to settle any disputes, controversies, or claims arising out of this Agreement through consultation and negotiation in good faith and in a spirit of mutual cooperation. If those attempts fail, then any dispute, controversy or claim shall be submitted first to a mutually acceptable neutral advisor for mediation. Neither party may unreasonably withhold acceptance of a neutral advisor. The selection of the neutral advisor must be made within forty-five (45) days after written notice by one party demanding mediation, and the mediation must be held within six months after the initial demand for it. By mutual agreement, however, the parties may postpone mediation until they have each completed some specified but limited discovery about the dispute, controversy, or claim. The cost of mediation shall be equally shared between the parties. Any dispute that the parties cannot resolve through mediation within six (6) months after the initial demand for it may then be submitted to a state or federal court of competent jurisdiction within the State of Illinois for resolution. The use of mediation shall not be construed (under such doctrines as laches, waiver, or estoppel) to have adversely affected any party's ability to pursue its legal remedies, and nothing in this provision shall prevent any party from resorting to judicial proceedings if good faith efforts to resolve a dispute under these procedures have been unsuccessful or interim resort to a court is necessary to prevent serious and irreparable injury to any party or others.

14. ENTIRE AGREEMENT

This Exhibit C3 and the Fuel Tech Proposal attached to it constitute the entire agreement between the parties and can be modified only in writing signed by authorized representatives of each of the parties.

PPC Industries
3000 East Marshall Longview, TX 75601
903-758-3395 Fax 903-758-6487

To: Mr. Dave Buff

Golder Associates

Email: dbuff@golder.com

Date: 07/23/07

Number of Pages: 01

Quotation No: 07121-B –150,000 pph case

Gentlemen:

This document is in response to your request for a budget quotation for an electrostatic precipitator for your bagasse & oil fired boiler at West Palm Beach, FL. The unit is designed to operate at 150,000 acfm and 350 degrees F. The electrostatic precipitator will reduce the emissions from 492 kg/hr to 6.8 kg/hr..

The electrostatic precipitator would be our Model **29R-1330-3712S.** The price includes three cells (fields), structural steel supports, transverse trough hoppers with 18" x 24'-0" openings and hopper heaters, complete roof assemblies, three transformers with microprocessor controllers mounted on the roof assemblies, roof mounted power distribution panel, shop roof electrical wiring, pyramid inlet nozzle, box outlet nozzle, stack transition, 125' discharge elevation stub stack mounted on the outlet nozzle, 270 degree stack testing platform with ladder to precipitator roof, grade to roof access ladder with platform, shop installed thermal insulation, freight to the jobsite.

The base price does not include any airlocks, conveying system, main disconnect, foundations, field electrical wiring or grounding, field erection and field insulation of construction seams and lagging.

Power consumption will be 116 kva. PPC's scope includes the unit delivered to the jobsite. Pressure drop across the unit is 0.50" wc.

Price delivered .... $ 1,477,000.00

OPTIONS:
1. Conveyors and Airlocks (delivered) .... $ 51,700.00
2. Stairway in lieu of ladder .... $ 23,700.00

If you need anything else, please let us know.

Sincerely,

Bill Fisher
President

PPC Industries
3000 East Marshall Longview, TX 75601
903-758-3395 Fax 903-758-6487

To: Mr. Dave Buff
Golder Associates
Email: dbuff@golder.com

Date: 07/23/07
Number of Pages: 01

Quotation No: 07121-A – 200,000 pph case

Gentlemen:

This document is in response to your request for a budget quotation for an electrostatic precipitator for your bagasse & oil fired boiler at West Palm Beach, FL. The unit is designed to operate at 200,000 acfm and 350 degrees F. The electrostatic precipitator will reduce the emissions from 492 kg/hr to 6.8 kg/hr.

The electrostatic precipitator would be our Model **37R-1330-3712S**. The price includes three cells (fields), structural steel supports, transverse trough hoppers with 18" x 24'-0" openings and hopper heaters, complete roof assemblies, three transformers with microprocessor controllers mounted on the roof assemblies, roof mounted power distribution panel, shop roof electrical wiring, pyramid inlet nozzle, box outlet nozzle, stack transition, 125' discharge elevation stub stack mounted on the outlet nozzle, 270 degree stack testing platform with ladder to precipitator roof, grade to roof access ladder with platform, shop installed thermal insulation, freight to the jobsite.

