Appendix H
Reasonable Progress Evaluation, BART and Long-Term Strategy

Appendix H

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1.0 BASE G CAA CONTROLS

2009 and 2018 emissions projections include the following existing State and Federal regulations:

- Clean Air Interstate Rule (CAIR): Utility projections are based on Integrated Planning Model**.** CAIR will permanently cap emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) in the eastern United States. CAIR achieves large reductions of SO2 and/or NOx emissions across 28 eastern states and the District of Columbia. When fully implemented, CAIR will reduce SO2 emissions in these states by over 70 percent and NOx emissions by over 60 percent from 2003 levels.

- Georgia Rule 391-3-1-.02 (2) (sss) (i.e., The Multipollutant Control for Electric Utility Steam Generating Units) was enacted in 2007. The effective date of the rule varies for various EGU units, but it will start being effective from December 31, 2008, and will be in place over all the rule-effected units by January 1, 2018. When fully implemented, Rule (sss) will reduce SO2 emissions by about 90 percent, NOx emissions by approximately 85 percent and mercury emissions by approximately 79 percent.

- 1-hr Ozone SIPs (Atlanta/Birmingham/Northern Kentucky). The purpose of a State implementation plan (SIP) is to demonstrate attainment or maintenance of the 1-hour ozone National Ambient Air Quality Standard (NAAQS). States must determine which Clean Air Act requirements are applicable to their area and submit plans to EPA for public comment and approval.

- Georgia Rule 391-3-1-.02(2)(yy) (e.g., Emissions of Nitrogen Oxides from Major Sources) based on Section 182 of the Federal CAA Amendments of 1990, requires that every major source (i.e., a source with potential to emit > 50 tons/yr) of NOx located in the13-county Atlanta non-attainment area should apply reasonably available control technology (RACT) in controlling NOx emissions. Georgia EPD has required full compliance with NOx RACT limits since July 31, 1995.

- Heavy Duty Diesel (2007) Engine Standard. This standard is a PM emissions standard for new heavy-duty engines of 0.01 grams per brake-horsepower-hour (g/bhp-hr), to take full effect for diesels in the 2007 model year. It also includes standards for NOx and non-methane hydrocarbons (NMHC) of 0.20 g/bhp-hr and 0.14 g/ bhp-hr, respectively. These NOx and NMHC standards will be phased in together between 2007 and 2010 for diesel engines. Sulfur in diesel fuel must be lowered to enable modern pollution-control technology to be effective on these trucks and buses. EPA will require a 97 percent reduction in the sulfur content of highway diesel fuel from its current level of 500 parts per million (low sulfur diesel, or LSD) to 15 parts-per-million (ultra-low sulfur diesel, or ULSD).

- Tier 2 Tail pipe. Tier 2 is a fleet averaging program modeled after the California LEV II standards. Manufacturers can produce vehicles with emissions ranging from relatively dirty to zero, but the mix of vehicles a manufacturer sells each year must have average NO_x emissions below a specified value.

- Large Spark Ignition and Recreational Vehicle Rule. Sets emission standards for these categories of nonroad engines and vehicles.

- Nonroad Diesel Rule. Implements a low sulfur fuel requirement that affects both future (CMV) Commercial Marine Vessels and locomotive emissions.

- Industrial Boiler/Process Heater/RICE MACT. The Environmental Protection Agency (EPA) issued final rules to substantially reduce emissions of toxic air pollutants from industrial, commercial and institutional boilers, process heaters and from stationary reciprocating internal combustion engines (RICE). These rules reduce emissions of a number of toxic air pollutants, including hydrogen chloride, manganese, lead, arsenic and mercury by 2009. This rule also reduces emissions of sulfur dioxide and particulate matter in conjunction with the toxic air pollutant reductions. The applied Maximum Achievable Control Technology (MACT) control efficiencies were four percent for SO_2 and 40 percent for PM10 and PM2.5. [It should be noted that EPA's industrial boiler MACT rules were vacated on June 8, 2007. The emissions reductions that were modeled to account for the industrial boiler MACT were 1,343.5 tons/year of SO2, 879.4 tons/year of PM2.5, and 1,304.2 tons/year of PM10. These reductions are insignificantly small (0.69% for SO2, 0.39% for PM2.5, and 0.13% for PM10) compared to the statewide totals (193,665.5 tons/year SO2; 225,104.5 tons/year PM2.5; and 1,002,873.2 tons/year PM10) and should not impact the conclusions made in the SIP (Appendix H.1). If another VISTAS "best and final" modeling run is performed, it will remove control assumptions solely due to this MACT rule.]

VOC 2-, 4-, 7-, and 10-year MACT Standards. The point source MACTs and associated emission reductions were designed from Federal Register (FR) notices and discussions with EPA's Emission Standards Division (ESD) staff. We did not apply reductions for MACT standards with an initial compliance date of 2001 or earlier, assuming that the effects of these controls are already accounted for in the 2002 inventories supplied by the States.

The following are source category specific controls used to project future-year emissions inventories:

1.1 Point Source Controls

Different approaches were used for the Electric Generating Unit (EGU) and the non-EGU sectors of the point source inventory:

- For the EGUs, the State relied primarily on the Integrated Planning Model® (IPM®) to project future generation, as well as to calculate the impact of future emission control programs, to include CAIR. The IPM results were adjusted based on State and local (S/L) agency knowledge of planned emission controls at specific EGUs.
- For non-EGUs, we used recently-updated growth and control data consistent with the data used in EPA's CAIR analyses and supplemented these data with available S/L agency input and updated fuel use forecast data for the U.S. Department of Energy.

For both sectors, we generated 2009 and 2018 inventories for a combined on-the-books (OTB) and on-the-way (OTW) control scenario. The OTB/OTW control scenario accounts for post-2002 emission reductions from promulgated and proposed Federal, State, local, and site-specific control programs as of July 1, 2004.

1.1.1 Electric Generating Units (EGUs)

S/L agencies specified a number of changes to the IPM results to better reflect current information on when and where future controls would occur. These changes to the IPM results primarily involved S/L agency addition or subtraction of future emission controls based on the best available data from State rules, enforcement agreements, compliance plans, permits, and discussions/commitments from individual companies.

Table 1-1 lists adjustments to IPM control determinations as specified by S/L agencies for the Base G 2009/2018 EGU inventories. Table 1-2 lists other adjustments to IPM results specified by S/L agencies for Base G 2009/2018 inventories.

Table 1-1. Adjustments to IPM Control Determinations Specified by S/L Agencies for the Base G 2009/2018 EGU Inventories.

State	Plant Name	Unit	NO_x Emission Controls				SO_2 Emission Controls			
			2009		2018		2009		2018	
			IPM	State	IPM	State	IPM	State	IPM	State
AL	James H. Miller ORISID=6002	1 & 2	SCR during ozone season	SCR probable year round due to CAIR	SCR during ozone season	SCR year round due to CAIR	None	None	None	None
		3 & 4	SCR during ozone season	SCR year round from Consent Decree	SCR during ozone season	SCR year round from Consent Decree	None	Scrubber	None	Scrubber
	Barry ORISID=3	1, 2, 3	None	SNCR	SCR	SNCR	None	None	None	None
		4	None	SNCR	SCR	SNCR	None	None	Scrubber	None
		5	None	None	SCR	SCR	None	None	Scrubber	None
	E C Gaston ORISID=26	4-Jan	SCR	None	SCR	None	None	None	Scrubber	None
		5	SCR	SCR	SCR	SCR	Scrubber	None	Scrubber	None
	Gorgas ORISID=8	6 & 7	None	None	None	None	None	None	None	None
		8 & 9	None	None	None	None	None	Scrubber	None	Scrubber
		10	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
	Charles R. Lowman ORISID=56	1	None	None	None	None	None	Scrubber	None	Scrubber
		2 & 3	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
GA	Bowen ORISID=703	1BLR	SCR	SCR	SCR	SCR	IPM had retrofit scrubbers but little emission reductions	None	Scrubber	Scrubber
		2BLR	SCR	SCR	SCR	SCR		None	Scrubber	Scrubber
		3BLR	SCR	SCR	SCR	SCR		Scrubber	Scrubber	Scrubber
		4BLR	SCR	SCR	SCR	SCR		Scrubber	Scrubber	Scrubber
	Wansley ORISID=6052	1	SCR	SCR	SCR	SCR	IPM had scrubbers but little emission reductions	Scrubber	Scrubber	Scrubber
		2	SCR	SCR	SCR	SCR		None	Scrubber	Scrubber
	Kraft ORISID=733	1, 2	None	None	None	None	None	None	None	None
		3	None	None	SCR	None	None	None	None	None
	McIntosh ORISID=6124	1	None	None	SCR	None	None	None	None	None
	Yates ORISID=728	1	None	None	None	None	Scrubber	Scrubber	Scrubber	Scrubber
		2, 3	None	None	None	None	None	None	None	None
		4 – 7	None	None	SCR	None	None	None	Scrubber	None
	Hammond ORISID=708	1	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		2	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		3	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		4	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
KY	Ghent ORISID=1356	1	None	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
		2	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		3, 4	None	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber

Table 1-1 (continued)

State	Plant Name and ID	Unit	NO_x Emission Controls				SO_2 Emission Controls			
			2009		2018		2009		2018	
			IPM	State	IPM	State	IPM	State	IPM	State
KY	Coleman ORISID=1381	C1	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		C2	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		C3	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
	HMP&L Station 2	H1	SCR	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
		H2	None	SCR	SCR	SCR	Scrubber	Scrubber	Scrubber	Scrubber
	E W Brown ORISID=1355	1	None	None	None	None	None	Scrubber	None	Scrubber
		2	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
		3	None	None	SCR	SCR	None	Scrubber	Scrubber	Scrubber
SC	Jeffries ORISID=3319	3	SCR	None	SCR	None	None	None	None	None
		4	None	None	None	None	None	None	None	None
	Wateree ORISID=3297	WAT1	SCR	SCR	SCR	SCR	None	Scrubber	None	Scrubber
		WAT2	SCR	SCR	SCR	SCR	None	Scrubber	Scrubber	Scrubber
	Canadys ORISID=3280	CAN1	None	None	None	None	None	None	None	None
		CAN2	None	None	None	None	None	None	None	None
		CAN3	None	None	None	None	None	Scrubber	None	Scrubber
	Rainey ORISID=7834	CT1A	None	SCR	None	SCR	None	None	None	None
		CT1B	None	SCR	None	SCR	None	None	None	None
TN	Kingston ORISID=3407	1 – 8	SCR	SCR	SCR	SCR	None	None	Scrubber	Scrubber
		9	None	SCR	SCR	SCR	None	None	Scrubber	Scrubber
	Johnsonville ORISID=3406	1 – 10	SCR	None	SCR	SCR	None	None	None	None
WV	Willow Island ORISID=3946	2	SCR	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber
	Kammer ORISID=3947	3-Jan	SCR	None	SCR	SCR	Scrubber	None	Scrubber	Scrubber

Table 1-2. Other Adjustments to IPM Results Specified by S/L Agencies for the Base G 2009/2018 EGU Inventories.

Stat	Plant Name and ID	Units	Nature of Update/Correction
FL	Central Power and Lime ORISID= 10333	GEN1	Central Power and Lime (ORIS10333) is a duplicate entry. This is point 18 in Florida Crushed Stone (12-053-0530021). Removed IPM emissions for Central Power and Lime.
	Cedar Bay Generating ORISID=10672	GEN1	FLDEP disagrees with IPM projections - no knowledge of expansion of this facility and the cogeneration facility should not grow faster than the underlying industry. Cedar Bay is connected to Stone Container (12-031-0310067). Replaced IPM emissions with 2002 emissions for Cedar Bay (12-031-0310337) times the growth factors for Stone Container.
	Indiantown Cogeneration ORISID=50976	GEN1	FLDEP disagrees with IPM projections - no knowledge of expansion of this facility and the cogeneration facility should not grow faster than the underlying industry. Indiantown is connected to Louis Dreyfus Citrus (12-085-0850002). Replaced IPM emissions with 2002 emissions for Indiantown (12-085-0850102) times the growth factors for Louis Drefus Citrus.
GA	Bowen ORISID=703	1BLR 2BLR 3BLR 4BLR	IPM indicated retrofit scrubbers on all 4 units in 2009, but the IPM emissions showed little reductions from 2002 levels. Changed emissions to reflect scrubbers on 1BLR and 2BLR by 2009.
	Wansley ORISID=6052	1, 2	IPM indicated retrofit scrubbers on both units in 2009, but the IPM emissions showed little reductions from 2002 levels. Changed emissions to reflect one scrubber on Unit 1 by 2009.
	Riverside ORISID=734	4	All of plant Riverside was retired from service June 1, 2005; emissions set to zero in 2009 and 2018.
	McIntosh ORISID=727	CT10A CT10B CT11A CT11B	The McIntosh Combined Cycle facility became commercial June 1, 2005. Added 346 tons of NO_x and 121 tons of SO_2 per unit to the 2009 and 2018 inventories.
	Longleaf Energy Station	1, 2	Longleaf Energy Station is being proposed by LS Power Development, Inc. GA specified that the emissions from this proposed plant be included in the 2018 projections. Boilers 1 and 2 added 1,882 tons of NO_x and 3,227 tons of SO_2 per unit to the 2018 inventory.
MS	R D Morrow ORISID=6061	1, 2	Revised the 2018 emissions to reflect controls not indicated by IPM. The SO_2 emissions are much lower than IPM, but their expected NO_x emissions are actually higher than IPM. The controls will be coming online 2009 or 2010, so the 2009 inventory did not change.
	Jack Watson (2049) Victor J Daniel (6073) Chevron Oil (2047)	All	MS DEQ specified that the emission projections provided by the Southern Company for their units in Mississippi were to be used instead of the IPM results.

Table 1-2 (continued)

State	Plant Name and ID	Unit	Nature of Update/Correction
NC	G G Allen (2718) Belews Creek (8042)1 Buck (2720) Cliffside (2721) Dan River (2723) Marshall (2727) Riverbend (2732)	All	Replaced all IPM 2009 results with emission projections from Duke Power's NC Clean Air Compliance Plan for 2006. Used IPM results for 2018
	Asheville (2706) Cape Fear (2708) Lee (2709) Mayo (6250) Roxboro (2712) Sutton (2713) Weatherspoon (2716)	All	Replaced all IPM 2009 results with emission projections from Progress Energy's NC Clean Smokestacks Act Calendar Year 2005 Progress Report. Used IPM results for 2018
	Dwayne Collier Battle Cogeneration Facility ORISID=10384	GEN1 GEN2	Dwayne Collier Battle is a duplicate entry. This is Cogentrix of Rocky Mount (37-065-3706500146, stacks G-26 and G-27). Duplicate entries were removed both the 2009 and 2018 inventories.
	Kannapolis Energy Partners ORISID=10626	GEN2 GEN3	Kannapolis Energy emissions are being used as credits for another facility. IPM emissions from this facility (37-025-ORIS10626) were removed from the EGU inventory for 2009 and 2018. Emissions from Kannapolis Energy (37-025-3702500113) were carried forward in the 2009/2018.
SC	Cross ORISID=130	1, 2	Unit 1: upgrade scrubber from 82 percent to 95 percent removal efficiency by June 30, 2006. Recalculate emissions based on upgrade in control efficiency. Unit 2: upgrade scrubber from 70 percent to 87 percent removal efficiency by June 30, 2006. Recalculate emissions based on upgrade in control efficiency.
	Winyah ORISID=6249	1 – 4	Unit 1: Install scrubber that meets 95 percent removal efficiency by Dec. 31, 2008; Upgrade ESP from 0.38 to 0.03 lb/mmBTU by Dec. 31, 2008 Unit 2: Replace scrubber with one that meets 95 percent removal efficiency from 45 percent by Dec. 31, 2008; Upgrade ESP from 0.10 to 0.03 lb/mmBTU by Dec. 31, 2008 Unit 3: Upgrade scrubber from 70 percent to 90 percent removal efficiency by Dec. 31, 2012; Upgrade ESP from 0.10 to 0.03 lb/mmBTU by Dec. 31, 2012 Unit 4: Upgrade scrubber from 70 percent to 90 percent removal efficiency by Dec. 31, 2007; Upgrade ESP from 0.10 to 0.03 lb/mmBTU by Dec. 31, 2007 Recalculated SO_2 and PM emissions based on upgrade in control efficiencies.

Table 1-2 (continued)

State	Plant Name and ID	Unit	Nature of Update/Correction
SC	Dolphus Grainger ORISID=3317	1, 2	Unit 1: Upgrade ESP from 0.60 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM_{10} and PM25 emissions in 2018 by 95 percent based on change in allowable emission rate Unit 2: Install low NO_x burners that meet 0.46 lb/mmBTU from 0.9 by May 1, 2004. Recalculated NO_x emissions using 0.46/lbs/mmBtu and IPM heat input Unit 2: Upgrade ESP from 0.60 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM_{10} and PM25 emissions in 2018 by 95 percent based on change in allowable emission rate
SC	Jeffries ORISID=3319	3, 4	Unit 3: Upgrade ESP from 0.54 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM_{10} and PM25 emissions in 2018 by 94.44 percent based on change in allowable emission rate Unit 4: Upgrade ESP from 0.54 to 0.03 lb/mmBTU by Dec. 31, 2012. Reduced PM_{10} and PM25 emissions in 2018 by 94.44 percent based on change in allowable emission rate
	W S Lee ORISID=3264	1, 2	IPM does not indicate that these units are installing SOFA NO_x control technology by April 30, 2006 to meet 0.27 lb/mmBTU, down from 0.45 lb/mmBtu. Calculated NO_x emissions using IPM heat input and 0.27 lbs/mmBtu
	Generic Unit ORISID=900545	All	All predictions for generic units appear reasonable with the exception of Plant ID ORIS900545 Point ID GSC45 which was modeled in Georgetown County. It will be very difficult to add new generation this close to the Cape Romain Class I area. Santee Cooper has no plans for future generation in Georgetown County, but does have plans for new future generation in Florence County. This unit was moved to coordinates specified in Florence County.
VA	AEP Clinch River ORISID=3775	1, 2, 3	Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
	AEP Glen Lyn ORISID=3776	51, 52, 6	Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
	Dominion Clover ORISID=7213	1, 2	Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
	Dominion Bremo ORISID=3796	3, 4	Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
	Dominion Chesterfield ORISID=3797	3, 4, 5, 6	Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
	Dominion Yorktown ORISID=3809	1, 2, 3	Units 1, 2: Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates. Unit 3: IPM predicts zero heat input for this 880 MW #6 oil fired unit. IPM does not predict a retirement, just that the heat input is zero. Dominion plans to continue to operate Unit 3. Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.

Table 1-2 (continued)

State	Plant Name and ID	Unit	Nature of Update/Correction
VA	Dominion Chesapeake ORISID=3803	1 – 4	Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
	Dominion Possum Point ORISID=3804	3 & 4 5 6	Unit 3&4: IPM had 137 tons of NO_x for these units in 2009 and 111 tons in 2018. VA DEQ specified that the permitted emission rates should be used, which equates to 3,066 tons in 2009 and 2018. Unit 5: IPM had zero heat input for this unit. Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates. Unit 6: Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
	Potomac River ORISID=3788	1 - 5	Units 1&2: IPM retired these units. Mirant has no plans at this time to retire any units. Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates. Units 3, 4, 5: Replaced all 2009/2018 IPM results using VADEQ's growth and control estimates.
WV	Albright ORISID=3942	1, 2	IPM predicted early retirement for these units. AEP indicated there are no for early retirement. For 2009, used 2002 emissions as these units are not likely to retire by 2009. For 2018, used IPM prediction of retirement.
	Rivesville ORISID=3945	7, 8	IPM predicted early retirement for these units. AEP indicated there are no for early retirement. For 2009, used 2002 emissions as these units are not likely to retire by 2009. For 2018, used IPM prediction of retirement.
	Willow Island ORISID=3946	1, 2	Unit 1: IPM predicted early retirement for these units. AEP indicated there are no for early retirement. For 2009, used 2002 emissions as these units are not likely to retire by 2009. For 2018, used IPM prediction of retirement. Unit 2: IPM predicted SCR and scrubber for 2009. These controls will not be in place by 2009.
	North Branch Power Station ORISID=7537	1A, 1B	SO_2 Permit Rate was corrected from 2.7 to 0.678 lb/MMBtu. Used SO_2 Permit Rate of 0.678 lb/MMBtu and IPM predicted total fuel used to calculate SO_2 emissions in 2009 and 2018
	Mt. Storm ORISID=3954	1, 2, 3	SO_2 Permit Rate was corrected from 2.7 to 0.15 lb/MMBtu. Used SO_2 Permit Rate of 0.15 lb/MMBtu and IPM predicted total fuel used to calculate SO_2 emissions in 2009 and 2018

1.1.2 Non-EGUs

The general approach for assembling future-year data was to use recently-updated growth and control data consistent with the data used in EPA's Clean Air Interstate Rule analyses, supplement these data with available stakeholder input, and provide the results for stakeholder review to ensure accuracy.

MACTEC (MACTEC, 2006) used the same control programs for both the 2009 and 2018 non-EGU point inventory. Two control scenarios were developed: on-the-books (OTB) controls and

on-the-way (OTW) controls. The OTB control scenario accounts for post-2002 emission reductions from recently-promulgated Federal, State, local, and site-specific control programs. The OTW control scenario accounts for proposed (but not final) control programs that are reasonably anticipated to result in post-2002 emission reductions.

Maximum achievable control technology (MACT) requirements were also applied, as documented in the report entitled *Control Packet Development and Data Sources,* dated July 14, 2004. The point source MACTs and associated emission reductions were derived from Federal Register (FR) notices and discussions with EPA's Emission Standards Division (ESD) staff. We did not apply reductions for MACT standards with an initial compliance date of 2001 or earlier, assuming that the effects of these controls are already accounted for in the 2002 inventories supplied by the States. Emission reductions were applied only for MACT standards with an initial compliance date of 2002 or later.

The final Phase II NO_x SIP call rule was finalized on April 21, 2004. States had until April 21, 2005, to submit SIPs meeting the Phase II NO_x budget requirements. The Phase II rule applies to large IC engines, which are primarily used in pipeline transmission service at compressor stations. We identified affected units using the same methodology as was used by EPA in the proposed Phase II rule (i.e., a large IC engine is one that emitted, on average, more than one ton-per-day during 2002). The final rule reflects a control level of 82 percent for natural gas-fired IC engines and 90 percent for diesel or dual fuel categories. Several S/L agencies provided more specific information on the anticipated controls at the compressor stations. This information was used instead of the default approach used by EPA in the proposed Phase II rule.

A summary of Non-EGU point source control programs included in 2009/2018 projection inventories include:

- Atlanta/Northern Kentucky/Birmingham 1-hr Ozone Non-attainment SIPs;

- Industrial Boiler/Process Heater/RICE MACT. EPA's industrial boiler MACT rules were vacated on June 8, 2007. The emissions reductions that were modeled to account for the industrial boiler MACT were 1,343.5 tons/year of SO2, 879.4 tons/year of PM2.5, and 1,304.2 tons/year of PM10. These reductions are insignificantly small (0.69% for SO2, 0.39% for PM2.5, and 0.13% for PM10) compared to the statewide totals (193,665.5 tons/year SO2; 225,104.5 tons/year PM2.5; and 1,002,873.2 tons/year PM10) and should not impact the conclusions made in the SIP;

- NO_x RACT in 8-hr Ozone NAA SIPs;

- Petroleum Refinery Initiative (October 1, 2003 notice; MS & WV). This initiative addresses the most significant Clean Air Act compliance concerns affecting the petroleum refinery industry. Since December 2000, 17 global refinery settlements have been reached with refiners representing nearly 77 percent of domestic refining capacity. Three refineries in the VISTAS region are affected by two October 2003 Clean Air Act settlements under the EPA Petroleum Refinery Initiative. The refineries are: (1) the

Chevron refinery in Pascagoula, Mississippi; (2) the Ergon refinery in Vicksburg, Mississpipp; and (3) the Ergon refinery in Newell, West Virginia;

- Reasonable Further Progress 3 percent plans where in place for 1-hour plans (Metropolitan Washington, DC, and Atlanta, Georgia);

- VOC 2-, 4-, 7-, and 10-year MACT Standards. The point source MACTs and associated emission reductions were derived from Federal Register (FR) notices and discussions with EPA's Emission Standards Division (ESD) staff. We did not apply reductions for MACT standards with an initial compliance date of 2001 or earlier, assuming that the effects of these controls are already accounted for in the 2002 inventories supplied by the States;

- Combustion Turbine MACT. The projection inventories do not include the NO_x co-benefit effects of the MACT regulations for Gas Turbines or stationary Reciprocating Internal Combustion Engines, which EPA estimates to be small compared to the overall inventory; and

- NOx SIP Call (Phase II – remaining States & IC engines).

For more information on the development of point source inventories, see Appendix C of the SIP narrative.

1.2 Area Source Controls

Controls (including control efficiency, rule effectiveness and rule penetration) provided by the States or originally developed for use in estimating projected emissions for U.S. EPA's Heavy Duty Diesel (HDD) rulemaking emission projections and used in the Clean Air Interstate Rule (CAIR) projections were used to calculate controlled emissions.

The controls obtained by MACTEC (MACTEC, 2006) for the HDD rulemaking were controls for the years 2007, 2020, and 2030. Since MACTEC was preparing 2009 and 2018 projections, control values for intermediate years were prepared using a straight-line interpolation of control level between 2007 and 2020.

State-submitted controls had precedence over the U.S. EPA-developed controls. Control measures submitted by the Georgia Environmental Protection Division (GA EPD) include Stage I controls for gasoline dispensing facilities and open burning controls.

As part of the air toxics program, Stage I controls for gasoline dispensing facilities was adopted by the State and became effective May 1990 with final compliance by January 1, 1994. Stage I is the vapor recovery technology on the underground storage tanks and reduces the emissions during the tank-filling operations at service stations.

The GA EPD is responsible for going to all gasoline-dispensing facilities and testing the fuels to ensure that they meet the quality standards of the State. The GA EPD checks for Stage I controls

and proper maintenance of the control equipment. If a facility is not found to be properly maintaining the control equipment, then the GA EPD sends a notice of violation informing the facility that the controls are required and gives the facility time to correct the violation before fines are accessed. From this information, the rule effectiveness and rule penetration can be estimated. The rule effectiveness is the percentage of facilities complying with the rule, whereas, the rule penetration is the percentage of facilities requiring Stage I controls. Control efficiency is the expected percent reduction from this control technology.

Open burning is treated as a means of waste disposal in rural areas. Materials burned generally include household trash, agricultural refuse, landscaping refuse, or scrap wood. The open burning emissions inventory includes SCC 2610030000, residential open burning of household waste and SCC 2610000100, and open burning of yard trimmings. Since it is illegal to burn within the corporate limits, the rural population in each county is used to estimate emissions.

For more information on the development of area source inventories, see Appendix C of the SIP narrative.

1.3 Mobile Sources

Local controls included vehicle emissions inspection (i.e., I/M) programs, Stage II vapor recovery programs, anti-tampering programs, etc. By nature, the assumptions used for the 2002 initial base-year inventory vary across the VISTAS region, but our presumption is that these data accurately reflected each State's situation as it existed in 2002. If a State had no plans to change program requirements between 2002 and 2018, we proposed to maintain the 2002 program descriptions without change. However, if a State planned changes, we requested information on those plans. In the final implementation of the inventory, Stage II controls were exercised in the area source component of the inventory, since the units used to develop Stage II refueling estimates are different between MOBILE6 and the NONROAD models.

For more information on the development of mobile source inventories, see Appendix C of the SIP narrative.

1.4 Non-Road

Using the 2002 base-year emissions inventory for aircraft, locomotives, and commercial marine vessels (CMV) prepared as described earlier in this document, corresponding emission projections for 2009 and 2018 were developed. Detailed inventory data (both before and after controls) for these same emission sources for 1996, 2010, 2015, and 2020 were obtained from the EPA's Clean Air Interstate Rule (CAIR) Technical Support Document. Using these data, combined growth and control factors for the period 2002-2009 and 2002-2018 were estimated using straight-line interpolation between 1996 and 2010 (for 2009) and 2015 and 2020 (for 2018). This is done at the State-county-SCC-pollutant level of detail. According to EPA documentation, the CAIR baseline emissions include the impacts of the Tier 4 (T4) non-road diesel rulemaking, which implements a low-sulfur fuel requirement that affects both future CMV and locomotive emissions.

For more information on the development of non-road source inventories, see Appendix C of the SIP narrative.

1.5 Summary of Emissions Projections

Figures 1.1-1.4 depict pollutant totals for NH3, PM2.5, NOx, and SO2 for the various sectors by state for 2002, 2009, and 2018 Base G2 modeling. The totals are presented assuming the anticipated growth and implementation discussed in previous subsections. As can be seen in Figure 1-1 there is a gradual increase in the ammonia emissions. In Figure1-2, PM 2.5 emissions do not show any relative change in 2009 or 2018 as compared to 2002. Although, in Georgia, they are showing a slightly increasing trend. NOx and SO2 emissions in Figure 1-3 and 1-4, respectively, show a steep decrease in their 2018 emissions as compared to 2002. This decrease can be attributed to various Federal and State controls that will be in place on or before 2018.

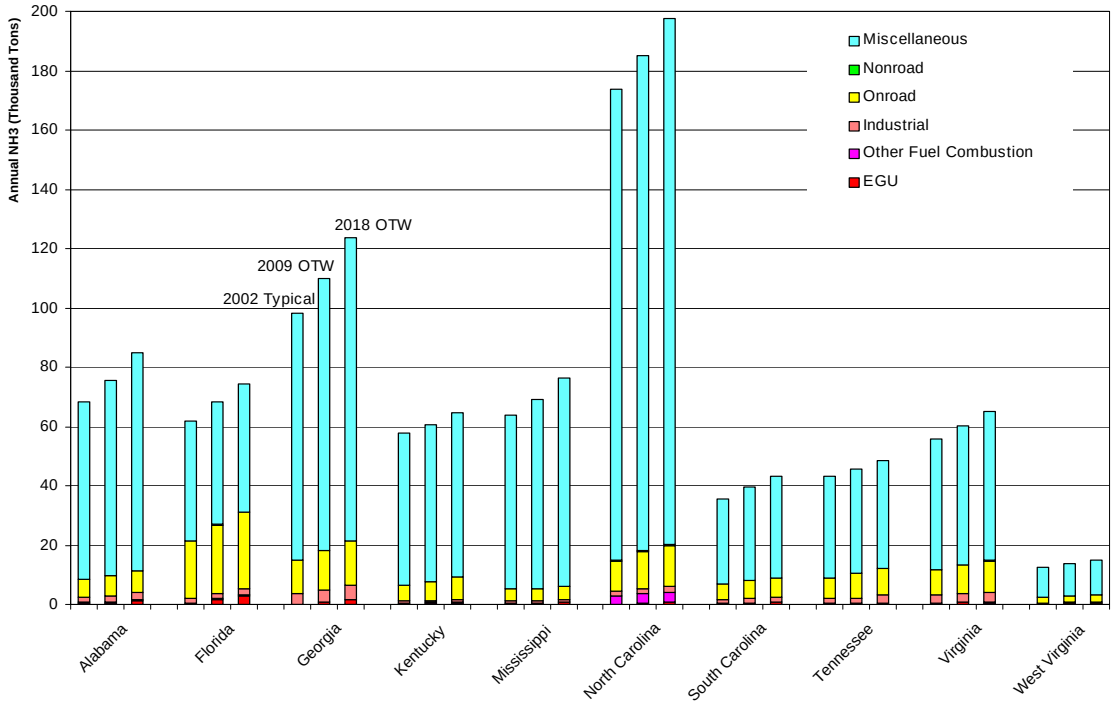


Figure 1-1. Annual NH3 emissions – Base G4.

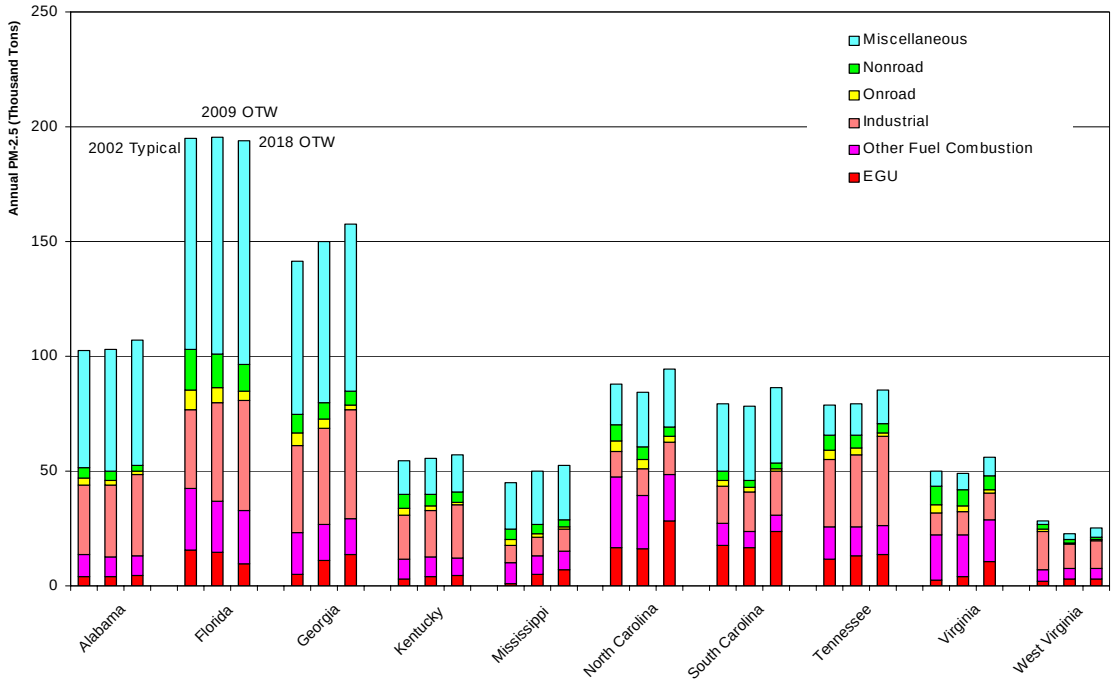


Figure 1-2. Annual PM2.5 emissions – Base G4.

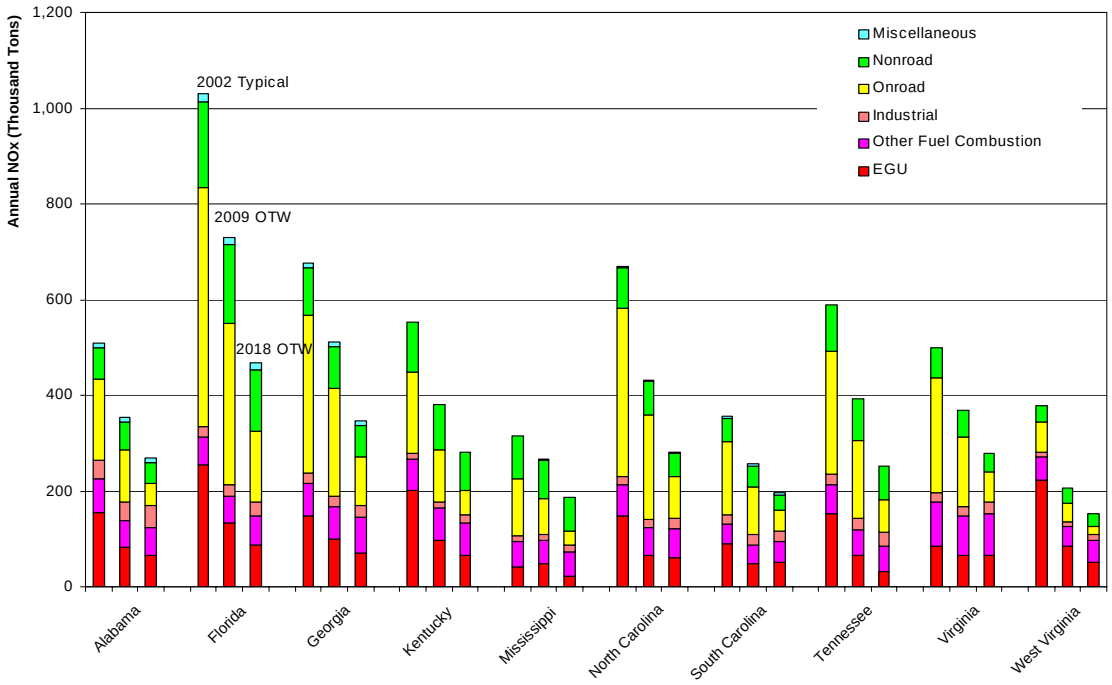


Figure 1-3. Annual NOx emissions – Base G4.

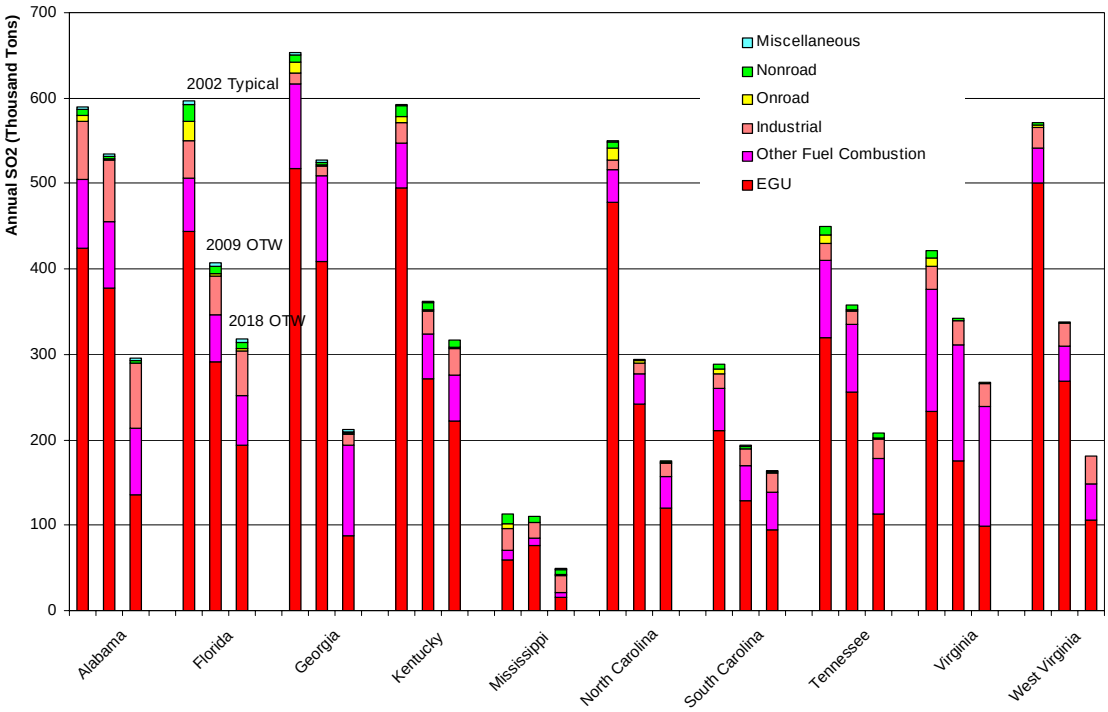


Figure 1-4. Annual SO2 emissions – Base G4.

2.0 UNIFORM RATE OF PROGRESS

The linear rate of improvement sufficient to attain natural conditions by 2064 is referred to as the "uniform rate of progress" or "glide path." The baseline represents the starting point from which reasonable progress will be measured. There are two baseline values for each Class I area. Using 2000 - 2004 Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring data, the deciview values for the 20% best days in each year are averaged together, producing a single average deciview value for the best days. Similarly, the deciview values for the 20% worst days in each year are averaged together producing a single average deciview value for the worst days. Extinction from individual PM components is calculated from the IMPROVE equation (EPA, 2003; Hand and Malm, 2006). EPA defined target natural conditions in 2064 for each Class I area (EPA, 2003). For each VISTAS Class I area, a baseline visibility using 2000-2004 IMPROVE data and uniform rate of progress was established, using EPA default assumptions for calculating visibility and natural background. Most recently, the scientific community has reviewed the assumptions used to calculate current and natural background visibility and has agreed to revised methods (Hand and Malm, 2006, Pitchford, 2006). VISTAS intends to present both the original and revised methods to calculate visibility and visibility improvement. Figures 2.1-2.2 illustrate the average 20% worst visibility days in the 2000-2004 baseline period for Cohutta Wilderness Area (COHU), and Okefenokee Wilderness Area (OKEF), the target natural condition in 2064 for the 20% worst days, and the incremental deciview changes assuming a uniform rate of progress between current and natural

conditions in 2064, using the original method for calculating visibility. This is known as "glidepath."

