Four-Factor Analysis:

Georgia Power Company
Plant McIntosh

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for Georgia Power Company

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1.0 Executive Summary

EPA's regional haze rules require each state to develop and submit to EPA by December 17, 2007 a state implementation plan (SIP) to address regional haze visibility impairment in mandatory Federal Class I areas. This plan must, among other things, establish reasonable progress goals (RPGs) (expressed in deciviews) for all such areas within the state and include a long-term strategy for achieving the RPGs for such areas and for mandatory Federal Class I areas that are located in other states and that have visibility conditions that are affected by emissions from within the state.

Based on its initial analysis of certain information, including emission amounts and distance of sources from Class I areas, GEPD identified sources of sulfur dioxide (SO_2) that it believes are likely to contribute more than 0.5% to total visibility impairment due to sulfate at nearby Class I areas in 2018. This initial analysis included Unit 1 at GPC's Plant McIntosh among the potentially contributing sources. In a letter dated March 21, 2007, GEPD asked GPC to analyze whether additional controls on SO_2 emissions from that unit may be feasible and reasonable, using the four statutory factors used in setting RPGs. GPC has followed the approach set out by GEPD in its March 21 letter and assessed whether any additional, feasible SO_2 controls at Plant McIntosh Unit 1 are reasonable.

GPC, with the assistance of Southern Company Services (SCS) and RMB Consulting and Research, Inc. (RMB), has identified three feasible SO_2 control options for Plant McIntosh Unit 1 (i.e., coal washing, coal switching, and flue gas desulfurization). The flue gas desulfurization (FGD) option consists of two possible versions: wet FGD and dry FGD. Of the two FGD options, only wet FGD was assessed in detail since, for reasons explained in this report, it would be the preferred option of the two. The cost of each option, the option's potential for further reducing SO_2 emissions, the resulting dollar-per-ton-reduced cost effectiveness, and the energy and non air quality environmental impacts of each option, as well as the time necessary for compliance with a wet FGD option, have also been analyzed.

Table 1-1 summarizes the cost effectiveness, in dollars-per-ton-reduced, of each of the SO_2 control options assessed for McIntosh Unit 1. Table 1-2 shows the weighted average cost effectiveness for all of the WFGD systems currently under construction or planned to be built by GPC to comply with the Georgia Multipollutant Rule. The table also shows the percentage of the total SO_2 projected to be emitted by GPC plants in 2018 that will be reduced by these WFGD systems. The remainder of Table 1-2 shows the control options considered in the cost analysis along with the incremental additional reduction in total SO_2 emissions that each of these controls would achieve if implemented at Plant McIntosh Unit 1. This table illustrates that the cost of each of these controls is unreasonable compared to the cost of installing WFGD on the GPC units for which WFGD is currently planned or being built, that each of these controls would produce only negligible marginal reductions in 2018 SO_2 emissions, and therefore that none of these controls is cost effective.

Indeed, because of recent (and anticipated future) rapid escalation in control-technology costs for reasons noted in this report, it can be expected that any future WFGD or other control-technology installations at units such as McIntosh Unit 1 would be even more expensive -- perhaps much more expensive -- than is suggested by current estimates, which are based on historical data. Furthermore, a full budget-quality cost estimate for significant control installations such as those evaluated here takes far more time to prepare than the period given for this analysis. GPC has found that, when compared to estimated costs based on historical data, costs traditionally are significantly, if not drastically, higher when a full estimate is prepared that takes into account all site-specific information.

Table 1-1 Summary of Cost Analysis Results

Control Option	Cost Effectiveness [$/ton]
WFGD	
Capital Cost Cases:	
EPA Minimum	5,745
Industry Curve Fit minus 30%	5,105
Industry Curve Fit	7,115
Industry Curve Fit plus 70%	12,205
EPA Maximum	28,747
Coal Switching	
Baseline:	
Colombian	Base
Alternatives:	
CAPP	n/a
Indonesian	9,647
Russian	4,352
PRB	6,742
Colorado	7,371
Coal Washing	
Low Capital & High Removal	5,534
High Capital & Low Removal	112,236

Table1-2 Removal Costs vs. Percent Reduction in Projected 2018 GPC SO_2 Emissions

	Wtd. Average Cost Effectiveness [$/ton]	SO_2 Tons Removed [%]
All Currently Planned GPC WFGD Retrofits	743	93
CONTROL OPTION	Cost Effectiveness [$/ton]	Incremental SO_2 Reduction [%]
WFGD		
Industry Curve Fit	7,115	0.2786
Coal Switching		
Baseline:		
Colombian	Base	n/a
Alternatives:		
CAPP	n/a	n/a
Indonesian	9,647	0.0872
Russian	4,352	0.1135
PRB	6,742	0.0732
Colorado	7,371	0.0568
Coal Washing		
Low Capital & High Removal	5,534	0.0059
High Capital & Low Removal	112,236	0.0007

Although it is not listed specifically as one of the statutory factors for states to consider in determining RPGs, the achievement of actual visibility improvement in mandatory Federal Class I areas is, of course, the regional haze rules' underlying objective. Indeed, that objective is the foundation for the rules' requirement that, in setting RPGs, a state consider the uniform rate of progress toward a return to natural visibility conditions. Thus, any reasonable progress analysis of potential emission controls must take into account the degree to which those controls improve visibility in those areas. Accordingly, GPC conducted modeling to project visibility improvement at relevant Class I areas that might result from additional SO_2 emission controls on Plant McIntosh Unit 1.