The base price does not include any airlocks, conveying system, main disconnect, foundations, field electrical wiring or grounding, field erection and field insulation of construction seams and lagging.

Power consumption will be 132 kva. PPC's scope includes the unit delivered to the jobsite. Pressure drop across the unit is 0.50" wc.

Price delivered .... $ 1,657,000.00

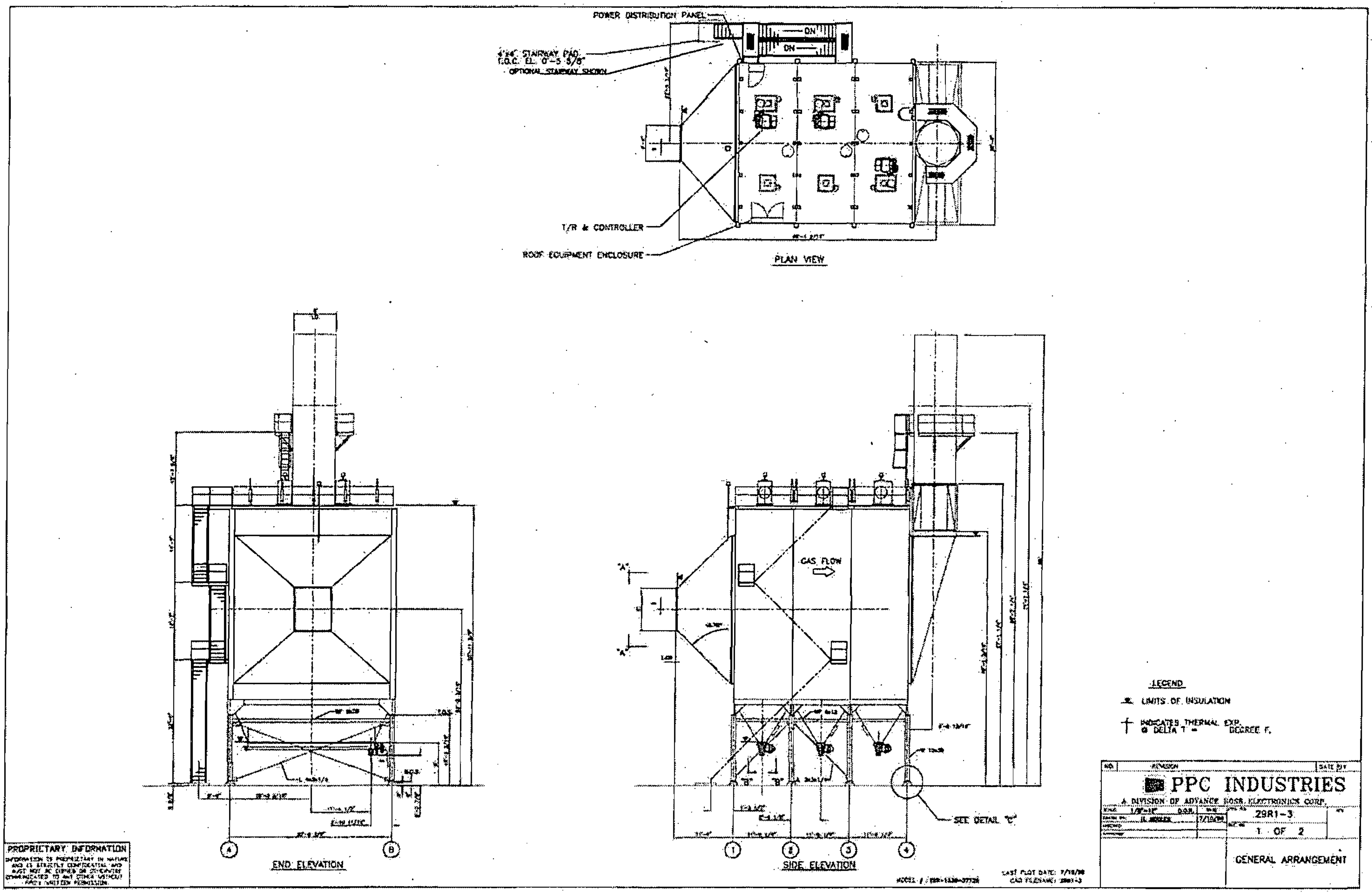
Options:
1. Conveyors and Airlocks (delivered) .... $ 63,500.00
2. Stairway in lieu of ladder .... $ 23,700.00

If you need anything else, please let us know.