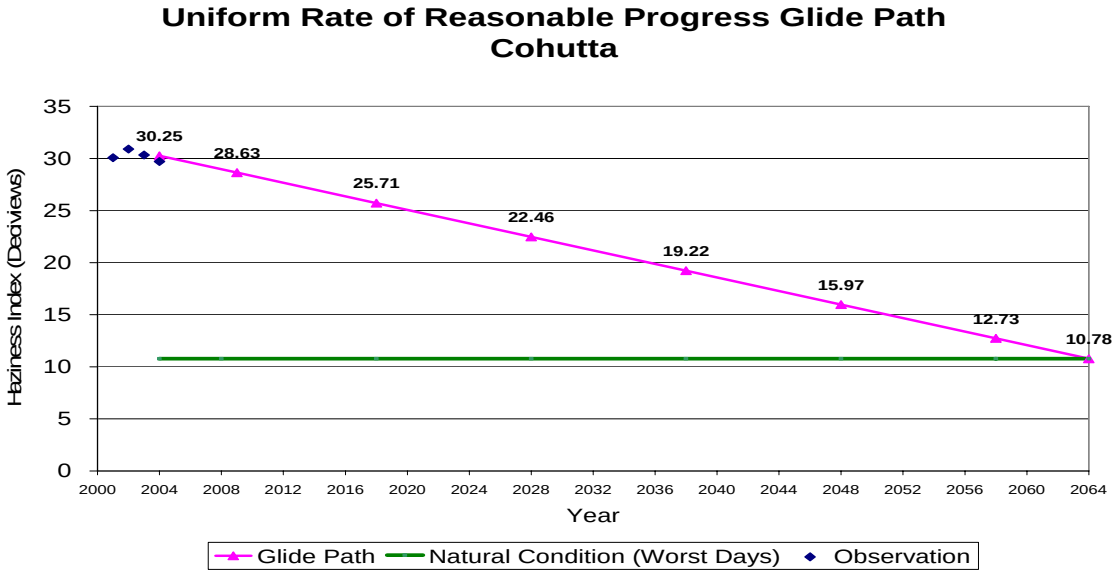


Figure 2-1. Uniform Rate of Progress at Cohutta Wilderness

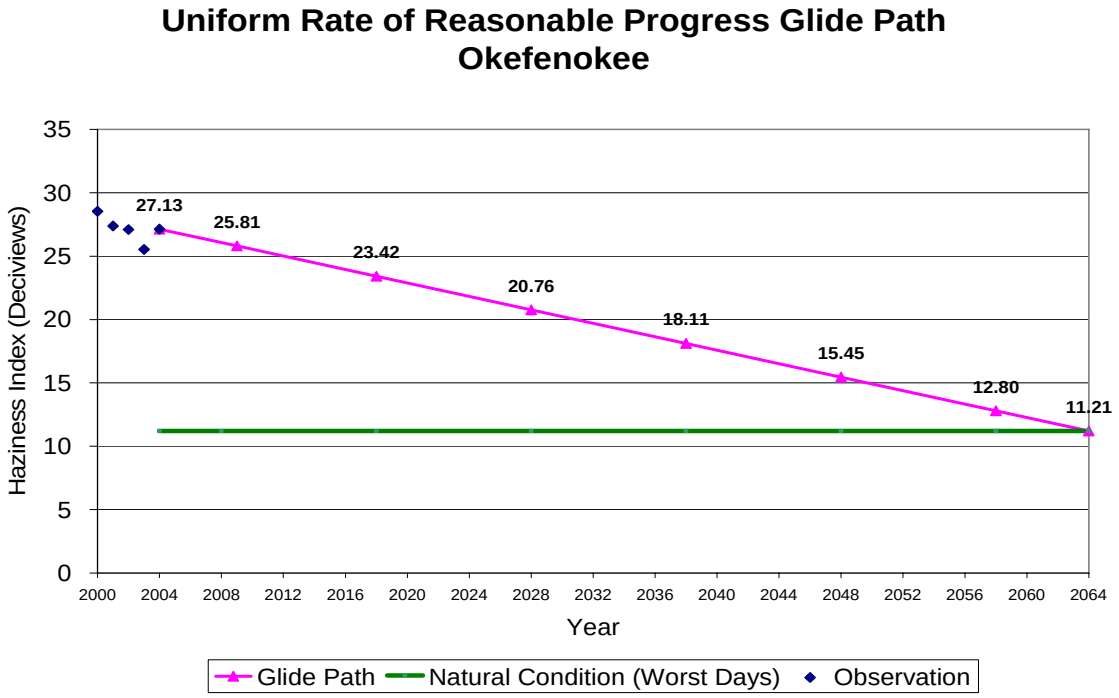


Figure 2-2. Uniform Rate of Progress at Okefenokee Wilderness

3.0 GEORGIA TECH SENSITIVITIES

Georgia Tech performed emission sensitivities to examine the impact of emission reductions on regional haze, annual PM2.5, and 8-hour ozone concentrations using CMAQv4.4_SOA modifications on the VISTAS 12 km modeling domain, using the 2009 OTW (on the way) BaseD emissions. Once the key pollutants contributing to visibility impairment at each Class I area were identified, the sources or source categories responsible for emitting these pollutants or pollutant precursors were determined. Emissions sensitivity analyses were conducted using CMAQ with 2009 Base D inventory and considering 30% reductions from major pollutants and source categories. The sensitivity runs were initially designed to consider pollutant contributions in 2009 to PM2.5 in urban areas; results were also considered for Class I areas even though the full benefit of controls anticipated by 2018 are not included in these sensitivity analyses. Results are qualitatively similar to previous sensitivity results using an earlier (Base A) 2018 inventory. While the 2009 sensitivity analyses cannot be used to judge absolute contributions from each state or source sector, the results do indicate relative levels of responses among pollutants, sectors, and geographic areas.

3.1 Evaluation for Cohutta Wilderness Area, Georgia

Figure 3-1 shows the results of emissions sensitivity run for COHU for summer (since summer is when 20% worst days occur). CMAQ was run using 30% reductions from the 2009 Base D inventory assumptions for implementing existing State and Federal regulations (listed on Page 2) for major source categories of SO2, NOx, VOC, and PM. The results identify geographic origins for visibility impairing pollutants, and serve as a good starting point when considering potential air quality benefits from additional controls for specific source sectors in VISTAS states or neighboring RPOs. The greatest benefits at COHU in 2009 are projected to come from further reducing SO2 from electric generating utilities (EGUs). Additional, smaller benefits are projected from additional SO2 emission reductions from non-utility, industrial point sources. Reductions of nitrogen oxide emissions from point sources (EGU and non-EGU) or ground-level sources (on road vehicles, off road engines, and area sources) and reductions of primary carbon from point- or ground-level sources are projected to be significantly less beneficial than reductions in SO2 emissions. Reductions in anthropogenic VOC emissions show no response in visibility, while a 30 percent reduction in biogenic VOC emissions result in a measurable improvement. However, controlling the VOCs from vegetation is not possible or appropriate. For this sensitivity run, further reducing SO2 emissions from electricity-generating utilities in Alabama, Georgia, West Virginia, Tennessee, and North Carolina would have the greatest benefit for COHU; reductions from electric generating utilities in other VISTAS states would have additional but smaller benefits at COHU.

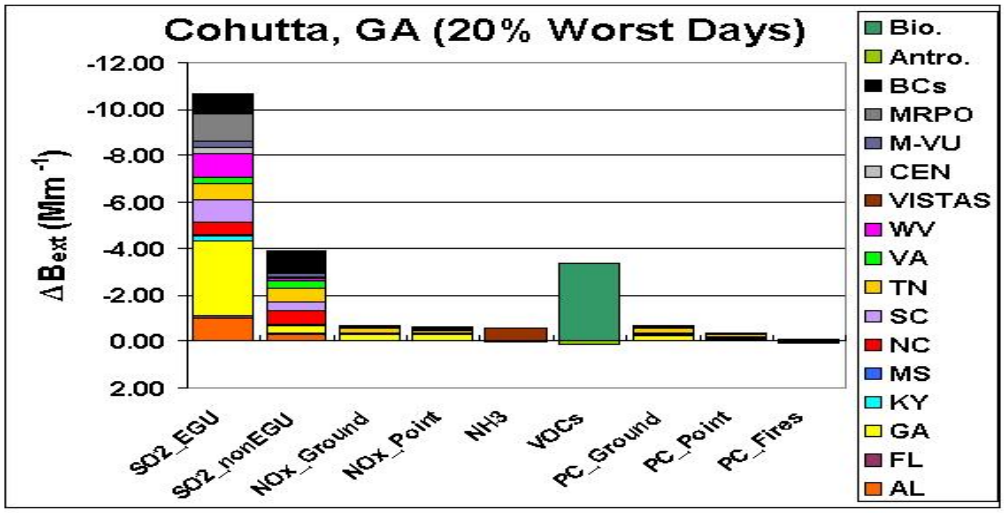


Figure 3-1. Sources of various visibility-reducing pollutants – COHU summer using 2009 Base D emissions.

3.2 Evaluation for Okefenokee Wilderness Area, Georgia

Figure 3-2 shows the results of the emissions sensitivity run for OKEF for summer (since summer is when 20% worst days occur). CMAQ was run using 30% reductions from the 2009 Base D inventory assumptions for implementing existing state and federal regulations (listed on page 4) for major source categories of SO2, NOx, and PM. The results identify geographic origins for visibility impairing pollutants, and serve as a good starting point when considering potential air quality benefits from additional controls for specific source sectors in VISTAS states or neighboring RPOs. The greatest benefits at OKEF in 2009 are projected to come from further reducing SO2 from electric generating utilities (EGUs). Additional, smaller benefits are projected from additional SO2 emission reductions from non-utility, industrial point sources. Reductions of nitrogen oxide emissions from point sources (EGU and non-EGU) or ground level sources (on road vehicles, off road engines, and area sources) and reductions of primary carbon from point or ground level sources are projected to be significantly less beneficial than reductions in SO2 emissions. Reductions in anthropogenic VOC emissions show no response in visibility, while a 30 percent reduction in biogenic VOC emissions result in a measurable improvement. However, controlling the VOCs from vegetation is not possible or appropriate. For this sensitivity run, further reducing SO2 emissions from electricity generating utilities in Alabama, Florida, and Georgia, would have the greatest benefit for OKEF.

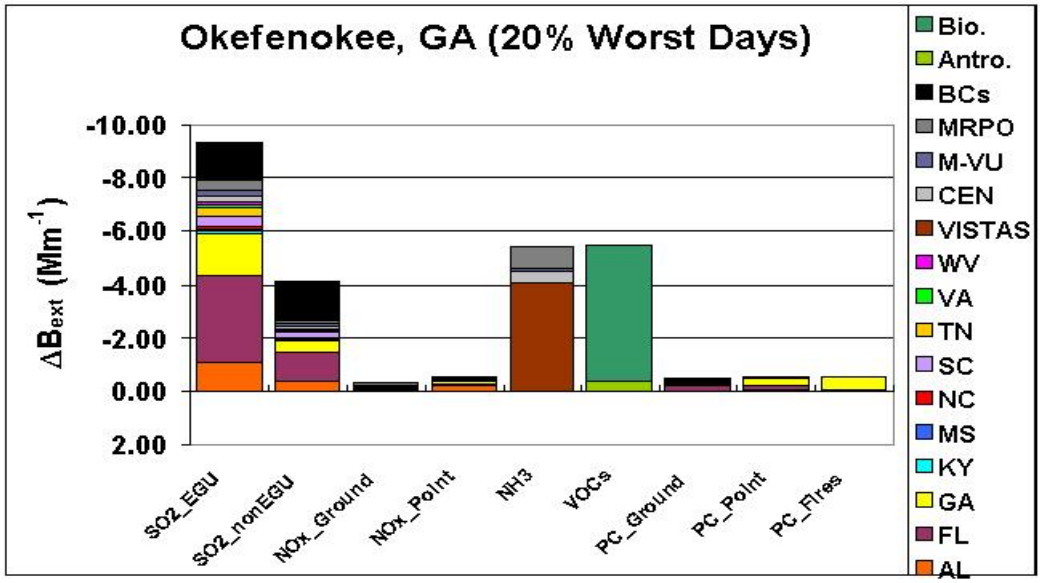


Figure 3-2. Sources of various visibility-reducing pollutants – OKEF summer using 2009 Base D emissions

4.0 REASONABLE PROGRESS EVALUATION

4.1 Area of Influence Analyses

The objective of the VISTAS Area of Influence analysis is to identify the geographic source regions that are contributing to visibility impairment at the Class I areas on the 20% worst visibility days. This information will be used by the State as part of the evaluation and demonstration of reasonable progress toward visibility improvement in Class I areas.

VISTAS' contribution assessment based on IMPROVE monitoring data (Brewer and Adlhoch, 2005) demonstrated that ammonium sulfate is the major contributor to PM2.5 mass and visibility impairment at Class I areas in the VISTAS and neighboring states. As illustrated in Figure 4-1, on the 20% worst visibility days in 2000-2004, ammonium sulfate accounted for greater than 70% of the calculated light extinction at Class I areas in the Southern Appalachians and greater than 60% of the calculated light extinction for

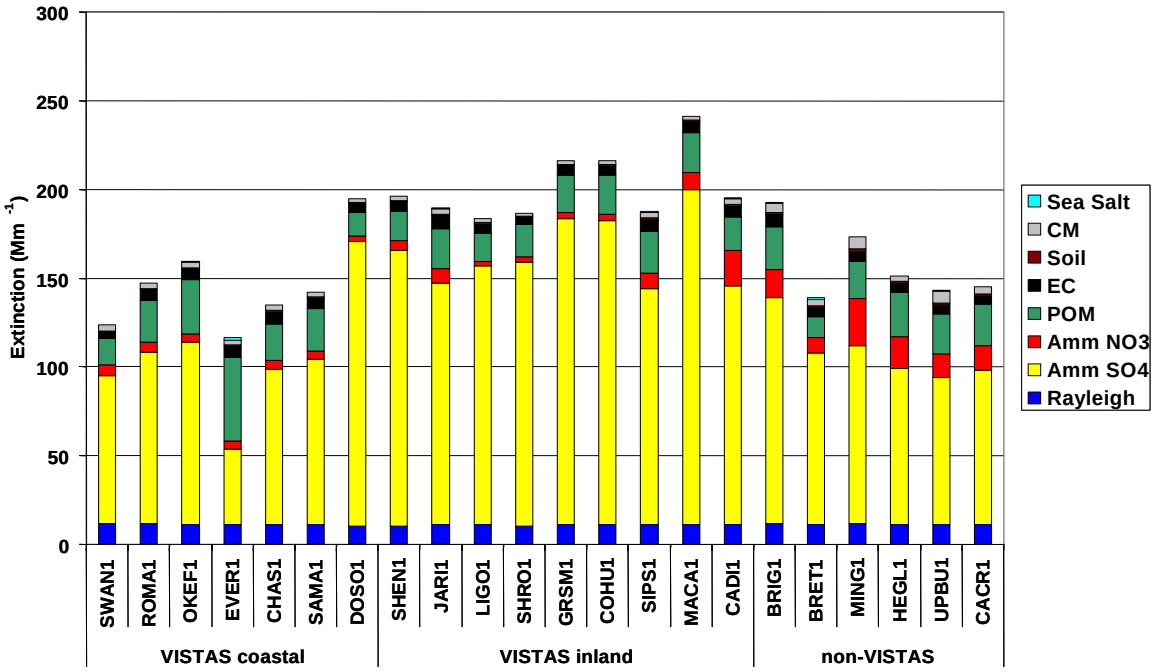


Figure 4-1. Average Extinction for 20% Worst Visibility Days in 2000-2004 using New IMPROVE Equation (data from VIEWS Sep 2006).

coastal sites in the VISTAS states (excepting Everglades). In contrast, ammonium nitrate contributed less than 5% of the calculated light extinction at VISTAS Class I areas on the 20% worst visibility days. (Nitrate has a somewhat larger contribution on 20% worst days at Class I areas in neighboring states to the VISTAS region.) Particulate organic matter (organic carbon) accounted for 10-20% of light extinction on 20% worst visibility days (except Everglades where organic carbon accounted for 40%).

VISTAS emissions sensitivity analyses using the CMAQ regional air quality model project that reductions in SO2 emissions from Electric Generating Utilities (EGU) and non-EGU industrial point sources will result in the greatest improvements in visibility at VISTAS Class I areas. EGU and non-EGU industrial point sources comprise 95+% of the SO2 emissions inventory in the VISTAS states. The emissions sensitivity analyses also indicate that improvements in visibility from reductions in NOx or primary carbon emissions from ground-level sources or point sources would be small. Based on these analyses, VISTAS states chose to focus their reasonable progress evaluation for the first regional haze SIP on potential controls of SO2 emissions from EGU and non-EGU point sources. To select the specific point sources that would be considered for each Class I area, states first identified the geographic areas that most likely influence visibility in each Class I area and then identified the major SO2 point sources in that geographic area.

4.2 Source Type Analyses

The following analyses are illustrative of an initial approach from September 2005 to evaluate potential control strategies. These analyses rely on the 200 km area surrounding the Class I area and use the Base F4 model run.

VISTAS emissions inventory for the simplest area of influence, the 200 km concentric circle, indicated for COHU in 2018 that fuel combustion from electric utilities and industrial processes produces the majority of the remaining SO2 emissions (Table 4-1), with 86% of 2018 SO2 total coming from fuel combustion.

Table 4-1. Source types 2018 Base G4 modeling COHU – Percentage.

	Annual 2018 BaseG2 Emissions (%)						
Tier	**VOC**	**NOX**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
Fuel Comb. Elec. Util.	0%	21%	1%	52%	9%	17%	1%
Fuel Comb. Industrial	1%	19%	2%	28%	3%	5%	0%
Fuel Comb. Other	5%	6%	3%	6%	5%	10%	1%
Chemical & Allied Product Mfg	2%	1%	0%	2%	1%	1%	1%
Metals Processing	1%	1%	1%	3%	2%	5%	0%
Petroleum & Related Industries	0%	0%	0%	1%	0%	0%	0%
Other Industrial Processes	7%	6%	1%	5%	9%	11%	1%
Solvent Utilization	42%	1%	0%	0%	0%	1%	0%
Storage & Transport	6%	0%	0%	0%	1%	1%	0%
Waste Disposal & Recycling	4%	2%	4%	0%	5%	12%	0%
Highway Vehicles	18%	25%	48%	0%	2%	2%	12%
Off-highway	11%	18%	34%	1%	2%	4%	0%
Miscellaneous	2%	1%	7%	0%	61%	30%	83%
VISTAS Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

VISTAS emissions inventory for the simplest area of influence, the 200 km concentric circle, indicated for OKEF in 2018 that fuel combustion from electric utilities and industrial processes produces the majority of the remaining SO2 emissions (Table 4-2), with 82% of 2018 SO2 total coming from fuel combustion.

Table 4-2. Source types 2018 Base G4 modeling OKEF – Percentage.

	Annual 2018 BaseG2 Emissions (%)						
Tier	**VOC**	**NOX**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
Fuel Comb. Elec. Util.	0%	22%	1%	51%	7%	12%	1%
Fuel Comb. Industrial	1%	16%	2%	25%	3%	5%	0%
Fuel Comb. Other	3%	4%	1%	6%	2%	4%	0%
Chemical & Allied Product Mfg	0%	0%	0%	4%	0%	1%	0%
Metals Processing	0%	0%	0%	4%	0%	0%	0%
Petroleum & Related Industries	0%	0%	0%	0%	0%	0%	0%
Other Industrial Processes	7%	6%	1%	7%	8%	11%	2%
Solvent Utilization	39%	0%	0%	0%	0%	0%	0%
Storage & Transport	7%	0%	0%	0%	0%	0%	0%
Waste Disposal & Recycling	4%	3%	7%	0%	8%	16%	0%
Highway Vehicles	18%	25%	38%	1%	1%	1%	10%
Off-highway	14%	19%	29%	1%	2%	3%	0%
Miscellaneous	6%	4%	20%	1%	68%	46%	86%
VISTAS Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

VISTAS emissions inventory for the simplest area of influence, the 200 km concentric circle, indicated for WOLF in 2018 that fuel combustion from electric utilities and industrial processes produces the majority of the remaining SO2 emissions (Table 4-3), with 84% of 2018 SO2 total coming from fuel combustion.

Table 4-3. Source types 2018 Base G4 modeling WOLF – Percentage.

	Annual 2018 BaseG2 Emissions (%)						
Tier	**VOC**	**NOX**	**CO**	**SO2**	**PM-10**	**PM-2.5**	**NH3**
Fuel Comb. Elec. Util.	0%	21%	1%	47%	7%	14%	1%
Fuel Comb. Industrial	1%	16%	2%	31%	3%	5%	0%
Fuel Comb. Other	3%	5%	2%	6%	3%	6%	1%
Chemical & Allied Product Mfg	1%	2%	0%	4%	0%	1%	1%
Metals Processing	0%	0%	0%	3%	0%	0%	0%
Petroleum & Related Industries	0%	0%	0%	0%	0%	0%	0%
Other Industrial Processes	6%	5%	1%	5%	7%	8%	2%
Solvent Utilization	39%	0%	0%	0%	0%	0%	0%
Storage & Transport	7%	0%	0%	0%	0%	1%	0%
Waste Disposal & Recycling	4%	3%	7%	1%	7%	16%	0%
Highway Vehicles	19%	25%	40%	1%	1%	1%	10%
Off-highway	15%	21%	32%	1%	2%	5%	0%
Miscellaneous	5%	3%	15%	1%	67%	43%	85%
VISTAS Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

4.3 Back Trajectory Analyses

The GA EPD defined AOIs to identify source regions for which additional controls might be considered and that are likely to have the greatest impact on each Class I area. Initial focus on AOIs is on SO2 emissions because SO4 contributes greater than 60% of the calculated light extinction on the haziest days. In fact, figure 4-1 shows that for Cohutta (COHU), SO4 contributes roughly 80% to the calculated light extinction on the haziest days. To better understand the sources that should be considered in a four factor analysis for reasonable progress, VISTAS contracted ENVIRON to partner with VISTAS's Data Analysis contractor, Air Resource Specialists (ARS), to provide SO2 Areas of Influence for each VISTAS and six neighboring Class I areas. ARS generated meteorological back trajectories for IMPROVE sites in VISTAS and neighboring states. Back trajectory analyses use interpolated measured or modeled meteorological fields to estimate the most likely central path of air masses that arrive at a receptor at a given time. The method essentially follows a parcel of air backward in hourly steps for a specified length of time. Back trajectories account for the impact of wind direction and wind speed on delivery of emissions to the receptor, but do not account for chemical transformation and dispersion of emissions.

Trajectories were generated using the Hybrid-Single Particle Lagrangian Integrated Trajectory (HYSPLIT) model developed by the National Oceanic and Atmospheric Administration's (NOAA) Air Resources Laboratory (ARL). HYSPLIT uses archived 3-dimensional meteorological fields generated from observations and short-term forecasts. HYSPLIT can be run to generate forward or backward trajectories using several available meteorological data archives.

The data archives used in this analysis were the National Weather Service's National Centers for Environmental Prediction Eta Data Assimilation System (EDAS). The EDAS fields are archived by the ARL across the continental U.S., including a buffer zone, at a horizontal resolution of 80 km before 2004, and at a horizontal resolution of 40 km starting in 2004. Detailed information regarding the trajectory model and these data sets can be found on NOAA's Web site (http://www.arl.noaa.gov/ready/hysplit4.html).

The major model parameters selected for this analysis include those listed in Table 4-4.

Table 4-4. Back Trajectory Model Parameters Selected for VISTAS AOI Analysis

Model Parameter	Value
Trajectory duration	72 hours backward in time
Top of model domain	14,000 meters
Vertical motion option	used model data
Meteorological Field	EDAS
End Times	0600, 1200, 1800 and 2400 EST
End Heights	100 and 500 m

The choice of these parameters affects the trajectories generated and the final attribution analyses. In particular, trajectories tend to become increasingly uncertain the further back in time they are used. Vertical motion in the model is sometimes best represented by following actual vertical motion measurements (represented by model data), surfaces of constant entropy, or surfaces of constant pressure, depending on the meteorological conditions at a given location and time. The impact of receptor height (or end height) on an individual trajectory is also important. Low-ending trajectories represent air parcels nearer to ground-level and high-ending trajectories may represent more accurate boundary layer flow above the local terrain.

For the years 2000 – 2004, back trajectories were computed for the following IMPROVE sampling sites in and around the VISTAS region:

1. Breton, LA (BRET1)
2. Brigantine NWR, NJ (BRIG1)
3. Cadiz, KY (CADI1)
4. Caney Creek, AR (CACR1)
5. Cape Romain National Wilderness Area, SC (ROMA1)
6. Chassahowitzka National Wilderness Area, FL (CHAS1)
7. Cohutta Wilderness, GA (COHU1)
8. Dolly Sods Wilderness, WV (DOSO1)
9. Everglades NP, FL (EVER1)
10. Great Smoky Mountains NP, TN (GRSM1)
11. Hercules-Glades, MO (HEGL1)
12. James River Face Wilderness, VA (JARI1)
13. Linville Gorge, NC (LIGO1)
14. Mammoth Cave NP, KY (MACA1)
15. Mingo, MO (MING1)
16. Okefenokee Wilderness, GA (OKEF1)
17. Shenandoah NP, VA (SHEN1)
18. Shining Rock Wilderness, NC (SHRO1)
19. Sipsy Wilderness, AL (SIPS1)
20. St. Marks, FL (SAMA1)
21. Swanquarter, NC (SWAN1)
22. Upper Buffalo Wilderness, AR (UPBU1)
23. Wolf Island Wilderness, GA (WOLF)

Figure 4-2 shows the 72-hour back trajectory analysis performed for Cohutta Wilderness area.

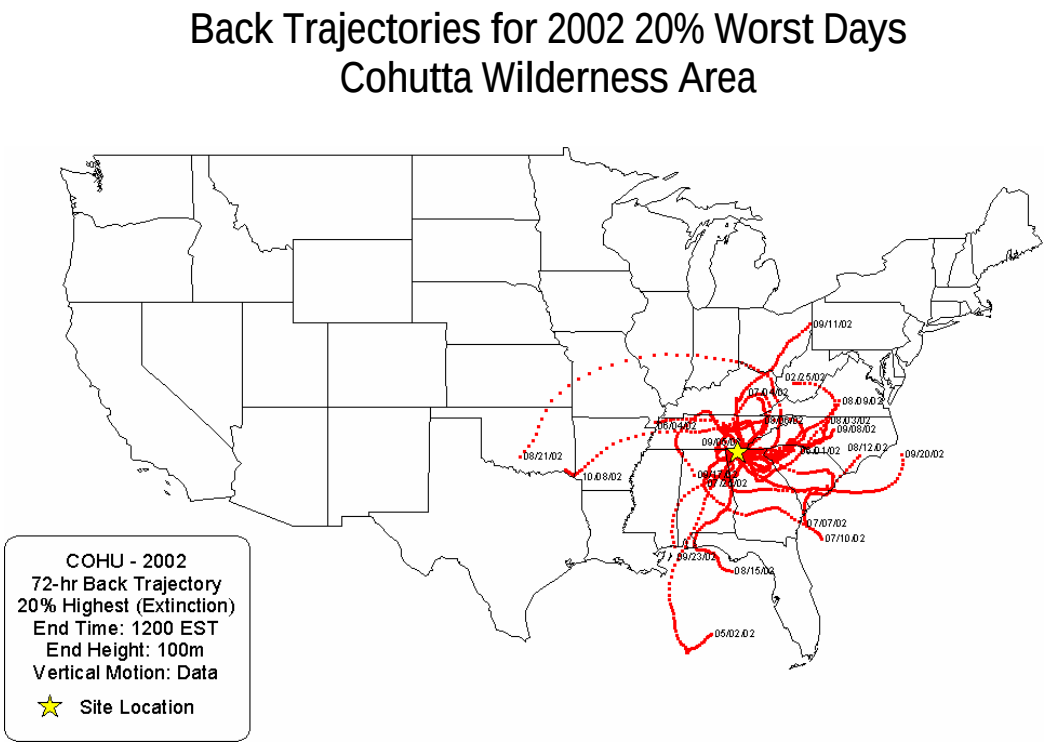


Figure 4-2. Example 72-hour back trajectories for 20% worst visibility days in 2002 for Cohutta Wilderness Area

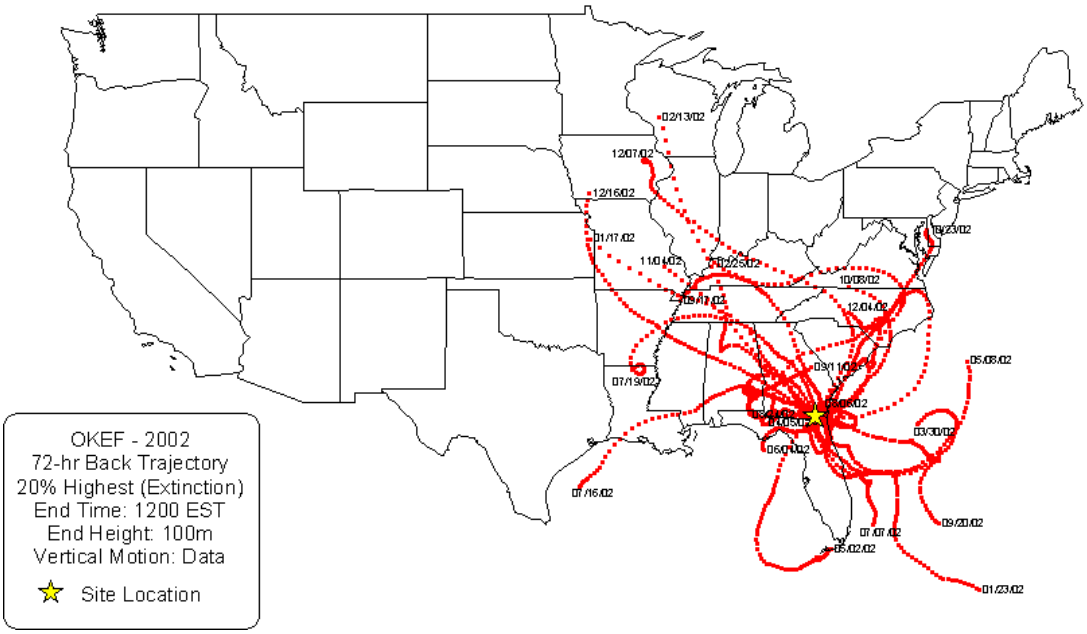


Figure 4-3. Example 72-hour back trajectories for 20% worst visibility days in 2002 for Okefenokee Wilderness Area

Based on the five years of individual back trajectories, ARS generated extinction-weighted residence time data for each IMPROVE site. Each hourly trajectory point was tagged with its associated sample (or end) date. Back trajectories with end dates corresponding to the 20% worst visibility days were weighted with calculated extinction values and summed into 1-degree horizontal grid cells of latitude and longitude.

Extinction data is based on the IMPROVE Regional Haze Rule dataset, as available from the VIEWS website (http://vista.cira.colostate.edu/views/Web/IMPROVE/SummaryData.aspx) in November 2005 and is calculated based on the original IMPROVE algorithm. For sites with less than three complete years of data, ARS developed and applied a data substitution protocol to fill missing data. Organic carbon and elemental carbon values were filled based on correlations to hydrogen and sulfate values for the same site. Other components were filled based on data from nearby sites.

Trajectory data was weighted by total extinction and by extinction components including ammonium sulfate (AmmSO4), ammonium nitrate (AmmNO3), particulate organic material (POM), Light Absorbing Carbon (LAC), Soil, and Coarse Mass (CM). Weighting trajectories for the 20% worst days by sulfate extinction gave greater importance to days influenced by SO2 emissions and lesser importance to days influenced by organic carbon emissions. This allowed a geographic area of influence to be identified based on sulfate contributions and not skewed by contributions from fire.

These data files were provided to ENVIRON. ENVIRON was charged with developing residence time plots to define the geographic area with highest probability of influencing

the receptor on the 20% worst days dominated by sulfate. Residence time over an area is indicative of general flow patterns, but since it does not account for emissions and removal processes, it does not necessarily imply specific areas contributed significantly to haze compounds at a receptor site.

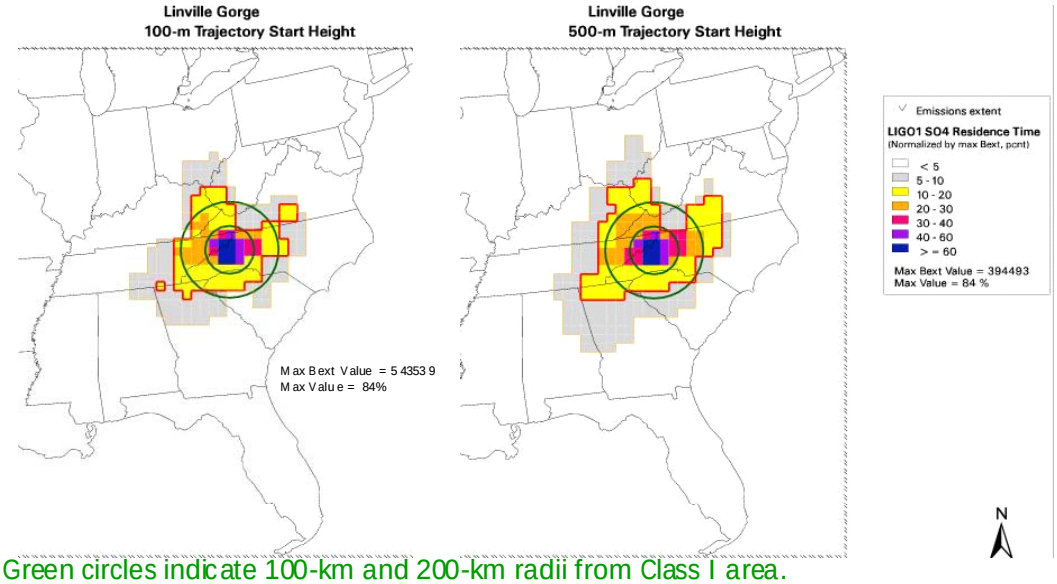
4.4 Area of Influence Data and Displays

The primary objective of the Area of Influence (AOI) displays and data sets are to assist the State in focusing its reasonable progress analysis on those geographic regions and source categories which most impact a particular Class I Area. The sources of data used in these analyses include back-trajectory residence time data provided by ARS and described above and the VISTAS 2002 and 2018 36-km gridded emissions data (Base G, August 2006 inventory version).

Extinction weighted back-trajectory residence time plots were provided by ARS for all Class I Areas in the VISTAS region as well as for the surrounding, neighboring states. These trajectories were processed on an un-projected (i.e., geodetic lat/lon 1 degree by 1 degree) grid and transferred to ENVIRON for further GIS processing and analysis. Back-trajectories were run for 100-meter and 500-meter start heights. Because the back-trajectories were to be combined with gridded emissions data, the first step in the analysis and GIS processing involved re-projecting the data to the Inter-RPO Unified Lambert Conformal Projection domain. Once the data was re-projected, the data was mapped to the 36-km grid cells in the RPO projection using an area-weighted mapping routine. The re-projected extinction weighted back-trajectory residence times were then plotted on the VISTAS 12-km modeling domain. As sulfate is the primary visibility-impairing component of the total extinction in the Southeast, the SO4-weighted residence time trajectories were chosen as the basic data set for display. For clarity, these data are scaled by the maximum value of the total extinction-weighted residence time within the modeling domain. The 100-km and 200-km distances from the Class I area were labeled.

Using the trajectories with the 100-m start height, the State has defined the SO2 Areas of Influence as the area with grid cells showing 5% (area shaded in yellow in following plots) or greater residence time (the frequency that winds pass over that area on the way to the Class I area on the 20% worst days dominated by sulfate) for the period 2000-2004. Residence time over an area is indicative of general flow patterns, but since it does not account for emissions and removal processes, it does not necessarily imply specific areas contributed significantly to haze compounds at a receptor site. The following figures, 4-4 through 4-11, are extinction-weighted residence time plots for LIGO, SHRO, SWAN, GRSM, OKEF, COHU, ROMA and SIPS for 100-m and 500-m trajectory start heights.

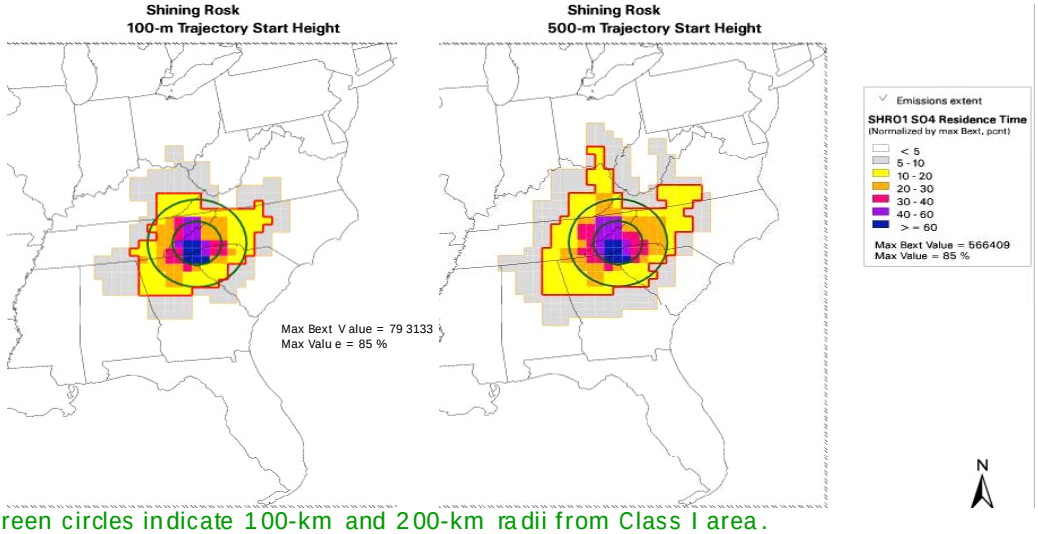
SO2 Area of Influence for Linville Gorge, NC



Green circles indicate 100-km and 200-km radii from Class I area.
Red line perimeter indicate Area of Influence with Residence Time ≥ 10%.
Orange line perimeter indicate Area of Influence with Residence Time ≥ 5%.

Figure 4-4. Linville Gorge SO4 extinction-weighted residence time plots for the period 2000-2004.

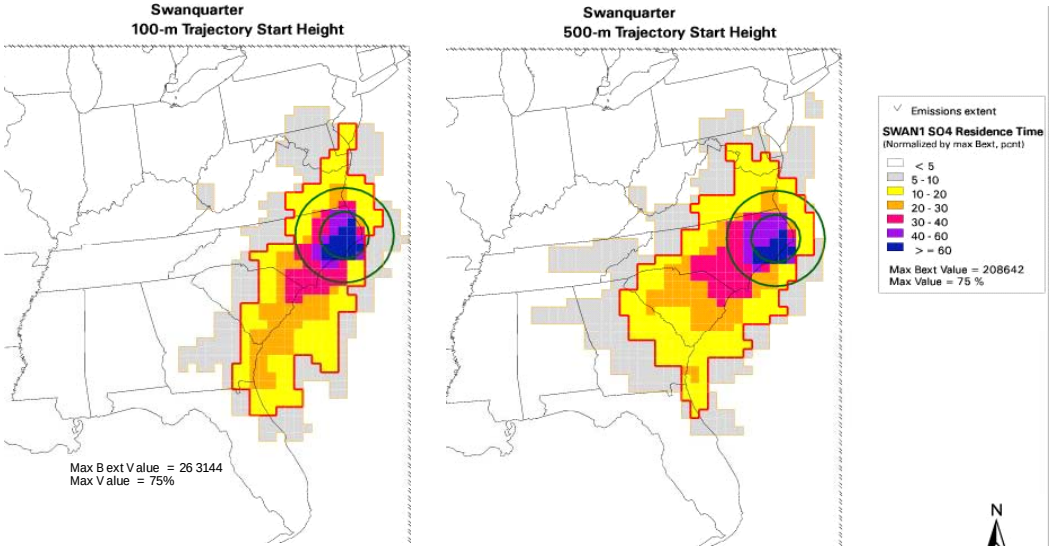
SO2 Area of Influence for Shining Rock, NC



Green circles indicate 100-km and 200-km radii from Class I area.
Red line perimeter indicate Area of Influence with Residence Time ≥ 10%.
Orange line perimeter indicate Area of Influence with Residence Time ≥ 5%.