Lacking specific guidance and facing constraints on time and resources and the difficulty of modifying existing modeling tools and data bases to match the metrics and assumptions appropriate for this analysis, GPC used two different approaches to bound the estimate of visibility improvement that may result from controls on Plant McIntosh Unit 1.

First, the VISTAS version of CMAQ was used to simulate the effect of maximum controls on all units anticipated by GPC to be candidates for four-factor analysis. The visibility changes simulated in this modeling vastly overestimate the unit-control-specific benefits for Unit 1 at Plant McIntosh because, in this modeling, a) many units in addition to Plant McIntosh Unit 1 are assumed to be controlled, b) pollutants in addition to SO2 are assumed to be controlled, and c) the amount of control is overestimated on several units, including Plant McIntosh Unit 1. Results are presented below in Table 1-3. The maximum average visibility benefit on the 20% worst days for the emissions reductions simulated is 0.15 dv at Wolf Island. Any projected visibility benefit from controls at Unit 1 at Plant McIntosh alone would be far less than these modeled benefits.

Second, to obtain unit-specific information on visibility impact, GPC ran the VISTAS version of the CALPUFF model for each of the four-factor units. The visibility changes projected by this modeling reflect a maximum-case estimate of visibility benefits from controls at Plant McIntosh Unit 1 because the modeling a) simulated SO_2 emission reductions only from use of wet FGD, which is the control option that would produce the largest reduction in emissions (assumed for purposes of modeling to be a 95% reduction), and b) used BART maximum (rather than actual) emissions rates. In an effort to estimate what the results might have been had actual emissions rates been used, the CALPUFF results were scaled down using the ratio of the actual daily emissions rate (on the date for each 20% worst day in 2002) to the maximum rate. Results are presented below in Table 1-3. The maximum benefit for the average of the 20% worst days from an FGD at Plant McIntosh Unit 1 using the scaled results from the simulated maximum emissions rate is 0.07 dv at Wolf Island. Projected visibility benefits from the smaller emissions reductions that would result from either the fuel switching option or the coal washing option at Unit 1 at Plant McIntosh would be far less than these results.

Table 1-3 CMAQ and CALPUFF Modeling Results w/ New IMPROVE Equation

Class I Area	Metrics	Average Change in 20% Worst Days Delta-Delta-Deciview
Okefenokee	CMAQ	0.14
	CALPUFF-Scaled	0.06
Wolf Island	CMAQ	0.15
	CALPUFF-Scaled	0.07
St. Marks	CMAQ	0.08
	CALPUFF-Scaled	N/A

In sum, the cost of each of the SO_2 controls evaluated for Plant McIntosh Unit 1 is unreasonably high, on a dollar-per-ton-reduced basis, and any of these extraordinarily expensive controls would in any event yield only negligible further reductions in GPC's SO_2 emissions. Moreover, there are additional energy and non air quality environmental impacts associated with these additional controls. In addition, any visibility improvement that would result from the small additional SO_2 reductions that any of these controls would produce is projected to be minimal and far below the level that would be perceptible at any of the relevant Class I areas. For all of these reasons, GPC believes that no additional controls to reduce SO_2 emissions at Plant McIntosh Unit 1 are necessary or appropriate for the purpose of setting or achieving the 2018 RPGs.

2.0 Introduction

EPA's regional haze rules require each state to develop and submit to EPA a state implementation plan (SIP) to address regional haze visibility impairment in mandatory Federal Class I areas. This plan must, among other things, establish reasonable progress goals (RPGs) (expressed in deciviews) for each such area within the state and include a long-term strategy for achieving the RPGs for such areas and for mandatory Federal Class I areas that are located in other states and that have visibility conditions that are affected by emissions from within the state.

In promulgating the final rules governing regional haze reasonable progress requirements (which are in 40 C.F.R. § 51.308(d)) and in its June 2007 final guidance to states addressing establishment of RPGs,[1] EPA describes a four-step process for states to follow in determining RPGs. That process begins with a "glidepath" analysis for each relevant Class I area. The first step is to identify the baseline conditions for the Class I area. The second step is to identify natural visibility conditions and to define the uniform rate of progress that would have to be achieved to reach those natural conditions by the year 2064. The third step is to identify, assuming the uniform rate of progress determined in the second step, the amount of progress that would be achieved for the relevant planning period (*e.g.*, for the SIPs currently being developed, the period through 2018). The result is a glidepath RPG for each Class I area. The fourth and final step involves identification of a control strategy that would achieve the glidepath RPG for each Class I area in the state and a determination by the state whether that control strategy, or some other control strategy, is "reasonable" based on the statutory factors for determining reasonable progress. 64 Fed. Reg. 35714, 35732 (July 1, 1999) (preamble to final regional haze rules). The control strategy is to include emission limitations and compliance schedules "as necessary to achieve the reasonable progress goals." 40 C.F.R. § 51.308(d)(3).