Sincerely,

Bill Fisher
President

BEST AVAILABLE COPY



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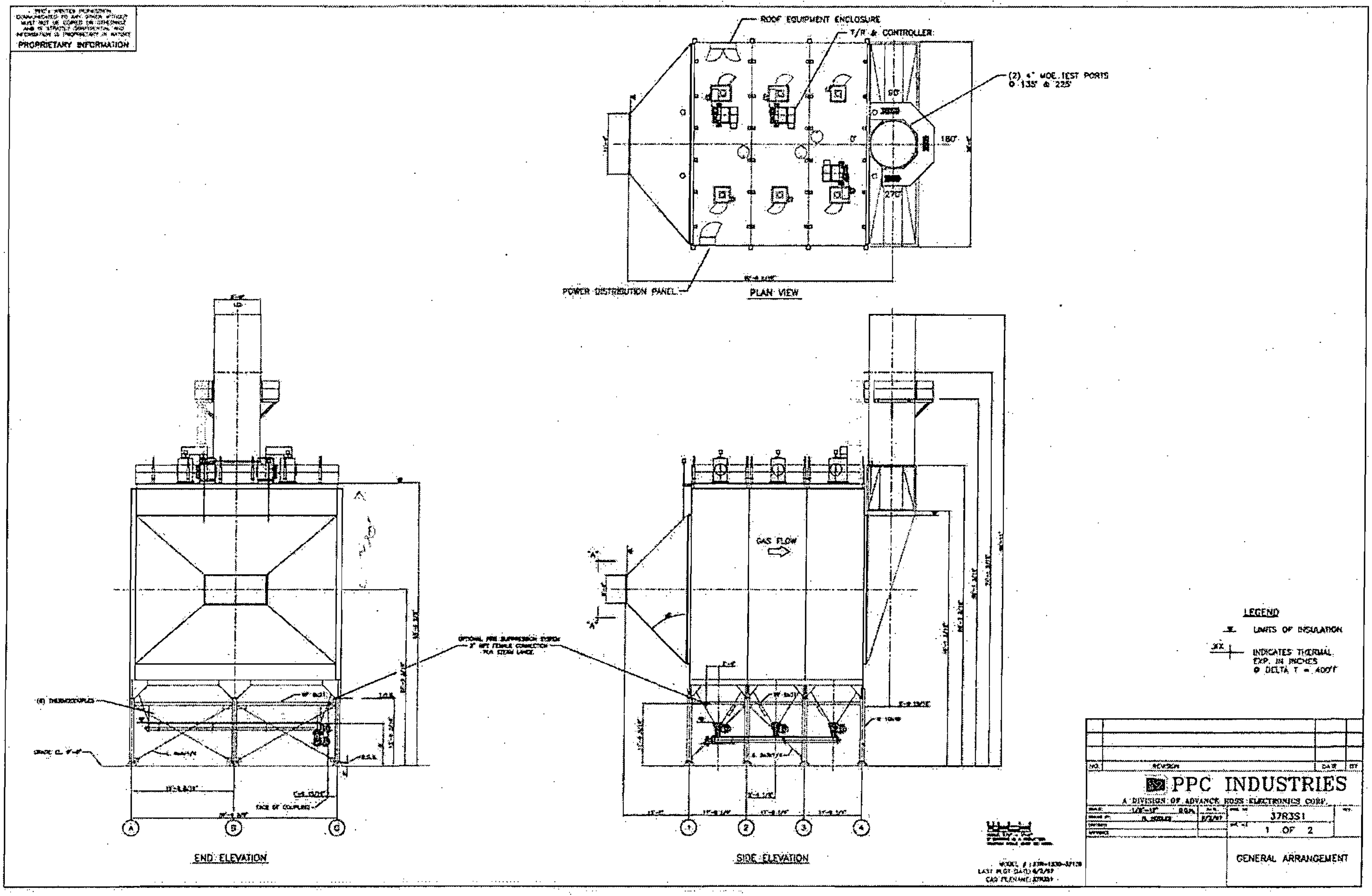
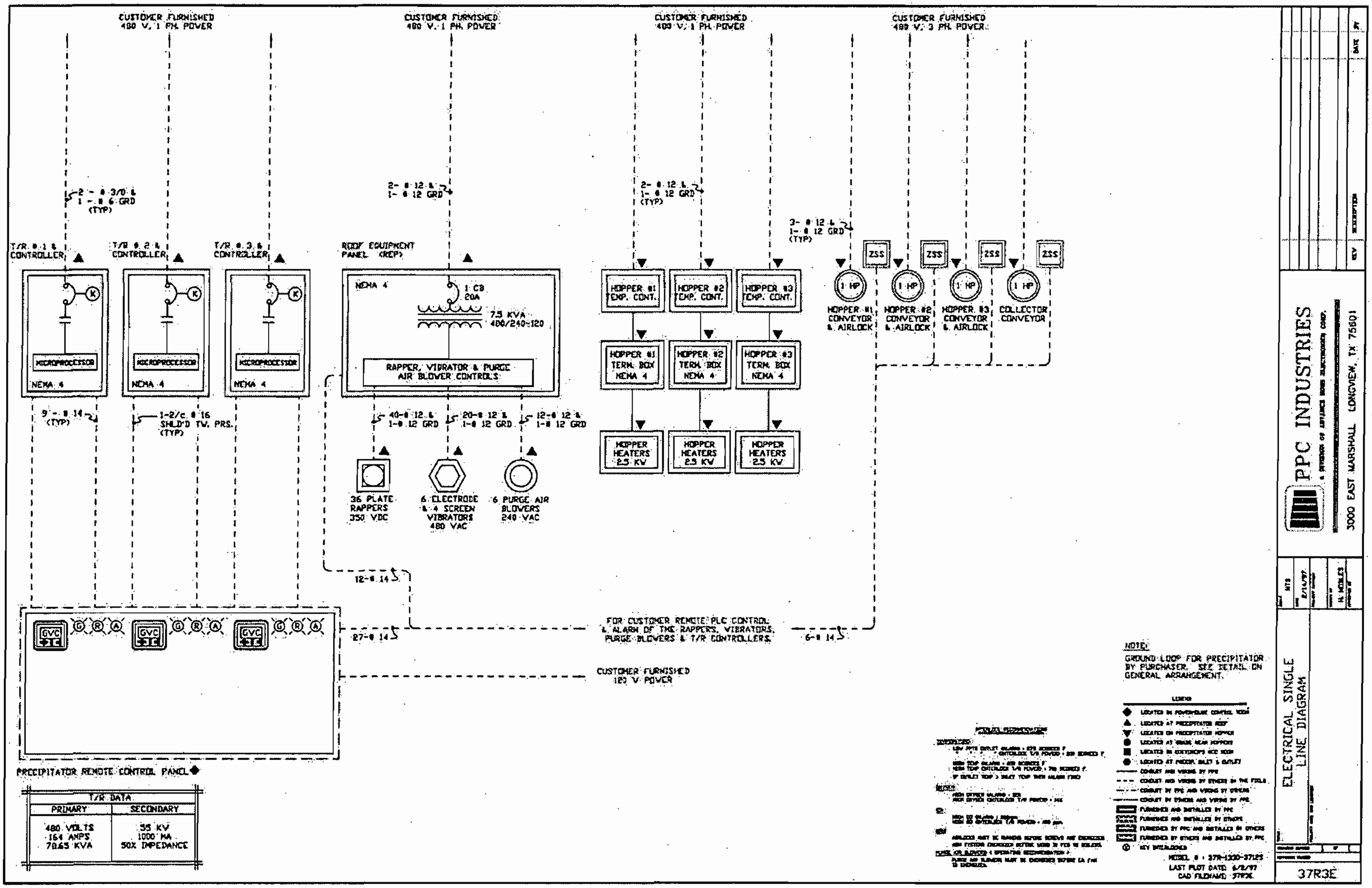
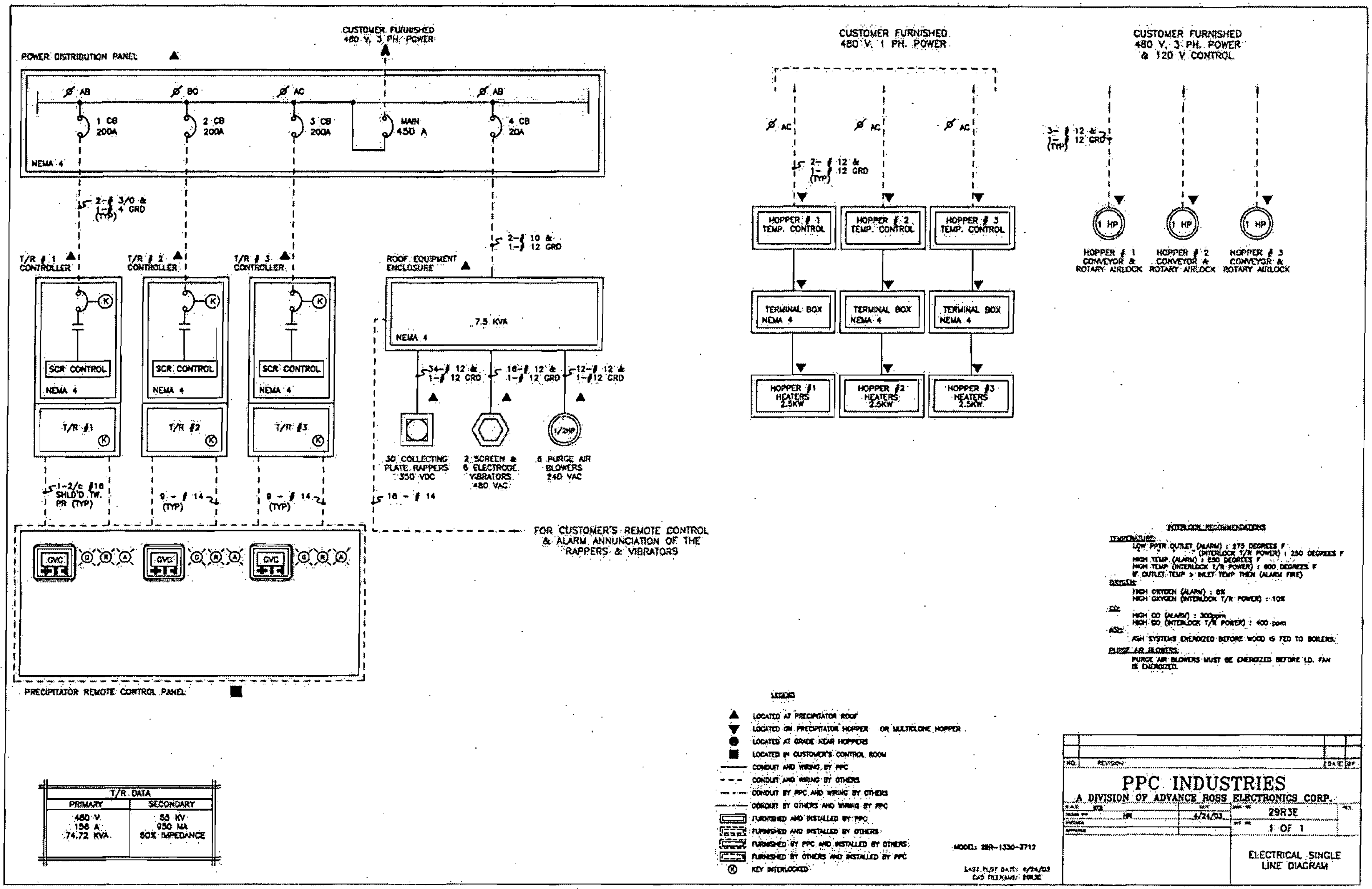