Figure 4-5. Shining Rock SO4 extinction-weighted residence time plots for the period 2000-2004.

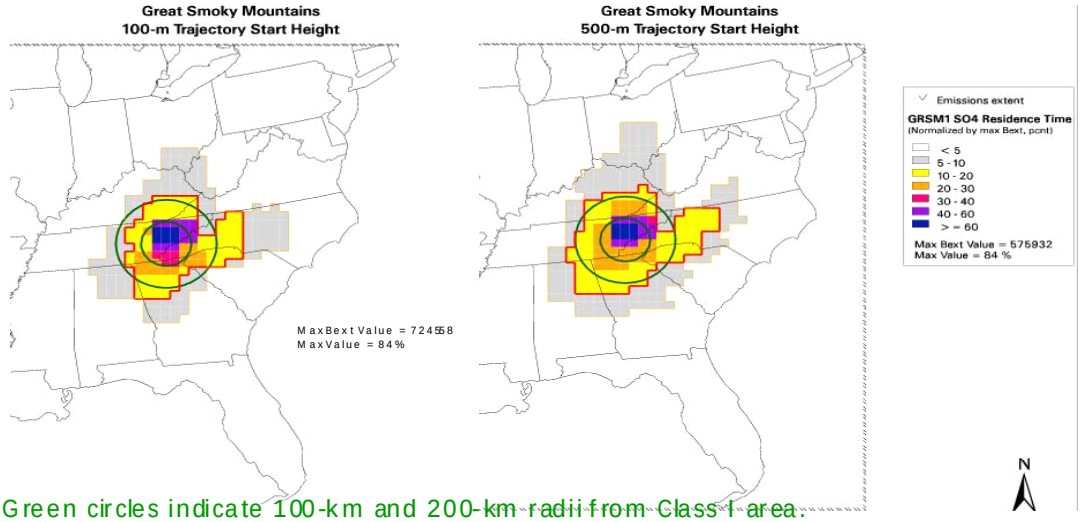
SO2 Area of Influence for Swanquarter, NC



Green circles indicate 100-km and 200-km radii from Class I area.
Red line perimeter indicate Area of Influence with Residence Time ≥ 10%.
Orange line perimeter indicate Area of Influence with Residence Time ≥ 5%.

Figure 4-6. Swanquarter SO4 extinction-weighted residence time plots for the period 2000-2004.

SO2 Area of Influence for Great Smoky Mountains, NC-TN



Green circles indicate 100-km and 200-km radii from Class I area.
Red line perimeter indicate Area of Influence with Residence Time ≥ 10%.
Orange line perimeter indicate Area of Influence with Residence Time ≥ 5%.

Figure 4-7. Great Smoky Mountains SO4 extinction-weighted residence time plots for the period 2000-2004.

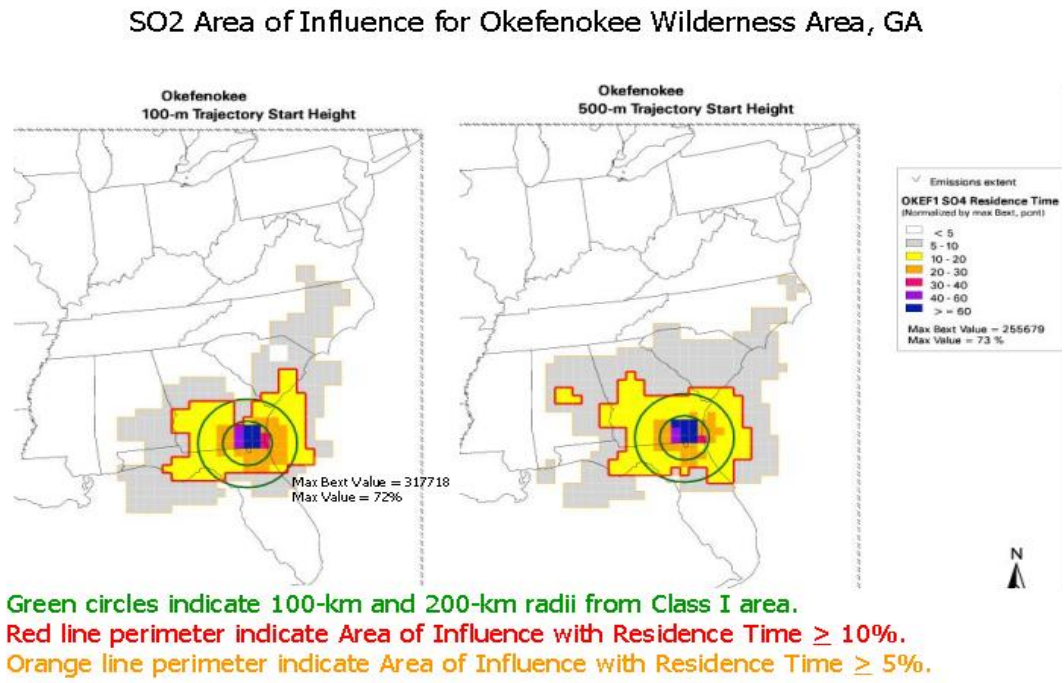


Figure 4-8. Okefenokee Wilderness Area SO4 extinction-weighted residence time plots for the period 2000-2004.

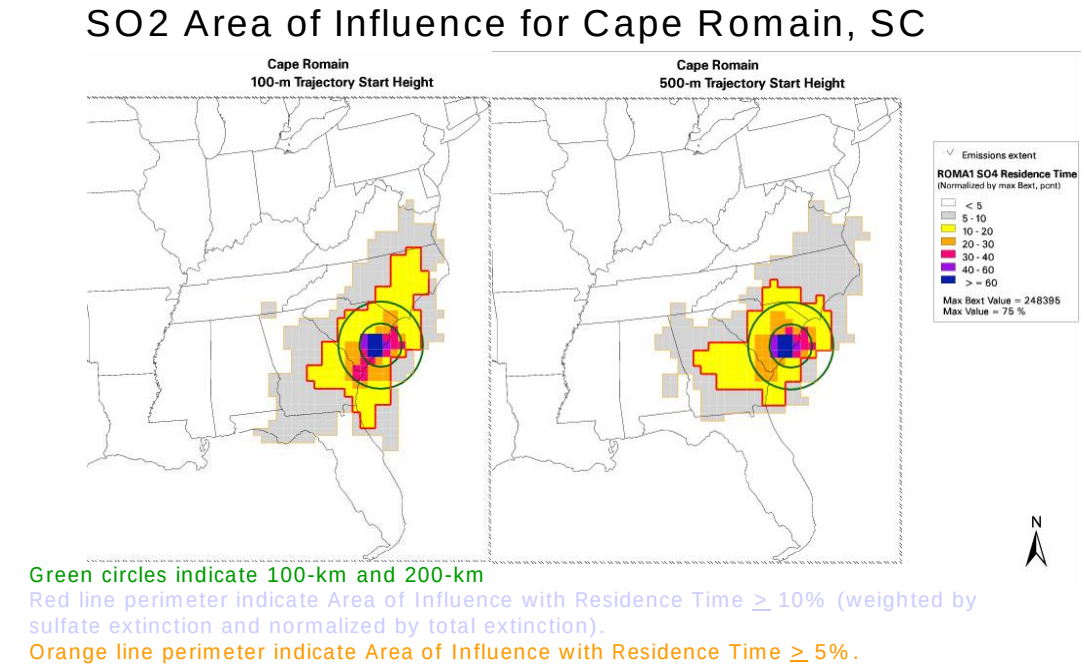


Figure 4-9. Cape Romain SO4 extinction-weighted residence time plots for the period 2000-2004.

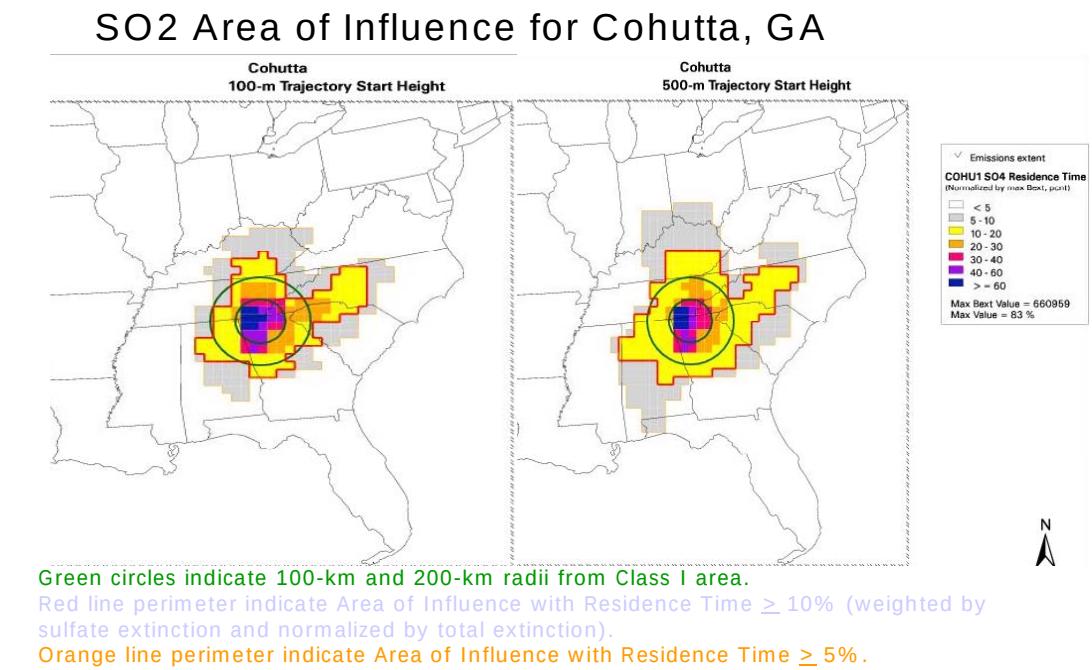


Figure 4-10. Cohutta SO4 extinction-weighted residence time plots for the period 2000-2004.

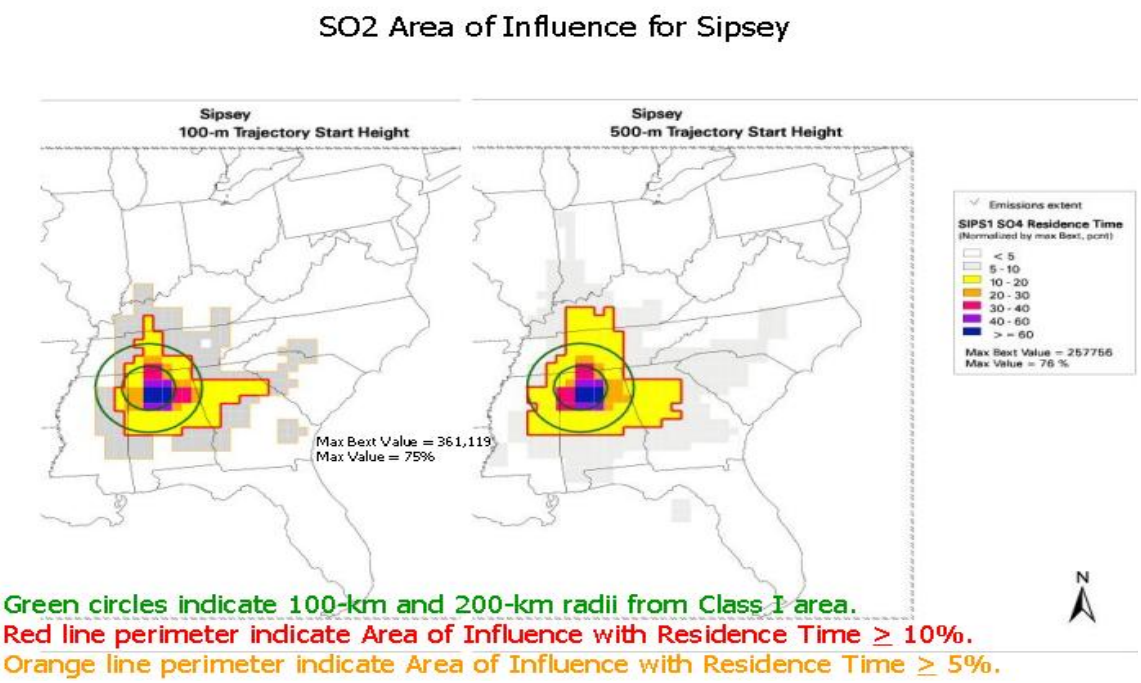


Figure 4-11. Sipsey SO4 extinction-weighted residence time plots for the period 2000-2004.

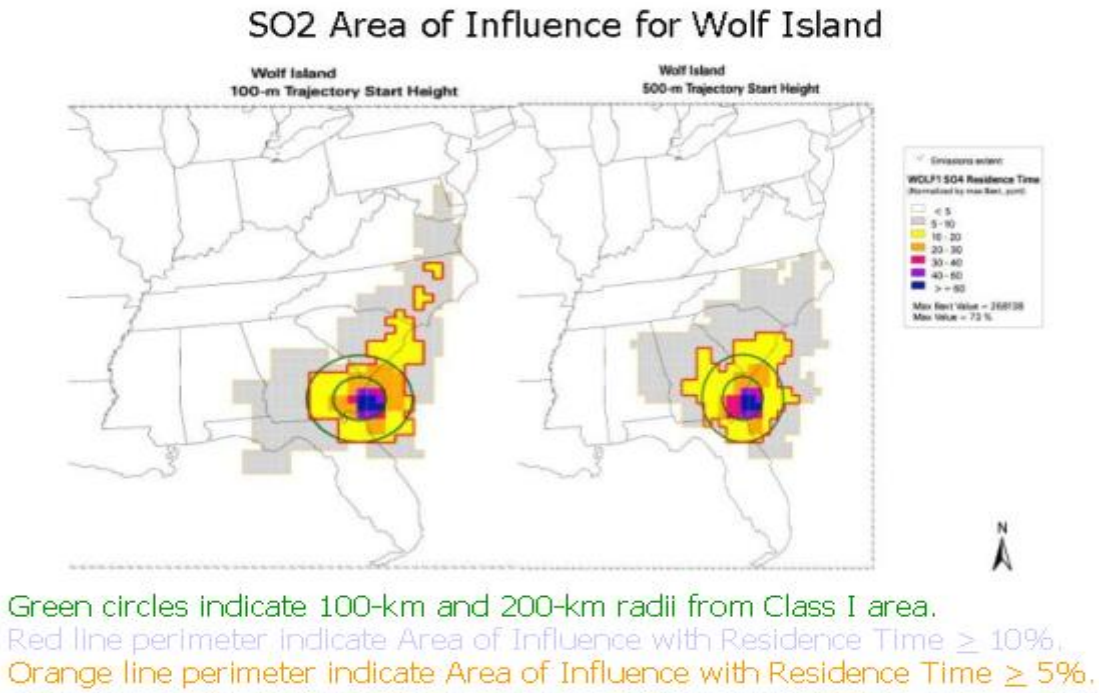


Figure 4-12. Wolf Island SO4 extinction-weighted residence time plots for the period 2000-2004.

As an aid to the analysis, all regions with scaled residence time values greater than 5% and greater than 10% were noted on the display. Finally, county boundaries were overlaid to identify those counties and 36-km modeling grid cells for which the extinction-weighted residence time back-trajectories exceeded 5% and 10%. This data was then exported as comma-delimited ASCII data files for further analyses. These residence time displays are used primarily to determine the regions (counties and/or grid cells) impacting each Class I Area. The next step in the analysis is to determine the potential impact from emission sources within the regions identified from the extinction-weighted back-trajectory residence time displays and analyses.

Previous VISTAS contribution assessment, emissions sensitivity modeling, and inventory analyses have indicated that SO4 is the largest contributor to haze on the 20% worst visibility days and that electric generating utilities and industrial point sources are the largest contributors to SO4 levels at the Class I areas. These two source categories make up 95% of the VISTAS SO2 inventory. Therefore these two source categories were identified as the highest priority for evaluation of reasonable progress in 2018 at the Class I areas. The potential impacts of SO2 point source emissions for each Class I Area are determined by combining gridded emissions data and weighted back-trajectory residence times for the 36-km grid cells. The analysis was carried out with both the 2002 and 2018 base-year emission inventories. Figures 4-13 and 4-14 display the gridded point source SO2 emissions from the VISTAS modeling databases, for 2002 and 2018, respectively. This data was processed by summing all vertical layers for each grid column and then summing across all days to obtain a total annual emission for each grid cell.

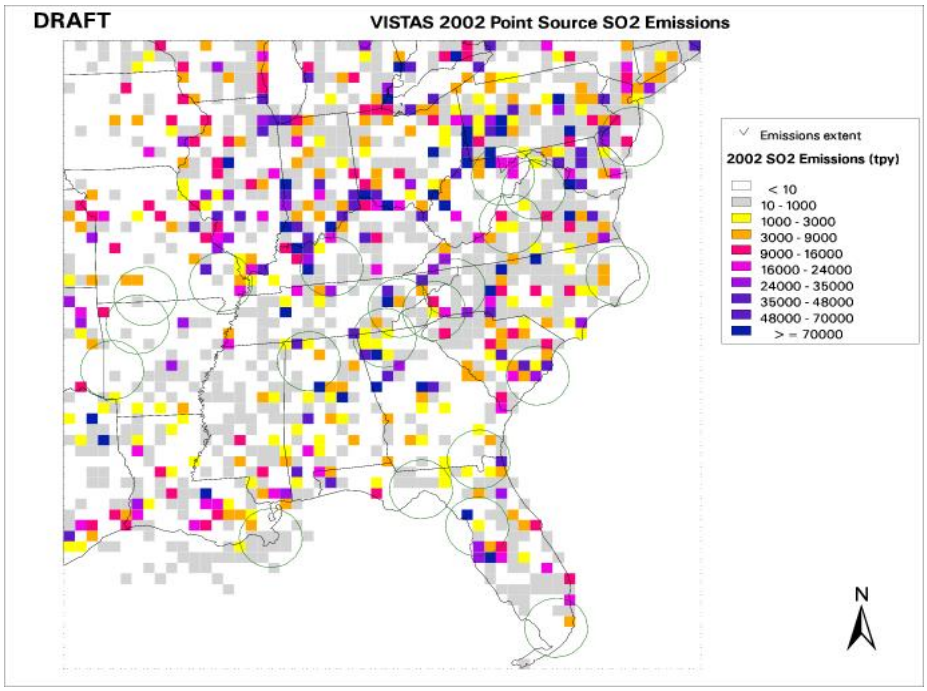


Figure 4-13. Annual point source SO2 emissions for the VISTAS region in tons/year. (2002 BaseG)

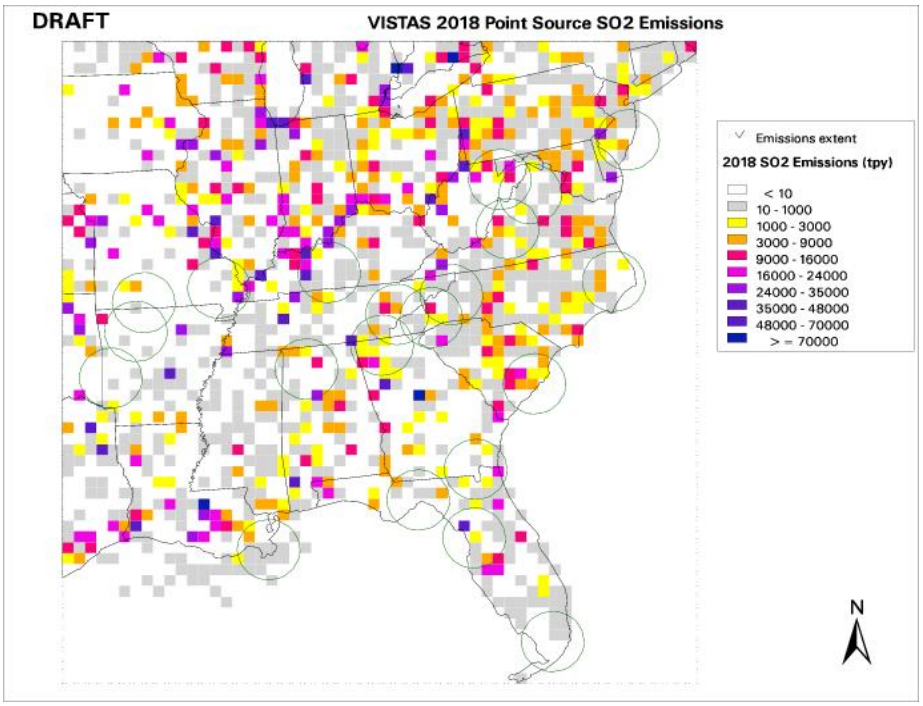


Figure 4-14. Annual point source SO2 emissions for the VISTAS region in tons/year. (2018 BaseG)

As a way of incorporating the effects of transport, deposition, and chemical transformation of point source emissions along the path of the trajectories, the data was

weighted by 1/d, where d was calculated as the distance between grid cell centers, in kilometers. For the grid cell containing the Class I Area monitor, a weighting of 1/9 was applied. The distance-weighted point source SO2 emissions are then combined with the gridded extinction-weighted back-trajectory residence times at a spatial resolution of 36-km.

The final step in the development of the displays and datasets involve the combination of the residence times and gridded emission data. The distance weighted (1/d) gridded point source SO2 emissions are multiplied by the total extinction-weighted back-trajectory residence times [SO2 * Bext-weighted RT * (1/d)] on a grid cell by grid cell basis. These results are then normalized by the domain-wide total and displayed as a percentage (Appendix H.2). The analysis is carried out for both the 2002 and 2018 base year inventories. Figures 4-15 through 4-23 display the result of this final analysis step. Note that the outlined regions (in red and light orange) represent the extent of the >10% and >5% sulfate extinction-weighted residence times determined from the first step in the analysis (see Figures 4-3 through 4-11). As with the residence time analysis, the results of the combined distance-weighted SO2 emissions and extinction-weighted residence times are overlayed with county boundaries and exported to comma-delimited ASCII data files for further analyses of emissions and control options for specific sources.

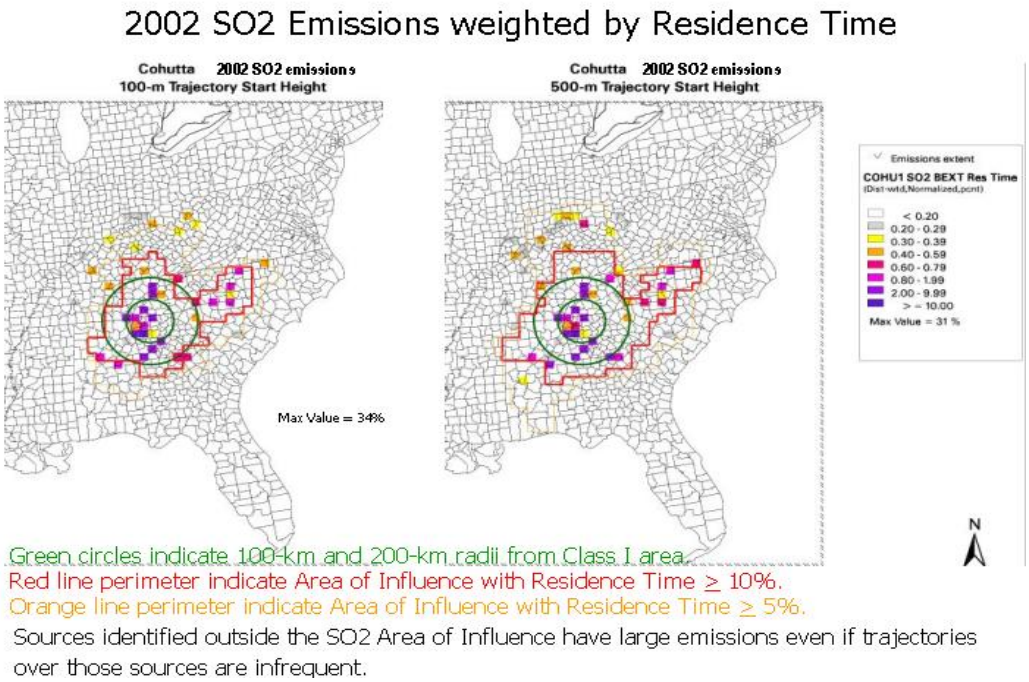


Figure 4-15. Cohutta 2002 SO2 Emissions * SO4 extinction-weighted residence time plots.

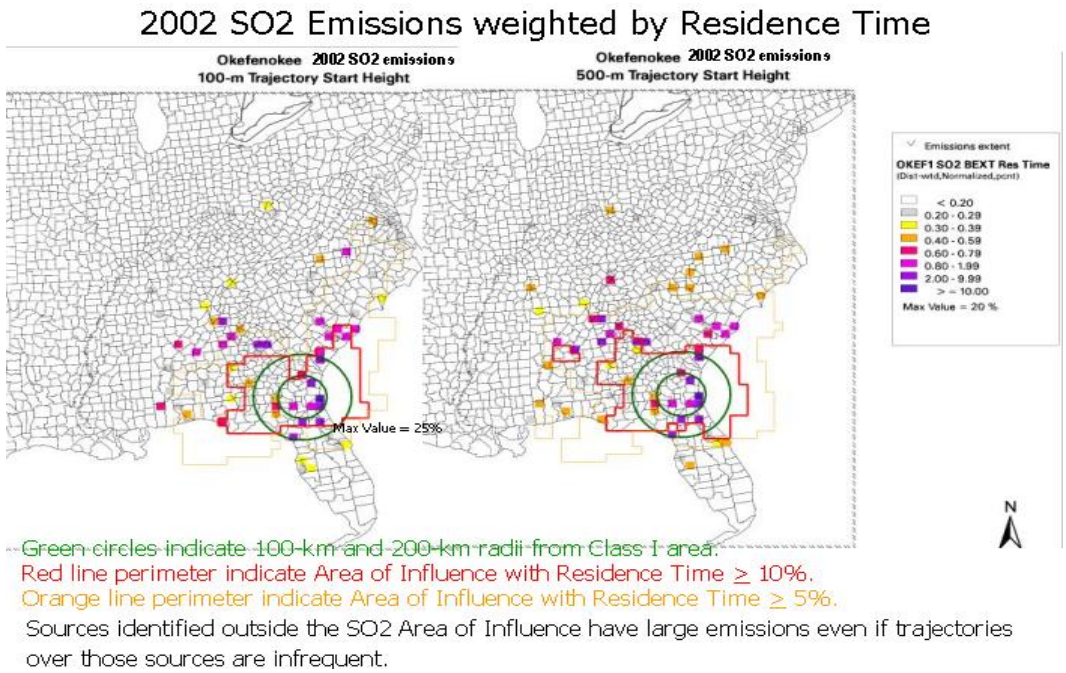


Figure 4-16. Okefenokee 2002 SO2 Emissions * SO4 extinction-weighted residence time plots.

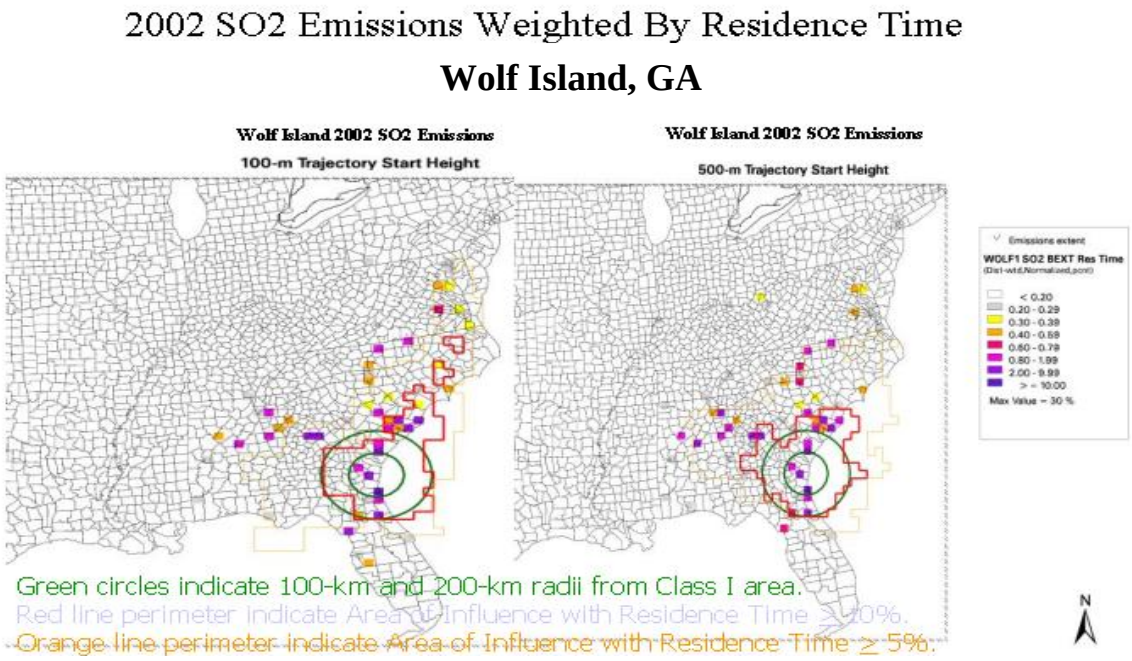


Figure 4-17. Wolf Island 2002 SO2 Emissions * SO4 extinction-weighted residence time plots.

The following sets of plots show the 2018 SO2 Emissions multiplied by the SO4 extinction-weighted residence time plots. These were produced the same way as the previous plots, only using 2018 emissions instead of 2002 emissions.

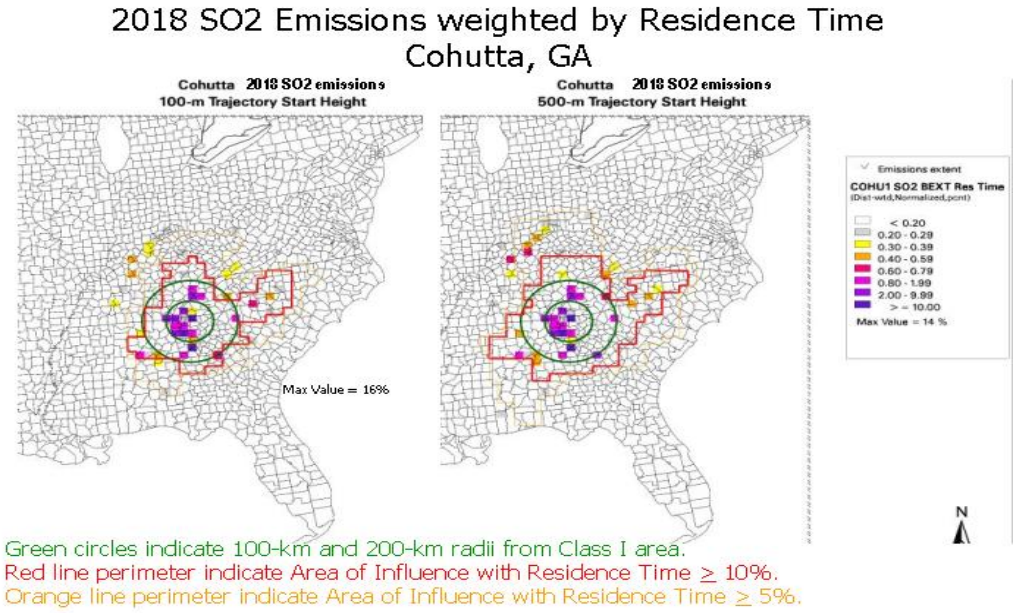


Figure 4-18. Cohutta 2018 SO2 Emissions * SO4 extinction-weighted residence time plots.

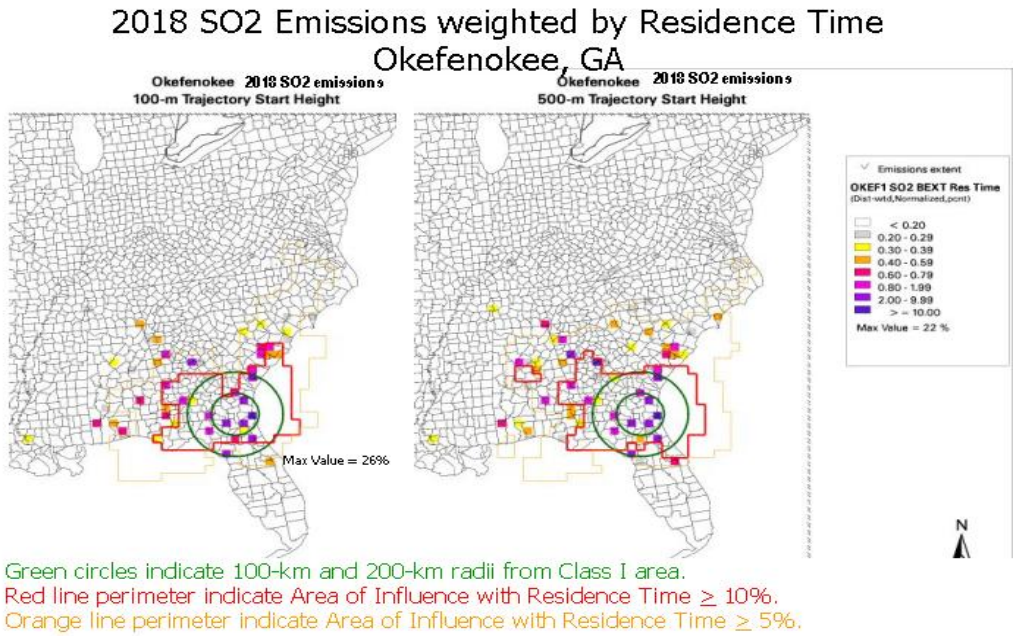


Figure 4-19. Okefenokee 2018 SO2 Emissions * SO4 extinction-weighted residence time plots.

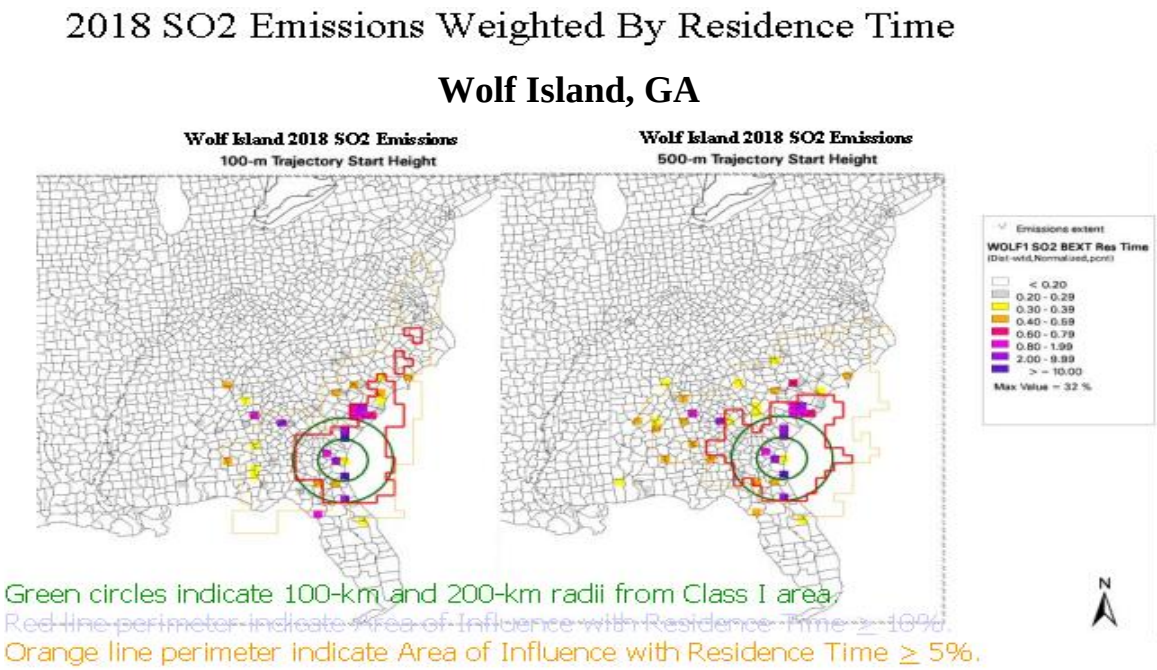


Figure 4-20. Wolf Island 2018 SO2 Emissions * SO4 extinction-weighted residence time plots.

To understand how emissions have changed by 2018, the following plots, 4-21 – 4-23, compare 2002 and 2018 SO2 multiplied by residence time.

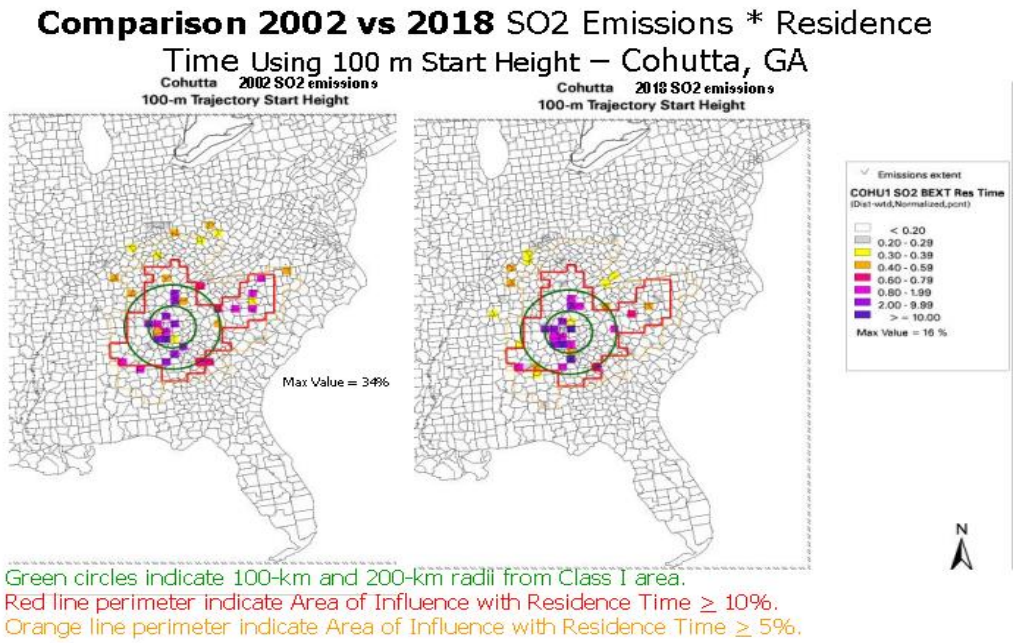


Figure 4-21. Cohutta 2002 vs. 2018 SO2 emissions multiplied by residence time.

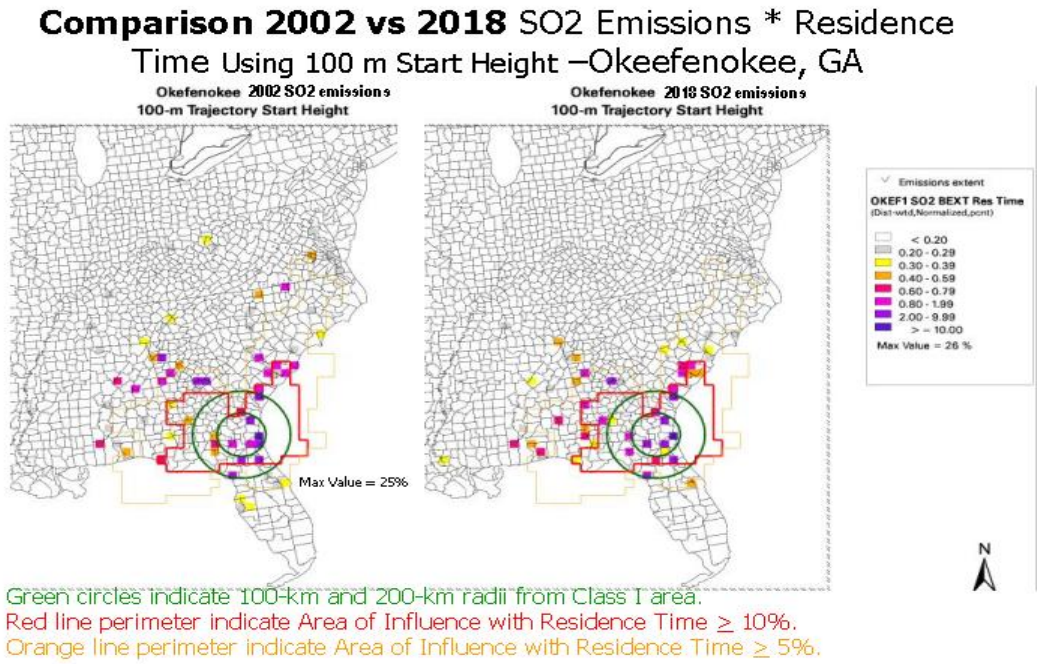


Figure 4-22. Okefenokee 2002 vs. 2018 SO2 emissions multiplied by residence time.