If the state determines that the control strategy that achieves the glidepath RPG(s) is "reasonable" based on the statutory factors specified in § 169A(g)(1) of the Clean Air Act (CAA) -- 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 existing source subject to the reasonable progress requirements -- then the state should choose that strategy for inclusion in the SIP (unless the state determines that "additional progress beyond this amount" is reasonable). 64 Fed. Reg. at 35732. On the other hand, if the state determines that the strategy that achieves the glidepath RPG is not reasonable, based on the state's evaluation of the statutory factors, then the state should choose a control strategy that achieves less progress than that represented by the glidepath RPG. *Id.* (noting that in that event, the state must include in the SIP its "analysis and rationale supporting this determination"). The RPG selected by the state must, however, be at least as demanding as the rate of progress that would result from implementation of other CAA requirements applicable during the planning period for the SIP. 40 C.F.R. § 51.308(d)(1)(vi).

The four-step approach described in EPA's regulations and guidance is the approach that the southeastern multi-state regional planning organization, VISTAS, has used to develop information

[1] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program (June 1, 2007) (hereinafter "Final Reasonable Progress Guidance").

available to Georgia and other VISTAS states as they develop their regional haze SIPs. For example, VISTAS has identified the glidepath RPGs for the Class I areas located in the VISTAS region and has modeled a control strategy that reflects current CAA requirements, including the Clean Air Interstate Rule (CAIR), to determine whether those requirements are adequate to meet the 2018 glidepath RPGs. Although VISTAS has not yet completed all of its work, VISTAS and VISTAS states appear to be assuming that, if this control strategy will comfortably achieve the 2018 glidepath RPG for a Class I area, then the reasonable progress requirement for EGUs will be satisfied for that Class I area.

Based on its initial analysis of certain information, including emission amounts and distance of sources from Class I areas, GEPD identified sources of sulfur dioxide (SO_2) that it believes are likely to contribute more than 0.5% to total visibility impairment due to sulfate at nearby Class I areas in 2018. This initial analysis included Unit 1 at GPC's Plant McIntosh among the potentially contributing sources to Okefenokee, Saint Marks, and Wolf Island. In a letter dated March 21, 2007, GEPD asked GPC to analyze whether possible additional controls on SO_2 emissions from that unit may be feasible, using the four statutory factors used in setting RPGs.

In conducting this "four-factor" feasibility analysis, the results of which are described in section 3.0 of this document, GPC has followed the approach set out by GEPD in its March 21 letter. Section 3.1 addresses the "remaining useful life" factor. Section 3.2 then identifies the SO_2 emission control technologies that are available. Section 3.3 evaluates which potential control technologies should be eliminated from further analysis because they are infeasible. Section 3.4 addresses the remaining control technologies, ranking them by cost effectiveness. Section 3.5 then analyzes the control technologies discussed in section 3.4 and analyzes them in terms of the first three statutory factors: compliance costs, time necessary for compliance, and energy and non air quality environmental impacts of compliance. Section 4.0 evaluates, as additional information in a weight-of-evidence analysis, a highly conservative projection of improvement in visibility from hypothetical additional reductions in SO_2 emissions. Finally, section 5.0 proposes a recommendation for a reasonable progress emission control determination for Plant McIntosh Unit 1.

3.0 Four-Factor Analysis for SO_2 Control at Plant McIntosh Unit 1

3.1 Factor d: Remaining Useful Life

One of the four factors is the "remaining useful life" of the emissions unit. In situations in which the unit will retire before the 2018 RPG date, the "remaining useful life" factor would allow a state to determine that no control of that unit is required. Similarly, in situations in which the unit will retire before conclusion of the assumed control-equipment life used for the capital recovery factor in annualizing the cost of the control options, the state would consider the "remaining useful life" factor in determining the cost effectiveness of the control options being evaluated.

For McIntosh Unit 1, currently neither situation exists. This unit is not currently planned to be retired before the 2018 RPG date, and the unit is not currently planned to be retired before conclusion of the equipment life for annualizing the cost of control options. Thus, currently there is no basis for considering the "remaining useful life" factor in the four-factor analysis for Plant McIntosh Unit 1.

3.2 Identification of SO_2 Control Technologies

Coal Washing

Coal sulfur content may be reduced prior to combustion by pretreating the coal using one of a variety of coal cleaning methods. In addition to sulfur removal, coal cleaning removes impurities, may increase the heating value of the coal, and may reduce plant maintenance costs. Approximately 50% of U.S.-mined coal undergoes some form of pretreatment prior to combustion. Most coal cleaning is conducted on Eastern and Midwestern bituminous coals. Western coals are inherently low in ash and sulfur and typically do not require pretreatment. A brief description of the various coal cleaning techniques is provided in the subsection below.

Physical Coal Cleaning
The most common method of coal cleaning is physical cleaning, which relies on the physical properties of the coal to separate the sulfur from the coal matrix. Coal contains chemically bound organic sulfur and inorganic sulfur, with pyrite as the most common form of inorganic sulfur. Physical cleaning techniques only remove some of the pyritic portion of the sulfur. Ability to remove pyritic sulfur depends on the coal characteristics. Some coals have small pyrite particles and do not clean well. Pyritic sulfur represents only about half of the total sulfur in the coal. Thus, physical coal cleaning is an ineffective control for approximately 50% of the total coal sulfur content.