CUSTOMER FURNISHED 480 V, 1 PH. POWER
CUSTOMER FURNISHED 480 V, 1 PH. POWER
CUSTOMER FURNISHED 480 V, 1 PH. POWER
CUSTOMER FURNISHED 480 V, 3 PH. POWER
2 - # 3/0 & 1 - # 6 GRD (TYP)
2- # 12 & 1- # 12 GRD
2- # 12 & 1- # 12 GRD (TYP)
3- # 12 & 1- # 12 GRD (TYP)
T/R # 1 & CONTROLLER
T/R # 2 & CONTROLLER
T/R # 3 & CONTROLLER
MICROPROCESSOR
NEMA 4
ROOF EQUIPMENT PANEL (REP)
NEMA 4
1 CB 20A
7.5 KVA 480/240-120
RAPPER, VIBRATOR & PURGE AIR BLOWER CONTROLS
HOPPER #1 TEMP. CONT.
HOPPER #2 TEMP. CONT.
HOPPER #3 TEMP. CONT.
HOPPER #1 TERM. BOX NEMA 4
HOPPER #2 TERM. BOX NEMA 4
HOPPER #3 TERM. BOX NEMA 4
HOPPER HEATERS 2.5 KV
ZSS
1 HP
HOPPER #1 CONVEYOR & AIRLOCK
HOPPER #2 CONVEYOR & AIRLOCK
HOPPER #3 CONVEYOR & AIRLOCK
COLLECTOR CONVEYOR
9 - # 14 (TYP)
1-2/c. # 16 SHLD'D TW. PRS. (TYP)
40-# 12 & 1-# 12 GRD
20-# 12 & 1-# 12 GRD
12-# 12 & 1-# 12 GRD
36 PLATE RAPPERS 350 VDC
6 ELECTRODE & 4 SCREEN VIBRATORS 480 VAC
6 PURGE AIR BLOWERS 240 VAC
12-# 14
27-# 14
6-# 14
FOR CUSTOMER REMOTE PLC CONTROL & ALARM OF THE RAPPERS, VIBRATORS, PURGE BLOWERS & T/R CONTROLLERS.
CUSTOMER FURNISHED 120 V POWER
GVC
PRECIPITATOR REMOTE CONTROL PANEL
T/R DATA
PRIMARY
480 VOLTS
164 AMPS
70.65 KVA
SECONDARY
55 KV
1000 MA
50% IMPEDANCE
NOTE:
GROUND LOOP FOR PRECIPITATOR BY PURCHASER. SEE DETAIL ON GENERAL ARRANGEMENT.
LEGEND
MODEL # : 37R-1330-37125
LAST PLOT DATE: 6/2/97
CAD FILENAME: 37R3E
PPC INDUSTRIES
3000 EAST MARSHALL LONGVIEW, TX 75601
ELECTRICAL SINGLE LINE DIAGRAM
37R3E