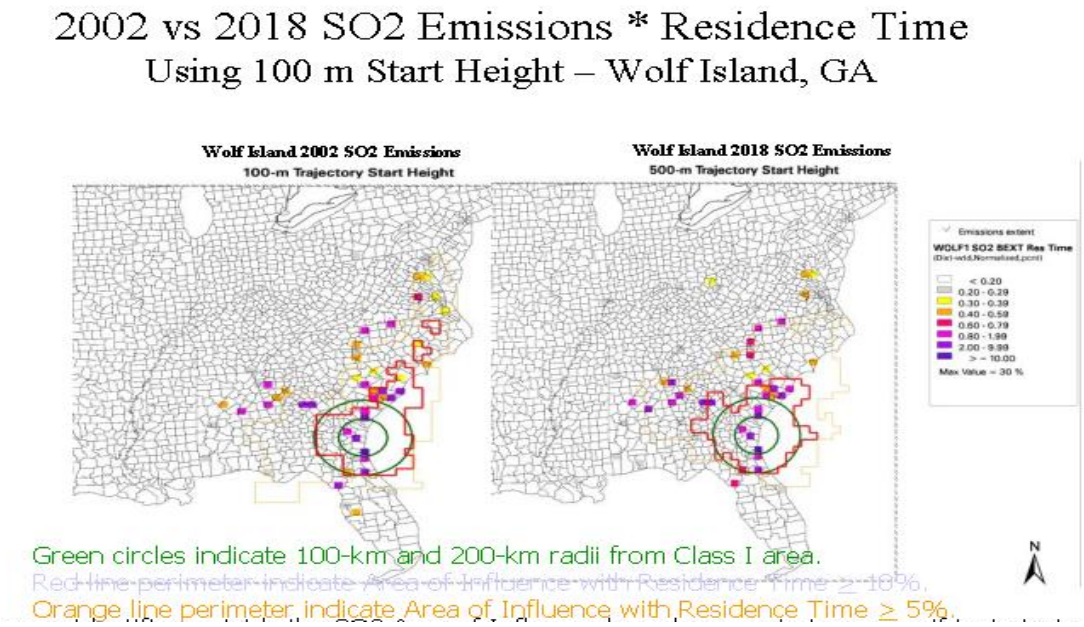


Figure 4-23. Wolf Island 2002 vs. 2018 SO2 emissions multiplied by residence time.

VISTAS states evaluated these plots of residence time weighted by sulfate extinction plots of gridded SO2 emissions and defined the SO2 Areas of Influence as those areas with residence time greater than 10%, based on trajectories with start height of 100m and 4 start times per day.

Extinction-weighted residence plots for Class I areas indicate that the areas of probable influence for sulfate contribution to visibility impairment are similar to those for nitrate contribution even though the visibility impact of nitrate is an order of magnitude smaller than that of sulfate. From these plots we can initially conclude that it is appropriate to focus on sources that contribute to sulfate concentrations and that sources near a Class I area are more likely to contribute to visibility impairment than more distant sources. Gridded SO2 emissions for the sulfate extinction-weighted residence time plots indicate that large emissions sources at great distance from the Class I area can contribute to visibility impairment on some 20% worst days.

4.5 Importance of Pollutants Other Than Sulfate

For completion, the following is a brief discussion of the importance of other PM components and contributing source categories. If NOx controls are considered, 54% of NOx is from point sources, 23% is from highway vehicles, and 20% is from nonroad engines. Elevated organic carbon (OC) and elemental carbon (EC) are indicators of fire. Some states may need to consider emissions from residential wood burning, forest fires Nitrate (NH4NO3) levels in winter can be significant and are dependent on availability of NH3; 88% of NH3 is from area sources (e.g. agriculture). However, given that sulfate contributes almost 60% at OKEF and greater than 70% at COHU on the 20% worst

visibility days, the GAEPD believes it is appropriate to focus on SO2 reductions in this first Regional Haze SIP.

4.6 Summary of Emission Inventories Used in Cost Analysis

A necessary component of control strategy design is a thorough review of the emission inventories that are used in the modeling of the future year base case. These inventories can shed light on the residual emissions from sources or source categories defined to be within areas of transport or impact of a Class I area. We used the most current (BaseG fall 2006) VISTAS future year (2018) base case and 2002 base year emissions to conduct this control cost analysis. For purposes of listing sources within the Area of Influence, data were provided for all sources with emissions over distance (Q/d) greater than 5 and maximum residence time (RTmax) greater than 5. States independently defined the criteria for selecting which sources from this list would be considered for reasonable control measures.

The NIF formatted and SMOKE-ready modeling files for both 2002 and 2018 base year and base cases were obtained from VISTAS emissions development and modeling contractors and converted to annual emissions and summed for the geography and domain of interest.

Tables 4-5 and 4-6 present the State breakdown of these emissions for the entire VISTAS domain. Because the SMOKE-ready files were used in this analysis, the particulate matter transport factor (0.90 times inventory values) is included in the PM emission summaries. This factor is applied to account for the removal of a substantial portion of fugitive dust emissions near a source by surrounding vegetation and structures when such emissions are used in regional scale modeling analyses.

Table 4-5. VISTAS 2002 Base Year Annual Emissions Summary (tons).

State	VOC	NOx	CO	SO2	PM-10	PM-2.5	NH3
AL	455986.6	508186.18	2639729.125	589958.722	229647.3855	102441.48	68365.2496
FL	1336653	1029414.61	7973550.506	597069.646	394623.2101	194814.88	61707.8367
GA	758324.4	676086.152	4640051.048	653870.886	346056.1024	141583.09	98059.1961
KY	298654.1	553437.753	1887662.518	591941.591	152553.0869	54788.97	57652.5317
MS	310938	315509.534	1283278.075	113148.074	182518.1506	45115.861	63991.004
NC	679631.8	668399.482	4410127.923	549402.424	183096.9552	87817.724	173832.4682
SC	393472.3	356431.368	2186195.351	289105.501	166503.9202	79326.939	35637.6515
TN	490647.5	588121.105	2813567.115	450018.744	168682.1637	78674.286	43281.8017
VA	464505.2	499762.38	3256848.719	421145.767	112841.3165	49843.365	55614.3642
WV	140149.3	378559.602	859397.9753	570885.53	48974.9782	28313.253	12468.711
Total	5328963	5573908.16	31950408.35	4826546.89	1985497.269	862719.84	670610.8147

Table 4-6. 2018 Base Case Annual Emissions Summary (tons).

State	VOC	NOx	CO	SO2	PM-10	PM-2.5	NH3
AL	327,243	269,679	1,976,259	295,593	249,430	106,872	84,746
FL	990183.7	467164.541	6003566.751	318293.487	447956.9962	193995	74420.0253
GA	562557.3	346853.445	3373857.236	212461.783	412358.7798	157692.4	123465.3064
KY	239819.6	281504.202	1422317.011	316508.674	165239.7959	57042	64504.0178
MS	249234.7	186848.555	865445.2111	48997.5324	203073.9879	52586.703	76272.3655
NC	428356	280996.238	2789482.511	175581.317	201461.5264	94657.988	197515.9242
SC	301998.5	196269.879	1585057.47	164409.353	186931.0623	86491.75	43361.5571
TN	389063	253040.352	1802311.755	207667.049	187913.2215	85495.927	48448.8788
VA	316675.2	279807.32	2103008.414	267852.827	129835.5692	56201.147	65077.764
WV	107982.3	152446.79	596152.6817	181085.221	46698.516	25158.089	15034.6498
Total	3,913,114	2,714,610	22,517,458	2,188,450	2,230,899	916,193	792,847

Our review was conducted in a top down fashion starting with an analysis of the major source categories in the domains of interest to determine which major categories had the highest residual contribution to the area. Once the highest source types were identified, subcategories within those source types were reviewed. Again, a ranking of the highest residual sub source types was performed and additional analyses on these categories were conducted. Using the extinction weighted analysis, these emission reviews and summaries like those presented in Figure 4-24, VISTAS made a decision to further review only point source controls in increment to the Clean Air Act scenario.

In addition to reviewing the residual emission categories in the future-year base, it was important to identify reductions that had already occurred within each category or at specific units. This allowed VISTAS States to determine if certain source categories that had yet to be controlled under the future-year base case had the potential for reduction or if source types already reduced have reached the full cost potential.

Finally, once each subcategory was identified, unit-level tables of emission comparisons from 2002 to 2018 were developed allowing VISTAS States to review existing emission reductions and providing the ability to assign new cost-effective controls to units using the best control for the scenario. These tables presented comparisons of 2002 and 2018 emission levels for SO2 and future-year control technology assignment (by IPM forecasting and State modification) for EGUs. Georgia EPD then used the processes described in Section 5.0 to identify additional reasonable controls for these units.

Ultimately, the final control strategy decisions will include the application of BART subject source reductions in the future-year base case.

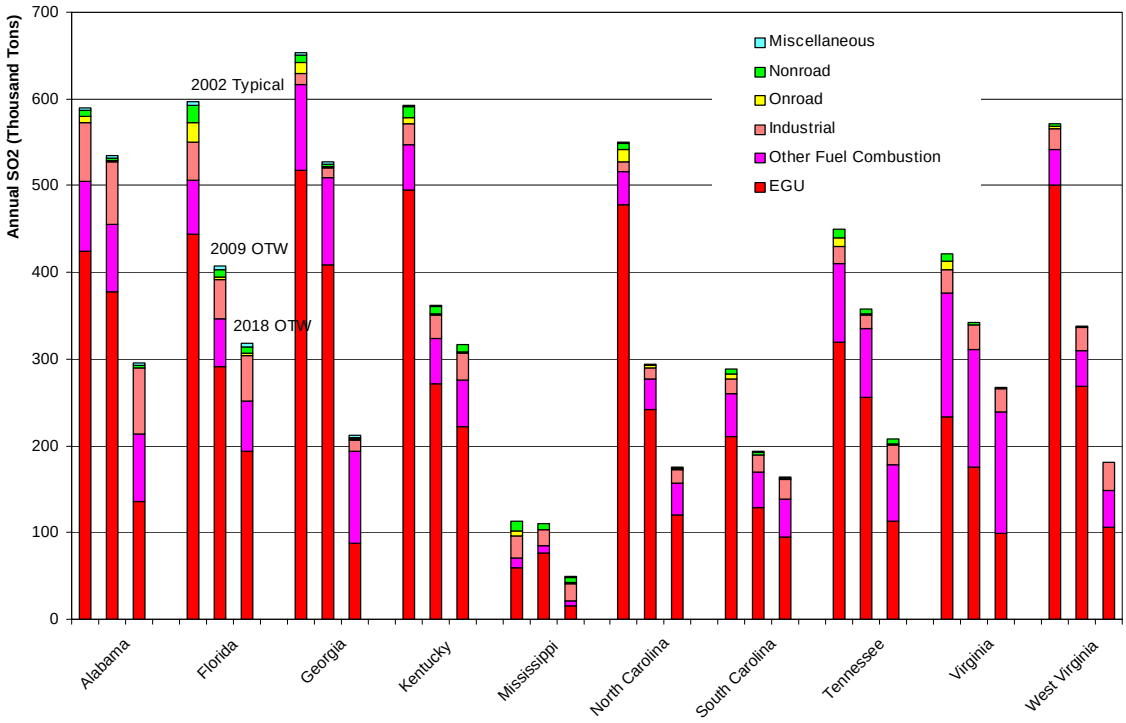


Figure 4-24. VISTAS Base G2 SO2 Emissions Contribution by Major Source Sector.

Note: Sections 4.7 through 4.9 discuss the use of AirControlNET to determine cost efficiencies of possible control measures. Georgia EPD relied upon site-specific cost efficiencies supplied by each source to identify cost-efficient control strategies. Results of AirControlNET analyses were used for comparison with source supplied information when evaluating control strategies.

4.7 Process in Preparing Files for Cost Effectiveness Curve Development

The 2018 IPM file used by VISTAS for EGU sources (RPO 2.1.9) was obtained and matched to the 2018 base-base inventory of EGU sources. This step was conducted to ensure that incremental controls assigned to these source types did not duplicate existing base-case assumptions. Because IPM does not assign a control efficiency with each control device applied to SO_2 and NO_X, we made some assumptions, based on IPM documentation, as to what pollutant-specific level of reduction was applied in the future-year base case runs. These assumptions, by primary and secondary control device code combinations for SO_2, are presented in Table 4-7.

Since many of the control-technology-control-cost equations within AirControlNET require additional unit-level characteristic data, we also made matches of the SMOKE IDA files to VISTAS NIF, EPA NEI, or EPA CAMD CEM data sets to obtain these variables when missing. Unit-level boiler capacity (MMBtu/hr) or NETDC (MW) values

are required for capital, operating and maintenance cost calculations for many of the SO2 applied technologies. In cases where these nameplate capacity values could not be identified, emission-weighted capacities (based on the final EPA 2002 NEI) were assigned to boilers using a primary (highest emitting) SCC. Table 4-8 presents these weighted capacities. Additionally, stack flow, sulfur content, and primary SCC assignment were necessary to cross-reference available incremental control technologies to the base-case emissions inventory data. These variables were obtained where matches could be found in priority order of VISTAS, CAMD, and other EPA datasets, respectively.

Table 4-7. IPM Post Processing Assigned Device Codes and Applied SO_2 Control Efficiencies.

Primary Device Code	Secondary Device Code	Description	CE	RE
0	0	No Control	0	0
119	0	Dry Scrubber	90	100
141	0	Wet Scrubber	90	100

Table 4-8. Emissions Weighted NETDC (MW) Association.

SCC	Description	NETDC (MW)
10100201	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Wet Bottom (Bituminous Coal)	200
10100202	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Dry Bottom (Bituminous Coal)	500
10100203	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Cyclone Furnace (Bituminous Coal)	200
10100212	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal)	500
10100215	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Cell Burner (Bituminous Coal)	1300
10100218	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Atmospheric Fluidized Bed Combustion: Circulating Bed (Bitum. Coal)	200
10100222	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Dry Bottom (Subbituminous Coal)	400
10100223	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Cyclone Furnace (Subbituminous Coal)	400
10100226	External Combustion Boilers; Electric Generation; Bituminous/Subbituminous Coal; Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	500
10100401	External Combustion Boilers; Electric Generation; Residual Oil; Grade 6 Oil: Normal Firing	400
10100404	External Combustion Boilers; Electric Generation; Residual Oil; Grade 6 Oil: Tangential Firing	500
10100501	External Combustion Boilers; Electric Generation; Distillate Oil; Grades 1 and 2 Oil	400
10100601	External Combustion Boilers; Electric Generation; Natural Gas; Boilers > 100 Million Btu/hr except Tangential	400
10100701	External Combustion Boilers; Electric Generation; Process Gas; Boilers > 100 Million Btu/hr	200
10100801	External Combustion Boilers; Electric Generation; Petroleum Coke; All Boiler Sizes	600
10101204	External Combustion Boilers; Electric Generation; Solid Waste; Tire Derived Fuel : Shredded	200
10300811	External Combustion Boilers; Commercial/Institutional; Landfill Gas; Landfill Gas	200
20100101	Internal Combustion Engines; Electric Generation; Distillate Oil (Diesel); Turbine	200
20100109	Internal Combustion Engines; Electric Generation; Distillate Oil (Diesel); Turbine: Exhaust	200
20100201	Internal Combustion Engines; Electric Generation; Natural Gas; Turbine	200
	All other boilers	100

4.8 Application of AirControlNET Technologies

AirControlNET is a control technology analysis tool developed to support the US EPA in its analyses of air pollution policies and regulations (Pechan, 2005). The tool provides

data on emission sources, potential pollution control measures and emission reductions and the costs of implementing those controls.

The core of AirControlNET is a relational database system in which control technologies are linked to sources within EPA emissions inventories. The system contains a database of control measure applicability, efficiency, and cost information for reducing the emissions contributing to ambient concentrations of ozone, PM_{10}, $PM_{2.5}$, SO_2, NO_X, as well as visibility impairment (regional haze) from point, area, and mobile sources. PM_{10} and $PM_{2.5}$ as included in AirControlNET represent primary emissions of PM. The control measure data file in AirControlNET includes not only the technology's control efficiency, and calculated emission reductions for that source, but also estimates the costs (annual and capital) for application of the control measure.

Since available versions of AirControlNET contain the preprocessed application of control technologies to a predetermined set of EPA emission inventories, direct use of the model in this analysis was not possible. However, Alpine received approval from EPA's Innovative Strategies and Economics Group (ISEG) to modify the AirControlNET Version 4.1 source code (Sorrels, 2006) and data tables in order to make it useful to this study. The results of the application of this modified version of the code still retain the applicability, efficiency, and cost information from the unmodified version of the source code, but were applied to the VISTAS modeling inventories with updated price index scalars to reflect control costs in 2005 dollars.

Using the modified inventories identified above, we ran every available SO2 control strategy in AirControlNET against the EGU and non-EGU point source inventories to develop a master list of available, *incremental* control strategies for the entire VISTAS 36 km domain necessary for VISTAS states to design command-and-control or cost-effectiveness-based control strategies by source or domain.

4.9 Development of AOI-Based Cost Curves

Each Class I area in the VISTAS modeling domain had an associated AOI as identified earlier in this document. In order to best determine where emission reduction has the greatest benefit, this geography was designed to limit the available source type list from including all sources within the entire domain.

These marginal cost curves include the application of all available control measures to all applicable point sources within the AoI. The curves will allow VISTAS States to determine if, based on the generic application of SO2 control technologies from the associations originally developed in AirControlNET and improved upon with stakeholder input will help attain reasonable progress emission reduction objectives while presumably minimizing the number and type of controlled sources in each AOI.

Using a geocoded county list from these AOIs, we parsed the master list of incremental control measures from all point sources located within the boundaries of the AOIs. This parsed list was then sorted by incremental cost-effectiveness (marginal cost) basis to

determine the most cost-effective control suite available to attain emission reduction targets for SO2 within each AOI. Each individual source had its own cost-effectiveness curve generated.

In aggregate, the results of these applications are SO2 emission cost curves for all EGU and non-EGU point sources within the geographic domain of the AOI. Incremental controls on area and mobile sources were not considered in this analysis. An illustrative example of the steps involved with the cost-effectiveness curve design can be found in the Attachment H-1a of this document.

With each AOI's cost curve, additional metrics, calculated for the distance from the emission release point to the Class I area IMPROVE monitor (in km), the 2018 residual emissions and distance (Q/d) or squared distance (Q/d^2), and the normalized 2018 SO2 point source emissions times distance-weighted residence time (RTMax) values for the county in which the emission release point was located, were calculated for incremental review and consideration. The GA EPD used these values to further determine control strategy development for individual Class I areas.

5.0 REASONABLE PROGRESS ASSESSMENT

The State concluded that SO2 emissions from EGU and non-EGU point sources in geographic Areas of Influence (AOIs) are sources to consider for further controls. VISTAS developed source matrices for SO2 AOIs for each Class I area, using data delivered by ENVIRON for 2002 and 2018 SO2 emissions multiplied by SO4 extinction-weighted residence time plots.

Spreadsheets were developed for each Class I area with:

- Plant name
- Point ID
- Tons of SO2 projected for 2018
- Q (tons)
- Current control efficiency, CE (%)
- Stationary source distance to Class I area [d (km)]
- Analysis of emissions per distance from source [Q/d and Q/d^2]
- RT Max, the maximum percentage of time that winds pass over that area on the way to the Class I area on the 20 worst days

The ranking refers to the source rank by Q/d when sources from all states are included.

In an analysis of emissions-per-distance from source, Q/d^2 is more representative when d is less than 20 km because plumes are still dispersing in two dimensions. After about 100 km, plumes only disperse in one dimension. The distance calculation is based on a single stack at a unit (when more than one are represented in the inventory) and is calculated in distance in km to the IMPROVE monitor at each Class I area. The residence time for the

county where the source is located was reviewed. It was generally agreed that states would focus on those sources where RT max was equal to or greater than 10%. A second matrix for sources in the SO2 AOI was developed for sources with a 2018 Q/d > 5 when d was greater than 100 km, $Q/d^2 > 0.03$ when d was less than 20 km, and Q/d > 5 or $Q/d^2 > 0.03$ when d was 20-100 km (these values were chosen to limit the number of sources on the list and focus on those that are most influential).

Next, the GA EPD elected to focus on those units that contributed at least half a percent to sulfate visibility impairment at a given Class I area for several reasons. First, the units with the larger contribution toward visibility impairment would likely show an environmental benefit under a control evaluation, and GA EPD would be able to use that environmental benefit to require controls on a given unit. Secondly, there are several regulatory programs that use a higher threshold than half a percent for evaluation thresholds.

1. The BART rule specifies that a maximum impact of 0.5 dv is an acceptable threshold for establishing significance. This threshold equates to roughly a five percent change in visible perception. This same significance level is used in the Prevention of Significant Deterioration/New Source Review program for the visibility air quality related value.

2. For the CAIR rule, a PM contribution of 0.2 ug/m3 was used to demonstrate a significant impact, which is 1.3% of the annual PM2.5 standard of 15 ug/m3.

3. Lastly, when human health standards are proposed (NAAQS), significant impact levels are assigned which allow sources to determine their significance on air quality in the area around their facilities. Sources that demonstrate that their "contribution" from the new or modified sources is less than these significance levels do not have to complete any further modeling. The SILS represent a percentage of the NAAQS.

After looking at all averaging periods for the criteria pollutants, GA EPD determined that the one half of one percent (0.5%) threshold proposed for reasonable progress was as protective or more protective than the significant impact levels. The most restrictive threshold identified was for NOx, which has a NAAQS of 100 ug/m3 and a significance level of 1 ug/m3, which represents one percent of the total.

Finally, GA EPD considered available resources to evaluate the sources in the each Class I area's sulfate AOI. GA EPD recognized that there was neither sufficient time nor resources available to evaluate all units within a given AOI. Therefore, a threshold needed to be established to determine which units would be evaluated. Table 5-1 shows that half a percent contribution threshold captures greater than 70% percent of the total point source SO2 contribution to two of Georgia's three Class I areas while requiring an evaluation of 30 or more units. At the remaining area, Cohutta Wilderness Area, the half a percent threshold represents 69 percent of the total contribution, while requiring an evaluation of 38 units. In order to capture a significant percentage of the total contribution, the next increment would involve an evaluation of many more units. GA EPD believes that half percent threshold is appropriate, given the contribution to the total

visibility impairment at each Class I area and the limited resources available to conduct the unit-by-unit evaluation for reasonable progress.

Table 5-1. Numbers and percentage of 2018 SO2 emission units that contribute to Georgia Class I areas.

	Georgia Class I Area			Non-Georgia class I areas		
	COHU	**OKEF**	**WOLF**	**SAMA**	**JOKI**	**ROMA**
# Units Contributing > 0.5%	38	31	29	51	17	36
Percentage of total contribution	69%	83.16%	73.39%	86.74%	42.91%	83.61%
# Units Contributing > 0.1%, but < 0.5%	121	90	95	70	46	72
Percentage of total contribution	31.61%	26.09%	29.4%	17.73%	14.2%	22.95%
# Units Contributing < 0.1%	119	43	46	7	26	106
Percentage of total contribution	6.3%	2.57%	2.72	0.48%	1.31%	4.92%

The following three tables, 5-2 through 5-4, show the analysis for COHU, OKEF, WOLF, and non-Georgia Class I Areas for sources that met the above criteria. The full spreadsheets containing all VISTAS Class I area results can be found in Appendix H.2.

Table 5-2. Cohutta Wilderness Area Q/d, Q/d^2, RTMax, and fractional contribution analysis.

STATE	PLANT	POINT ID	(2018 G)	CE (%)*	DIST (KM)	Q/D	Q/D^2	RT MAX**	FRACTION
GEORGIA	TEMPLE INLAND ROME LINERBOARD (THIS UNIT IS PERMENTLY SHUT DOWN)	F2	1,148	4	87.55	13.11	0.15	78.87	0.0137
GEORGIA	TEMPLE INLAND ROME LINERBOARD	F4	3,696	4	87.55	42.22	0.48	78.87	0.0442
GEORGIA	MOHAWK INDUSTRIES - SOUTH HAMILTON STREE	BL06	200	0	31.93	6.28	0.20	83.31	0.0069
GEORGIA	MOHAWK INDUSTRIES - SOUTH HAMILTON STREE	BL07	200	0	31.93	6.28	0.20	83.31	0.0069
GEORGIA	MOUNT VERNON MILLS, INC., APPAREL FABRIC	EU03	351	4	67.72	5.18	0.08	78.87	0.0054
GEORGIA	MOUNT VERNON MILLS, INC., APPAREL FABRIC	EU04	828	4	67.72	12.22	0.18	78.87	0.0128
TENNESSEE	A.E. STALEY MANUFACTURING COMPANY	005	2,982	4	109.35	27.27	0.25	38.49	0.0139
TENNESSEE	ALUMINUM COMPANY OF AMERICA - SOUTH PLAN	16	2,370	0	125.75	18.85	0.15	33.77	0.0084

TENNESSEE	ALUMINUM COMPANY OF AMERICA - SOUTH PLAN	17	2,320	0	125.75	18.45	0.15	33.77	0.0083
TENNESSEE	BOWATER NEWSPRINT & DIRECTORY - CALHOUN	015	5,871	4	58.30	100.71	1.73	82.90	0.1107
TENNESSEE	E. I. DU PONT DE NEMOURS AND COMPANY	0002	1,173	0	67.08	17.48	0.26	83.31	0.0193
TENNESSEE	EASTMAN CHEMICAL COMPANY	021520	16,729	4	270.21	61.91	0.23	8.43	0.0069
TENNESSEE	INTERTRADE HOLDINGS, INC.	001	2,530	4	32.47	77.92	2.40	82.90	0.0857
TENNESSEE	U.S. DEPARTMENT OF ENERGY, Y-12 PLANT	002	2,336	4	137.55	16.99	0.12	24.66	0.0056
GEORGIA	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	SG03	3,056	95	78.34	39.01	0.50	44.32	0.0233
GEORGIA	GEORGIA POWER COMPANY, HAMMOND STEAM-ELE	SG04	1,728	95	88.75	19.47	0.22	78.87	0.0207
GEORGIA	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	SG02	2,432	95	78.34	31.05	0.40	44.32	0.0185
GEORGIA	GEORGIA POWER COMPANY, BOWEN STEAM-ELECT	SG01	2,415	95	78.34	30.83	0.39	44.32	0.0184
ALABAMA	TVA - WIDOWS CREEK	008	10,185	90	103.54	98.37	0.95	20.39	0.0270
GEORGIA	GEORGIA POWER COMPANY, YATES STEAM-ELECT	SG05	6,643	0	149.41	44.46	0.30	39.91	0.0239
GEORGIA	GEORGIA POWER COMPANY, YATES STEAM-ELECT	SG04	6,500	0	149.41	43.50	0.29	39.91	0.0234
TENNESSEE	TVA BULL RUN FOSSIL PLANT	001	8,657	90	144.05	60.10	0.42	24.66	0.0199
ALABAMA	TVA - WIDOWS CREEK	009	6,712	90	103.54	64.83	0.63	20.39	0.0178
GEORGIA	GEORGIA POWER COMPANY, YATES STEAM-ELECT	SG03	3,916	0	149.41	26.21	0.18	39.91	0.0141
ALABAMA	TVA - WIDOWS CREEK	005	4,839	0	103.54	46.73	0.45	20.39	0.0128
ALABAMA	TVA - WIDOWS CREEK	004	4,828	0	103.54	46.63	0.45	20.39	0.0128
ALABAMA	TVA - WIDOWS CREEK	002	4,821	0	103.54	46.56	0.45	20.39	0.0128
GEORGIA	GEORGIA POWER COMPANY, YATES STEAM-ELECT	SG02	3,547	0	149.41	23.74	0.16	39.91	0.0127
ALABAMA	TVA - WIDOWS CREEK	006	4,707	0	103.54	45.46	0.44	20.39	0.0125
ALABAMA	TVA - WIDOWS CREEK	003	4,625	0	103.54	44.67	0.43	20.39	0.0122

ALABAMA	TVA - WIDOWS CREEK	007	4,550	0	103.54	43.95	0.42	20.39	0.0121
SOUTH CAROLINA	DUKE ENERGY:LEE	003	7,274	0	201.57	36.09	0.18	22.06	0.0107
ALABAMA	ALABAMA POWER COMPANY - GORGAS	004	9,854	0	268.85	36.65	0.14	13.76	0.0068
SOUTH CAROLINA	DUKE ENERGY:LEE	001	4,347	0	201.61	21.56	0.11	22.06	0.0064
SOUTH CAROLINA	DUKE ENERGY:LEE	002	4,140	0	201.57	20.54	0.10	22.06	0.0061
ALABAMA	ALABAMA POWER COMPANY - GORGAS	005	8,091	0	268.85	30.09	0.11	13.76	0.0056
ALABAMA	ALABAMA POWER COMPANY - E C GASTON	006	7,542	90	240.83	31.32	0.13	11.99	0.0051

Table 5-3. Okefenokee Wilderness Area Q/d, Q/d^2, RTMax, and fractional contribution analysis

STATE	PLANT	POINT ID	(2018 G)	CE (%)*	DISTANCE (KM)	Q/D	Q/D^2	RT MAX**	FRACTION
GEORGIA	JESUP MILL, RAYONIER PERFORMANCE	PB02	624	4	106.37	5.87	0.06	71.58	0.0094
GEORGIA	JESUP MILL, RAYONIER PERFORMANCE	PB03	1,597	4	106.27	15.03	0.14	71.58	0.0240
GEORGIA	JESUP MILL, RAYONIER PERFORMANCE	RF01	333	0	106.22	3.14	0.03	71.58	0.0050
GEORGIA	JESUP MILL, RAYONIER PERFORMANCE	RF04	334	0	105.88	3.15	0.03	71.58	0.0050
FLORIDA	ANCHOR GLASS CONTAINER CORPORATION	3	206	0	59.04	3.49	0.06	65.70	0.0051
FLORIDA	ANCHOR GLASS CONTAINER CORPORATION	4	212	0	59.04	3.60	0.06	65.70	0.0053
FLORIDA	CEDAR BAY GENERATING COMPANY L P	GEN1	2,227	0	61.17	36.41	0.60	65.70	0.0534
FLORIDA	GEORGIA-PACIFIC CORP. PULP/PAPER MILL	15	4,329	0	125.55	34.48	0.27	22.94	0.0177
FLORIDA	GEORGIA-PACIFIC CORP. PULP/PAPER MILL	16	1,581	4	125.55	12.59	0.10	22.94	0.0064
FLORIDA	IFF CHEMICAL HOLDINGS, INC.	3	733	0	56.66	12.94	0.23	65.70	0.0190
FLORIDA	JEFFERSON SMURFIT CORPORATION (US)	15	3,639	4	64.58	56.35	0.87	71.58	0.0900

FLORIDA	JEFFERSON SMURFIT CORPORATION (US)	6	300	0	64.42	4.66	0.07	71.58	0.0074
FLORIDA	MILLENNIUM SPECIALTY CHEMICALS	5	269	0	60.46	4.45	0.07	65.70	0.0065
FLORIDA	MILLENNIUM SPECIALTY CHEMICALS	6	590	0	60.46	9.76	0.16	65.70	0.0143
FLORIDA	PROGRESS ENERGY FLORIDA, INC. CRYSTAL RI	1	13,537	0	205.80	65.78	0.32	5.47	0.0080
FLORIDA	PROGRESS ENERGY FLORIDA, INC. CRYSTAL RI	2	15,241	0	205.80	74.06	0.36	5.47	0.0090
FLORIDA	RAYONIER PERFORMANCE FIBERS LLC	6	1,256	0	63.34	19.83	0.31	71.58	0.0317
FLORIDA	SAINT JOHNS RIVER	16	5,882	90	65.12	90.33	1.39	65.70	0.1325
FLORIDA	SAINT JOHNS RIVER	17	7,420	90	65.12	113.95	1.75	65.70	0.1671
FLORIDA	SEMINOLE ELECTRIC COOPERATIVE, INC.	1	6,779	95	121.83	55.64	0.46	22.94	0.0285
FLORIDA	SEMINOLE ELECTRIC COOPERATIVE, INC.	2	6,508	95	121.83	53.42	0.44	22.94	0.0274
FLORIDA	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	66	1,496	0	69.96	21.39	0.31	48.81	0.0233
FLORIDA	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	67	1,308	0	69.96	18.69	0.27	48.81	0.0204
GEORGIA	SAVANNAH ELECTRIC: MCINTOSH STEAM - ELEC	SG01	7,015	0	201.59	34.80	0.17	15.51	0.0124
FLORIDA	PROGRESS ENERGY FLORIDA, INC. CRYSTAL RI	2	15,241	0	205.80	74.06	0.36	5.47	0.0093
GEORGIA	SAVANNAH ELECTRIC: KRAFT STEAM - ELECTRI	SG03	4,474	0	182.45	24.52	0.13	15.53	0.0088
GEORGIA	GEORGIA POWER COMPANY, MITCHELL STEAM-EL	SG03	4,930	0	206.79	23.84	0.12	14.43	0.0079
SOUTH CAROLINA	SCE&G:CANADYS	001	5,203	0	295.33	17.62	0.06	16.79	0.0068
SOUTH CAROLINA	SCE&G:CANADYS	002	5,144	0	295.35	17.42	0.06	16.79	0.0067

Table 5-4. Wolf Island Q/d, Q/d^2, RTMax, and fractional contribution analysis.

STATE	PLANT	POINT ID	(2018 G)	CE (%)*	DISTANCE (KM)	Q/D	Q/D^2	RT MAX*	FRACTION
GEORGIA	GEORGIA-PACIFIC BRUNSWICK	F1	1,842	4	28.39	64.89	2.29	73.01	0.1255
GEORGIA	GEORGIA-PACIFIC BRUNSWICK	M24	193	0	28.39	6.80	0.24	73.01	0.0131
GEORGIA	GEORGIA-PACIFIC CORP SAVANNAH	BO01	1,844	90	109.91	16.78	0.15	25.08	0.0111
GEORGIA	GEORGIA-PACIFIC CORP SAVANNAH	BO02	1,415	90	109.95	12.87	0.12	25.08	0.0086
GEORGIA	GEORGIA-PACIFIC CORP SAVANNAH	BO03	1,282	90	109.99	11.66	0.11	25.08	0.0077
GEORGIA	INTERNATIONAL PAPER - SAVANNAH	PB13	8,578	4	85.82	99.96	1.16	25.08	0.0664
GEORGIA	INTERSTATE PAPER LLC	F1	188	0	44.67	4.20	0.09	46.19	0.0051
GEORGIA	SAVANNAH ELECTRIC: KRAFT	SG01	691	0	90.18	7.66	0.08	25.08	0.0051
GEORGIA	SAVANNAH ELECTRIC: KRAFT	SG02	704	0	90.18	7.80	0.09	25.08	0.0052
GEORGIA	SAVANNAH ELECTRIC: KRAFT	SG03	4,474	0	90.18	49.62	0.55	25.08	0.0330
GEORGIA	SAVANNAH ELECTRIC: MCINTOSH	SG01	7,015	0	112.72	62.24	0.55	25.08	0.0413
GEORGIA	SAVANNAH SUGAR REFINERY	U161	997	4	89.65	11.13	0.12	25.08	0.0074
GEORGIA	SOUTHERN STATES PHOSPHATE &	SA02	808	0	83.92	9.62	0.11	25.08	0.0064
SOUTH CAROLINA	GIANT CEMENT CO	005	3,893	0	222.58	17.49	0.08	14.78	0.0068
SOUTH CAROLINA	HOLCIM:HOLLY HILL	002	4,074	0	235.40	17.31	0.07	12.19	0.0056
SOUTH CAROLINA	MEADWESTVACO CORPORATION INC	006	2,706	0	213.39	12.68	0.06	24.20	0.0081
SOUTH CAROLINA	SANTEE COOPER CROSS	002	3,380	87	244.36	13.83	0.06	14.73	0.0054
SOUTH CAROLINA	SANTEE COOPER CROSS	3	3,835	0	244.36	15.69	0.06	14.73	0.0061
SOUTH CAROLINA	SANTEE COOPER JEFFERIES	003	6,761	0	244.62	27.64	0.11	14.73	0.0108
SOUTH CAROLINA	SANTEE COOPER JEFFERIES	004	6,609	0	244.62	27.02	0.11	14.73	0.0105
SOUTH CAROLINA	SCE&G:CANADYS	001	5,203	0	201.47	25.83	0.13	24.20	0.0166
SOUTH CAROLINA	SCE&G:CANADYS	002	5,144	0	201.47	25.53	0.13	24.20	0.0164
FLORIDA	SAINT JOHNS RIVER	17	7,420	90	105.18	70.55	0.67	50.75	0.0976
FLORIDA	SAINT JOHNS RIVER	16	5,882	90	105.18	55.92	0.53	50.75	0.0774
FLORIDA	CEDAR BAY GENERATING	GEN1	2,227	0	107.25	20.77	0.19	50.75	0.0287
FLORIDA	SEMINOLE ELECTRIC COOPERATIVE. INC.	1	6,779	95	182.71	37.10	0.20	15.88	0.0161
FLORIDA	SEMINOLE ELECTRIC COOPERATIVE. INC.	2	6,508	95	182.71	35.62	0.19	15.88	0.0154

Table 5-5. Non-Georgia Class I Areas Q/d, Q/d^2, RTMax, and fractional contribution analysis (Georgia sources only)

STATE	PLANT	POINT ID	(2018 G)	CE (%)*	DISTANCE (KM)	Q/D	Q/D^2	RT MAX**	FRACTION
SAINT MARKS									
GEORGIA	GEORGIA PACIFIC CORPORATION, CEDAR SPRINGS	U500	2428	4	149.70	16.22	0.11	12.89	0.0108
GEORGIA	GEORGIA PACIFIC CORPORATION, CEDAR SPRINGS	U501	2533	4	149.70	16.92	0.11	12.89	0.0113
GEORGIA	GEORGIA PACIFIC CORPORATION, CEDAR SPRINGS	R402	1726	0	149.78	11.53	0.08	12.89	0.0077
GEORGIA	GEORGIA POWER COMPANY, PLANT MITCHELL	SG03	4930	0	150.49	32.76	0.22	16.16	0.0274
GEORGIA	INTERNATIONAL PAPER SAVANNAH MILL	PB13	8578	4	366.31	23.42	0.06	5.81	0.0070
GEORGIA	SAVANNAH ELECTRIC, PLANT MCINTOSH	SG01	7015	0	380.33	18.44	0.05	5.81	0.0055
GEORGIA	MILLER BREWING CO	B001[1]	1073	0	164.59	6.52	0.04	15.16	0.0054
GEORGIA	PACKAGING CORPORATION OF AMERICA	1017	653	0	105.83	6.17	0.06	15.90	0.0051
JOYCE KILMER/SLICKROCK									
GEORGIA	TEMPLE INLAND ROME LINERBOARD	F4	3696	4	175.7	21.04	0.12	29.12	0.0099
CAPE ROMAIN									
GEORGIA	INTERNATIONAL PAPER SAVANNAH MILL	PB13	8578	4	165.98	51.68	0.31	31.04	0.0155
GEORGIA	SAVANNAH ELECTRIC, PLANT MCINTOSH	SG01	7089	0	155.93	44.99	0.29	31.04	0.0135
GEORGIA	SAVANNAH ELECTRIC, PLANT KRAFT	SG03	3992	0	165.25	27.08	0.16	31.04	0.0081
SHINING ROCK									
GEORGIA	GEORGIA POWER, PLANT SCHERER	SGO3	27,735	0	276.79	100.2	0.36	8.61	0.0071
GEORGIA	GEORGIA POWER, PLANT SCHERER	SGO4	26,616	0	276.79	96.16	0.35	8.61	0.0068
GEORGIA	GEORGIA POWER, PLANT SCHERER	SGO1	26,264	0	276.79	94.89	0.34	8.61	0.0067
GEORGIA	GEORGIA POWER, PLANT SCHERER	SGO2	26,075	0	276.79	94.20	0.34	8.61	0.0067

[1] Note that Boiler B002 at Miller Brewing Company is identical to B002 and was originally included in Georgia's 4-factor list along with B001.