Physical coal cleaning requires crushing the raw coal so that mineral and coal particles can then be separated by either density or surface characteristics. Larger sulfur-containing coal particles are removed using methods that exploit the differences in density between the coal and pyrite (e.g. hydraulic jig, hydroclone, or classifier). Pyrites are much heavier than coal, so they can be easily separated. Surface-based cleaning techniques, such as froth flotation, are used to clean fine coal particles and rely on the hydrophilic nature of mineral impurities and hydrophobic nature of coal particles to achieve separation.

Physical coal cleaning has shown sulfur removal of up to 20-90% of the pyritic sulfur. Removal efficiency of sulfur and impurities increases with decreasing coal particle size. However, the ability to control coal particle size and to achieve a given level of removal efficiency is limited by transportation and storage constraints. Finely ground coal is subject to wind losses and water absorption. Since physical coal cleaning removes ash-forming minerals, the increase in the heating value of the coal further reduces sulfur content on a 'lb/mmbtu' basis. However, this potential benefit can be offset by reduced heat content due to residual moisture, which can cause handling problems and some efficiency loss in boilers.

Chemical Coal Cleaning
Coal cleaning using various chemical processes has been applied to reduce both the organic and pyritic sulfur. Some of these processes use either elevated temperatures or higher pressures to oxidize pyritic sulfur to water-soluble compounds. Others use a chemical leaching process to directly extract organic and/or pyritic components. Chemical cleaning processes are designed to complement physical cleaning methods and, in some cases, have shown up to 95% removal of pyritic sulfur and 40-80% removal of organic sulfur. However, many of these methods are still under development, and high processing costs preclude commercial use.

Biological Coal Cleaning
Biological processes have also been used to reduce both organic and pyritic sulfur through the use of microorganisms. Biological processes typically have lower processing costs than physical and chemical methods. However, these processes are relatively new and have seen very limited use. Also, since this method may require weeks for processing time, its application may be limited to long term storage piles.

Coal Switching

SO_2 emissions may also be reduced by switching to lower sulfur coals or other low-sulfur fuels such as natural gas or oil. In the 1990s, many utilities achieved reductions in SO_2 emissions by switching from bituminous coals to low sulfur sub-bituminous coals. However, coal switching may not be feasible for some boilers and can be expensive, since the plant may need to reduce generation capacity due to mill limitations caused by the lower heating value of the coal. In addition, lower sulfur coals can have negative impacts on electrostatic precipitator (ESP) performance.

Flue Gas Desulfurization

Various methods are used to reduce SO_2 in the flue gas. These methods are referred to as "flue gas desulfurization" techniques or "FGD" and are generally classified as either wet FGD (WFGD) or dry FGD (DFGD) processes depending on whether the sulfur-containing byproducts are either wet or dry. A brief description of each process type is provided as follows:

WFGD Processes
WFGD is the dominant SO_2 control technology in the utility industry and accounts for approximately 90% of all installations. In a typical WFGD process, flue gas is treated with a calcium-containing sorbent (typically either a lime or limestone slurry) in a spray tower or absorber located downstream of the particulate control device. The calcium reacts with the SO_2 in the flue gas to form either calcium sulfite or calcium sulfate, which is collected in the reaction vessel and

subsequently treated for disposal or further oxidized to form gypsum, which may be disposed or sold, if the quality is high enough.

The most common WFGD process ("limestone with forced oxidation" or "LSFO") utilizes limestone as the reagent. The calcium sulfite byproduct that is formed in the reaction vessel is then completely oxidized by forcing compressed air through the slurry in the reaction tank to form calcium sulfate (gypsum). The final byproduct is gypsum, which can be sold (depending on quality and available markets) or disposed on-site without additional treatment.

WFGD systems typically provide relatively high SO_2 removal efficiencies (typically designed for 95% removal of fuel sulfur) across a wide range of fuels, although they require high capital and operating costs because of the need for corrosion-resistant materials and water treatment systems. WFGD systems also provide additional particulate removal, depending on the scrubber design and the inlet characteristics of the flue gas.

DFGD Processes

DFGD processes differ from the WFGD processes in that the resulting reaction product is a relatively dry solid. DFGD processes utilize a variety of alkaline sorbents (typically calcium-based) and injection techniques. Sorbent may be injected directly into the boiler or downstream of the air preheater, in either slurry or solid form, depending on the design. Since DFGD systems are incorporated upstream of the particulate control device, adverse affects on particulate control device performance, particularly ESPs, must be considered. In many cases, the addition of a polishing baghouse is required to treat the additional particulate and enhance SO_2 removal.

The lime spray dryer has been used since the 1970s and is the most common type of DFGD system. In this process, hot flue gas exits the air preheaters and enters the spray dryer vessel where an atomized blend of lime slurry and recycled solids (fly ash) contacts the flue gas stream. The SO_2 in the flue gas reacts with the lime/ash mixture to form calcium salts, which are collected along with unreacted reagent and fly ash in the downstream particulate control device. Reaction is enhanced in baghouse-equipped units, which facilitate direct contact of the flue gas with the reagent on the filter cake.

DFGD processes have a much smaller water requirement than do WFGD processes and, since the flue gas is maintained above saturation, standard materials of construction can be used for ductwork and internal components, a fact that significantly reduces capital costs. Unlike byproducts of WFGD processes, however, DFGD byproducts have limited, if any, market value and disposal costs can be higher because additional treatment may be necessary to stabilize the byproducts. In addition, reduced capture performance and reduced cost efficiency when using higher sulfur coals may limit future fuel flexibility.