CUSTOMER FURNISHED
480 V. 3 PH. POWER
POWER DISTRIBUTION PANEL
Ø AB
Ø BC
Ø AC
Ø AB
1 CB 200A
2 CB 200A
3 CB 200A
MAIN 450 A
4 CB 20A
NEMA 4
2-# 3/0 & 1-# 4 GRD (TYP)
2-# 10 & 1-# 12 GRD
T/R # 1 CONTROLLER
T/R # 2 CONTROLLER
T/R # 3 CONTROLLER
ROOF EQUIPMENT ENCLOSURE
7.5 KVA
NEMA 4
SCR CONTROL
NEMA 4
T/R #1
T/R #2
T/R #3
34-# 12 & 1-# 12 GRD
16-# 12 & 1-# 12 GRD
12-# 12 & 1-# 12 GRD
30 COLLECTING PLATE RAPPERS 330 VDC
2 SCREEN & 6 ELECTRODE VIBRATORS 480 VAC
6 PURGE AIR BLOWERS 240 VAC
1/2HP
1-2/c #16 SHLD'D TW. PR (TYP)
9 - # 14 (TYP)
16 - # 14
FOR CUSTOMER'S REMOTE CONTROL & ALARM ANNUNCIATION OF THE RAPPERS & VIBRATORS
GVC
PRECIPITATOR REMOTE CONTROL PANEL
CUSTOMER FURNISHED
480 V. 1 PH. POWER
Ø AC
2-# 12 & 1-# 12 GRD (TYP)
HOPPER # 1 TEMP. CONTROL
HOPPER # 2 TEMP. CONTROL
HOPPER # 3 TEMP. CONTROL
TERMINAL BOX NEMA 4
HOPPER #1 HEATERS 2.5KW
HOPPER #2 HEATERS 2.5KW
HOPPER #3 HEATERS 2.5KW
CUSTOMER FURNISHED
480 V. 3 PH. POWER
& 120 V. CONTROL
3-# 12 & 1-# 12 GRD (TYP)
1 HP
HOPPER # 1 CONVEYOR & ROTARY AIRLOCK
HOPPER # 2 CONVEYOR & ROTARY AIRLOCK
HOPPER # 3 CONVEYOR & ROTARY AIRLOCK
INTERLOCK RECOMMENDATIONS
TEMPERATURE:
LOW PPTR OUTLET (ALARM) : 275 DEGREES F
(INTERLOCK T/R POWER) : 250 DEGREES F
HIGH TEMP (ALARM) : 550 DEGREES F
HIGH TEMP (INTERLOCK T/R POWER) : 600 DEGREES F
IF OUTLET TEMP > INLET TEMP THEN (ALARM FIRE)
OXYGEN:
HIGH OXYGEN (ALARM) : 8%
HIGH OXYGEN (INTERLOCK T/R POWER) : 10%
CO:
HIGH CO (ALARM) : 300ppm
HIGH CO (INTERLOCK T/R POWER) : 400 ppm
ASH:
ASH SYSTEMS ENERGIZED BEFORE WOOD IS FED TO BOILERS.
PURGE AIR BLOWERS:
PURGE AIR BLOWERS MUST BE ENERGIZED BEFORE I.D. FAN IS ENERGIZED.
LEGEND
LOCATED AT PRECIPITATOR ROOF
LOCATED ON PRECIPITATOR HOPPER OR MULTICLONE HOPPER
LOCATED AT GRADE NEAR HOPPERS
LOCATED IN CUSTOMER'S CONTROL ROOM
CONDUIT AND WIRING BY PPC
CONDUIT AND WIRING BY OTHERS
CONDUIT BY PPC AND WIRING BY OTHERS
CONDUIT BY OTHERS AND WIRING BY PPC
FURNISHED AND INSTALLED BY PPC
FURNISHED AND INSTALLED BY OTHERS
FURNISHED BY PPC AND INSTALLED BY OTHERS
FURNISHED BY OTHERS AND INSTALLED BY PPC
KEY INTERLOCKED
MODEL: 28R-1330-3712
LAST PLOT DATE: 4/24/03
T/R DATA
PRIMARY
480 V.
156 A.
74.72 KVA
SECONDARY
55 KV
950 MA
60% IMPEDANCE
PPC INDUSTRIES
A DIVISION OF ADVANCE ROSS ELECTRONICS CORP.
29R3E
1 OF 1
ELECTRICAL SINGLE LINE DIAGRAM