GEORGIA	GEORGIA POWER, PLANT YATES	SG07	16,530	0	290.63	56.88	0.20	12.35	0.0058
GEORGIA	GEORGIA POWER, PLANT YATES	SG06	16,367	0	290.63	56.31	0.19	12.35	0.0057
SIPSEY									
GEORGIA	GEORGIA POWER, PLANT YATES	SG07	16,530	0	245.30	67.39	0.27	15.03	0.0111
GEORGIA	GEORGIA POWER, PLANT YATES	SG06	16,367	0	245.30	66.72	0.27	15.03	0.0110
GEORGIA	GEORGIA POWER, PLANT SCHERER	SGO3	27,735	0	356.99	77.69	0.22	6.86	0.0059
GEORGIA	GEORGIA POWER, PLANT SCHERER	SGO4	26,616	0	356.99	74.56	0.21	6.86	0.0056
GEORGIA	GEORGIA POWER, PLANT SCHERER	SGO1	26,264	0	356.99	73.57	0.21	6.86	0.0056
GEORGIA	GEORGIA POWER, PLANT SCHERER	SGO2	26,075	0	356.99	73.04	0.20	6.86	0.0055
SWANQUARTER									
GEORGIA	INTERNATIONAL PAPER SAVANNAH MILL	PB13	8578	4	587.64	14.60	0.02	24.37	0.0086
GEORGIA	SAVANNAH ELECTRIC, PLANT MCINTOSH	SG01	7089	0	573.33	12.24	0.02	24.36	0.0072

Note that only units located within Georgia are listed in Table 5.5. Since Georgia EPD is only responsible for Four Factor Analyses for sources located in Georgia that impact non-Georgia Class I areas, units outside of Georgia that exceed the threshold value of 0.5% are not included.

Spreadsheets were developed for each Class I area source with $Q/d > 3$ or $Q/d^2 > 0.03$, indicating the plant name, industry description, emissions projections for 2018, current control efficiency (CE%), distance from Class I area, Q/d, Q/d^2, RT average, RT maximum, Q/d*RT, the fraction a single source contributes to the total Q/d*RT for a Class I area.

Using the process described above, GA EPD initially identified 27 emissions units for analysis of additional controls in accordance with the four statutory factors. The 27 units were selected based on analyses that indicated that each one's contribution to total sulfate visibility impairment was at least 0.5% of the total sulfate visibility impairment at one or more Class I areas. The eligible units are listed below in Table 5-6.

Table 5-6. Facilities and emissions units eligible for 4-factor analysis

Facility	Eligible Unit(s)
Georgia Pacific, Brunswick Cellulose	Power Boiler No. 4
	Recovery Boiler (M24)
Georgia Pacific, Cedar Springs	Power Boiler U500
	Power Boiler U501
	Recovery Boiler R402
Georgia Pacific, Savannah River Mill	Boiler B001
	Boiler B002
	Boiler B003
Georgia Power, Plant Kraft	Steam Generator 1
	Steam Generator 2
	Steam Generator 3
Georgia Power, Plant Mitchell	Steam Generator 3
Georgia Power, Plant McIntosh	Steam Generator 1
International Paper, Savannah Mill	Power Boiler 13
Interstate Paper	Power Boiler F1
Miller Brewing	Boiler B001
	Boiler B002
Mount Vernon Mills	Boiler E U 03
	Boiler E U 04
Packaging Corporation of America	C E Boiler
Rayonier Performance Fibers, Jessup Mill	Power Boiler 2
	Power Boiler 3
	Recovery Furnace 1
	Recovery Furnace 4
Savannah Sugar Refinery	Boiler U161
Southern States Phosphate and Fertilizer	Sulfuric Acid Plant 2
Temple Inland Rome Linerboard	Power Boiler No. 4

GA EPD reviewed the sources for which the Four Factor Analysis was to be conducted.

The first review was of existing permit and compliance files, pending permit applications and information provided by EPD permitting staff. As a result, one emissions unit (Temple Inland Corrugated Container Plant – Unit F2) was determined to have permanently ceased operation and was thus removed from the requirement for reasonable progress determination. According to correspondence from Temple Inland, the last day of operation of the Corrugated Container Plant (in Rome, Georgia) was November 11, 2008. Georgia EPD revoked permit number 2653-115-088-V-02-0 on April 15, 2009.

GA EPD requested a Four Factor Analysis from each of the remaining reasonable progress facilities on March 21, 2007. As a result of this inquiry, updated projected 2018 emissions were received from some facilities. Other facilities requested emission limits to reduce the emission unit's contribution to sulfate visibility impact on the nearest Class I area to less than the threshold of 0.5%. Table 5-7 gives a list of the units that were removed from the requirement for four-factor analysis as a result of updated emission projections or emission limitations.

Table 5-7. Units dropped from four-factor analysis

STATE	PLANT	POINT ID	REASON FOR REMOVING UNIT FROM FOUR FACTOR ANALYSIS
GEORGIA	MOUNT VERNON MILLS, INC., APPAREL FABRIC	EU03	Facility updated their 2018 emission information, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	MOUNT VERNON MILLS, INC., APPAREL FABRIC	EU04	Facility updated their 2018 emission information, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	JESUP MILL, RAYONIER PERFORMANCE FIBERS	PB02	Facility took limit on units eligible for four factor analyses, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	JESUP MILL, RAYONIER PERFORMANCE FIBERS	PB03	Facility took limit on units eligible for four factor analyses, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	JESUP MILL, RAYONIER PERFORMANCE FIBERS	RF01	Facility took limit on units eligible for four factor analyses, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	JESUP MILL, RAYONIER PERFORMANCE FIBERS	RF04	Facility took limit on units eligible for four factor analyses, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	SOUTHERN STATES PHOSPHATE & FERTILIZER C	SA02	Facility took limit on units eligible for four factor analyses, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	SAVANNAH SUGAR REFINERY	U161	Facility updated their 2018 emission information, resulting in lowering of sulfate visibility impact to less than 0.5 %
GEORGIA	PACKAGING CORPORATION OF AMERICA	CE	Facility took limit on units eligible for four factor analyses, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	MILLER BREWING	B001	Facility updated their 2018 emission information, lowering sulfate visibility impact to less than 0.5 %

GEORGIA	MILLER BREWING	B002	Facility updated their 2018 emission information, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	INTERSTATE PAPER LLC	F1	Facility subject to full BART determination analysis. Exempt from 4-factor analysis per EPA guidance.
GEORGIA	MOHAWK INDUSTRIES	BL06	Facility updated their 2018 emission information, lowering sulfate visibility impact to less than 0.5 %
GEORGIA	MOHAWK INDUSTRIES	BL07	Facility updated their 2018 emission information, lowering sulfate visibility impact to less than 0.5 %

Georgia EPD conducted Four Factor Analyses on the remaining Georgia Sources on the lists. For Non-Georgia units whose percentage contribution to sulfate visibility impact on a Georgia Class I area of 0.5% or greater, Georgia EPD requested, in writing, that the state that the unit is located in conduct a Four Factor Analysis on the unit to determine and require reasonable control measures. A copy of the letter sent to those states is found in Appendix J of the SIP narrative.

6.0 FOUR FACTOR ANALYSIS

Section 169A(g)(1) of the Clean Air Act (CAA) and 40 CFR 51.308(d)(1)(i)(A). Four statutory factors that are outlined have been identified as mandatory for purposes of establishing a reasonable progress goal for any mandatory Class I area within a State: cost of compliance, time necessary for compliance, energy and non-air quality environmental impacts of compliance, and remaining useful life of any existing source subject to such requirements. These statutory factors would be specific to the sources being considered for additional controls.

6.1 The Four Statutory Factors

6.1.1 Cost of Compliance

The "cost of compliance" is a factor used to determine whether compliance costs for sources are reasonable compared to the emission reduction and visibility improvement they will achieve. Note that visibility improvement is not only related to tons of pollutant removed, but also involves how the pollutant or chemical compound affects the extinction coefficient in each Class I area. For example, on a pound-to-pound comparison, sulfate particulate impairs visibility greater than coarse particulate. Costs should be determined for one-time capital costs, as well as ongoing annual operation and maintenance.

6.1.2 Time Necessary for Compliance

The "time necessary for compliance" factor may be used to adjust the reasonable progress goals to reflect the degree of improvement achievable within the long-term strategy period, as opposed to the improvement expected at full implementation of a control measure, if the time needed for full compliance exceeds the length of the long-term strategy period. For instance, if implementation of a control measure could not be completed within the schedule outlined by the control strategy, the RPG should reflect what visibility improvement could be expected within the strategy period.

For example, if construction labor availability constraints preclude the installation of controls at all sources of a particular category within the LTS period, the RPG should reflect the visibility improvement anticipated from installation of controls at the percentage of sources that could be controlled within the strategy period. (The SIP could still include control strategies that extend beyond the 2018 milestone. In the above example, the visibility improvement anticipated from installation of controls at the percentage of sources that could not be controlled within the first strategy period would have to be counted in a later SIP.)

6.1.3 Energy and Non-Air Quality Environmental Impacts of Compliance

The "energy and non-air quality environmental impacts of compliance" factor is meant to consider whether the energy requirements of the control technology result in energy penalties or benefits. For example, controls on diesel engines may decrease the overall efficiency and require a significant increase in diesel fuel consumption. The State should also consider any significant or unusual non-air environmental impacts such as a waste stream that may be generated by a particular control technology.

6.1.4 Remaining Useful Life of the Source

The statutory factor of the "remaining useful life of the source" is applicable only to those measures which would require retrofitting of control devices (or possibly production changes) at *existing* sources. In such cases, this factor should be treated as one element of the overall cost analysis. For purposes of this analysis, the remaining useful life is the difference between the year of the reasonable progress analysis and the date the facility permanently stops operations. The remaining useful life of a source affects the annualized costs of retrofit controls.

6.2 Evaluating Four Statutory Factors for Specific SO2 Emissions Sources in Each Area of Influence

The next step was to identify emission reductions that have already occurred within each source category and at specific units. Unit-level tables of emission comparisons from 2002 to 2018 were developed, allowing VISTAS States to review existing emission reductions. These tables assigned future-year control technology from IPM forecasting and State modification for EGU and from control-efficiency tables for non-EGU point sources.

Once emission control profiles for specific units were defined, the next step is to determine what, if any, additional control measures would feasibly be available, and to assign costs to those control measures.

For EGUs, the 2018 IPM file used by VISTAS for EGU sources was obtained and matched to the 2018 base-case inventory of EGU sources. This step was conducted to ensure that incremental controls assigned to these source types did not duplicate existing base-case assumptions.

For non-EGUs, VISTAS used EPA's AirControlNET database, modified for the VISTAS emission inventories. The core of AirControlNET is a relational database system in which control technologies are linked to sources within EPA emissions inventories. The system contains a database of control measure applicability, efficiency, and cost information for reducing emissions. The control measure data file in AirControlNET includes not only the technology's control efficiency and calculated emission reductions

for that source, but also estimates the costs (annual and capital) for application of the control measure.

Using the modified inventories identified above, VISTAS ran every available SO2 control strategy in AirControlNET against the EGU and non-EGU point source inventories to develop a master list of incremental control strategies for each unit in the VISTAS 36 km domain.

For the sources within the AOIs for each Georgia Class I area, Georgia requested site-specific analysis from the affected facilities. Data obtained from AirControlNet (Appendix H.3) was used for comparison with site-specific analyses to identify possible control options that need to be evaluated and to determine possible over-estimation or under-estimation of cost efficiencies.

The Regional Haze Rule requires that states consider the following factors and demonstrate how these factors were taken into consideration in selecting the reasonable progress goal:

- the costs of compliance,
- the time necessary for compliance,
- the energy and non-air quality environmental impacts of compliance, and
- the remaining useful life of any potentially affected sources.

The general considerations taken into account in Georgia EPD's 4-factor evaluations and the evaluations of the specific emissions units are presented below.

6.2.1 Cost of Compliance

Georgia EPD evaluated cost of compliance using a variety of factors. Facilities provided data for various control options for each affected unit. The data typically included total capital costs and cost-per-ton of pollutant removed ($/ton). Georgia EPD compared this data with similarly-controlled units as well as AirControlNET estimates. Costs were presented in 2007 dollars for consistency. In addition, Georgia EPD conducted CMAQ modeling to determine the amount of visibility improvement resulting from each ton of SO2 reduced from each unit subject to analysis. This cost-efficiency metric is expressed in dollar-per-inverse megameter ($/Mm-1) and was considered in addition to cost efficiency expressed in $/ton. This approach is similar to the approach used by Georgia EPD to evaluate cost efficiency for other SIPS (e.g., ozone and PM2.5).

6.2.2 Time Necessary for Compliance

Georgia EPD based the time necessary for compliance on the installation and operation of controls by the beginning of the year 2012. Since the next Regional Haze SIP will be due December 17, 2017, a compliance date of 2012 will result in visibility improvement for all five years of monitoring data (2012, 2013, 2014, 2015, and 2016) that will be assessed to determine conformity with 2018 progress goals at the time the next Regional

Haze SIP is due. Any control options that can be installed and operated prior to 2012 were determined to be timely. Control options that cannot be installed and operated prior to 2012, but can be prior to 2018, would not result in the optimal amount of visibility improvement by the 2018 reasonable progress goal, but were still considered. Control options that could not be installed and operated until 2018 or after were not considered for this Regional Haze SIP.

6.2.3 Energy and Non-Air Environmental Impacts

Additional factors that were considered were the energy requirements of the control technology and the non-air impacts (that is, impacts on other environmental media). Energy impacts were generally included in the cost-efficiency estimates. Non-air impacts that were considered included solid waste disposal, water withdrawal, and wastewater discharge. The review of control strategies that were not eliminated because of excessive cost efficiencies and that involved water withdrawal and wastewater discharge were coordinated with Georgia EPD's Watershed Protection Branch.

6.2.4 Remaining Useful Life

The remaining useful life of an affected emissions unit can potentially impact reasonableness of control strategies in two ways. If the remaining useful life of an affected emission unit did not extend past 2018, no controls would be considered for that unit. If the remaining useful life of a unit was less than the amortization period for a particular control option, the shorter period was used in annualizing the capital costs of the control option when determining the cost efficiency. It should be noted that remaining useful life was not an issue for any of the control options reviewed by Georgia EPD.

6.3 Process of Applying Statutory Factors

The Georgia EPD has completed the reasonable progress assessment for the first regional haze SIP. This process was based on U.S. EPA's "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," June of 2007 [Reasonable Progress guidance]. The following was Georgia EPD's Process on reasonable progress assessment for the current time period (from the present to 2018):

<u>Step 1: Determine pollutants of concern.</u>

VISTAS evaluated the species contribution on the 20 percent worst visibility days and concluded that sulfate accounted for greater than 70 percent of the visibility-impairing pollution. The VISTAS States concluded that controlling SO2 emissions was the appropriate step in addressing the reasonable progress assessment for 2018. The VISTAS findings were consistent with the findings of the Southern Appalachian Mountain Initiative (SAMI). As you may recall, SAMI confirmed that sulfate particles account for the greatest portion of the haze affecting Class I areas in the Southern

Appalachian region and that these sulfates were produced in large part from SO2 emissions from coal combustion.

Step 2: Determine which source sectors should be evaluated for reasonable progress.

Since SO2 point source emissions in 2018 are projected to represent greater than 95 percent of the total SO2 emissions inventory, the VISTAS States concluded that the focus should be on electric generating unit (EGU) and non-EGU point sources of SO2 emissions.

Step 3: Consideration of Emissions Reductions from State and Federal Control Measures.

64 FR 35733 states that "In determining the emissions and visibility improvement achieved during each implementation period, states should include all air quality improvements that will be achieved by other programs and activities under the CAA and any state air pollution control requirements." In keeping with this recommendation, Georgia, as part of its long-term reasonable progress analysis to consider potential sources contributing to visibility impairment, examined other CAA requirements such as CAIR. Under Georgia's CAIR rule for SO2 [391-3-1-.02(13)], SO2 emissions from Georgia EGUs will be capped at 149,140 tons in 2015, a 70 % reduction from 2002 actual emissions. In addition, a 70 % reduction of SO2 emissions is expected during this time period across all CAIR-affected EGUs in 28 eastern states. Through these programs between the present and 2018, EPD concluded that additional EGU control during this time period is not reasonable.

For EGUs subject to CAIR, EPA evaluated a number of factors, including the cost of compliance and time necessary for compliance. In the CAIR rule, EPA determined "that the earliest reasonable deadline for compliance with the final highly cost effective control levels for reducing emissions was 2015…" (70 FR 25197 – 25198, May 12, 2005). The State believes that the cost of compliance and time necessary for compliance are the dominant factors for determining if additional reductions would be reasonable from CAIR-subject EGUs. The detailed analyses in the preamble to the May 12, 2005 CAIR rule support a conclusion that CAIR controls satisfy reasonable progress for SO2 for the first regional haze planning period ending in 2018.

The SO2 emission reductions that are predicted by the IPM to meet the CAIR requirements are not certain due to the current rule's reliance on unchecked trading and the use of banked Title IV allowances. The GA EPD intends to re-evaluate the IPM predictions of SO2 reductions for CAIR for EGUs at the time of the first 5-year periodic report [40 CFR 51.308(g)] to ensure that the reductions currently predicted by IPM for CAIR are, in fact, taking place where they are expected and needed.

The Cohutta Class I Area is expected, based on modeling, to clearly meet the glide slope in 2018. GA EPD has therefore concluded that CAIR constitutes reasonable measures for Georgia EGUs that significantly impact visibility in Cohutta during this first assessment period (between baseline and 2018). Because the Okefenokee, Wolf Island, and Saint

Marks areas are not expected to clearly meet the glide slope, controls required under CAIR have not been deemed to constitute reasonable measures for Georgia EGUs that significantly impact visibility in these Class I areas.

Step 4: Determine which emission units would be evaluated based on impact.

Georgia EPD calculated the fractional contribution from all emission units within the SO2 Area of Influence for a given Class I area and identified those emission units with a contribution of half of a percent or more.

Step 5: Evaluate the four factors.

Each emission unit identified in Step 4 above was evaluated using the statutory and regulatory factors of 1) cost of compliance, 2) time necessary for compliance, 3) the energy and non-air quality environmental impacts of compliance, and 4) the remaining useful life of the emissions unit. Georgia EPD believes that the cost of compliance is typically the dominant factor in whether a source will be required to install controls. Therefore, much emphasis was placed on cost of control as part of this reasonable progress assessment, as compared to the other three statutory factors.

6.4 Evaluation of Four-factor Eligible Emissions Units and Recommendations

The Georgia EPD focused the reasonable progress assessments on specific units at the following non-EGU and EGU facilities in the State:

Georgia Pacific Brunswick Cellulose
Class I Areas: Wolf Island, Okefenokee Area
Units (Wolf Island): F-1 (Power Boiler), M-24 (Recovery Boiler)
Units (Okefenokee Wilderness Area): F-1 (Power Boiler)

Georgia Pacific Cedar Springs
Class I Area: St. Marks Area, Florida
Units: U-500 (Power Boiler), U-501 (Power Boiler), R-402 (Recovery Boiler)

Georgia Pacific Savannah River
Class I Area: Wolf Island
Units: B001, B002, B003

International Paper Savannah Mill
Class I Area: Wolf Island, Okefenokee, St. Marks, Florida, Swanquarter, North Carolina, Cape Romain, South Carolina
Units: PB-13

Interstate Paper
Class I Area: Wolf Island
Units: Power Boiler F1

Temple Inland Rome
Class I Area: Cohutta Wilderness Area
Units: Power Boiler 4

Georgia Power Plant Kraft
Class I Area: Wolf Island, Okefenokee Wilderness Area, and Cape Romain, SC NC
Units: SG01, SG02 and SG03

Georgia Power Plant McIntosh
Class I Area: Wolf Island, Okefenokee , St. Marks Wilderness Area, FL, Cape Romain, SC, Swanquarter, NC
Units: SG01

Georgia Power Plant Mitchell
Class I Area: Okefenokee and St. Marks, NC
Units: SG03

In March of 2007, Georgia EPD requested 4-factor analyses from affected facilities for each of their emissions units that were deemed eligible (Appendix H.4). In May 2007, EPD sent a follow-up letter extending the deadline for submission of the 4-factor analyses and providing further guidance on the compliance deadline for any controls determined to be reasonable. As discussed in the narrative, eligible units were those emissions units likely to contribute more than 0.5% to the total visibility impairment caused by sulfate at any Class I area in 2018. Facilities were requested to evaluate the feasibility of additional SO2 controls on these units based on the four statutory factors required to be analyzed in the setting of reasonable progress goals:

1) The costs of compliance;

2) The time necessary for compliance;

3) The energy and non-air-quality environmental impacts of compliance; and

4) The remaining useful life of existing sources that contributes to visibility impairment.

The first step was to screen each unit using the fourth factor: remaining useful life of the source. If the remaining useful life extended beyond 2018, EPD requested that the other three statutory factors be analyzed using a “top-down” approach as follows:

Step 1: Identification of all control technologies;

Step 2: Elimination of technically-infeasible options;

Step 3: Ranking of remaining control technologies (top down) by control effectiveness;

Step 4: Application of the first three statutory factors (cost of compliance, time necessary for compliance, energy and non air quality environmental impacts) to the control technologies identified in Step 3 and documentation of the results; and

Step 5: Selection of control technology.

In general, the cost estimates provided in the facilities' submittals followed the methods outlined in EPA's Air Pollution Control Cost Manual (EPA/452/B-02-001). Company cost estimates were typically prepared as study-level estimates, which are presumed to be accurate to within +/- 30 percent. Study-level estimates are appropriate for the 4-factor analysis.

EPD reviewed the four-factor analyses received from the facilities to determine what, if any, controls may be reasonable to implement. Additional information was requested as needed. After reviewing all of the analyses, a list of emissions units was developed along with information regarding the four factors for all technically-feasible controls identified (see Table FF-1). EPD identified emissions units and associated controls that were deemed to be "reasonable" and then met with staff from affected facilities for discussion of controls, further communication of the reasonable progress goals, and verification of facility data.

Georgia EPD used a number of factors to determine what should be considered "reasonable" for each emissions unit on a case-by-case basis. Included in these factors were the magnitude of the contribution to visibility impairment at the nearest Class I area, the number of Class I areas for which the emissions unit contributed to sulfate visibility impairment above the 0.5% "threshold," the impact on $PM_{2.5}$ non-attainment areas, existing SO_2 controls, and cross-comparison of facility cost estimates to an EPA database (Air Control Net) and to other facility's estimates (for comparably-sized control equipment).

The following subsections provide details of the 4-factor analysis and decision process for each eligible unit. The results of the 4-factor analysis and review process are summarized for each eligible unit in Tables 6.1 and 6.2. An entry of "below threshold" means that the sulfate-related visibility impairment to the specific Class I area was below 0.5 %. Table 6.3 provides explanatory notes for the various fields (columns) in Tables 6.1 and 6.2. Summaries of the four-factor analyses submitted by the facilities are presented in Appendix H.10.

Table 6-1. Summary of Four-factor Analyses – South Georgia Facilities

Table 6-1. Summary of Four-Factor Analyses - South Georgia Facilities

Facility	Emiss. unit / Fuel	VISTAS SO2 (tons) / Class 1 sulfate impact fractions	4F Base-line SO2 (tons) / Existing Controls	Control Technology	Reduct. from 4F baseline (tons)	Annual cost, company (10^6, 2007)	$/ton SO2 / statut. factor	Annual cost, ACNet (10^6, 2006)	Time to implem. / statut. factor	Energy Impacts / statut. factor	Other Environ. Impacts: Water Use / statut. factor	Other Environ. Impacts: Wastewate / statut. factor	Other Environ. Impacts: Solid / statut. factor	Wolf Island Visibility - Sensitivity to emissions reductions: (ton SO_2)/ (Mm^{-1})	Wolf Island: 10^6 $/ ($Mm^{-1}$) company cost	Wolf Island: Control extinction reduction (Mm^{-1})	Okefenokee Visibility - Sensitivity to emissions reductions: (ton SO_2)/ (Mm^{-1})	Okefenokee: 10^6 $/ ($Mm^{-1}$) company cost	Okefenokee: Control extinction reduction (Mm^{-1})	St. Marks Visibility - Sensitivity to emissions reductions: (ton SO_2)/ (Mm^{-1})	St. Marks: 10^6 $/ ($Mm^{-1}$) company cost	St. Marks: Control extinction reduction (Mm^{-1})
Brunswick Cellulose (GA Pac)	F1 P.B. No.4	1842	1642	**Wet FGD**	1560	8.5	5449	3.24	before 2013	did not address	98 MG per year	34 MG per year	did not address	5813	31.7	0.26836	6557	35.7	0.23790	below threshold	below threshold	below threshold
	bark, wood waste, No.6 oil, TDF, sludge	.1255 WOLF* .0389 OKEF*	ESP	**Oil limit, 5 Mgal/yr, S = 3% (existing %)**	543	0	0	ND	before 2012	none	none	none	none	5813	0.0	0.09342	6557	0.0	0.08281	below threshold	below threshold	below threshold
				In duct sorbent injection	769	2.7	3562	ND	before 2013	insignifi-cant	none	none	8000 tons per year	5813	20.7	0.13235	6557	23.4	0.11733	below threshold	below threshold	below threshold
				Oil limit and fuel switch to S = 2.2%	294	0.4	1429	ND	before 2012	0	0	0	0	5813	8.3	0.05058	6557	9.4	0.04484	below threshold	below threshold	below threshold
				Oil limit and fuel switch to S = 1.0%	731	2.4	3228	ND	before 2012	0	0	0	0	5813	18.8	0.12576	6557	21.2	0.11149	below threshold	below threshold	below threshold
	M24 RB No. 6	193	193	**Increase black liquor solids conc.**										5813			below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
	blk. liquor	.0131 WOLF*	ESP																			
GA Pac - Cedar Springs	U500 power boiler	2428	1976	**Wet FGD with caustic**	1835	5.0	2725	11.9	before 2013	0	0	0	15000 tons/yr	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	1381.9	0.00362
	bitum. coal, wood waste, fuel oil	.0108 SAMA*	venturi scrubber (water)	**Add spray towers and caustic to existing venturi**	1694	5.0	2952	ND	before 2012	0	0	0	15000 tons/yr	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	1497.0	0.00334
				Add caustic to existing venturi	1553	2.6	1675	ND	before 2012	0	0	0	15000 tons/yr	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	849.2	0.00306
				Duct sorbent injection	1383	2.3	1663	ND	before 2012	0	0	0	0	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	843.2	0.00273
				Coal washing	296	3.2	10796	ND	before 2012	0	0	0	0	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	5474.8	0.00058
				Coal switching	494	2.8	5668	ND	before 2012	0	0	0	0	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	2874.3	0.00097

Table 6-1. Summary of Four-Factor Analyses - South Georgia Facilities (continued)

Facility	Emiss. unit / Fuel	VISTAS SO2 (tons) / Class 1 sulfate impact fractions	4F Base-line SO2 (tons) / Existing Controls	Control Technology	Reduct. from 4F baseline (tons)	Annual cost, company (10^6, 2007)	$/ton SO2 / statut. factor	Annual cost, ACNet (10^6, 2006)	Time to implem. / statut. factor	Energy Impacts / statut. factor	Other Environ. Impacts: Water Use / statut. factor	Other Environ. Impacts: Wastewater / statut. factor	Other Environ. Impacts: Solid Waste / statut. factor	Wolf Island Visibility - Sensitivity to emissions reductions: (ton SO_2)/(Mm^{-1})	Wolf Island: 10^6 $/($Mm^{-1}$) company cost	Wolf Island: Control extinction reduction (Mm^{-1})	Okefenokee Visibility - Sensitivity to emissions reductions: (ton SO_2)/(Mm^{-1})	Okefenokee: 10^6 $/($Mm^{-1}$) company cost	Okefenokee: Control extinction reduction (Mm^{-1})	St. Marks Visibility - Sensitivity to emissions reductions: (ton SO_2)/(Mm^{-1})	St. Marks: 10^6 $/($Mm^{-1}$) company cost	St. Marks: Control extinction reduction (Mm^{-1})
GA Pac - Cedar Springs	U501 power boiler	2533	1976	Wet FGD with caustic	1835	5.0	2725	11.9	before 2013	0	0	0	15000 tons/yr	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	1381.9	0.00362
	bitum. coal, wood waste, fuel oil	.0113 SAMA*	venturi scrubber (water)	Add spray towers and caustic to existing venturi	1694	5.0	2952	ND	before 2012	0	0	0	15000 tons/yr	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	1497.0	0.00334
				Add caustic to existing venturi	1553	2.6	1675	ND	before 2012	0	0	0	15000 tons/yr	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	849.2	0.00306
				Duct sorbent injection	1383	2.3	1663	ND	before 2012	0	0	0	0	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	843.2	0.00273
				Coal washing	296	3.2	10796	ND	before 2012	0	0	0	0	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	5474.8	0.00058
				Coal switching	494	2.8	5668	ND	before 2012	0	0	0	0	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	2874.3	0.00097
	R402 recovery boiler	1726	184	Conversion to high solids firing	40	6.0	148962.5	ND	ND	ND	ND	ND	ND	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	75539.2	0.00008
		.0077 SAMA*	571	Conversion to No. 6 oil, 1 % sulfur	251	3.0	12060.2	ND	ND	ND	ND	ND	ND	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	6115.7	0.00050
			571	Conversion to No. 2 oil, 0.5% sulfur	411	9.4	22864.4	ND	ND	ND	ND	ND	ND	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold	507102	11594.6	0.00081
			ESP																			

Table 6-1. Summary of Four-Factor Analyses - South Georgia Facilities (continued)

Facility	Emiss. unit	VISTAS SO2 (tons)	4F Base-line SO2 (tons)	Control Technology	Reduct. from 4F baseline (tons)	Annual cost, company (10^6, 2007)	$/ton SO2	Annual cost, ACNet (10^6, 2006)	Time to implem.	Energy Impacts	Other Environ. Impacts: Water Use	Other Environ. Impacts: Wastewater	Other Environ. Impacts: Solid Waste	Wolf Island Visibility - Sensitivity to emissions reductions			Okefenokee Visibility - Sensitivity to emissions reductions			St. Marks Visibility - Sensitivity to emissions reductions		
	Fuel	Class 1 sulfate impact fractions	Existing Controls				statut. factor		statut. factor	statut. factor	statut. factor	statut. factor	statut. factor	(ton SO_2)/ (Mm^{-1})	10^6 $/ ($Mm^{-1}$) company cost	Control extinction reduction (Mm^{-1})	(ton SO_2)/ (Mm^{-1})	10^6 $/ ($Mm^{-1}$) company cost	Control extinction reduction (Mm^{-1})	(ton SO_2)/ (Mm^{-1})	10^6 $/ ($Mm^{-1}$) company cost	Control extinction reduction (Mm^{-1})
GA Pac - Savannah River	**B001** No. 3 Boiler	1844	1659	**Wet FGD with caustic**	1576	3.83	2430.13	ND	after 2012	0	20 MG per year	increased dissolved solids load	0	247801	602.2	0.00636	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Circ. fluidized bed scrubber	1576	7.10	4504.93	ND	after 2012	0	0	0	0	247801	1116.3	0.00636	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
	petcoke, bitum. coal, bark?	.0111 WOLF*	limestone injection (87% eff,)	**Switch to 100% coal firing**	1078	4.80	4451.24	ND	after 2012	0	0	0	0	247801	1103.0	0.00435	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Increased limestone injection	249	1.80	7233.27	ND	before 2012	0	0	0	24000 to 60000 tpy	247801	1792.4	0.00100	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Rotating opposed fire air	498	1.07	2149.89	ND	after 2012	0	0	0	0	247801	532.7	0.00201	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
	B002 No. 4 Boiler	1415	1195	**Wet FGD with caustic**	1135	3.60	3171.11	ND	after 2012	0	20 MG per year	increased dissolved solids load	0	247801	785.8	0.00458	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Circ. fluidized bed scrubber	1135	7.00	6166.04	ND	after 2012	0	0	0	0	247801	1528.0	0.00458	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
	petcoke, bark?	.0086 WOLF*	limestone injection (90% eff,)	**Switch to 100% coal firing**	777	5.80	7467.01	ND	after 2012	0	0	0	0	247801	1850.3	0.00313	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Increased limestone injection	120	0.60	5020.92	ND	before 2012	0	0	0	24000 to 60000 tpy	247801	1244.2	0.00048	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Rotating opposed fire air	359	0.85	2370.99	ND	after 2012	0	0	0	0	247801	587.5	0.00145	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
	B003 No. 5 Boiler	1282	1190	**Wet FGD with caustic**	1131	3.50	3095.98	ND	after 2012	0	20 MG per year	increased dissolved solids load	0	247801	767.2	0.00456	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Circ. fluidized bed scrubber	1131	6.70	5926.58	ND	after 2012	0	0	0	0	247801	1468.6	0.00456	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
	petcoke, bitum. coal, bark?	.0077 WOLF*	limestone injection (90% eff,)	**Switch to 100% coal firing**	774	5.70	7369.10	ND	after 2012	0	0	0	0	247801	1826.1	0.00312	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Increased limestone injection	119	0.80	6722.69	ND	before 2012	0	0	0	24000 to 60000 tpy	247801	1665.9	0.00048	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Rotating opposed fire air	357	0.85	2380.95	ND	after 2012	0	0	0	0	247801	590.0	0.00144	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold

Table 6-1. Summary of Four-Factor Analyses - South Georgia Facilities (continued)

Facility	Emiss. unit / Fuel	VISTAS SO2 (tons) / Class 1 sulfate impact fractions	4F Base-line SO2 (tons) / Existing Controls	Control Technology	Reduct. from 4F baseline (tons)	Annual cost, company (10^6, 2007)	$/ton SO2 / statut. factor	Annual cost, ACNet (10^6, 2006)	Time to implem. / statut. factor	Energy Impacts / statut. factor	Other Environ. Impacts: Water Use / statut. factor	Other Environ. Impacts: Wastewater / statut. factor	Other Environ. Impacts: Solid Waste / statut. factor	Wolf Island Visibility - Sensitivity to emissions reductions: (ton SO_2)/(Mm^{-1})	Wolf Island: 10^6 $/($Mm^{-1}$) company cost	Wolf Island: Control extinction reduction (Mm^{-1})	Okefenokee Visibility - Sensitivity to emissions reductions: (ton SO_2)/(Mm^{-1})	Okefenokee: 10^6 $/($Mm^{-1}$) company cost	Okefenokee: Control extinction reduction (Mm^{-1})	St. Marks Visibility - Sensitivity to emissions reductions: (ton SO_2)/(Mm^{-1})	St. Marks: 10^6 $/($Mm^{-1}$) company cost	St. Marks: Control extinction reduction (Mm^{-1})
GPC – Plant Kraft	SG01	691	632	Wet FGD	600	4.90	8161	6.38	Jan. 2016	2 % of generation (1000 kW)	90 gal per MWh	30 gal per MWh	2.7 ton gypsum/ ton SO2	17700	144.5	0.03392	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
		.0051 WOLF*		Coal switching	245	0.99	4041	ND	not addressed	possible boiler efficiency reduction	-	-	0	17700	71.5	0.01384	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Coal washing	38	0.07	1839	0.22	not addressed	power for coal washing machinery	4400 gal per day	acidic WW needs treatment	coal refuse, approx. 5 % of total coal	17700	32.5	0.00214	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
	SG02	704	889	Wet FGD	845	5.10	6039	6.38	Jan. 2016	2 % of generation (1000 kW)	90 gal per MWh	30 gal per MWh	2.7 ton gypsum/ ton SO2	17700	106.9	0.04772	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
		.0052 WOLF*		Coal switching	344	1.39	4041	ND	not addressed	possible boiler efficiency reduction	-	-	0	17700	71.5	0.01944	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Coal washing	53	0.10	1847	0.26	not addressed	power for coal washing machinery	4600 gal per day	acidic WW needs treatment	coal refuse, approx. 5 % of total coal	17700	32.7	0.00301	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
	SG03	4474	2455	Wet FGD	2332	7.50	3216	8.88	Jan. 2016	2 % of generation (2000 kW)	90 gal per MWh	30 gal per MWh	2.7 ton gypsum/ ton SO2	17700	56.9	0.13177	18112	58.2	0.12877	below threshold	below threshold	below threshold
		.0330 WOLF* .0085 OKEF* .0081 ROMA		Coal switching	950	3.84	4042	ND	not addressed	possible boiler efficiency reduction	-	-	0	17700	71.5	0.05367	18112	73.2	0.05245	below threshold	below threshold	below threshold
				Coal washing	147	0.27	1845	0.53	not addressed	power for coal washing machinery	7500 gal per day	acidic WW needs treatment	coal refuse, approx. 5 % of total coal	17700	32.7	0.00832	18112	33.4	0.00813	below threshold	below threshold	below threshold

Table 6-1. Summary of Four-Factor Analyses - South Georgia Facilities (continued)

Facility	Emiss. unit / Fuel	VISTAS SO2 (tons) / Class 1 sulfate impact fractions	4F Base-line SO2 (tons) / Existing Controls	Control Technology	Reduct. from 4F baseline (tons)	Annual cost, company (10^6, 2007)	$/ton SO2 / statut. factor	Annual cost, ACNet (10^6, 2006)	Time to implem. / statut. factor	Energy Impacts / statut. factor	Other Environ. Impacts: Water Use / statut. factor	Other Environ. Impacts: Wastewater / statut. factor	Other Environ. Impacts: Solid Waste / statut. factor	Wolf Island Visibility - Sensitivity to emissions reductions: (ton SO_2)/ (Mm^{-1})	10^6 $/ ($Mm^{-1}$) company cost	Control extinction reduction (Mm^{-1})	Okefenokee Visibility - Sensitivity to emissions reductions: (ton SO_2)/ (Mm^{-1})	10^6 $/ ($Mm^{-1}$) company cost	Control extinction reduction (Mm^{-1})	St. Marks Visibility - Sensitivity to emissions reductions: (ton SO_2)/ (Mm^{-1})	10^6 $/ ($Mm^{-1}$) company cost	Control extinction reduction (Mm^{-1})
GPC – Plant McIntosh	SG01	7015	1860	Wet FGD	1767	12.6	7131	11.59	Jan. 2016	1 - 2 % of generation	80 - 110 gal/MWh	treatment of scrubber blowdown	2.7 tons gypsum/ton SO2 removed - landfill	16615	118.5	0.10635	18602	132.6	0.09499	57639	411.0	0.03066
		.0413 WOLF* .0120 OKEF* .0055 SAMA* .0135 ROMA .0072 SWAN		Coal switching	720	3.1	4306	ND	not addressed	possible boiler efficiency reduction	not addressed	not addressed	not addressed	16615	71.5	0.04333	18602	80.1	0.03870	57639	248.2	0.01249
				Coal washing	37	0.2	5534	0.84	not addressed	not addressed	16,300 gal/day	acidic wastewater	81.5 tons coal refuse/day at full load - landfill	16615	91.9	0.00223	18602	102.9	0.00199	57639	319.0	0.00064
GPC - Plant Mitchell	SG03	4930	1189	Wet FGD	1130	10.3	9119	10.92	Jan. 2016	1 - 2 % of generation (1250 to 2500 kW)	0	0	0	below thresthold	below thresthold	below thresthold	16283	148.5	0.06937	32836	299.4	0.03440
		.0274 SAMA* .0077 OKEF*		Coal switching	554	1.3	2347	ND	not addressed	possible reduced generation efficiency with some coals	not addressed	not addressed	not addressed	below thresthold	below thresthold	below thresthold	16283	38.2	0.03402	32836	77.1	0.01687
Internat. Paper	PB13	8578.00	8578.00	Wet FGD (packed tower)	8149.10	39.90	4896.25	12.83	2010 to 2012	2210 kW	212 MG per year	161 MG per year	0	14766.80	72.3	0.55185	16334	80.0	0.49891	66949	327.8	0.12172
	bitum. coal, bark, others	.0664 WOLF* .0166 OKEF* .0070 SAMA* .0155 ROMA	ESP	FGD, wet limestone spray tower	7720.20	33.90	4391.08	4.05	2010 to 2012	2210 kW	0	0	22000 tpy	14766.80	64.8	0.52281	16334	71.7	0.47265	66949	294.0	0.11531
		.0086 SWAN		Semi-dry lime spray tower	7291.30	35.50	4868.82	3.15	2010 to 2012	780 kW	0	114 MG per year	19300 tpy	14766.80	71.9	0.49376	16334	79.5	0.44639	66949	326.0	0.10891
				Fuel switching, nat. gas	5575.70	53.00	9505.53		0	0	0	0	0	14766.80	140.4	0.37758	16334	155.3	0.34136	66949	636.4	0.08328
				Dry sorbent injection	2144.50	11.20	5222.66	1.91	2010 to 2012	280 kW	0	0	7900 tpy	14766.80	77.1	0.14522	16334	85.3	0.13129	66949	349.7	0.03203
				RTO/scrubbing opt. 1: control HVLC[2]	314.00	1.64	5222.93		2010 to 2012	422 kW	17 MG per year	6 MG per year	0	14766.80	77.1	0.02126	16334	85.3	0.01922	66949	349.7	0.00469
				RTO/scrubbing opt. 2: control LVHC & SOG2	1533.00	2.80	1826.48		2010 to 2012	357 kW	81 MG per year	31 MG per year	0	14766.80	27.0	0.10381	16334	29.8	0.09385	66949	122.3	0.02290
				RTO/scrubbing opt. 3: control HVLC, LVHC & SOG2	1847.00	3.80	2057.39		2010 to 2012	601 kW	98 MG per year	37 MG per year	0	14766.80	30.4	0.12508	16334	33.6	0.11308	66949	137.7	0.02759