3.3 Elimination of Technically Infeasible Options

All of the available SO_2 control technologies are technically feasible for the unit under consideration. However, there are various cost and application considerations for each, and these considerations may vary over time.

Coal Washing

Coal washing is widely practiced for many Eastern bituminous coals. The coals that are washed and the extent of the washing depend on the sulfur and pyrites content of the coal. Coal washing clearly reduces the sulfur content of the coal; however, the extent of reduction depends on the sulfur forms present in the coal and the extent of the washing process. Sulfur reductions of greater than 25-30% should not be expected. Virtually all low sulfur Eastern coals have either been washed to remove pyrites or contain naturally low levels of pyrites. Most coals that are naturally low in sulfur, like Powder River Basin (PRB) sub-bituminous coals, contain very little pyritic sulfur, and coal washing therefore is not a cost effective means of reducing the sulfur content of the coal.

Coal washing is a mature technology and is widely applied, and thus can be considered technically feasible. However, since McIntosh Unit 1 already burns a low sulfur (~0.62%) Colombian coal, the benefits of washing this coal are likely to be limited and expensive. However, for completeness, coal washing will be carried forward for further analysis.

Coal Switching

Coal switching is also a widely used technique for SO_2 reduction. Many utilities have switched to Eastern low sulfur coals or PRB sub-bituminous coals in recent years as a result of the Acid Rain Program. This coal switch was considered to be a more cost effective SO_2 control measure than the addition of SO_2 scrubbers. Virtually any boiler can utilize Eastern low sulfur coals. However, the ability of a specific boiler to switch to a PRB coal is dictated by the boiler and auxiliary equipment design. Many boilers are not able to switch to a sub-bituminous coal because the furnace volume is too low and the furnace exit temperature is too high. A high furnace exit temperature that is fine for an Eastern bituminous coal may create excessive slagging and fouling when a sub-bituminous coal is combusted. In addition, the unit may be limited by pulverizer and fan capacity when a sub-bituminous coal is burned. If so, maximum unit load will have to be reduced and will require replacement capacity. Most sub-bituminous coals have much higher moisture content than bituminous coals. This means that the heat rate of the unit is degraded because a significant portion of the heat generated in the boiler goes toward driving off the excess moisture. This also means that for a given quantity of coal, less energy is generated, which requires purchase of replacement energy to get back to equilibrium.

Coal switching is a mature technology and is widely applied; however, since McIntosh Unit 1 is already firing a relatively low sulfur coal, there may be limited benefit to switching to alternative lower sulfur coals. In any event, this option will be carried forward for further analysis

Flue Gas Desulfurization

WFGD is the most commonly used equipment for SO_2 removal from flue gas. The SO_2 removal efficiency of a modern wet scrubber is typically designed for 95%. In addition, when combined with forced oxidization, the waste from a wet scrubber is gypsum that may be marketable to a wall board manufacturer. There are also market opportunities for gypsum in the agriculture and cement industries. Even if the gypsum cannot be sold, it is physically and chemically stable and can be easily land-filled. Because the operating cost of a wet scrubber is lower than that of a dry scrubber, the wet scrubber is almost always the lower-cost option for larger units with a reasonable period of remaining life.

Wet SO_2 scrubbing is a mature technology and thus can be considered technically feasible. In the case of Unit 1, a small single scrubber could be applied to the unit. However, this unit falls into a size range and age where the major capital expenditure of a wet scrubber application may not be justified.

DFGD typically combines a spray tower using lime slurry reagent with a baghouse. When compared to a typical wet limestone based SO_2 scrubber, the dry scrubber has a higher cost reagent and a lower SO_2 removal efficiency, uses less water, and produces a waste product that cannot be recycled. Therefore, dry scrubber technology is most amenable to low sulfur coal applications and arid regions of the country.

However, capital costs are not expected to be any lower for DFGD than for WFGD if a baghouse is included as part of the DFGD system, and the operating cost of DFGD is higher than the operating cost of WFGD. This usually results in the wet scrubber having a lower overall cost of ownership in the absence of other mitigating factors. In addition, if a baghouse is required with DFGD, it will increase the delta-pressure, which causes the need for more fan horsepower, which in turn typically requires a new fan and duct strengthening.

Therefore, considering that a WFGD is likely to have lower overall cost than DFGD, only the WFGD has been carried forward for further analysis.

3.4 Rank of Remaining Control Technologies by Control Effectiveness

For the reasons discussed above, coal washing, coal switching, and WFGD are all considered technically feasible. Therefore, each of these technologies will be carried forward for further analysis. The following section discusses the control effectiveness of each of these options, beginning with most common type of WFGD (LSFO).

<u>WFGD (LSFO)</u>

In general, this control option provides the highest level of SO_2 reduction and the lowest operating cost. WFGD removal efficiencies are typically 95% across a wide range of fuels, depending on the specific design.

<u>Coal Switching</u>

Since the coal currently being fired at McIntosh Unit 1 is already relatively low in sulfur (0.62%), coal switching will have a relatively low SO2 removal efficiency. Considering the sulfur content of available alternative coals and their heat content, the removal efficiency of coal switching will be no more than about 20-40%.

<u>Coal Washing</u>

The control effectiveness of washing for the baseline coal (Colombian) is highly uncertain. However, an optimistic estimate of the control effectiveness of washing this coal is about 15%.