APPENDIX C

APPLICATION FOR AIR PERMIT – LONG FORM

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial/revised/renewal Title V air operation permit.

Air Construction Permit & Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Sugar Cane Growers Cooperative of Florida**	
2. Site Name: **Glades Sugar House**	
3. Facility Identification Number: **0990026**	
4. Facility Location...: Street Address or Other Locator: **1500 West Sugar House Road** City: **Belle Glade** County: **Palm Beach** Zip Code: **33430-0666**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Kathy Lockhart**
2. Application Contact Mailing Address... Organization/Firm: **Sugar Cane Growers Cooperative of Florida** Street Address: **1500 West Sugar House Road / P.O. Box 666** City: **Belle Glade** State: **FL** Zip Code: **33430-0666**
3. Application Contact Telephone Numbers... Telephone: **(516) 996-4779** ext. Fax: **(561) 996-4780**
4. Application Contact Email Address: **kdlockhart@scgc.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 1/31/08	3. PSD Number (if applicable):
2. Project Number(s): 0990026-014-AC	4. Siting Number (if applicable):

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☒ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

This application is for the purpose of obtaining a BART determination for the BART-eligible emissions units at the SCGCF Belle Glade facility.

There is no change to any of the BART-eligible emissions units at the Belle Glade facility as a result of this project and no new emissions limits are requested.

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	Boiler No. 1	AC1F	
002	Boiler No. 2	AC1F	
004	Boiler No. 4	AC1F	
005	Boiler No. 5	AC1F	

Application Processing Fee

Check one: ☐ Attached - Amount: $________________ ☒ Not Applicable

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **Jose F. Alvarez, Senior Vice President, Planning and Operations**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Sugar Cane Growers Cooperative of Florida** Street Address: **1500 West Sugar House Road / P.O. Box 666** City: **Belle Glade** State: **FL** Zip Code: **33430-0666**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(561) 996-4759** ext. Fax: **(561) 996-4747**
4.	Owner/Authorized Representative Email Address: **jfalvarez@scgc.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* [signature] Signature 1/28/2008 Date

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

- ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
- ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
- ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
- ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...

Organization/Firm:

Street Address:

City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...

Telephone: ext. Fax:

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

Signature Date

Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext. **545** Fax: **(352) 336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**

5. Professional Engineer Statement:

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

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

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

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☒, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff

Signature

1/30/08

Date

(seal)

* Attach any exception to certification statement.

**** Board of Professional Engineers Certificate of Authorization #00001670**