Table 6-1. Summary of Four-Factor Analyses - South Georgia Facilities (continued)

Facility	Emiss. unit / Fuel	VISTAS SO2 (tons) / Class 1 sulfate impact fractions	4F Base-line SO2 (tons) / Existing Controls	Control Technology	Reduct. from 4F baseline (tons)	Annual cost, company (10^6, 2007)	$/ton SO2 / statut. factor	Annual cost, ACNet (10^6, 2006)	Time to implem. / statut. factor	Energy Impacts / statut. factor	Other Environ. Impacts: Water Use / statut. factor	Other Environ. Impacts: Wastewater / statut. factor	Other Environ. Impacts: Solid Waste / statut. factor	Wolf Island Visibility - Sensitivity to emissions reductions: (ton SO_2)/(Mm^{-1})	Wolf Island: 10^6 $/($Mm^{-1}$) company cost	Wolf Island: Control extinction reduction (Mm^{-1})	Okefenokee Visibility - Sensitivity to emissions reductions: (ton SO_2)/(Mm^{-1})	Okefenokee: 10^6 $/($Mm^{-1}$) company cost	Okefenokee: Control extinction reduction (Mm^{-1})	St. Marks Visibility - Sensitivity to emissions reductions: (ton SO_2)/(Mm^{-1})	St. Marks: 10^6 $/($Mm^{-1}$) company cost	St. Marks: Control extinction reduction (Mm^{-1})
Southern States Phosphate and Fert.	**SA02 (Sulfuric Acid Plant 2)**	808.00	808.00	**Increase acid capture with Cs-promoted catalyst**	**Status:** Cs-promoted catalyst proposed but insufficient. Company wants to take a 580 ton/yr limit, **effective in Jan. 2014**, by doing 502(b)10 (see 12-7-07 letter). This would drop the unit below the 0.5 % sulfate threshold.									14766.80		0.00274	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
		.0064 WOLF*	mist eliminator	**Conversion to dual absorption process**										14766.80		0.04104	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold
				Tail gas scrubbing										14766.80		0.04925	below threshold	below threshold	below threshold	below threshold	below threshold	below threshold

Abbreviations:

ACNet	Air Control Net (EPA cost database)
Mm	megameter
MG	million gallons
ND	no data
0	not addressed in 4-factor submittal

Class I Areas:

WOLF*	Wolf Is.
OKEF*	Okefenokee
SAMA*	St. Marks
ROMA	Romain
SWAN	Swan Quarter

(company cost estimate) / (ACNet cost estimate) > 1.3 **OR** < 0.7

estimated implementation date earlier than Jan. 1, 2012

extinction reduction (visibility improvement) > 0.100

0.010 < extinction reduction < 0.100

* Class I area is currently behind the glide path schedule for attaining reasonable progress by 2018

Table 6-2. Summary of Four-Factor Analyses - North Georgia Facilities

SUMMARY - REGIONAL HAZE FOUR-FACTOR ANALYSES - NORTH GEORGIA FACILITIES
updated 12-2-08

Facility	Emiss. unit / Fuels	VISTAS SO2 (tons) / Class 1 sulfate impact fractions	4F Base-line SO2 (tons) / Existing Controls	Control Technology	Reduct. from 4F baseline (tons)	Annual cost, company (10^6, 2007)	$/ton SO2 / statut. factor	Annual cost, ACNet (10^6, 2006)	Time to implem. / statut. factor	Energy Impacts / statut. factor	Other Environ. Impacts: Water Use / statut. factor	Other Environ. Impacts: Wastewater / statut. factor	Other Environ. Impacts: Solid Waste / statut. factor	Cohutta Visibility - Sensitivity to emissions reductions: (ton SO_2)/ (Mm^{-1})	10^6 $/ ($Mm^{-1}$) company cost	Control extinction reduction (Mm^{-1})
Temple-Inland Rome LB Mill	No. 4 Power Boiler	3696	3837	Wet FGD (MEL)	3453	7	2027	3.4875	before 2012	450 kW	37 MG/yr	0	16,000 ton/yr gypsum	19468	39.5	0.17738
				Wet FGD (LSFO)	3453	7	2027	3.4875	before 2012	450 kW	37 MG/yr	0	16,000 ton/yr gypsum	19468	39.5	0.17738
	bit. coal, fuel oil	.0442 COHU .0099 JOKI	ESP, multiclone, LNB	Dry FGD (lime absorbent)	3070	5.7	1857	13.3875	before 2012	650 kW	0	0	10,000 ton/yr gypsum	19468	36.2	0.15767
				Fuel Switching	2494	7	2807	ND	before 2010	650 kW	0	0	increase ash by 30%	19468	54.6	0.12811
				Duct sorbent injection	2110	4.1	1943	1.4625	before 2012	650 kW	0	0	10,000 ton/yr gypsum	19468	37.8	0.10840

Abbreviations:

ACNet	Air Control Net (EPA cost database)
Mm	megameter
MG	million gallons
ND	no data
0	not addressed in 4-factor submittal

Class I Areas:

COHU Cohutta
JOKI Joyce Kilmer

estimated implementation date earlier than Jan. 1, 2012
extinction reduction (visibility improvement) > 0.100
0.010 < extinction reduction < 0.100

Table 6.3. Explanatory Notes for Summary of Four-Factor Analyses and Metrics

Column	Source	Notes
Class I sulfate impact fraction	P&S Modeling unit	This is the impact of sulfate emissions from the specific emissions unit on visibility in the specified Class I area, expressed as a fraction of the combined sulfate impacts of all of the impacting facilities. The impact given is based on the VISTAS SO2 projected 2018 emissions. Threshold for inclusion in 4-factor analysis was impact of 0.005 (0.5 %) or more.
4F baseline SO2	company	The baseline emissions used by the facility in the 4-factor submittal. In the cases of U500 and U501 at GA Pacific Cedar Springs, the number represents emissions after an existing venturi scrubber with water scrubbant (they estimate 30% SO2 control). In the case of GA Pacific Savannah River, all 3 emissions units currently perform limestone injection for SO2 removal.
Baseline basis	company	In many instances the company used a different baseline emissions level than the VISTAS projected value. A blank field means that the company did not provide a full evaluation and that the VISTAS value has been inserted into the baseline field.
Control Technology	company	Control, deemed technically feasible by the facility, evaluated for reduction of SO2 emissions.
Control Effectiveness	company	Percent reduction as presented in the facility's 4-factor analysis. In cases where the facility did not list a control effectiveness, this was back-calculated from the tons of reductions.
Annual cost, company	company	Company cost estimates were typically prepared as study-level estimates, accurate to within +/- 30 percent. The costs are assumed to be in 2007 dollars (some companies stated this explicitly). The annual cost is the sum of the annual operation and maintenance cost and the total installed cost (capital cost), annualized over the life of the project. Project lives ranged from 15 to 20 years, interest rates from 7% to 10%, and capital recovery factors from 0.094 to 0.117.
Cost/ton	calculation	The annual cost divided by the tons reduced from the 4F baseline.
Annual Cost, ACNet	Air Control Net	The estimated annual cost from a query of EPA's Air Control Net database. The costs listed came from queries which found matches for the applicable technology at the specific unit and facility. The queries provide estimates in 2004 dollars. This number was then escalated to 2006 dollars using the Chemical Engineering Plant Cost Index.

Cost ratio, company to ACNet	calculation	Comparison of company estimate to ACNet estimate. Yellow cell indicates a ratio that is greater than 1.3.
Statutory factors	Company	A "0" indicates that the submittal provided no information pertaining to the specific factor. A blue cell indicates that the company has indicated that the option could be implemented prior to Jan. 1, 2012. This would allow the control measure to be in place during all five years that visibility data will be collected for the 2018 Regional Haze progress report. The expected useful life of all of the emissions units is 2018 or later. The expected useful life of all of the emissions units also exceeds the project life (i.e., amortization period) of all control options considered.
Visibility Sensitivity: Tons SO_2/Mm^{-1}	P&S Modeling unit	The tons of SO2 required to effect a reduction of 1 Mm^{-1} (inverse megameter) in the applicable Class I area. This value is independent of the control technology.
Visibility Sensitivity: $\$10^6/Mm^{-1}$	Calculation	The cost, based on the specific technology, to effect a reduction of 1 Mm^{-1} (inverse megameter) in the applicable Class I area. This is the product of $/ton and ton/ Mm^{-1}. This figure, along with dollars per ton ($/ton) was used in evaluating cost efficiency.
Visibility Sensitivity: Tons SO_2/Mm^{-1}	Calculation	The extinction reduction (visibility improvement) in Mm^{-1} that would be achieved in the applicable Class I area by implementation of the specific control. An orange cell indicates an extinction reduction of greater than 0.010 and less than 0.100. A light green cell indicates an extinction reduction of greater than 0.100.

6.4.1 GA Pacific Brunswick Cellulose, Power Boiler No. 4 (F1)

Georgia Pacific's Brunswick Cellulose facility is located in Glynn County, near the Georgia coast. Power Boiler No. 4 is an 800 MMBtu/hr boiler that burns primarily No. 6 fuel oil and wood waste, including bark. It is also permitted to burn tire-derived fuel and wastewater treatment sludge. The sulfur content of the fuel oil is 3% or less. Particulate emissions are controlled by an electrostatic precipitator (ESP). The baseline SO2 emissions reported by the company were 1642 tons, based on the 2002 emissions report. In the course of communications with Georgia Pacific, it was learned that a boiler modification in 2002 had resulted in increased production efficiency when burning oil. The increased efficiency had reduced typical annual oil consumption to less than five million gallons-per-year.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit had the highest contribution to visibility impact on a Class I area (12.55 at Wolf Island) of any other Georgia emission unit subject to the 4-factor analysis. EPD also took into consideration that this unit significantly contributed to two Class I areas that were predicted to clearly not meet the Uniform Rate of Progress (glide slope) in 2018 based on "on the books" controls.

Georgia Pacific's original submittal identified the following control technologies, from most effective to least effective as being technically feasible:

1. Wet scrubbing with caustic (wet flue gas desulfurization)
2. Dry scrubbing with limestone injection
3. In-duct sorbent injection
4. Cleaner fuels
5. Wet scrubbing with water only

As noted above, a boiler modification in 2002 resulted in increased production efficiency when burning oil. Therefore, EPD added a 5 million gallon oil limit as a control option for evaluation and also combined the oil limit with other control technologies (in-duct sorbent injection and cleaner fuels) for evaluation.

Wet flue gas desulfurization. Wet flue gas desulfurization (FGD) would achieve an SO2 reduction of approximately 95% and could be implemented before 2013. The cost metrics are $5449 per ton of SO2 reduced and $31.7 million and $35.7 million per inverse megameter (Mm-1) of visibility improvement (at Wolf Island and Okefenokee Class I areas, respectively). Regarding energy and non-air environmental impacts, this option would consume approximately 98 million gallons of water and generate an estimated 34 million gallons per year of wastewater. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.27 and 0.24 Mm-1 at Wolf Island and Okefenokee, respectively. The cost effectiveness of this control option was determined not to be reasonable.

Dry scrubbing with limestone injection. Georgia Pacific installed dry scrubbing with limestone injection at its Port Hudson, LA, facility in 2007. The Port Hudson design was for a unit comparable in size to Brunswick's Power Boiler No. 4. The total installed cost of the Port Hudson equipment was more than twice the estimated installed cost for wet FGD at Brunswick. Because the typical removal efficiencies of wet FGD and dry scrubbing are approximately the same, dry scrubbing was not considered further in the Brunswick four-factor submittal due to its high expected cost. The cost effectiveness of this control option was determined not to be reasonable.

Five million gallon oil limit and in-duct sorbent injection. A five million gallon oil limit combined with in-duct sorbent injection was evaluated. This could be implemented before 2013 and would reduce allowable SO2 emissions to approximately 330 tons (accounting for 70% control efficiency applied to 1100 tons of emissions). The cost metrics are $3562 per ton of SO2 reduced and $20.7 million and $23.4 million per inverse megameter (Mm-1) of visibility improvement (at Wolf Island and Okefenokee Class I areas, respectively). Regarding energy and non-air environmental impacts, this option would generate an estimated 8000 tons per year of solid waste. This control option is projected to achieve light extinction reductions of 0.13 and 0.12 Mm-1 at Wolf Island and Okefenokee, respectively. This control option is considered to be reasonable due to cost-effectiveness, the relatively high visibility impact on two Class I areas and the fact that neither of these Class I areas is clearly meeting the uniform rate of progress.

Five million gallon oil limit and fuel switch to 1.0 % sulfur oil. A five million gallon oil limit combined with switching to 1.0 % sulfur oil was evaluated. This could be implemented before 2012 and would reduce allowable SO2 emissions to approximately 368 tons (accounting for 67% SO2 reduction applied to 1100 tons of emissions). The cost metrics are $3228 per ton of SO2 reduced and $18.8 million and $21.2 million per inverse megameter (Mm-1) of visibility improvement (at Wolf Island and Okefenokee Class I areas, respectively). No energy or non-air environmental impacts were documented. This control option is projected to achieve light extinction reductions of 0.13 and 0.11 Mm-1 at Wolf Island and Okefenokee, respectively. This control option is considered to be reasonable due to cost-effectiveness, the relatively high visibility impact on two Class I areas and the fact that neither of these Class I areas is clearly meeting the uniform rate of progress.

Five million gallon oil limit. Implementing a five million gallon limit on burning oil with the existing sulfur percentage would mimic typical operation since the improvement to boiler efficiency. This could be implemented immediately and would reduce allowable SO2 emissions to approximately 1100 tons, a 33% reduction from 1642 tons. There is no cost associated with this control, and there would be no energy or non-air environmental impacts. This control option is projected to achieve light extinction reductions of 0.093 and 0.083 Mm-1 at Wolf Island and Okefenokee, respectively. This control option has a lower control efficiency than other options that are considered reasonable.

Five million gallon oil limit and fuel switch to 2.2% sulfur oil. This could be implemented before 2012 and would reduce allowable SO2 emissions to approximately 805 tons (accounting for 27% SO2 reduction applied to 1100 tons of emissions). This control option has a lower control efficiency than other options that are considered reasonable.

Wet scrubbing with water only. This control option has a lower control efficiency (30%) than other options that are considered reasonable.

Conclusion. In-duct sorbent injection and fuel-switching to 1% sulfur oil, both including the five million gallon per year oil consumption limit, were identified as reasonable controls. This was based on reasonable costs/ton, very low costs/visibility improvement, and timeliness of implementation. In addition, the visibility improvements at Wolf Island and Okefenokee would be relatively large. Implementation of the less restrictive of these two options would reduce SO2 emissions to 368 tons/12-consecutive months, as discussed above.

Supplemental information provided by the facility indicated that the two controls deemed to be reasonable would control emissions from oil combustion but would not affect SO2 emissions from combustion of wood waste and tire-derived fuel (TDF). The facility requested an allowance for an additional 200 tons of emissions based on calculations of historical emissions from wood waste and TDF. This request was also supported by the facility's assertion that the sulfur content of locally available TDF may be above what has been burned historically. EPD concurred with the facility's request and established an SO2 emissions limit for the power boiler of 568 tons (368 plus 200) for Regional Haze reasonable progress with a compliance date of 2012.

6.4.2 Georgia Pacific Brunswick Cellulose, Recovery Boiler No. 6 (M24)

Recovery Boiler No. 6 burns black liquor with a 72% solids concentration. Particulate emissions are controlled by an electrostatic precipitator (ESP). The baseline SO2 emissions estimated by VISTAS were 193 tons per year, contributing about 1.3% to the sulfate visibility impairment at Wolf Island.

Georgia Pacific's four-factor submittal found combustion control and wet FGD (scrubber) to be the only technically-feasible control options. The company stated that emissions of SO2 of 38 ppm, as measured in a 2006 stack test, is too low of a load for effective operation of a wet scrubber. Therefore, the company ruled out wet FGD based on cost effectiveness. Combustion control, the other technically-feasible control option, is already included in the boiler design.

Conclusion. Due to the fact that this emission unit only contributes to visibility impairment at one Class I area and the relatively low baseline emissions level, Georgia EPD will not require any additional controls for Regional Haze Reasonable Progress.

6.4.3 Georgia Pacific Cedar Springs, Power Boiler No. 1 (U 500)

Georgia Pacific's Cedar Springs facility is located in Early County in the southwest corner of the state. Power Boiler No. 1 is a 784 MMBtu/hr boiler that burns primarily bituminous coal, wood waste, and fuel oil. The sulfur content of the fuel oil is typically 1%. A venturi scrubber (water) controls particulate emissions and also provides some control of SO2 emissions estimated at 30%. The baseline SO2 emissions reported by the company were 1976 tons based on 2006 CEMS data.

Georgia Pacific's original submittal identified the following control technologies, from most effective to least effective, as being technically feasible:

1. New wet FGD with caustic;
2. Addition of spray towers and caustic to existing venturi scrubber;
3. Addition of caustic to existing venturi scrubber;
4. Duct sorbent injection;
5. Cleaner coal; and
6. Coal washing.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit had a relatively low visibility impact on only one Class I area (St. Marks, although it is not clearly meeting the uniform rate of progress). EPD also took into consideration that this unit is BART-eligible and that the facility desired to take reductions for the unit to be exempt from BART.

New wet FGD with caustic. This option would achieve an SO2 reduction of approximately 93% and could be implemented before 2013. The cost metrics are $2725 per ton of SO2 reduced and $1391.2 million per inverse megameter (Mm-1) of visibility improvement (at Saint Marks Class I area). Regarding energy and non-air environmental impacts, this option would generate approximately 15,000 tons per year of solid waste. This control is projected to achieve a light extinction reduction of 0.0036 Mm-1 at Saint Marks. This option was not considered cost effective.

Addition of spray towers and caustic to existing venture scrubber. This option would achieve an SO2 reduction of approximately 86% and could be implemented before 2012. The cost metrics are $2952 per ton of SO2 reduced and $1497.0 million per inverse megameter (Mm-1) of visibility improvement (at the Saint Marks Class I area). Regarding energy and non-air environmental impacts, this option would generate approximately 15,000 tons per year of solid waste. This control is projected to achieve a light extinction reduction of 0.0033 Mm-1 at Saint Marks. This option was not considered cost effective.

Addition of caustic to existing venturi scrubber. This option would achieve an SO2 reduction of approximately 79% (total control, in lieu of existing 30%) and could be implemented before 2012. The cost metrics are $1675 per ton of SO2 reduced and $849 million per inverse megameter (Mm-1) of visibility improvement (at Saint Marks Class I

area). Regarding energy and non-air environmental impacts, this option would generate approximately 15,000 tons per year of solid waste. This control is projected to achieve a light extinction reduction of 0.0031 Mm-1 at Saint Marks. The cost efficiencies (in both $/ton and $/Mm-1), the energy and non-environmental impacts were determined not to be unacceptable, and the controls could be installed in time for the full benefit to be realized during all five years in which the 2018 Regional Haze progress report will be based. Therefore, this control option is determined to be reasonable.

Duct sorbent injection. This option would achieve an SO2 reduction of approximately 70% (upstream of and in conjunction with the 30% scrubber removal) and could be implemented before 2012. The cost metrics are $1663 per ton of SO2 reduced and $843 million per inverse megameter (Mm-1) of visibility improvement (at the Saint Marks Class I area). No energy or non-air environmental impacts were documented. This control is projected to achieve a light extinction reduction of 0.0027 Mm-1 at Saint Marks. The cost efficiencies (in both $/ton and $/Mm-1), the energy and non-environmental impacts were determined not to be unacceptable, and the controls could be installed in time for the full benefit to be realized during all 5 years in which the 2018 Regional Haze progress report will be based. Therefore, this control option is determined to be reasonable.

Cleaner coal. This control option was not considered because the SO2 control efficiency (25%) is lower than other options that are considered reasonable.

Cleaner washing. This control option was not considered because the SO2 control efficiency (15%) is lower than other options that are considered reasonable.

Conclusion. Addition of caustic to the existing venturi scrubber and duct sorbent injection were determined to be reasonable because of their relatively low costs per unit of visibility improvement**.** The other options had higher costs per visibility improvement and coal washing and coal switching also had lower total visibility improvements. As part of Georgia Pacific's BART exemption modeling, the company has proposed SO2 emission limits of 135 pounds per hour from Power Boiler. A limit of 135 lb/hr would result in maximum annual emissions of 591 tons/yr of SO2. This is a 70% reduction from baseline emissions. The actual annual reduction should be even higher since the boiler would not be expected to emit SO2 at the maximum allowable level for an entire year. Therefore, the 70+% reduction required by the BART exemption limit satisfies the requirement for reasonable progress. No additional limitations will be required.

6.4.4 Georgia Pacific Cedar Springs, Power Boiler No. 2 (U 501)

Power Boiler No. 2 is the same size, burns the same fuels, and has the same estimated SO2 emissions as Power Boiler 1. The 4-factor analysis and recommendations are identical to those for Power Boiler No. 1.

6.4.5 Georgia Pacific Cedar Springs, Recovery Boiler No. 3 (R402)

Recovery Boiler No. 3 burns black liquor and has a capacity of 769 MMBtu/hr. Particulate emissions are controlled by an electrostatic precipitator (ESP). The baseline SO2 emissions estimated by VISTAS were 1726 tons per year, which contributes about 0.77 % to the sulfate visibility impairment at Saint Marks.

Georgia Pacific's original submittal did not contain any control measures for 4-factor analysis. However, the company did include control scenarios as part of the company's BART exemption modeling request that included modifications to Recovery Boiler 3. Scenario 1 included repaired concentrator sets. This should result in a decrease of peak SO2 emissions. However, the company could not estimate the annual reduction in emissions from this control option. Therefore, it is assumed to be zero. Scenario 2 included new concentrator sets and a new multi-level air system for the recovery boiler. This control measure would reduce SO2 emissions to 919.8 tons/yr. The Division requested cost analysis information for a new concentrator/multi-level air system and received this information on July 31, 2008. This submittal also contained further information regarding SO2 emissions from Recovery Boiler 3 and regarding the cost effectiveness of switching to 1% sulfur fuel oil. After reviewing this information, the Division requested information regarding the cost-effectiveness of switching from no. 6 fuel oil to no. 2 fuel oil and received this information on August 15, 2008.

Based on the information received from Georgia-Pacific, the recovery boiler has two operating modes. The normal operating mode is when the recovery boiler is burning black liquor (and at times co-firing fuel oil) at which time the furnace is operating in a reducing mode and thus has relatively low SO2 emissions (20-30 ppm). The other operating mode is when there is no black liquor being fired, but the mill is burning fuel oil in the recovery boiler in order to produce steam needed for the mill processes. During these periods, SO2 emissions are emitted uncontrolled (approximately 400-500+ ppm). The company provided information for 2006-2007 regarding SO2 emissions during each of these operating modes. Recovery Boiler 3 emitted 184 and 169 tons of SO2 per year in 2006 and 2007, respectively, when burning black liquor. Recovery Boiler 3 emitted 278 and 571 tons of SO2 per year in 2006 and 2007, respectively, when burning only fuel oil.

The control options reviewed for Recovery Boiler 3, ranked from most effective to least effective, are:

1. Switching from no. 6 to no. 2 fuel oil with 0.5% sulfur;
2. Switching from no. 6 fuel oil with 1.8 % sulfur [typical max)] to no. 6 fuel oil with 1% sulfur;
3. New concentrator and new multi-level air system for high solids firing

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit had a relatively low visibility impact on only one Class I area (St. Marks, although it is not clearly meeting the uniform rate of progress).

New Concentrator and New Multi-Level Air System. This option would only reduce SO2 emissions when black liquor is fired in the recovery boiler. This is the normal operating mode of the recovery boiler. This conversion is estimated to reduce SO2 emissions by 22% when firing black liquor. The company provided SO2 emissions information for periods when black liquor was being fired in the recovery boiler. This amount is 184 tons in 2006 and 169 tons in 2007. The cost metrics are $149,000 per ton of SO2 reduced and $75,500 million per inverse megameter (Mm-1) of visibility improvement (at Saint Marks Class I area). These high cost figures are logical considering that this control option would only be effective when SO2 emissions from the recovery boiler are already low. The company did not provide any indication that the control measure could not be operated prior to 2012 nor that there would be any energy or non-air quality environmental impacts. This option was not considered cost effective.

Switching to 1% Fuel Oil . This option would only reduce SO2 emissions when only fuel oil is being fired in the recovery boiler. This sulfur content of fuel oil burned in this unit is limited to 3%. The company stated that the actual sulfur content ranged from 0.7% to 1.8%. 1.8% sulfur fuel oil is used as the basis for this cost estimate. Conversion to 1% fuel oil would reduce SO2 emissions by 44% when burning fuel oil. The cost metrics are $12,000 per ton of SO2 reduced and $6116 million per inverse megameter (Mm-1) of visibility improvement (at Saint Marks Class I area). The company did not provide any indication that the control measure could not be operated prior to 2012 nor that there would be any energy or non-air quality environmental impacts. This option was not considered cost effective.

Switching from no. 6 to no. 2 Fuel Oil . This option would reduce SO2 emissions only when fuel oil is being fired in the recovery boiler. The recovery boiler currently burns no. 6 fuel oil and the company stated that the actual sulfur content ranged from 0.7% to 1.8%. 1.8% sulfur fuel oil is used as the basis for this cost estimate. The sulfur content for no. 2 fuel oil is defined as 0.5%. Conversion to no. 2 fuel oil would reduce SO2 emissions by 72% when burning fuel oil. The cost metrics are $22,900 per ton of SO2 reduced and $11,594 million per inverse megameter (Mm-1) of visibility improvement (at Saint Marks Class I area). The company did not provide any indication that the control measure could not be operated prior to 2012 nor that there would be any energy or non-air quality environmental impacts. This option was not considered cost effective.

Conclusion. None of the control options were considered reasonable given the high-cost efficiencies (in both $/ton and $/Mm^{-1}), and the relatively low-visibility impact on a single Class I area. Georgia EPD, therefore, will not require any additional controls be required for Regional Haze reasonable progress.

6.4.6 Georgia Pacific Savannah River Mill, No. 3 Boiler (B001)

Georgia Pacific's Savannah River facility is located in Effingham County, northwest of the City of Savannah. The No. 3 Power Boiler is a re-circulating fluidized bed 422 MMBtu/hr boiler that burns petcoke (6.1 % sulfur[2]) and bituminous coal (1.55 % sulfur). Under current operation, petcoke is the primary fuel. Limestone injection into the combustion chamber provides control (approximately 90%) of SO2 emissions. The facility's current Title V permit limits SO2 emissions from this unit to 2152 tons. The baseline level of SO2 emissions reported by the company was 1659 tons, based on 2005 CEMS data. This compares with the VISTAS estimated baseline of 1844 tons.

Georgia Pacific's original submittal identified the following control technologies, from most effective to least effective, as being technically feasible:

1. Wet FGD with caustic;
2. Circulating fluidized bed scrubber;
3. Switch to 100 % coal firing;
4. Increased limestone injection; and
5. Rotating opposed fire air combustion control.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit had a relatively low visibility impact on only one Class I area (1.1% of the sulfate impact at Wolf Island, although it is not clearly meeting the uniform rate of progress). Another consideration was that this unit has an existing control (approximately 90%) for SO2.

Wet FGD with caustic. This option would achieve an SO2 reduction of approximately 95% and could be implemented after 2012 (a specific date was not provided). The cost metrics are $2430 per ton of SO2 reduced and $ 602.2 million per inverse megameter (Mm-1) of visibility improvement (at the Wolf Island Class I area). Regarding energy and non-air environmental impacts, this option would use 20 million gallons-per-year of water and increased the dissolved solids load to their wastewater treatment system. This control is projected to achieve a light extinction reduction of 0.0006 Mm-1 at Wolf Island. This option was not considered cost effective.

Circulating fluidized bed scrubber. This option would achieve an SO2 reduction of approximately 95% and could be implemented after 2012 (a specific date was not provided). The cost metrics are $4504 per ton of SO2 reduced and $1116.3 million per inverse megameter (Mm-1) of visibility improvement (at the Wolf Island Class I area). No energy and non-air environmental impacts were reported. This control is projected to

[2] The sulfur content of petcoke is allowed to exceed the 3 percent limit set by rule Georgia Air Quality Rule 391-3-1-.02(2)(g)2. because the boilers are equipped with flue gas desulfurization and thus qualifies for the provisions of 391-3-1-.02(2)(g)3.

achieve a light extinction reduction of 0.0006 Mm-1 at Wolf Island. This option was not considered cost effective.

Switch to 100% coal firing. This option would achieve an SO2 reduction of approximately 65% and could be implemented after 2012 (a specific date was not provided). The cost metrics are $4451 per ton of SO2 reduced and $1103.0 million per inverse megameter (Mm-1) of visibility improvement (at the Wolf Island Class I area). No energy and non-air environmental impacts were reported. This control is projected to achieve a light extinction reduction of 0.0004 Mm-1 at Wolf Island. This option was not considered cost effective.

Rotating opposed fire air. This option would achieve an SO2 reduction of approximately 30% and could be implemented after 2012 (a specific date was not provided). The cost metrics are $2150 per ton of SO2 reduced and $532.7 million per inverse megameter (Mm-1) of visibility improvement (at Wolf Island Class I area). No energy and non-air environmental impacts were reported. This control is projected to achieve a light extinction reduction of 0.0002 Mm-1 at Wolf Island. This option was not considered cost effective.

Increased limestone injection. Georgia-Pacific conducted trial operations with increased limestone injection rates and found that overall SO2 removal could only be increased by an additional two percent (from 87% to 89%) resulting in an additional SO2 reduction of approximately 15%. This option could be implemented prior to 2012. The cost metrics are $7223 per ton of SO2 reduced and $1792.4 million per inverse megameter (Mm-1) of visibility improvement (at Wolf Island Class I area). Regarding energy and non-air environmental impacts, this option would result in 24,000 to 60,000 tons per year of solid waste. This control is projected to achieve a light extinction reduction of 0.0001 Mm-1 at Wolf Island. This option was not considered cost effective.

Conclusion. None of the control options were considered reasonable given the resulting control efficiencies, the time delay to implementation (with the exception of increased limestone injection), the high-cost efficiencies (in both $/ton and $/Mm^{-1}), and the relatively low-visibility impact on a single Class I area. Georgia EPD, therefore, will not require any additional controls be required for Regional Haze reasonable progress.

6.4.7 Georgia Pacific Savannah River Mill, No. 4 Boiler (B002)

The No. 4 Power Boiler is also a re-circulating fluidized bed boiler that is the same size, burns the same fuels, and has the same SO2 controls as the No. 3 Boiler. The facility's current Title V permit limits SO2 emissions from this unit to 1671 tons. The baseline level of SO2 emissions reported by the company was 1195 tons based on 2005 CEMS data. This compares with the VISTAS estimated baseline of 1415 tons.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit had a relatively low visibility impact on only one Class I area (0.86% of the sulfate impact at Wolf Island although it is not clearly meeting

the uniform rate of progress). Another consideration was that this unit has a required minimum 90% control efficiency for SO2 as specified in NSPS Subpart Db.

The four-factor submittal identified the same control options as for the No. 3 Boiler. For the same reasons as listed for the No. 3 Boiler, Georgia EPD will not require any additional controls be required.

6.4.8 Georgia Pacific Savannah River Mill, No. 5 Boiler (B003)

The No. 5 Power Boiler is also a re-circulating fluidized bed boiler that is the same size, burns the same fuels, and has the same SO2 controls as the No. 3 and No. 4 Boilers. The facility's current Title V permit limits SO2 emissions from this unit to 1671 tons. The baseline level of SO2 emissions reported by the company was 1190 tons based on 2005 CEMS data. This compares with the VISTAS estimated baseline of 1282 tons.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit had a relatively low visibility impact on only one Class I area (0.77% of the sulfate impact at Wolf Island although it is not clearly meeting the uniform rate of progress). Another consideration was that this unit has a required minimum 90% control efficiency for SO2 as specified in NSPS Subpart Db.

The four-factor submittal identified the same control options as for the No. 3 and No. 4 Boilers. For the same reasons as listed for the No. 3 Boiler, Georgia EPD will not require any additional controls be required.

6.4.9 Georgia Power Plant Kraft, Steam Generator 1

Georgia Power's Plant Kraft is located in Chatham County, near the Georgia coast. Steam Generator Unit 1 is a 50 Megawatt coal-fired electric utility boiler. The sulfur content of the coal is limited to 3% or less and currently burns relatively low-sulfur coal (0.62% S). Particulate emissions are controlled by an electrostatic precipitator (ESP). The 2018 baseline SO2 emissions reported by the company were 632 tons which is close to the 2018 emissions projected by VISTAS using an IPM of 691 tons. 632 tons per year was used as the baseline SO2 emissions used in this analysis.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit significantly contributed to only one Class I area (Wolf Island) by a relatively low amount (0.51%; EPD's "threshold" for significant contribution was 0.5%). EPD also took into consideration that this unit significantly contributed to a Class I area that was predicted to not clearly meet the Uniform Rate of Progress (glide slope) in 2018 based on "on the books" controls.

Georgia Power's submittal identified the following control technologies, from most effective to least effective, as being technically feasible:

1. Wet flue gas desulfurization;

2. Coal switching; and
3. Coal washing.

Wet flue gas desulfurization. Wet flue gas desulfurization (FGD) would achieve an SO2 reduction of approximately 95% and could be implemented by January 2016. The cost efficiencies are $8161 per ton of SO2 reduced and $144.5 million per inverse megameter (Mm-1) of visibility improvement (at the Wolf Island Class I area). Regarding energy and non-air environmental impacts, this option would reduce energy production by approximately 2% (1000 k), consume approximately 90 gallons of water per Mwh, discharge 30 gallons of wastewater per Mwh, and generate 2.7 tons of gypsum per ton of SO2 removed. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.03 Mm-1 at Wolf Island. The cost effectiveness of this control option was determined not to be reasonable.

Coal Switching. Switching to 0.38 percent coal would achieve an SO2 reduction of approximately 39%. No data was submitted regarding the time to implement, thus it was assumed that coal washing could be achieved by January 1, 2012. The cost efficiencies are $4041 per ton of SO2 reduced and $71.5 million per inverse megameter (Mm-1) of visibility improvement (at the Wolf Island Class I area). Regarding energy and non-air environmental impacts, the company indicated that this option could possibly reduce boiler efficiency, but did not provide a quantitative amount. Non-air quality environmental impacts were not reported. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.01 Mm-1 at Wolf Island. The cost effectiveness of this control option was determined not to be reasonable.

Coal Washing. Coal washing would achieve an SO2 reduction of approximately 6%. No data was submitted regarding the time to implement, thus it was assumed that coal switching could be achieved by January 1, 2012. The cost efficiencies are $1839 per ton of SO2 reduced and $32.5 million per inverse megameter (Mm-1) of visibility improvement (at the Wolf Island Class I area). The annualized cost of this control was only about 30% of the cost predicted by AirControlNET, indicating that, if anything, the costs provided by the company may be underestimated. Regarding energy and non-air environmental impacts, the company indicated that this option could possibly reduce boiler efficiency, would use 4400 gallons per day of water, would result in acidic wastewater requiring treatment, and would result in coal refuse in the amount of approximately 5% of the total coal consumption. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.002 Mm-1 at Wolf Island. Based on the relatively low control efficiency of this option, the negative non-air environmental impacts, and the relatively low visibility impact, this control option was determined not to be reasonable.

Conclusion. No additional controls will be required for Plant Kraft Steam Generator 1.

6.4.10 Georgia Power Plant Kraft, Steam Generator 2

Georgia Power's Plant Kraft is located in Chatham County, near the Georgia coast. Steam Generator Unit 1 is a 54 Megawatt coal-fired electric utility boiler. The sulfur content of the coal is limited to 3% or less and currently burns relatively low-sulfur coal (0.62% S). Particulate emissions are controlled by an electrostatic precipitator (ESP). The 2018 baseline SO2 emissions reported by the company were 889 tons, which is higher, but relatively close, to the 2018 emissions projected by VISTAS using an IPM of 704 tons. 889 tons per year was used as the baseline SO2 emissions used in this analysis.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit significantly contributed to only one Class I area (Wolf Island) by a relatively low amount (0.52%; EPD's "threshold" for significant contribution was 0.5%.) EPD also took into consideration that this unit significantly contributed to a Class I area that was predicted to not clearly meet the Uniform Rate of Progress (glide slope) in 2018 based on "on the books" controls.

Georgia Power's submittal identified the following control technologies, from most effective to least effective, as being technically feasible:

1. Wet flue gas desulfurization;
2. Coal switching; and
3. Coal washing.

Wet flue gas desulfurization. Wet flue gas desulfurization (FGD) would achieve an SO2 reduction of approximately 95% and could be implemented by January 2016. The cost efficiencies are $6039 per ton of SO2 reduced and $106.9 million per inverse megameter (Mm-1) of visibility improvement (at the Wolf Island Class I area). Regarding energy and non-air environmental impacts, this option would reduce energy production by approximately 2% (1000 k), consume approximately 90 gallons of water per Mwh, discharge 30 gal of wastewater per Mwh, and generate 2.7 tons of gypsum per ton of SO2 removed. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.05 Mm-1 at Wolf Island. The cost effectiveness of this control option was determined not to be reasonable.

Coal Switching. Switching to 0.38 percent coal would achieve an SO2 reduction of approximately 39%. No data was submitted regarding the time to implement, thus it was assumed that coal switching could be achieved by January 1, 2012. The cost efficiencies are $4041 per ton of SO2 reduced and $71.5 million per inverse megameter (Mm-1) of visibility improvement (at the Wolf Island Class I area). Regarding energy and non-air environmental impacts, the company indicated that this option could possibly reduce boiler efficiency, but did not provide a quantitative amount. There were not reported non-air quality environmental impacts. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.02 Mm-1 at Wolf Island. The cost effectiveness of this control option was determined not to be reasonable.

Coal Washing. Coal washing would achieve an SO2 reduction of approximately 6%. No data was submitted regarding the time to implement, thus it was assumed that coal washing could be achieved by January 1, 2012. The cost efficiencies are $1847 per ton of SO2 reduced and $32.7 million per inverse megameter (Mm-1) of visibility improvement (at the Wolf Island Class I area). The annualized cost of this control was only about 30% of the cost predicted by AirControlNET, indicating that, if anything, the costs provided by the company may be underestimated. Regarding energy and non-air environmental impacts, the company indicated that this option could possibly reduce boiler efficiency, would use 4600 gallons per day of water, would result in acidic wastewater requiring treatment, and would result in coal refuse in the amount of approximately 5% of the total coal consumption. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.003 Mm-1 at Wolf Island. Based on the relatively low control efficiency of this option, the negative non-air environmental impacts, and the relatively low visibility impact, this control option was determined not to be reasonable.