This is based on the assumption that 40% of the total sulfur in the coal is pyritic, that 30% of the pyritic sulfur is available for washing, and that 50% of the available pyritic sulfur is removed.

3.5 Feasible SO_2 Control Technologies and Reduction Options

3.5.1 Factor a: Cost of Compliance

The cost effectiveness of the technically feasible control options has been determined in the analysis that follows. To the extent appropriate, the cost components used in this analysis are consistent with those found in the *EPA Air Pollution Control Cost Manual.* After a review of the VISTAS 2018 projected operation and SO_2 emissions data for McIntosh Unit 1, it was determined that the VISTAS-projected operation of this unit was not consistent with GPC projections. Therefore, GPC projections of capacity factor and SO_2 emissions in 2018 are used as the baseline for the cost effectiveness calculations.

<u>WFGD Cost Analysis</u>

Capital Cost Assumptions – WFGD Option
The total capital cost includes direct and indirect costs. Direct capital costs consist of basic equipment and installation costs, reasonable ductwork modifications (if applicable), various infrastructure costs incurred to accommodate the new equipment, design and engineering costs, and typical vendor contingencies. Indirect installation costs include costs such as construction and contractor fees, startup and testing, inventory capital, and any process and project contingency costs. This does not include balance of plant impacts if existing structures need to be relocated.

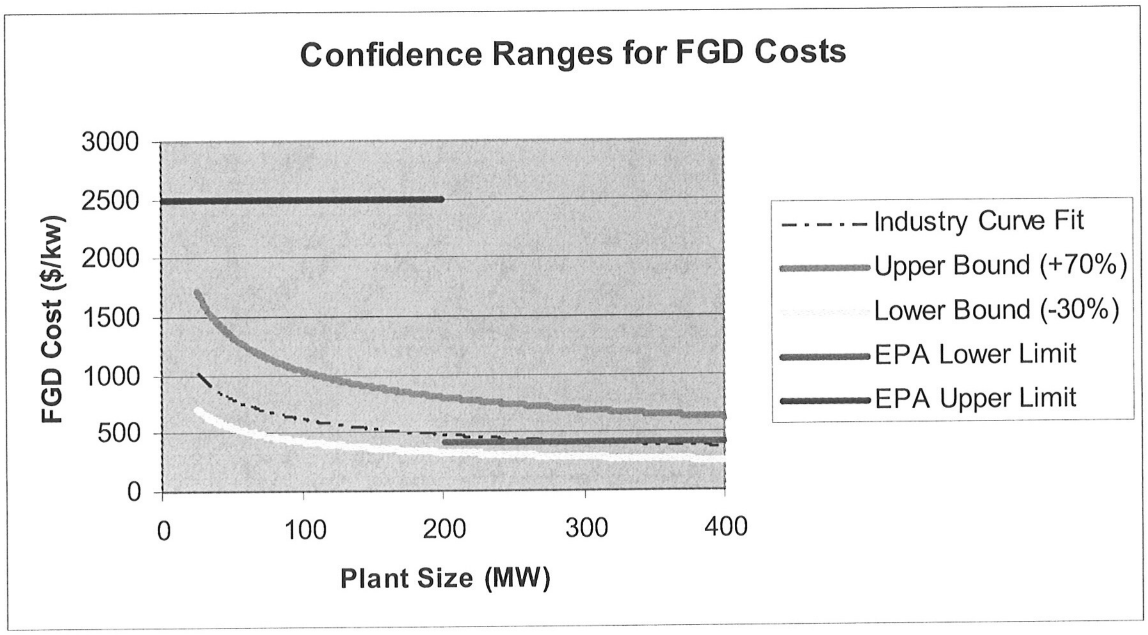
An accurate estimate of the total capital investment (TCI) for installing WFGD on relatively small units such as McIntosh Unit 1 is difficult to determine. Also, there was insufficient time to perform a detailed engineering analysis for retrofitting WFGD at this facility, and most historical cost data that is available apply to much larger units. To develop reasonably accurate capital estimates would require considerable effort to assess the unit's design and layout and to develop a plan for the control project that would ensure ease of construction, optimal performance and cost of operation, minimal maintenance cost, and flexibility to accommodate future requirements and enhancements.

A review of available data from the Southern Company, the electric industry, consultants, and regulatory sources revealed that the data pertains to scrubber projects larger than 200 MW and typically 700 MW in size. None of the data found addresses units as small as the unit that is the subject of this evaluation (163 MW). To address the lack of small-unit data, it was decided to bracket the cost of a WFGD retrofit for this unit using a range of capital cost assumptions based on extrapolating the large-unit data and other relevant information.

First, a power curve was fit to available historical data using a plus-70% and minus-30% error band consistent with conceptual cost estimates developed by SCS Engineering. This historical data was extracted from two construction cost surveys (one external and one internal) and two FGD cost papers presented at recent conferences. This resulted in a low, mid, and high range cost estimate based on the curve fit.