Conclusion. No additional controls will be required for Plant Kraft Steam Generator 2.

6.4.11 Georgia Power Plant Kraft, Steam Generator 3

Georgia Power's Plant Kraft is located in Chatham County, near the Georgia coast. Steam Generator Unit 1 is a 104 Megawatt coal-fired electric utility boiler. The sulfur content of the coal is limited to 3% or less and currently burns relatively low-sulfur coal (0.62% S). Particulate emissions are controlled by an electrostatic precipitator (ESP). The 2018 baseline SO2 emissions reported by the company were 2455 tons, which is significantly lower than the 2018 emissions projected by VISTAS using an IPM of 4474. Georgia Power provided information dated September 7, 2007, indicating that utilization of the boiler will drop significantly in 2015 as a result of new generation coming on-line about that same time. EPD used a baseline SO2 emission rate of 2455 tons in this analysis. EPD can review the actual utilization of Unit 3 when the next Regional Haze SIP is developed to ensure that the assumption of reduced utilization has actually occurred. If not, analysis of additional controls can be re-analyzed during development of that SIP.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit significantly contributed to three Class I areas [Wolf Island (3.3%), Okefenokee (0.9%), and Cape Roman (0.8%).] EPD also took into consideration that this unit significantly contributed to two Class I areas (Wolf Island and Okefenokee) that were predicted to not clearly meet the Uniform Rate of Progress (glide slope) in 2018 based on "on the books" controls.

Georgia Power's original submittal identified the following control technologies, from most effective to least effective, as being technically feasible:

1. Wet flue gas desulfurization;

2. Coal switching; and
3. Coal washing.

Wet flue gas desulfurization. Wet flue gas desulfurization (FGD) would achieve an SO2 reduction of approximately 95% and could be implemented by January 2016. The cost efficiencies are $3216 per ton of SO2 reduced and $56.9 and $58.2 million per inverse megameter (Mm-1) of visibility improvement at Wolf Island and Okefenokee Class I areas, respectively. Regarding energy and non-air environmental impacts, this option would reduce energy production by approximately 2% (2000 k), consume approximately 90 gallons of water per Mwh, discharge 30 gal of wastewater per Mwh, and generate 2.7 tons of gypsum per ton of SO2 removed. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.13 Mm-1 at both Wolf Island and Okefenokee. Taking into account the cost effectiveness and non-air quality environmental impacts, this option was determined not to be reasonable.

Coal Switching. Switching to 0.38 percent coal would achieve an SO2 reduction of approximately 39%. No data was submitted regarding the time to implement, thus it was assumed that coal switching could be achieved by January 1, 2012. The cost efficiencies are $4042 per ton of SO2 reduced and $71.5 and $73.2 million per inverse megameter (Mm-1) of visibility improvement at Wolf Island and Okefenokee Class I areas, respectively. Regarding energy and non-air environmental impacts, the company indicated that this option could possibly reduce boiler efficiency, but did not provide a quantitative amount. Non-air quality environmental impacts were not reported. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.05 Mm-1 at both Wolf Island and Okefenokee. The cost effectiveness of this control option was determined not to be reasonable.

Coal Washing. Coal washing would achieve an SO2 reduction of approximately 6%. No data was submitted regarding the time to implement, thus it was assumed that coal washing could be achieved by January 1, 2012. The cost efficiencies are $1845 per ton of SO2 reduced and $32.7 and $33.4 million per inverse megameter (Mm-1) of visibility improvement at Wolf Island and Okefenokee Class I areas, respectively. The annualized cost of this control was only about 50% of the cost predicted by AirControlNET, indicating that, if anything, the costs provided by the company may be underestimated. Regarding energy and non-air environmental impacts, the company indicated that this option could possibly reduce boiler efficiency, would use 7500 gallons per day of water, would result in acidic wastewater requiring treatment, and would result in coal refuse in the amount of approximately 5% of the total coal consumption. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.01 Mm-1 at both Wolf Island and Okefenokee. Based on the relatively low control efficiency of this option, the negative non-air environmental impacts, and the relatively low visibility impact, this control option was determined not to be reasonable.

Conclusion. No additional controls will be required for Plant Kraft Steam Generator 3. However, this conclusion may be revised should the reduction in utilization and SO2 emissions reported by the company not be realized.

6.4.12 Georgia Power Plant McIntosh, Steam Generator 1

Georgia Power's Plant McIntosh is located in Effingham County, near the Georgia coast about 10-15 miles north of Plant Kraft. Steam Generator Unit 1 is a 178 megawatt coal-fired electric utility boiler. The sulfur content of the coal is limited to 3% or less and currently burns relatively low-sulfur coal (0.62% S). Particulate emissions are controlled by an electrostatic precipitator (ESP). The 2018 baseline SO2 emissions reported by the company were 1860 tons, which is significantly lower than the 2018 emissions projected by VISTAS using an IPM of 7015. Georgia Power provided information dated September 7, 2007, indicating that utilization of the boiler will drop significantly between 2011 and 2015 as a result of new a generation coming on-line about that same time. EPD used a baseline SO2 emission rate of 1860 tons in this analysis. EPD can review the actual utilization of McIntosh Unit 1 when the next Regional Haze SIP is developed to ensure that the assumption of reduced utilization has actually occurred. If not, analysis of additional controls can be re-analyzed during development of that SIP.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit significantly contributed to five class I areas [Wolf Island (4.1%), Okefenokee (1.2%), Saint Marks (0.6%), Cape Romain (1.4%), and Swanquarter (0.7%)], the highest number of all of the units (except International Paper Power Boiler 13, which also impacts the same five class I areas) reviewed by EPD. EPD also took into consideration that this unit significantly contributed to three Class I areas (Wolf Island, Okefenokee, and Saint Marks) that was predicted to not clearly meet the Uniform Rate of Progress (glide slope) in 2018, based on "on the books" controls. However, should utilization and SO2 emissions by approximately 75%, as reported by the company, the visibility impairment will reduce to less than the 0.5% threshold for four of these Class I areas and will be significantly less on the remaining one (Wolf Island (1.1%).

Georgia Power's submittal identified the following control technologies, from most effective to least effective, as being technically feasible:

1. Wet flue gas desulfurization;
2. Coal switching; and
3. Coal washing.

Wet flue gas desulfurization. Wet flue gas desulfurization (FGD) would achieve an SO2 reduction of approximately 95% and could be implemented by January 2016. The cost efficiencies are $7131 per ton of SO2 reduced and $118.5, $132.6 and $411.0 million per inverse megameter (Mm-1) of visibility improvement at Wolf Island, Okefenokee, and St. Marks Class I areas, respectively. Regarding energy and non-air environmental impacts, this option would reduce energy production by approximately 1-2%, consume approximately 80-110 gallons of water per MWh and generate 2.7 tons of gypsum per ton of SO2 removed. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.11 Mm-1 at Wolf Island, 0.09 Mm-1

at Okefenokee, and 0.03 Mm-1 at St. Marks. The cost effectiveness of this control option was determined not to be reasonable.

Coal Switching. Switching to 0.38 percent coal would achieve an SO2 reduction of approximately 39%. No data was submitted regarding the time to implement, thus it was assumed that coal switching could be achieved by January 1, 2012. The cost efficiencies are $4306 per ton of SO2 reduced and $71.5, $80.1, and $248.2 million per inverse megameter (Mm-1) of visibility improvement at Wolf Island, Okefenokee, and St. Marks Class I areas, respectively. Regarding energy and non-air environmental impacts, the company indicated that this option could possibly reduce boiler efficiency, but did not provide a quantitative amount. Non-air quality environmental impacts were not reported. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.04 Mm-1 at both Wolf Island and Okefenokee, and 0.01 Mm-1 at St. Marks. The cost effectiveness of this control option was determined not to be reasonable.

Coal Washing. Coal washing would achieve an SO2 reduction of approximately 6%. No data was submitted regarding the time to implement, thus it was assumed that coal washing could be achieved by January 1, 2012. The cost efficiencies are $5534 per ton of SO2 reduced and $91.9, $102.9, and $319.0 million per inverse megameter (Mm-1) of visibility improvement at Wolf Island, Okefenokee, and St. Marks Class I areas, respectively. The annualized cost of this control was only about 25% of the cost predicted by AirControlNET, indicating that, if anything, the costs provided by the company may be underestimated. Regarding energy and non-air environmental impacts, the company indicated that this option would use 163,000 gallons per day of water, would result in acidic wastewater requiring treatment, and would result in coal refuse in the amount of approximately 5% of the total coal consumption. Energy impacts were not reported and are thus assumed to be minimal. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.002 Mm-1 at both Wolf Island and Okefenokee, and 0.0006 Mm-1 at St. Marks. The cost effectiveness of this control option was determined not to be reasonable.

Conclusion. No additional controls will be required for Plant McIntosh Steam Generator 1. However, this conclusion may be revised should the reduction in utilization and SO2 emissions reported by the company not be realized.

6.4.13 Georgia Power Plant Mitchell, Steam Generator 3

Georgia Power's Plant Mitchell is located in Dougherty County, in southwest Georgia. Steam Generator Unit 3 is a 163 Megawatt coal-fired electric utility boiler. The sulfur content of the coal is limited to 3% or less and currently burns relatively low-sulfur coal (1% S) and employs coal washing, which slightly reduces SO2 emissions. Particulate emissions are controlled by an electrostatic precipitator (ESP). The 2018 baseline SO2 emissions reported by the company were 1189 tons, which is significantly lower than the 2018 emissions projected by VISTAS using IPM of 4930. Georgia Power provided information dated September 7, 2007, indicating that utilization of the boiler will drop

significantly between 2008 and 2010 as a result of new a generation coming on-line about that same time. EPD used a baseline SO2 emission rate of 1189 tons in this analysis. EPD can review the actual utilization of McIntosh Unit 1 during the mid-course review to ensure that the assumption of reduced utilization has actually occurred. If not, analysis of additional controls can be re-analyzed during development of that SIP.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit significantly contributed to two Class I areas (Saint Marks (2.7%) and Okefenokee (0.8%). EPD also took into consideration that this unit significantly contributed to two Class I areas that were predicted to not clearly meet the Uniform Rate of Progress (glide slope) in 2018, based on "on the books" controls. However, should utilization and SO2 emissions drop by approximately 75%, as reported by the company, the visibility impairment will reduce to less than the 0.5% threshold for Okefenokee and will be significantly less on the remaining one [Saint Marks (0.7%)].

Georgia Power's submittal identified the following control technologies, from most effective to least effective, as being technically feasible:

1. Wet flue gas desulfurization; and
2. Coal switching.

Wet flue gas desulfurization. Wet flue gas desulfurization (FGD) would achieve an SO2 reduction of approximately 95% and could be implemented by January 2016. The cost efficiencies are $9119 per ton of SO2 reduced and $148.5, and $299.4 0 million per inverse megameter (Mm-1) of visibility improvement at Okefenokee and St. Marks Class I areas, respectively. Regarding energy and non-air environmental impacts, this option would reduce energy production by approximately 1-2% (1250-2500 kw). No non-air quality environmental impacts were reported. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.07 Mm-1 at Okefenokee and 0.03 Mm-1 at St. Marks. The cost effectiveness of this control option was determined not to be reasonable.

Coal Switching. Switching to 0.38 percent coal would achieve an SO2 reduction of approximately 47%. No data was submitted regarding the time to implement, thus it was assumed that coal switching could be achieved by January 1, 2012. The cost efficiencies are $2347 per ton of SO2 reduced and $38.2 and $77.1 million per inverse megameter (Mm-1) of visibility improvement at Okefenokee and St. Marks Class I areas, respectively. Regarding energy and non-air environmental impacts, the company indicated that this option could possibly reduce boiler efficiency. No non-air quality environmental impacts were reported. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.03 Mm-1 at Okefenokee, and 0.02 Mm-1 at St. Marks. Based on the relatively low visibility impairment resulting from significant reductions in SO2 emissions from this unit, the cost effectiveness of this control option was not low enough to be considered reasonable.

Conclusion. No additional controls will be required for Plant Mitchell Steam Generator 3. However, this conclusion may be revised should the reduction in utilization and SO2 emissions reported by the company not be realized.

6.4.14 International Paper Savannah Mill, Power Boiler 13

International Paper's Savannah Mill is located in Chatham County, on Georgia's coast at the border with South Carolina. Power Boiler 13 (PB 13) is a 1280 MMBtu/hr boiler that burns bituminous coal (primary fuel), bark, and wood fines. The sulfur content of the coal is typically 0.69 % or less. In addition, the boiler controls (by combustion) waste gas emissions from the pulping process: low-volume high-concentration (LVHC) non-condensable gases, high-volume low-concentration (HVLC) non-condensable gases, and stripper off-gases (SOG). These waste gases contribute approximately 35% of the total sulfur load to the boiler. An electrostatic precipitator controls particulate emissions. The baseline SO2 emissions level used by the company was the VISTAS estimate of 8578 tons with approximately 1944 tons/yr of this coming from the combustion of LVHC, HVLC, and SOG.

International Paper provided two 4-factor analyses in separate submittals. The second submittal was in response to a request from EPD and it identified controls specifically for the pulping waste gas emissions (options 7, 8, and 9 below). Also, facility representatives later suggested an SO2 reduction of 2000 tons/year as a control option that would provide maximum flexibility for compliance (i.e., a 6758 ton per year emission limit). The submittals identified the following control technologies, from most effective to least effective, as being technically feasible:

1. Wet FGD (packed tower);
2. FGD, wet limestone spray tower;
3. Semi-dry lime spray tower;
4. Fuel switching to natural gas;
5. Dry sorbent injection;
6. 6758 ton/year emission limit
7. Regenerative thermal oxidizer (RTO) with scrubber: control HVLC ;
8. Regenerative thermal oxidizer (RTO) with scrubber: control LVHC and SOG; and
9. Regenerative thermal oxidizer (RTO) with scrubber: control HVLC, LVHC, and SOG.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit significantly contributes to the sulfate visibility impairment at five Class I areas (approximately 6.4% at Wolf Island, approximately 1.7% at Okefenokee, approximately 0.7% at Saint Marks, approximately 1.6% at Cape Romain, and approximately 0.9% at Swanquarter). This is the highest number of Class I areas significantly impacted by any single emissions unit of all those reviewed.

Wet FGD, packed tower. This option would achieve an SO2 reduction of approximately 95% and could be implemented before 2012. The cost metrics are $4896 per ton of SO2 reduced and $72.3 million per inverse megameter (Mm^{-1}) of visibility improvement (at Wolf Island, the closest of the Class I areas). Regarding energy and non-air environmental impacts, this option would consume 2210 kW of power and approximately 212 million gallons of water per year. It would generate approximately 161 million gallons of wastewater per year. This control is projected to achieve a light extinction reduction of 0.55 Mm-1 at Wolf Island. Based on information received from EPD's Watershed Protection Branch, the Savannah River (into which this mill discharges) currently had a restriction on increased dissolved oxygen (DO) demand to the river. Although the Division did not receive sufficient information to determine whether this control option would result in actual DO load to the river, the potential for this to happen was sufficient for EPD to consider an option that did not result in increased wastewater load.

FGD, wet limestone spray tower. This option would achieve an SO2 reduction of approximately 90% and could be implemented before 2012. The cost metrics are $4391/ton reduced and $64.8 million/$Mm^{-1}$ at Wolf Island. Regarding energy and non-air environmental impacts, this option would consume 2210 kW of power and generate approximately 22,000 tons of solid waste per year. No additional water use or wastewater discharge was reported. This control is projected to achieve a light extinction reduction of 0.52 Mm^{-1} at Wolf Island. Based on cost estimates from other sources (i.e., the company's capital cost estimate was 8.37 times that derived from AirControlNet), the company's cost estimates may be high. EPD requested that a more precise site-specific cost analysis be performed by the company, but the company chose not to do so. However, despite the possibly high cost estimated, this control option is not considered reasonable at this time. This determination may be revisited at the mid-course review or when determining future Regional Haze reasonable progress goals (i.e., future Regional Haze SIPs.)

Semi-dry lime spray tower. A semi-dry lime spray dryer would achieve an SO2 reduction of approximately 85% and could be implemented by before 2012. The cost efficiencies are $4869 per ton of SO2 reduced and $71.9 million per inverse megameter (Mm^{-1}) of visibility improvement at Wolf Island. Regarding energy and non-air environmental impacts, this option would reduce energy production by 780 kw, would generate 19,300 tons per year of solid waste and approximately 114 million gallons of wastewater per year. The company reported no water withdrawal for this option. This control is projected to achieve a light extinction reduction of 0.49 Mm-1 at Wolf Island. Based on information received from EPD's Watershed Protection Branch, the Savannah River (into which this mill discharges) currently had a restriction on increased dissolved oxygen (DO) demand to the river. Although the Division did not receive sufficient information to determine whether this control option would result in actual DO load to the river, the potential for this to happen was sufficient for EPD to consider an option that did not result in increased wastewater load.

Fuel switching to natural gas. Switching from coal to natural gas would achieve an SO2 reduction of approximately 65% and could be implemented before 2012. The cost metrics are $9506/ton reduced and $140.4 million/$Mm^{-1}$ at Wolf Island. No negative energy or non-air environmental impacts were reported. This control is projected to achieve a light extinction reduction of 0.38 Mm-1 at Wolf Island. This control option results in a lower control efficiency and has a higher cost efficiency than others determined not to be cost effective at this time. Therefore, this option is not considered reasonable.

Dry sorbent injection. Dry sorbent injection would achieve an SO2 reduction of approximately 25% and could be implemented before 2012. The cost metrics are $5223/ton reduced and $77.1 million/$Mm^{-1}$ at Wolf Island. Regarding energy and non-air environmental impacts, this option would reduce energy production by 280 kw and would generate 7900 tons per year of solid waste. No water or wastewater impacts were reported. This control is projected to achieve a light extinction reduction of 0.15 Mm-1 at Wolf Island. This control option results in a lower control efficiency and has a higher cost efficiency than others determined not to be cost effective at this time. Therefore, this option is not considered reasonable.

6758 ton per year emission limit: The company has proposed to reduce SO2 emissions from this unit by 2000 tons per year from the projected 2018 baseline emissions of 8578 tons/year. This results in an emission limit of 6578 tons per year. This reduction could be accomplished by 2016. The need for a 2016 compliance date is due to uncertainty regarding controls that would be installed in response to the Boiler MACT. At this point, the Boiler MACT has been vacated and remanded to EPA. EPA is currently in the process of developing a proposed boiler MACT. A 2016 compliance date should provide sufficient time for the MACT to be proposed and promulgated, provide the three years required for compliance with the standard, and provide time to determine what the SO2 emissions from this unit will be following compliance with this standard. This control option would achieve SO2 reductions of approximately 23%. The company did not specify how the reductions would be accomplished. Possible measures to reduce SO2 from the power boiler would include increased bark combustion and reduced coal combustion, installation of a second white liquor scrubber to reduce TRS compounds in the non-condensible gases prior to combustion in the boiler, and installation of an RTO and scrubber for the control of HVLC, LVHC, and/or SOG (see control option below). Since this control option was proposed by the company, it is assumed to have no unacceptable energy or non-air environmental impacts. This control is projected to achieve a light extinction reduction of 0.14 Mm-1 at Wolf Island. The proposed limit of 6758 tons/year is based on a projected 2018 baseline SO2 emission rate of 8578 tons per year. EPD reviewed recent emission inventory data to determine if this 2018 baseline is reasonable. The 2002 (the inventory baseline year) through 2007 (the most recent year of available data) actual emissions from Power Boiler 13 were 7643, 7699, 7620, 7728, 8974, and 8761 tons/year. This data indicates that a 2018 future baseline of 8578 tons/year is reasonable, given that it is lower than the most two recent years of actual emissions. Also, the proposed 6758 ton/year emission limit is lower than any past actual

emission since 2002. Although no cost-effectiveness information was provided by the company, this control option is determined to be reasonable at this time.

Regenerative thermal oxidizer (RTO) with scrubber controlling HVLC, LVHC, and SOG: This control option would involve routing a portion of the mill's non-condensible gases or NCGs [in this case the high-volume low-concentration stream (HVLC), low-volume high-concentration stream (LVHC), and the stripper off-gas stream (SOG)] which contain sulfur-bearing compounds to a stand-alone RTO equipped with a scrubber (95% SO2 removal) to remove resulting SO2 emissions instead of using Power Boiler 13 to combust the NCGs. This control option was not considered because the SO2 control efficiency (approximately 22%) is lower than other options that are considered reasonable.

Regenerative thermal oxidizer (RTO) with scrubber controlling LVHC and SOG: This control option would involve routing a portion of the mill's non-condensible gases or NCGs (in this case LVHC and SOG) which contain sulfur bearing compounds to a stand-alone RTO equipped with a scrubber (95% SO2 removal) to remove resulting SO2 emissions instead of using Power Boiler 13 to combust the NCGs. This control option was not considered because the SO2 control efficiency (approximately 18%) is lower than other options that are considered reasonable.

Regenerative thermal oxidizer (RTO) with scrubber controlling HVLC: This control option would involve routing a portion of the mill's non-condensible gases or NCGs (in this case HVLC) which contain sulfur-bearing compounds to a stand-alone RTO equipped with a scrubber (95% SO2 removal) to remove resulting SO2 emissions instead of using Power Boiler 13 to combust the NCGs. This control option was not considered because the SO2 control efficiency (approximately 4%) is lower than other options that are considered reasonable.

Conclusion. Of the control options considered, an emission limit of 6578 tons per year was considered reasonable. To allow the facility flexibility in selection and implementation of a control, Georgia EPD will establish a permit limit of 6578 tons of SO2 per 12 months, including emissions from the pulping process.

6.4.15 Temple-Inland Rome Linerboard, No. 4 Power Boiler

The Temple-Inland Rome Linerboard facility is located in Floyd County, in northwest Georgia. The No. 4 Power Boiler is a 565 MMBtu/hr coal and oil fired boiler. The unit is also permitted to burn a relatively small amount of sawdust. The sulfur content of the coal and oil are limited by permit condition to 1.29% and 0.5%, respectively. There are hourly and annual SO2 permit limits of 1,130.0 pounds per hour and 3837 tons per 12-month period for the boiler. The permit also limits the combustion of fuel oil to 35,352,857 gallons per 12-month period. The pound per hour SO2 limit is a PSD limit. All of the others are for PSD avoidance. Particulate emissions are controlled by a multiclone followed by an electrostatic precipitator (ESP). The 2018 baseline SO2 emissions reported by the company were 3837 tons (the same as the permit limit). The

VISTAS 2018 projected emissions were 3696, relatively close to the permit limit. 3837 tons per year was used as the baseline SO2 emissions used in this analysis. Review of data submitted under the Consolidated Emissions Reporting Rule showed 3293 tons emitted in 2002, 3404 tons in 2003, 3396 tons in 2004, 2533 tons in 2005, and 2839 tons in 2006. Because a maximum permit limit is used as the 2018 baseline emissions in this review, the appropriate 2018 baseline may be over-estimated, but not by a significant amount. As a result, the amount of SO2 reduced by any particular control strategy may be slightly overestimated.

In determining what control options should be considered "reasonable" for this unit, EPD took into consideration that this unit significantly contributed to two Class I areas [Cohutta (4.4%) and Joyce Kilmer (1.0%)]. EPD also took into consideration that this unit significantly contributed to Class I areas that were predicted to clearly meet the Uniform Rate of Progress (glide slope) in 2018, based on "on the books" controls. EPD also took into consideration that this unit is located within a $PM_{2.5}$ non-attainment area (Floyd County) and within a county adjacent to another $PM_{2.5}$ non-attainment area (Atlanta.)

Temple-Inland's submittal identified the following control technologies, from most effective to least effective, as being technically feasible:

1. Wet flue gas desulfurization – magnesium enhanced lime (wet FGD MEL);
2. Wet flue gas desulfurization – limestone forced oxidation (wet FGD LSFO);
3. Dry flue gas desulfurization (dry FGD);
4. Fuel Switching to Powder River Basin coal (i.e., subbituminous coal); and
5. Duct Lime Sorbent Injection.

The company reported the control efficiency of both wet FGD MEL and wet FGD LSFO as equivalent. Cost estimates for the five control technologies were prepared as study-level estimates (which are not site-specific) in the company's original four-factor submittal. The company subsequently prepared and submitted to EPD a site-specific cost estimate for the wet FGD LSFO option. No site-specific analysis was presented for wet FGD MEL, but the submittal stated that the capital and operating costs for MEL technology would be approximately the same as LSFO. Costs from the site-specific analysis are presented in this SIP since these are expected to be more accurate than those from the study-level estimate.

It should also be noted that the company submitted a report dated April 3, 2008, proposing that EPD should establish thresholds of direct $PM_{2.5}$ emissions within Floyd County and require RACT and/or RACM analyses in lieu of controlling SO2 emissions from No. 4 Power Boiler. However, the report did not propose or analyze any specific direct $PM_{2.5}$ control measures from either No. 4 Power Boiler or any other source at the mill. Furthermore, EPD has determined for this particular Regional Haze SIP that reducing SO2 emissions from EGU and non-EGU point sources in the VISTAS states would have the greatest visibility benefits for the Georgia Class I areas.

Wet flue gas desulfurization – magnesium enhanced lime. Wet FGD MEL would achieve an SO2 reduction of approximately 90 % and could be implemented by before 2012. The cost efficiencies are $2027 per ton of SO2 reduced and $39.5 million per inverse megameter (Mm^{-1}) of visibility improvement (at the Cohutta Class I area). Regarding energy and non-air environmental impacts, this option would reduce energy production by 450 kw, consume 37 million gallons of water per year, and generate 16,000 tons of gypsum per year. The electrical usage was taken into account with the economic analysis. EPD's Watershed Protection Branch has indicated that mill had sufficient capacity within its currently permitted water withdrawal permit to easily handle the increased water use associated with wet FGD. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.17 Mm^{-1} at Cohutta. The cost effectiveness of this control option was determined not to be reasonable at this time. This determination may be revisited at the mid-course review or when determining future Regional Haze reasonable progress goals (i.e., future Regional Haze SIPs.)

Wet flue gas desulfurization – limestone forced oxidation. Wet FGD LSFO would achieve an SO2 reduction of approximately 90 % and could be implemented by before 2012. The cost efficiencies are $2027 per ton of SO2 reduced and $39.5 million per inverse megameter (Mm^{-1}) of visibility improvement (at the Cohutta Class I area). Regarding energy and non-air environmental impacts, this option would reduce energy production by 450 kw, consume 37 million gallons per year, and generate 16,000 tons of gypsum per year. The electrical usage was taken into account with the economic analysis. EPD's Watershed Protection Branch has indicated that mill had sufficient capacity within its currently permitted water withdrawal permit to easily handle the increased water use associated with wet FGD. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.17 Mm^{-1} at Cohutta. The cost effectiveness of this control option was determined not to be reasonable at this time. This determination may be revisited at the mid-course review or when determining future Regional Haze reasonable progress goals (i.e., future Regional Haze SIPs.)

Dry flue gas desulfurization. Dry FGD would achieve an SO2 reduction of approximately 80% and could be implemented before 2012. The cost efficiencies are $1857 per ton of SO2 reduced and $36.2 million per inverse megameter (Mm^{-1}) of visibility improvement (at the Cohutta Class I area). Regarding energy and non-air environmental impacts, this option would reduce energy production by 650 kw and would generate 10,000 tons of gypsum per year. The company reported no water or wastewater impacts. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.16 Mm^{-1} at Cohutta. This control option results in a lower control efficiency and has a similar cost efficiency than other control options determined not to be cost effective at this time. Therefore, this option is not considered reasonable.

Fuel switching. Switching to lower sulfur fuels would achieve an SO2 reduction of approximately 65% and could be implemented before 2012. The cost efficiencies are

$2807 per ton of SO2 reduced and $54.6 million per inverse megameter (Mm^{-1}) of visibility improvement (at the Cohutta Class I area). Regarding energy impacts, this option would reduce energy production by 650 kw. The company reported no non-air quality environmental impacts from this control option. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.13 Mm^{-1} at Cohutta. This control option results in a lower control efficiency and has a higher cost efficiency than others determined not to be cost effective at this time. Therefore, this option is not considered reasonable.

Duct lime sorbent injection. Duct sorbent injection would achieve an SO2 reduction of approximately 45% and could be implemented before 2012. The cost efficiencies are $1943 per ton of SO2 reduced and $37.8 million per inverse megameter (Mm^{-1}) of visibility improvement (at the Cohutta Class I area). Regarding energy impacts, this option would reduce energy production by 650 kw. The company reported no non-air quality environmental impacts from this control option. This control efficiency is projected to achieve light extinction reductions (which are visibility improvements) of 0.11 Mm^{-1} at Cohutta. This control option has a relatively low control efficiency and has a similar cost efficiency than other control options determined not to be cost effective at this time. Therefore, this option is not considered reasonable.

Conclusion. No additional controls will be required for Temple-Inland Rome No. 4 Power Boiler Plant. However, this determination may be revisited at the mid-course review or when determining future Regional Haze reasonable progress goals (i.e., future Regional Haze SIPs.) Furthermore, Temple-Inland Rome is located within a PM2.5 nonattainment area (Floyd County) and is near two other PM2.5 nonattainment areas (Atlanta and Chattanooga). Further evaluation of controls for this unit may be included in attainment plans for these nonattainment areas.

7.0 BART

7.1 Background

As required by the CAA, EPA included in the final regional haze rule a requirement for Best Available Retrofit Technology (BART) for certain large stationary sources that were placed in operation between 1962 and 1977. The BART-eligible sources are those sources which have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were placed in operation between August 7, 1962, and August 7, 1977, and whose operations fall within one or more of 26 specifically-listed source categories. Under the CAA, BART is required for any BART-eligible source that a State determines ‘‘emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area.’’ Accordingly, for stationary sources meeting these criteria, States must address the BART requirement when they develop regional haze SIPs. EPA has set guidance for identifying BART-eligible sources in 40 CFR Part 51 Appendix Y.

A BART-eligible source that is responsible for a 0.5 deciview (dv) change or more is considered to “cause” visibility impairment. Although the appropriate threshold may vary, the guidelines state that the contribution threshold used for BART applicability should not be higher than 0.5 deciviews. Thus a BART-eligible source that is responsible for a 0.5 dv change or more is considered to “contribute” to visibility impairment. Any source determined to cause or contribute to visibility impairment in any Class I area is subject to BART.

The guidelines direct that States should include SO2, NOX, and direct particulate matter (PM) emissions, including both PM10 and PM2.5, in determining whether sources cause or contribute to visibility impairment. States may use their best judgment to determine whether VOC or ammonia emissions are likely to have an impact on visibility in an area.

To determine which BART-eligible sources are subject to BART, states have several options. A state may consider all BART-eligible sources subject to BART; may perform analysis showing that the full group of BART-eligible sources in a State cumulatively may not be reasonably anticipated to cause or contribute to any visibility impairment in any Class I areas; or may consider the individualized contribution of a BART-eligible source to determine whether a specific BART-eligible source is subject to BART.

Sources that are subject to BART must undergo a BART determination. Section 169A(g)(7) of the CAA requires that States must consider the following factors in making BART determinations: (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any existing pollution control technology in use at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

To demonstrate the degree of improvement in visibility from various BART control options, the States may run CALPUFF or another appropriate dispersion model to predict visibility impacts. Scenarios would be run for the pre-controlled and post-controlled emission rates for each of the BART control options under review. The maximum 24-hour emission rates would be modeled for a period of three or five years of meteorological data. States have the flexibility to develop their own methods to evaluate model results.

7.2 Approach to Implementation of BART Requirements

Georgia has used a multi-faceted approach to implementation of the federal regional haze rule BART requirements. The approach consists of source identification efforts, use of a permitting process to establish any resulting BART limits for inclusion in the SIP submittal as well as participation in the VISTAS BART subgroup to resolve technical issues spanning states in the VISTAS region, and ongoing consultation with affected sources, and EPA and FLMs throughout the BART process.

EPA's Best Available Retrofit Technology (BART) applies to sources that have the potential to emit 250 tons or more of a visibility impairing pollutant, those that were in existence on August 7, 1977 and began operation after August 7, 1962, and those that fall within one of the 26 industrial source categories listed in 40 CFR Part 51 Appendix Y guidelines. The rule allows affected sources to demonstrate that the source does not contribute to visibility impairment and should be exempted. Non-exempt sources are required to undergo a determination of best available retrofit technology. BART controls are required to be installed and begin operating by January 1, 2012.

7.3 Identification of BART-Eligible Sources

EPA provided guidance for identifying BART-eligible sources in 40 CFR Part 51 Appendix Y. Georgia followed this guidance in identifying its BART-eligible sources. The Georgia 2002 air emissions inventory was reviewed to determine the population of potential BART-eligible sources. The data was initially queried for any sources emitting SO2, NOx, PM-10, VOC, or ammonia. The data set was refined based on emissions, whether emission units fit in any of the twenty-six listed source categories for BART, and available date information obtained through review of permit and inspection reports and discussion with permitting and compliance staff familiar with the facilities.

An information packet on BART was sent to and additional information was collected from the remaining sources regarding potential emissions and BART eligibility from the standpoint of source category and date criteria. Through this iterative review process, the list of potential BART-eligible sources was pared down to the 24 BART-eligible sources listed below. For more details on emissions and Q/d at these facilities, see Appendix H.5. These include one cement manufacturing facility, six pulp and paper facilities, ten electric utilities, two chemical manufacturers, two packaging facilities, one phosphoric acid manufacturer, one asphalt manufacturer, and one nitrogen fertilizer manufacturer.

Georgia BART Eligible Sources

FACILITY NAME

Chemical Products Corporation
DSM Chemicals, North America
Georgia Pacific – Cedar Springs
Georgia Power – Plant Bowen
Georgia Power Plant Branch
Georgia Power – Plant Hammond
Georgia Power – Plant McDonough
Georgia Power – Plant Mitchell
Georgia Power – Plant Scherer
Georgia Power – Wansley
Georgia Power – Yates
International Paper – Augusta
International Paper – Savannah
Interstate Paper, LLC
Koch Cellulose (Georgia Pacific – Brunswick / Brunswick Pulp & Paper)
Lafarge Building Materials (Blue Circle Cement – Atlanta Plant)
Owens Corning
PCA –Valdosta (Tenneco Packaging, Inc.)
PCS Nitrogen
Prayon, Inc.
Rayonier (Rayonier ITT, Inc.)
Savannah Electric – Plant Kraft
Savannah Electric – Plant McIntosh
Tronox (Kerr – McGee / Kemira)

Georgia BART-eligible sources were presumed to be subject to BART but were provided the opportunity to submit modeling demonstrations showing that they did not contribute to visibility impairment (i.e., had less than 0.5 deciviews (dv) impact on any Class I area within 300 km and thus could be exempt).

Georgia BART-Eligible Sources

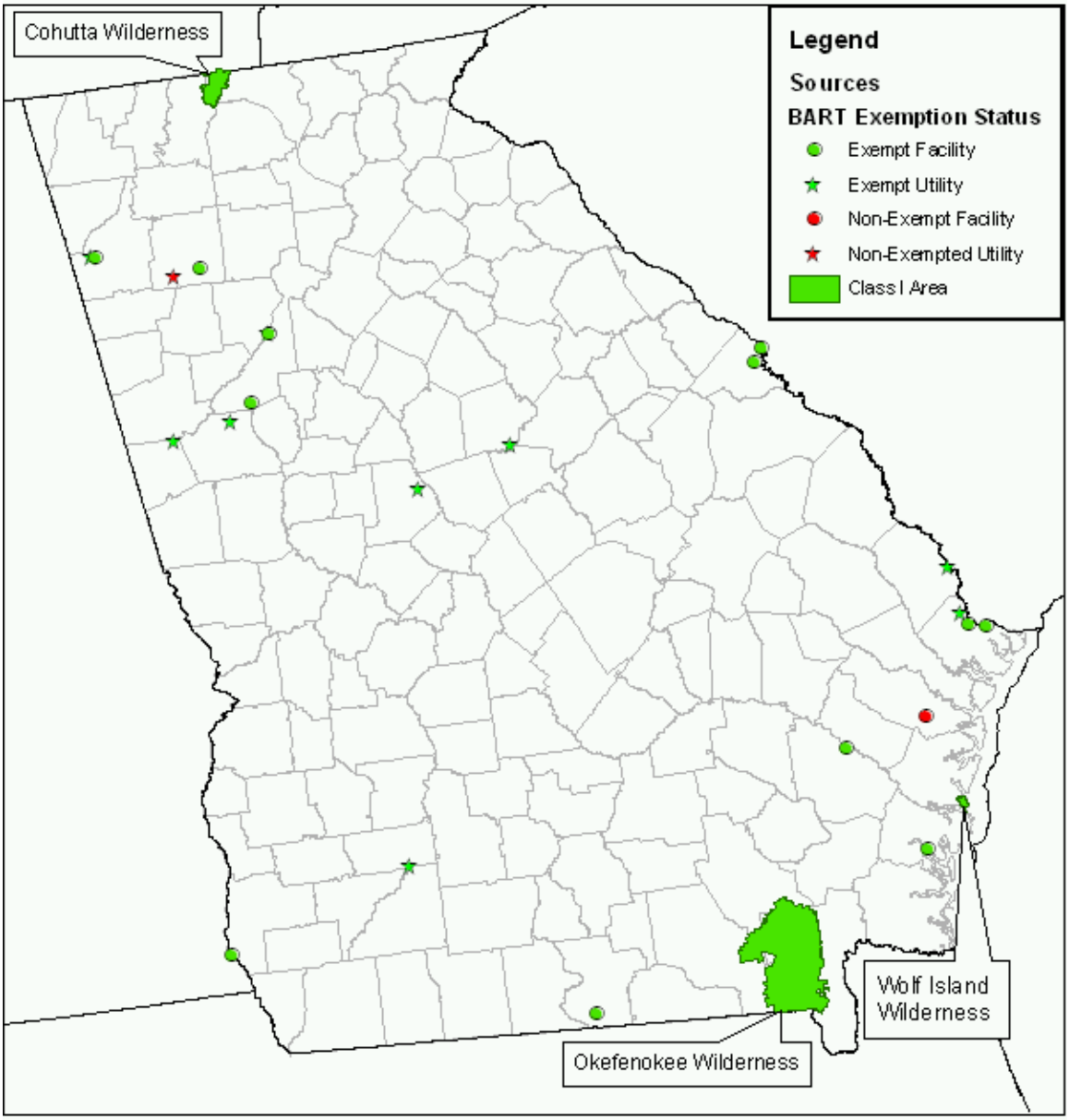


Figure 7-1. GA BART-Eligible Sources and Class I Areas.

Table 7-1. GA BART-Eligible Sources and Distances to Respective Class I Areas

	Distance From Class I Area											
Facility Name	**WOLF ISLAND**	**Okefenokee**	**Cohuttta**	**Cape Romain**	**Linville Gorge**	**Joyce Killmer**	**Shinning Rock**	**St. Marks**	**Great Smoky Mountains**	**Sipsey**	**Bardwell Bay**	**Chassahowitzka**
Georgia Power-Plant Bowen*												
Georgia Power-Plant Branch	274.4	254.8	218.6			247.4	242.5		250.5			
Georgia Power-Plant Hammond			93.7			174.8	252.4		187.5	183		
Georgia Power-Plant McDonough			113.7			176.9	221.8		189.8	269		
Georgia Power-Plant Mitchell	265.4	163.4						141.7				
Georgia Power-Plant Scherer	299.4	263.1	211.8			256.3	268.3		265.3			
Georgia Power-Plant Wansley			163.8			237.5	289.9		250.9	235		
Georgia Power-Plant Yates			156.3			228.2	278.3		241.5	240		
Savannah Electric-Plant Kraft	87	159		161.7								
Savannah Electric-Plant McIntosh	110.5	177.1		152.6								
Chemical Products Corp												
DSM Chemicals North America	236.9	266	288.7	219.2	266.7	281.5	2276					
Koch Cellulose (GP Brunswick, Brunswick Pulp & Paper)	26	100		130				280				
Georgia-Pacific Cedar Springs Operations		244						112				
International Paper – Augusta	226	254	294	219	275	289	236					
International Paper - Savannah (Union Camp Corp.)	83.6	156.9		162.5								
Interstate Paper, LLC	41	103		207							295	
Kerr-McGee Pigments, Inc. (Kemira)	90	180		210								
Lafarge Building Materials (Blue Circle Cement – Atlanta Plant)			114.3			177.3	221.9		190.2	269		
Owens Corning			146.4			212.3	255.6		225.3	267		
PCA (Tenneco Packaging, Inc.)	201	73.1						89.1			128.5	220.8
PCS Nitrogen Fertilizer, LP – Augusta	238	267	288	220	265	280	225					
Prayon, Inc. (Solutia, Inc.)*												
Rayonier (ITT Rayonier, Inc.)	58	76		246				264				

Exempt Source

Non-Exempt Source

Exempt Utility

Non-Exempt Utility

*Note: Georgia Power - Plant Bowen and Prayon Inc. do not have distances from applicable Class I areas listed in the table because exemptionmodeling was not performed on these sources.