Second, data from EPA was used to develop two estimates of cost for units smaller than 400 MW. The source of the EPA cost estimate is an EPA Air Pollution Control Technology Fact Sheet covering FGD equipment (EPA-452/F-03-034). Table 1b of this EPA document shows the range of cost expected for units <400 MW in 2001 dollars, giving a high estimate (1500 \$/kW) and a low estimate (250 \$/kW). These two estimates were escalated from 2001 to 2007 dollars using a 9% annual escalation rate, which is consistent with a range of estimates of increase in scrubber costs over the last several years.[2] This resulted in a low and high range estimate in 2007 dollars from the EPA data. See Figure 3-1 for an illustration of the curve-fit and the EPA data range.

Figure 3-1 Data Extrapolation Curves for WFGD Capital Costs



Therefore, five TCI assumption values were used to calculate the cost effectiveness of installing WFGD on McIntosh Unit 1 (three values from the curve-fit and two values from the range of escalated EPA costs). Table 3-1 shows these five capital costs which were used in the cost effectiveness calculations for WFGD.

The capital cost for a WFGD installation depends on a number of factors, including the configuration and size of the unit (based on required efficiency and gas flow rate), the cost of corrosion resistant materials used in construction, the required level of water treatment, and market conditions. These factors may result in as much as an order of magnitude variation in capital costs. In addition, capital costs for retrofit applications may be significantly higher, depending on the difficulty of the retrofit. For this analysis, SCS has assumed that an integrated retrofit configuration will be required for all units.

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[2] *See* J. E. Cichanowicz, "Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies," at 1, 15-16 & Fig. 4-8 (June 2007).

It should be noted that material costs can vary significantly depending on market conditions. As demand for new power plant construction and pollution control devices increases, market prices for materials and construction will also increase. These market pressures are already having a major impact on the real cost of materials and labor for construction. Therefore, it is reasonable to expect that any cost estimates based on historical data are much lower than can be anticipated for future controls in the time frame for consideration for the 2018 reasonable progress goals.

Table 3-1 WFGD Total Capital Cost Estimates

Estimate Source	Unit Size, MW	$/kW	TCI
EPA Minimum	163	420	68,460,000
Industry Curve Fit minus 30%	163	357	58,165,460
Industry Curve Fit	163	510	83,093,514
Industry Curve Fit plus 70%	163	867	141,258,974
EPA Maximum	163	2500	407,500,000

<u>WFGD Annualized Costs</u>

The cost impact analysis requires the determination of the annualized cost for retrofitting WFGD on McIntosh Unit 1. Annualized costs include operation and maintenance (O&M) costs, annualized TCI costs, and station service penalties. Annualized costs are based on the operation projected by GPC for 2018 for McIntosh Unit 1. The following section discusses the annualized costs associated with a WFGD retrofit with respect to the five TCI assumptions.

Operation and Maintenance Costs
O&M costs include the additional man-power and other resources (e.g., water requirements, sorbent materials, etc.) required to operate and maintain the equipment.[3] O&M costs for the range of WFGD capital cost estimates were estimated based on the same historical data sources used for the capital cost curve-fit and range from 13 to 38 $/kW-yr. It should be noted that the industry historical O&M data is likely to be low relative to the actual experience that would occur at Plant McIntosh. Because space at the plant for stacking gypsum is limited, a new landfill probably would be required; the estimated O&M costs do not include costs associated with a new landfill.

Annualized TCI Costs
TCI costs for major utility construction projects are typically referred to as "capital recovery costs" and are expressed on an annualized basis. Annual capital recovery costs are equivalent to an annual payment that is sufficient to finance the investment over the expected life of the equipment. Capital recovery costs are determined by applying a capital recovery factor to the TCI cost. The capital recovery factor used in this analysis (10.98%) is derived from a simple interest formula assuming a "real"[4] interest rate of 7% and an equipment life of 15 years. The capital recovery cost

[3] Station service requirements for WFGD are not included in O&M cost estimates. These costs are accounted for separately as station service penalties.

[4] A "real" interest rate does not take into account the effects of inflation.

approach does not include all revenues necessary to support an investment item, such as administrative costs, property taxes, and insurance expenses.

Capacity and Energy Penalties

This analysis also includes the calculation of indirect capacity and energy penalties associated with the increased station service requirements of the WFGD. Station service requirements were assumed to be 2% or about 3000 kW.

Reduced capacity at a plant like McIntosh has two consequences. First, the overall system capacity for the state of Georgia is reduced. GPC must maintain a certain amount of buffer capacity to meet peak demand. Thus, a reduction in overall capacity creates a void that must be filled with the construction or purchase of additional generating capacity. Second, if the generating ability at Plant McIntosh is reduced, additional generation must be constructed or purchased or more expensive plants must be operated to make up for the power lost to the WFGD or other controls. New capacity and then the ongoing cost of additional energy generation are, in fact, two different costs. Thus, it is appropriate to account for both costs in this analysis.

It was assumed that the incremental capacity reduction would be made up by additional capacity constructed to offset the reduction. It is estimated that the cost of this capacity would be about $600/kW and that this capital would be recovered under the same financial assumptions as the control technologies being evaluated. In addition, the analysis includes an additional cost penalty associated with the energy production capability lost from the capacity reduction. It is reasonable to assume that this energy will be made up by purchasing makeup power at an average cost of $0.05/kWh.

Annualized Cost Summary

A breakdown of the total, annualized costs (in 2007 dollars) associated with the WFGD retrofit for each of the five capital cost assumptions is shown in Table 3-2.