7.4 Contribution Threshold

Determining whether a source causes or contributes to visibility impairment is one step in the BART review process. The *Guidelines for BART Determinations Under the Regional Haze Rule*[3] states "a single source that is responsible for a 1.0 deciview change or more should be considered to 'cause' visibility impairment." The guideline document also states that "the appropriate threshold for determining whether a source 'contributes to visibility impairment' may reasonably differ across states," but, "as a general matter, any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be higher than 0.5 deciviews." The rationale for these instructions is provided in the preamble to the BART guidance in the statement, "if 'causing' visibility impairment means causing a humanly perceptible change in visibility in virtually all situations (*i.e.* a 1.0 deciview change), then 'contributing' to visibility impairment must mean having some lesser impact on the conditions affecting visibility that need not rise to the level of human perception."[4] The guidance document itself also states that, "States remain free to use a threshold lower than 0.5 deciviews if they conclude that the location of a large number of BART-eligible sources within the State and in proximity to a Class I area justify this approach."

EPA's documents strive to set these thresholds in the context of the human perception of visibility change. As noted above, the EPA considers a 1.0-deciview change in visibility to be humanly perceptible "in virtually all situations." Also, the preamble to the BART guidance[5] cites an analysis in an appendix of a NAPAP (National Acid Precipitation Assessment Program) report, which asserts that "changes in light extinction of 5 percent will evoke just noticeable changes in most landscapes." [6] (A 5% change is approximately 0.5 dv.) But, as noted above, the preamble also states that perceptibility is not a prerequisite for choosing a contribution threshold. Putting all this together, it appears that "causing" visibility impairment means having a humanly perceptible impact (for which EPA considers the practical threshold to be 1.0 dv) while "contributing" to visibility impairment means having a smaller impact (for which EPA considers the threshold to be 0.5 dv or some smaller value) that may or may not be perceptible.

The EPA argues that a contribution threshold of less than 0.5-dv-impact-per-source is appropriate when multiple sources contribute, in order to limit the combined effect of these sources. As an example, EPA asserts that if there were 100 sources, each affecting visibility by 0.1 dv (presumably an imperceptible amount), their total impact would be 10 dv (which can be expected to be quite perceptible).[7] The point remains that multiple sources can cause a larger impact than a single one. For BART purposes, visibility

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[3] 40 CFR 51, Appendix Y, Section III.A.1

[4] 70 FR 39120. Footnote 31

[5] 70 FR 39119. Footnote 28

[6] "The Quadratic Detection Model" by W. Malm. Appendix D in Acidic Deposition: State of Science and Technology, Report 24, Visibility: Existing and Historical Conditions -- Causes and Effects. National Acid Precipitation Assessment Program, Washington, DC. 1990.

[7] 70 FR 39121. 1st column

impacts are calculated as 24-hour averages of 1-hour plume impacts, so if the plumes from the various sources each impact the point of interest at some time during a 24-hour period (not necessarily all at the same hour) then the 24-hour average will reflect their combined impact.

Georgia EPD concluded that the EPA-suggested contribution threshold of 0.5 dv was appropriate in this situation since there are a limited number of sources that impact the various Class I areas in the State.

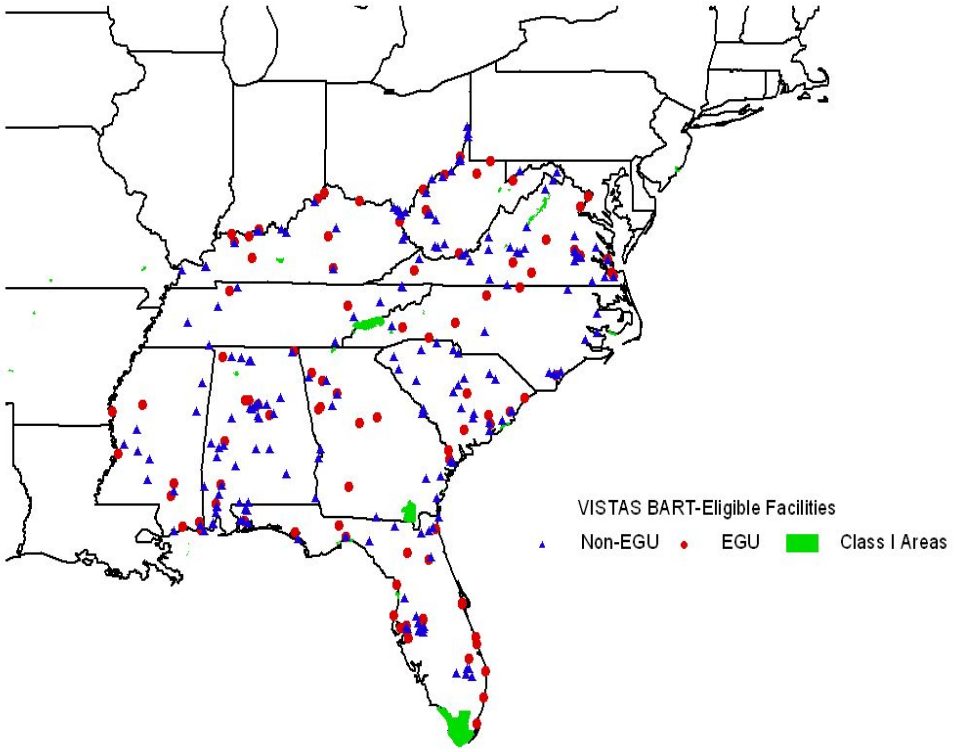

Figure 7-2. Location of VISTAS BART-Eligible Sources

7.5 Exemption of Point Source Volatile Organic Compounds for BART Purposes

The State of Georgia has determined through modeling that volatile organic compounds (VOCs) from point sources are not anticipated to cause or contribute significantly to any impairment of visibility in Class I areas and should be exempt for BART purposes.

7.5.1 Method

The State of Georgia determined through modeling that VOCs from point sources are not anticipated to cause or contribute significantly to any impairment of visibility in Class I areas.

Modeling was conducted through The Visibility Improvement State and Tribal Association of the Southeast (VISTAS). VISTAS is a collaborative effort of State governments, tribal governments, and various Federal agencies established to initiate and coordinate activities associated with the management of regional haze, visibility and other air quality issues in the Southeastern United States. VISTAS contracted with Georgia Institute of Technology to perform model sensitivity runs to determine the impact of point source VOCs on visibility in Class I areas.

Georgia Tech performed emission sensitivities to examine the impact of emission reductions on regional haze, annual PM2.5, and 8-hour ozone concentrations using CMAQv4.4_SOAmods on the VISTAS 12-km modeling domain, using the 2009 OTW (on the way) BaseD emissions. One such sensitivity run reduced anthropogenic, point source VOCs by 100%. The purpose was to quantify the impact of VOC emissions from VISTAS BART sources on Class I areas. Two episodes were examined: June 1-July 10, 2002 and November 19 – December 19, 2002. The approach included calculating the extinction coefficient in dv (deciviews), then determining the maximum impact of point source VOCs. The chart below shows the impact on the following twenty-two Class I areas within the VISTAS domain (Appendix H.6).

BRET = Breton, LA
BRIG = Brigantine NWR, NJ
CACR = Caney Creek, AR
CHAS = Chassahowitzka, FL
COHU = Cohutta, GA
DOSO = Dolly Sods, WV
EVER = Everglades, FL
GRSM = Great Smoky Mountains National Park
HEGL = Hercules Glade, MO
JARI = James River Face, VA
LIGO = Linville Gorge, GA
MACA = Mammoth Cave, KY
MING = Mingo, MO
OKEF = Okefenokee, GA
ROMA = Cape Romain, SC
SAMA = Saint Marks, FL
SHEN = Shenandoah, VA
SHRO = Shining Rock, GA
SIPS = Sipsey Wilderness, AL
SWAN = Swanquarter, GA
UPBU = Upper Buffalo Wilderness, AR

Maximum Point VOC Impact

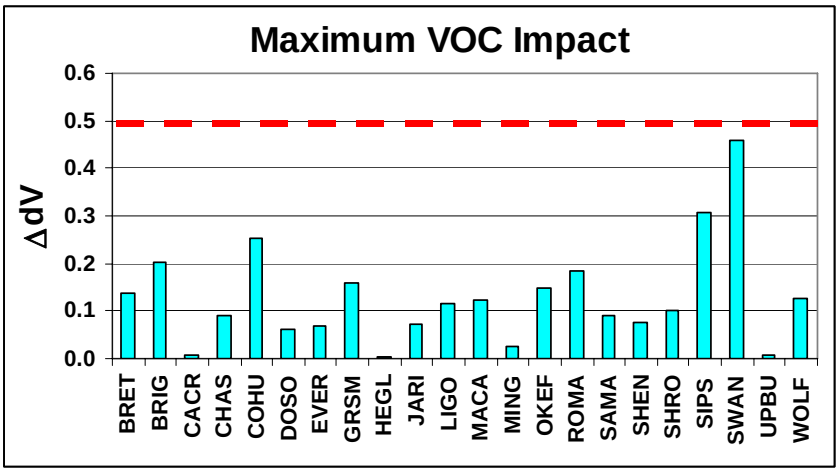

Figure 7-3. Maximum Point VOC Impact

7.5.2 Conclusions

The results show that the maximum impact from eliminating all point source VOC emissions in the VISTAS 12 km domain is less than a 0.5 dv for all Class I areas in the VISTAS domain. The expected impact of controlling VOCs from all BART sources in Georgia would be much less than the 0.5 dv threshold since the VOCs from BART sources are only a fraction of the total VOCs. VISTAS and the State of Georgia conclude that VOCs from point sources are not a visibility-impairing pollutant for BART purposes and that BART-eligible sources do not need to consider VOC emissions.

7.6 Treatment of Ammonia Emissions for BART Purposes

Similar to its treatment of VOCs, EPA guidance allows States the discretion to decide whether or not ammonia emissions are to be considered for BART purposes based on evaluations of the contributions of the emissions to haze at Class I areas in their areas of influence. One approach a State can use to determine whether applying BART will be needed is to evaluate the haze impacts of all current emissions from all BART-eligible sources in the State. If the impact from all sources in the state is less than the contribution threshold established by the State, 0.5 dv for Georgia, then source-by-source analysis for BART is not needed.

The State of Georgia has determined through modeling that ammonia (NH3) emissions from point sources are not anticipated to cause or contribute significantly to any impairment of visibility in Class I areas and should be exempt for BART purposes.

7.6.1 Method

The State of Georgia determined through modeling that ammonia emissions from point sources are not anticipated to cause or contribute significantly to any impairment of visibility in Class I areas with the exception of one large point source in close proximity to one Georgia Class I area.

VISTAS contracted with Georgia Institute of Technology to perform model sensitivity runs to determine the impact of point source ammonia on visibility in Class I areas.

Georgia Tech performed emission sensitivities to examine the impact of emission reductions on regional haze using CMAQv4.5 with SOA models on the VISTAS 12 km modeling domain using the VISTAS 2009 OTW (on the way) Base F4 emissions. One such sensitivity run reduced BART-eligible source, ammonia, by 100%. The purpose was to quantify the impact of ammonia emissions from VISTAS BART sources on Class I areas. Two episodes were examined: June 1-July 10, 2002, and November 19 – December 19, 2002. The approach included calculating the extinction coefficient in dv (deciviews), then determining the maximum impact of BART-eligible source ammonia. The chart below, taken from the VISTAS report *BART in the VISTAS Region: Sensitivity to VOC, NH3, and Primary PM Emissions* (included as Appendix H.6) shows the impact on the following 22 Class I areas within the VISTAS domain.

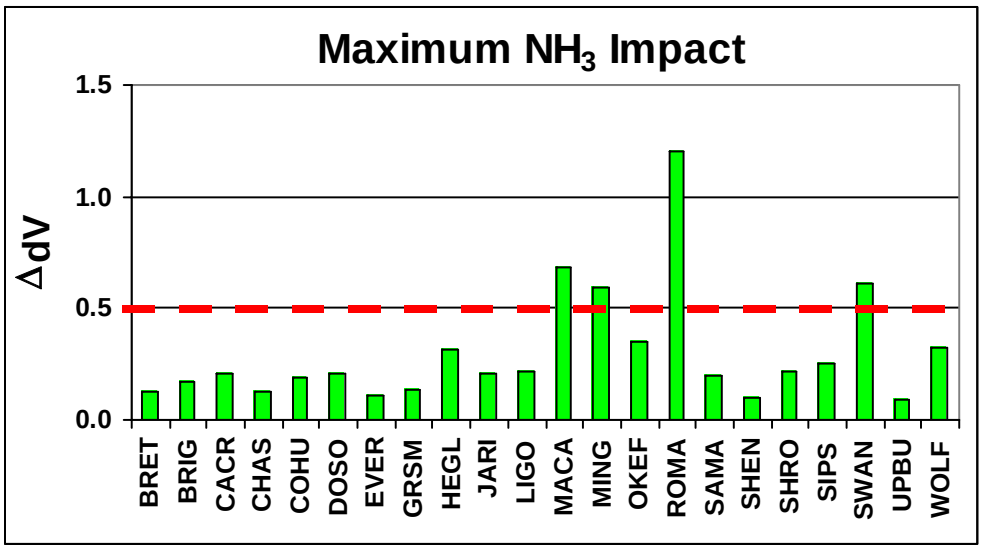

Figure 7-4. Maximum NH3 Impact - Maximum contributions of all BART-eligible NH_3 point sources in the VISTAS region to haze in Class I areas during the CMAQ-modeled periods.

The chart shows the largest haze impact in delta dv over the two timeframes at each Class I area. These delta dv changes represent the haze contribution of all BART source

ammonia emissions relative to assumed natural haze levels. The natural haze levels are based on EPA-default annual average natural concentrations for the East and monthly-varying "climatologically-representative" relative humidity at each Class I area. During the periods modeled, the ammonia emissions from all BART-eligible sources contributed more than 0.5 dv to haze at Mammoth Cave National Park (MACA), Kentucky; Mingo Wilderness (MING), Missouri, Cape Romain National Wildlife Refuge Area (ROMA) South Carolina, and Swanquarter National Wildlife Refuge (SWAN), North Carolina.

The majority of ammonia emissions in the VISTAS region come from four sources as shown in Table 7-2 below.

Table 7-2. Major NH_3 Sources in the VISTAS Region

Facility	State	NH_3 Emissions (tpy)	Distance to Nearest Class 1 Area (km)
MeadWestvaco Corp.	SC	174	30
PCS Phosphate – Savannah Ammonia Terminal*	GA	206	31
PCS Nitrogen	TN	1252	180
PCS Nitrogen	GA	1765	220

*Note: Although PCS Phosphate was included in the ammonia analysis; the facility is not subject to BART because it is a minor source for all pollutants.

7.6.2 Conclusions

The BART requirements of the regional haze rule allow states to determine whether or not ammonia is to be considered a visibility-impairing pollutant to be addressed for BART purposes. NH3 emissions from BART sources may impair visibility; however, the majority of NH3 emissions in the VISTAS region are from only a few sources. Removal of the large NH3 emission sources results in minimal impact on visibility at Class I areas in the VISTAS region. Furthermore, ammonia emissions from all sources contributed less than 0.5 dv to the Class I areas in Georgia [Cohutta Wilderness (COHU), Okefenokee Wilderness (OKEF), and Wolf Island Wilderness (WOLF)]. Therefore, the State of Georgia concludes that ammonia from point sources does not need to be considered for BART purposes.

8.0 Explanation of BART Exemption Criteria

8.1 Background

Georgia opted to consider its BART-eligible sources subject to BART unless the source demonstrated exemption via any of the following three options: 1) Exemption modeling 2) Meeting the specifically-listed model plant criteria for emissions and distance from

the; nearest class I area; and 3) accepting an emissions limit of less than 250 tpy of the visibility-impairing pollutant.

8.1.1 Exemption Modeling

BART-eligible sources can be excluded from BART determinations by demonstrating that the source cannot be reasonably expected to cause or contribute to visibility impairment in a Class I area. The threshold for determining that a source causes visibility impairment is set at 1.0-dv change from natural conditions over a 24-hour averaging period. The BART guidelines also propose that the threshold at which a source may "contribute" to visibility impairment should not be higher than 0.5 deciviews; however, depending on factors affecting a specific Class I area, it may be set lower than 0.5 deciviews.

As stated in the BART regulation, EPA's preferred approach for determining cause or contribution is an assessment with an air quality model such as CALPUFF or other appropriate model followed by comparison of the estimated 24-hour visibility impacts against a threshold above estimated natural conditions to be determined by the State. EPA recommends that the 98th percentile value from the modeling be compared to the State's chosen contribution threshold to determine if a source does not contribute to visibility impairment and, thus, is not subject to BART. Comparison of the 98th percentile value to the threshold must be made for each Class I area. For an annual period, this implies the 8th highest 24-hour value at a particular Class I area is compared to the contribution threshold. For a 3-year modeling period, the 98th percentile value may be interpreted as the highest of the three annual 98th percentile values at a particular Class I area or the 22nd highest value in the combined 3-year record, whichever is more conservative.

Georgia worked with the regional planning organization (RPO) VISTAS on development of the VISTAS *Protocol for the Application of the CALPUFF Model for Analyses of Best Available Retrofit Technology (BART)* (Appendix H.7). The common protocol was established to provide the basis for a common understanding among the organizations performing BART analyses or reviewing BART modeling results in the VISTAS region.

The VISTAS protocol describes common procedures for carrying out air quality modeling to support BART determinations that are consistent with the 40 CFR Part 51 Appendix Y guidelines. The protocol provides a consistent model, CALPUFF, and modeling guidelines for BART determinations, clearly delineated modeling steps, a common CALPUFF configuration, guidance for site-specific modeling, and common expectations for reporting model results. Details of the CALPUFF system can be found in Chapter 3 of the VISTAS protocol, specific recommendations for its application for BART purposes are found in Chapter 4, and specific information that should be included in site-specific protocols is found in Chapter 5.

VISTAS contracted Earth Tech to develop a version of the CALPUFF model appropriate for BART purposes. The VISTAS version of the CALPUFF model is CALPUFF Version 5.754 and CALMET Version 5.7.

For BART modeling purposes VISTAS made publicly available 12-km CALMET output files for the entire VISTAS modeling domain (eastern United States) and provided CALMET output files for five 4-km grid sub domains covering the VISTAS states and VISTAS Class I areas. To generate the CALMET input files, the VISTAS contractor used the MM5 databases developed by EPA for 2001, VISTAS for 2002, and Midwest RPO for 2003. For the 12-km grid, large domain covering the entire VISTAS region, the No-Obs setting was used. For the 4-km grid, available surface and upper air observations were used in addition to MM5 meteorological model outputs. Specific model settings were provided with the CALMET files and via the CALPUFF website so that work could be replicated.

For CALPUFF modeling, source emissions were to be defined using the maximum 24-hour actual emission rate during normal operation for the most recent three or five years. If maximum 24-hour actual emissions were not available, continuous emission data, permit allowable emissions, potential emissions, and emission factors from AP-42 source profiles could be used as available.

Key points on specific CALPUFF, CALPOST, and POSTUTIL configuration that were to be used for BART modeling are:

- After running CALPUFF for an individual facility, NO3 should be repartitioned in POSTUTIL.
- Ozone data from non-urban monitors should be used as the background ozone input.
- The Pasquill-Gifford dispersion method should be used.
- In CALPOST, Method 6 with monthly average RH for calculating extinction as recommended by EPA should be used.
- EPA default calculations of light extinction under current and natural background conditions should be used. In addition a source may also calculate visibility using the recently-revised IMPROVE algorithm.

Additional discussion of the CALPUFF model and VISTAS recommended settings can be found in the VISTAS protocol in Attachment H-7.

8.1.2 Model Plant Criteria

In its final BART rule, EPA included mechanisms for exempting sources from BART-determination requirements. Under one approach, EPA established specific exemption thresholds based on CALPUFF modeling conducted for a model plant. BART eligible sources meeting specifically-listed model plant criteria for emissions and distance from the nearest Class I area can be exempted from BART determination requirements. The criteria that must be met are that sources must have potential emissions of sulfur dioxide (SO2) and nitrogen oxides (NOx) combined of less than 500 tons and be greater than 50 km from any Class I area or have combined potential emissions less than 1000 tons and

be greater than 100 km from any Class I area. Sources must also have potential emissions of particulate matter (PM) of less than 15 tons-per-year to be exempted without some form of modeling. In situations where a source's combined SO2 and NOx emissions are less than 500 or 1000 tons, but PM emissions are greater than 15 tons, the emissions of SO2, NOx, and PM may be combined and compared to 500 or 1000 tons.

8.1.3 Accepting an Emissions Limit

If a facility is willing to take a facility-wide limit of 250 tpy on all BART eligible equipment for each pollutant for which the facility is BART eligible, then the facility is exempt from BART requirements. The facility must submit an application to this effect and such limits must be incorporated into an enforceable permit.

Table 8-1 below provides a summary of the exemption modeling results.

Table 8-1. BART Exemption Modeling Results

Facility	Class 1 Areas Impacted	Delta-Deciviews
PCS-Nitrogen	Okefenokee Wilderness Area	0.393
	Cohutta Wilderness Area	0.409
	Wolf Island	0.294
	Cape Romain	0.359
	Great Smoky Mountains	0.163
	Joyce Kilmer	0.175
	Shining Rock Wilderness	0.220
	Linville Gorge	0.393
	Shinning Rock Wilderness	0.220
Rayonier	Wolf Island	0.319
	Okefenokee Wilderness Area	0.254
	Cape Romain	0.132
	St. Marks	0.151
Georgia Power-Plant Wansley	Cohutta Wilderness Area	0.44
	Great Smoky Mountains	0.17
	Joyce Kilmer	0.18
	Shining Rock Wilderness	0.12
	Sipsey	0.14
DSM Chemicals North America	Cape Romain	0.094
	Cohutta Wilderness Area	0.112
	Great Smoky Mountains	0.072
	Joyce Kilmer	0.036

	Okefenokee Wilderness Area	0.063
	Shining Rock Wilderness	0.069
	Wolf Island	0.114
International Paper Augusta	Cohutta Wilderness Area	0.114
	Cape Romain National Wildlife Refuge	0.211
	Great Smoky Mountains	0.093
	Joyce Kilmer	0.086
	Linville Gorge	0.103
	Okefenokee Wilderness Area	0.157
	Shining Rock Wilderness	0.127
	Wolf Island	0.148
Georgia Power-Plant Branch	Cohutta Wilderness Area	0.17
	Great Smoky Mountains	0.11
	Joyce Kilmer	0.09
	Shining Rock Wilderness	0.09
	Okefenokee Wilderness Area	0.12
	Wolf Island	0.11
Georgia Power-Plant Hammond	Great Smoky Mountains	0.08
	Joyce Kilmer	0.09
	Cohutta Wilderness Area	0.29
	Shining Rock Wilderness	0.05
	Sipsey	0.06
Savannah Electric-Plant Kraft	Cape Romain National Wildlife Refuge	0.18
	Okefenokee Wilderness Area	0.18
	Wolf Island	0.21
Georgia Power-Plant McDonough	Great Smoky Mountains	0.07
	Joyce Kilmer	0.07
	Cohutta Wilderness Area	0.19
	Shining Rock Wilderness	0.05
	Sipsey	0.04
Savannah Electric-Plant McIntosh	Cape Romain National Wildlife Refuge	0.04
	Okefenokee Wilderness Area	0.03
	Wolf Island	0.03
Georgia Power-Plant Mitchell	Okefenokee Wilderness Area	0.04
	Wolf Island	0.02
	St. Marks	0.05

Georgia Power-Plant Scherer	**Okefenokee Wilderness Area**	**0.08**
	Wolf Island	**0.05**
	Joyce Kilmer	**0.07**
	Cohutta Wilderness Area	**0.08**
	Shining Rock Wilderness	**0.06**
	Great Smoky Mountains	**0.07**
Georgia Power-Plant Yates	**Cohutta Wilderness Area**	**0.15**
	Great Smoky Mountains	**0.05**
	Shining Rock Wilderness	**0.03**
	Joyce Kilmer	**0.06**
	Sipsey	**0.05**
Koch Cellulose (GP Brunswick, Brunswick Pulp & Paper	**Okefenokee Wilderness Area**	**0.282**
	Wolf Island	**0.447**
	St. Marks	**0.055**
	Cape Romain National Wildlife Refuge	**0.092**
PCA Valdosta	**Chassahowitzka (12 km)**	**0.197**
	Okefenokee Wilderness Area (12 Km)	**0.349**
	Wolf Island (12 Km)	**0.181**
	St. Marks (4 Km)	**0.190**
Kerr-McGee (Tronox)	**Okefenokee Wilderness Area**	**0.213**
	Wolf Island	**0.246**
	Cape Romain National Wildlife Refuge	**0.134**
Prayon	**Okefenokee Wilderness Area**	**0.007**
	Wolf Island	**0.005**
	Cape Romain National Wildlife Refuge	**0.009**
	Cohutta Wilderness Area	**0.004**
	Great Smoky Mountains	**0.002**
	Shining Rock Wilderness	**0.003**
	Joyce Kilmer	**0.002**
	Linville Gorge	**0.005**
Owens Corning	**Cohutta Wilderness Area**	**0.119**
	Great Smoky Mountains	**0.051**
	Shining Rock Wilderness	**0.072**
	Joyce Kilmer	**0.056**
	Sipsey	**0.054**
Georgia Pacific Cedar Springs	**Okefenokee Wilderness Area**	**0.306**

	St. Marks	0.499
Chemical Products Corporation	Cohutta Wilderness Area	0.442
	Great Smoky Mountains	0.173
	Shining Rock Wilderness	0.090
	Joyce Kilmer	0.197
	Sipsey	0.127

Table 8-2 below provides a list of facilities exempted from BART on the basis of model plant criteria or by acceptance of a limit of 250 tpy for visibility-causing pollutants.

Table 8-2 Facilities that demonstrated BART exemption based on model plant criteria or by accepting a limit of 250 tpy for visibility causing pollutants

BART Eligible Sources	Basis of Exemption
International Paper - Savannah	Total potential Emissions of visibility impairing pollutants is lesser than 500 tons and distance from the nearest Class I area is greater than 50 Km
Lafarge Building Materials (Blue Circle Cement –Atlanta Plant)	Total potential Emissions of visibility impairing pollutants is lesser than 1000 tons and distance from the nearest Class I area is greater than 100 Km

8.2 Use of New IMPROVE Equation

During the regional haze SIP development process, the IMPROVE Steering Committee made recommendations for a new IMPROVE equation. Among other things, the new equation includes components that take into account the effects of sea salt and site-specific Rayleigh scattering (Appendix H.11). These are important issues to consider for coastal and mountainous sites. Additional discussion of the new IMPROVE equation can be found in Appendix B of the SIP narrative.

VISTAS contracted Dr. Ivar Tombach to develop a postprocessor to allow CALPOST outputs to be used with the new IMPROVE equation. Georgia EPD submitted to EPA Region IV a request for approval to use the new IMPROVE equation and postprocessor developed by Dr. Tombach in BART modeling. A discussion of the rationale for use of the new IMPROVE equation follows.

<u>Rationale for Use of New IMPROVE Equation</u>
The new IMPROVE equation is a much better representation of the effects of particulate matter on light extinction than the old equation and takes into account the latest scientific understanding of several parameters.

1. The new algorithm overcomes biases of the old algorithm on the haziest days and the clearest days as demonstrated by comparing the measured light extinction from nephelometers at Class I areas to light extinction calculated using each of the equations.
2. The new algorithm recognizes spatial and temporal variation in light extinction as size distribution of the aerosol changes by increasing extinction efficiency as sulfate, nitrate and organic concentrations increase.
3. The new algorithm incorporates a term to reflect the contribution of fine sea salt and its hygroscopic growth with increasing relative-humidity-recognizing research findings showing that fine sea salt can be an important contributor to light extinction in coastal areas.
4. The new algorithm reflects research finding that the mass concentration of particulate organic matter in rural areas is greater than represented by the old equation.
5. The new algorithm includes an NO_2 term to represent times when light absorption by NO_2 is a meaningful contributor to light extinction.
6. The new algorithm incorporates site-specific Rayleigh scattering values to better represent sites close to sea level or with very hot or cold climates.

With this combination of revisions to the IMPROVE equation, the resulting apportionment of extinction to various components is more accurate on the haziest and clearest days. This is important for development of emission control strategies since the benefits of control of concentrations of each species will be represented more correctly with the new algorithm.

GA EPD submitted a request for approval to the use of the new IMPROVE equation instead of the original IMPROVE equation. This request also contains the new IMPROVE postprocessor and its instructions. Region 4 EPA granted this request to use the new IMPROVE equation (Appendix H.9).

9.0 BART Determination

For those facilities subject to BART, the state must determine what constitutes BART controls for the source by considering various control options and selecting the best alternative taking into consideration any pollution control equipment in use at the source, the costs of compliance with control options, the remaining useful life of the facility, the energy and non air-quality environmental impacts of compliance, and the degree of improvement in visibility that may reasonably be anticipated to result from the use of such technology. Under Georgia's approach, facilities subject to BART were requested to propose BART considering these factors.

9.1 BART Subject Sources

Only two BART-eligible sources in Georgia emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area. The two facilities, Interstate Paper in Riceboro, Georgia, and Georgia Power Company Plant Bowen, in Cartersville, Georgia, were unable to demonstrate less than a 0.5 dv impact on one or more Class I areas and, thus, are subject to BART.

9.1.1 BART-eligible Units and Existing Control

Georgia Power Plant Bowen has four BART-eligible emission units that comprise the BART-eligible source. These units are coal fired electric generating units 1,2,3 and 4. The above-mentioned units are BART eligible for their PM emissions. Each of these EGU's PM emissions are already controlled by electrostatic precipitators (ESPs) and wet flue gas desulfurization scrubbers (Wet FGD).

Interstate Paper has three BART-eligible emission units that comprise the BART-eligible source. These units are recovery boiler, power boiler and lime kiln. Each of these units is BART eligible for PM_{10}, SO_2 and NO_x. The recovery boiler has a venturi scrubber as an existing control for PM_{10} emissions, staged combustion and combustion control as an existing control strategy for NO_x and SO_2 respectively. The lime kiln has a wet scrubber as an existing control for both PM_{10} and SO_2.

9.2 BART Determination Analysis and Conclusion

In accordance to 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule the state is responsible for determining BART for all the subject-to-BART sources. Georgia EPD requested the two facilities to do a detailed BART determination analysis. Interstate Paper in Riceboro, Georgia failed to respond to the above-mentioned request hence, Georgia EPD did a complete detailed BART analysis for the facilities BART eligible units. Table 9.1 gives a summary of the BART determination analysis for the two facilities. A complete BART determination analysis for both of the subject-to-BART sources are given in Appendix H.8.

Table 9-1 BART determination analysis for both the subject-to-BART sources

Source	Unit	Required Control Option	Control Efficiency	Cost of Control ($/ton)
Interstate Paper	Power Boiler (F1)	Combustion of natural gas only except during periods of curtailment	99%	370
	Recovery Boiler	No cost effective control options Available	Not required	Not required

	Lime Kiln	No cost effective control options Available	Not required	Not required
Georgia Power Company – Plant Bowen	Boiler 1	No cost effective control options Available	Not required	Not required
	Boiler 2			
	Boiler 3			
	Boiler 4			

The required permit conditions to incorporate the BART determination for Interstate Paper Power Boiler F1 will be incorporated into the Title V permit as discussed in Section 7.7.2 of the narrative. The Power Boiler will be required to combust only natural gas except during a period of curtailment. Curtailment occurs during periods of high natural gas demand where the supplier begins restricting the supply starting with industrial sources. The facility has no control over curtailment. Curtailment occurs very infrequently, if at all, once per year during the coldest winter months (typically January). Additionally, the Power Boiler (and Multi-fuel Boiler MFB1) is permitted to combust TRS containing waste gas streams when the associated Lime Kiln, LM01, is not operating. Operational records have demonstrated that this scenario has not occurred; however, Georgia EPD will modify the Title V permit to restrict the combustion of waste gas in the Power Boiler only when both the lime kiln and multi-fuel boiler are not operational.

10.0 Final Long Term Strategy And Reasonable Progress Goals

The regional haze rule requires States to establish reasonable progress goals, expressed in deciviews, for visibility improvement at each affected Class I area covering each (approximately) 10-year period until 2064. This first set of reasonable progress goals must be met through measures contained in the State's long-term strategy covering the period from the baseline until 2018. This section discusses development of Georgia's long-term strategy.

10.1 Long-Term Strategy

Ammonium sulfate is the most important contributor to visibility impairment and fine particle mass on the 20 percent worst and 20 percent best visibility days at all of the Georgia Class I areas. Sulfate levels on the 20 percent worst days account for 60-70 percent of the visibility impairment. Across the VISTAS region, sulfate levels are higher at the Southern Appalachian sites than at the coastal sites. On the 20 percent clearest days, sulfate levels are more uniform across the region. Reduction of SO2 emissions would be the most effective means of reducing ammonium sulfate. Ninety-five percent of SO2 emissions in Georgia are attributable to electric generating facilities and industrial point sources. Thus, the long-term strategy for this first Regional Haze SIP focused on reductions in SO2 emissions. When fully implemented, Georgia Rule (sss) will reduce SO2 emissions by about 90 percent, NOx emissions by approximately 85 percent and mercury emissions by approximately 79 percent.

Such large SO2 reductions are predicted to result in significant improvements in visibility. Visibility improvements at all of the VISTAS mountain Class I areas and most of the coastal Class I areas are projected to be better than the uniform rate of progress. The percentage of the target reduction achieved for the Georgia Class I areas using the new IMPROVE equation is 90-160 percent.

In addition to improving visibility on the 20 percent worst visibility days, states are also required to protect visibility on the 20 percent best days at the Class I areas. Visibility on the 20 percent best days is projected to improve in 2018 at all VISTAS Class I areas as a result of the 2018 Base G2 emissions reductions. The percentage of the target achieved for the Georgia Class I areas is about -10 percent. Zero percent change would mean no change in visibility; -10 percent means that visibility is better than no change, or a 10 percent improvement (values lower than current conditions).

The Georgia EPD completed a reasonable progress assessment after modeling the Clean Air Act controls discussed previously. The assessment did not identify any cost-effective control measures for the SO2 EGU units that contributed greater than half a percent to visibility impairment at any of the Class I areas in Georgia or in neighboring States. The Georgia EPD did an in-depth 3-factor analysis and has proposed reasonable controls for some non-EGUs that contribute more than half a percent to visibility impairment at any of the Class I areas in Georgia or in neighboring States.

The Georgia EPD reviewed the BART determination from Georgia Power Plant Bowen, which is one of the two Georgia facilities that were determined to be subject to BART. From its review, Georgia EPD concluded that no cost-effective BART reductions are possible. Georgia EPD also did a BART determination analysis for Interstate Paper and concluded that burning of natural gas except during curtailment periods would be cost-effective BART control for the facility.

10.2 What Additional Emissions Controls Were Considered as Part of the Long-Term Strategy for Visibility Improvement by 2018?

Section 308(d)(3)(v) of the regional haze rule lists several factors that must be addressed in each SIP. These factors include smoke management techniques for agricultural and forestry management purposes and measures to mitigate emissions from construction activities.

Elemental carbon (sources include agriculture, prescribed wildland fires, and wildfires) is a relatively minor contributor to visibility impairment at the Class I areas in Georgia. However, on July 11, 2008, GA EPD entered into a memorandum of understanding with the Georgia Forestry and the Georgia Department of Natural Resources Wildlife Resources Division adopting a smoke management plan that addresses the issues laid out in US EPA’s 1998 draft guidance for smoke management plans. This plan is sufficient to satisfy the directive in Section 308(d)(3)(v)(E).

Georgia's Rules for Air Quality Control include requirements for precautions to prevent fugitive dust from becoming airborne and also limit the opacity of fugitive emissions to less than 20 percent. The requirements of Rule 391-3-1-.02(n) include preventive measures for construction activities and are deemed adequate to satisfy the directive in Section 308(d)(3)(v)(B) of the Regional Haze rule. The current version of Georgia's air rules is available on the Georgia EPD web site.

10.3 Reasonable Progress Goals

The Regional Haze Rule at 40 CFR Section 51.308(d)(1) requires States to establish reasonable progress goals for each Class I area within the state (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility. In addition, EPA released guidance on June 7, 2007, to use in setting reasonable progress goals. The goals must provide improvement in visibility for the most impaired days, and ensure no degradation in visibility for the least impaired days over the State Implementation Plan (SIP) period. The state must also provide an assessment of the number of years it would take to attain natural visibility conditions if improvement continues at the rate represented by the reasonable progress goal.

In accordance with the requirements of 40 CFR §51.308(d)(1), this Regional Haze Implementation Plan establishes reasonable progress goals for each Class I area in Georgia. To calculate the rate of progress represented by each reasonable progress goal, Georgia EPD compared baseline visibility conditions to natural visibility conditions in each class I area and determined the uniform rate of visibility improvement (in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. The Georgia EPD will summarize expected visibility improvements under existing Federal and State regulations, BART determinations in Georgia and neighboring states, and any additional control measures found to be reasonable to implement in this review period. These controls will be modeled in CMAQ as part of the long-term strategy. The modeling results will be used to set the reasonable progress goal. At this time, Georgia EPD knows that the reasonable progress goals will be at least as stringent as the Base G4 modeling results and will likely be more stringent when BART and reasonable measures are taken into account. VISTAS has already demonstrated that the 2018 Base G4 control scenario provides for an improvement in visibility better than the uniform rate of progress for all Georgia Class I areas for the most impaired days over the period of the implementation plan and ensures no degradation in visibility for the least impaired days over the same period. In addition, we expect that IMPROVE monitoring results for 2018 will, at that time, be used to establish a new baseline for the next planning period. Tables 10-1 and 10-2 list Georgia's Reasonable Progress Goals.

Table 10-1. Georgia Reasonable Progress Goals – 20 percent Worst Days

Class I Area	2004 Baseline Visibility (dv)	2018 Reasonable Progress Goal (dv) [2004 – 2018 decrease]	2018 Uniform Rate of Progress Glide Slope (dv) [2004 – 2018 decrease to meet uniform progress]	Natural Visibility (dv) [2018-2064 decrease needed from 2018 goal]
Cohutta Wilderness	30.25	22.78 [7.47]	25.71 [4.54]	10.78 [12.00]
Okefenokee Wilderness	27.13	23.77 [3.36]	23.42 [3.71]	11.21 [12.56]
Wolf Island	27.13	23.77 [3.36]	23.42 [3.71]	11.21 [12.56]

Table 10-2. Georgia Reasonable Progress Goals – 20 percent Best Days

Class I Area	2004 and 2018 Baseline Visibility (dv)	2018 Reasonable Progress Goal (dv) [2004 – 2018 improvement goal]
Cohutta Wilderness	13.77	11.75 [2.02]
Okefenokee Wilderness	15.23	13.92 [1.31]
Wolf Island	15.23	13.92 [1.31]

Class I Area	Baseline Visibility (dv, 20 percent Best Days)	Reasonable Progress Goal (Expected Visibility Improvement (dv) by 2018, 20 percent Best Days)	Deciview Improvement Needed 2018-2064 (20 percent Best Days)
Cohutta Wilderness Area	13.77	2.02	7.43
Okefenokee Wilderness Area	15.23	1.31	8.61
Wolf Island	15.23	1.31	8.61

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