As indicated above, FGD costs have increased about 9% per year over the last few years due in large part to the increased demand for FGD equipment and construction labor, and the increased cost in process equipment and materials. For example, copper wire and cable have escalated over 26% and steel pipe has escalated over 10% per year over the 2003-2007 period. Over the last two years nickel prices have doubled, and molybdenum prices have increased about 800% over the last 5 years. The demand for FGD equipment is expected to continue. By 2015 it is estimated that 250 units (125,000 MW) will be required to install FGD. Therefore, upward pressure on FGD costs is expected to continue. So, it is reasonable to expect that there will be significant real increases in FGD costs in the time frame of the 2018 reasonable progress goals, and this increased cost has not been reflected in this 2007-dollar analysis.

Table 3-2 Annualized Cost Summary (2007 Dollars)

Capital Cost Estimate	O&M Costs	TCI Capital Recovery	Capacity and Energy Penalties: Capital Cost of Additional Capacity	Capacity and Energy Penalties: Capital Recovery of Additional Capacity	Capacity and Energy Penalties: Cost of Makeup Energy	Annualized Cost
EPA Minimum	2,119,000	7,516,540	1,836,000	201,583	315,221	10,152,344
Industry Curve Fit minus 30%	2,119,000	6,386,255	1,836,000	201,583	315,221	9,022,059
Industry Curve Fit	2,934,000	9,123,221	1,836,000	201,583	315,221	12,574,025
Industry Curve Fit plus 70%	5,542,000	15,509,476	1,836,000	201,583	315,221	21,568,280
EPA Maximum	5,542,000	44,741,310	1,836,000	201,583	315,221	50,800,114

Baseline Emissions

Baseline emissions for the WFGD cost analysis are based on the projected operation of McIntosh Unit 1 in 2018. The baseline emissions are based on the characteristics of the current coal being fired at the plant (heat content and sulfur content) and assume no add-on sulfur controls. Table 3-3 summarizes the baseline annual SO_2 emissions for McIntosh Unit 1.

Estimated Post-Retrofit Emissions

The estimated SO_2 emissions for the WFGD were calculated by applying an incremental removal efficiency of 95% to the baseline emission value. The estimated controlled emissions after retrofit of the WFGD are also shown in Table 3-3.

Table 3-3 Baseline SO_2 Emissions, McIntosh Unit 1

Year	Capacity Factor [%]	Annual Boiler Heat Input [mmBtu]	Fuel Type	Heat Content, [Btu/lb]	Sulfur [%]	Baseline SO_2 Emissions [tons]	Controlled SO_2 Emissions [tons]
2018	24.0%	3,510,303	Colombian	11700	0.62	1,860.16	93.01

Cost Effectiveness

Cost effectiveness refers to the total annualized costs associated with the WFGD option, in dollars per year, divided by the estimated annual emissions reduction associated with WFGD, in tons per year. Cost effectiveness is expressed in terms of (annualized) dollars per ton of pollutant removed ($/ton). Table 3-4 summarizes the cost effectiveness of the WFGD option for the five capital cost assumptions.

Table 3-4 Cost Effectiveness of WFGD

Capital Cost Estimate	Annualized Cost [$/yr]	SO_2 Reduction [tpy]	Cost Effectiveness [$/ton]
EPA Minimum	10,152,344	1,767.15	5,745
Industry Curve Fit minus 30%	9,022,059	1,767.15	5,105
Industry Curve Fit	12,574,025	1,767.15	7,115
Industry Curve Fit plus 70%	21,568,280	1,767.15	12,205
EPA Maximum	50,800,114	1,767.15	28,747

Coal Switching Cost Analysis

Coal switching was evaluated by obtaining information from the SCS Fuel Department on several potential alternative fuel sources. The properties and delivered price of these fuels were compared to the baseline fuel currently burned at the unit (Colombian) to determine cost effectiveness using each of these alternative fuels to reduce the SO_2 emissions at McIntosh Unit 1. The subject unit already burns a coal low in sulfur content. Alternative coals with even lower sulfur content are not very common and therefore were sourced not only from mines in North America but also from mines all over the world. Such distant supplies of coal tend to command a higher price because of the increase in transportation cost and are more subject to delivery problems.

Using the delivered price, sulfur content, and heating value of the fuel, a calculation was performed to compare the amount of SO_2 reduced with the cost of the fuel and capacity and energy charges required to produce the same amount of electricity. Some of the alternative fuels differ greatly in their heat content and therefore adjustments were made to reflect the change in boiler capacity and heat rate that would result from use of the lower quality fuel. These changes reflect the general operating characteristics derived from knowledge of using similar fuels in other units in the Southern Company system.

For this analysis it was assumed that the current fuel being fired at McIntosh Unit 1 represents the baseline fuel. Table 3-3 shows the baseline (uncontrolled) annual SO_2 emissions for the baseline Colombian coal. Table 3-5 summarizes the delivered cost, heat content, and sulfur content for the baseline coal and the alternatives.

Table 3-5 Delivered Price and Characteristics – Baseline and Alternative Coals

Coal Types	Delivered Price [$/mmBtu]	Sulfur [%]	Heat Content, [Btu/lb]
Baseline Coal			
Colombian	2.738	0.62	11700
Alternative Coals			
CAPP	3.131	0.75	12500
Indonesian	4.028	0.35	9400
Russian	3.631	0.38	11700
PRB	3.021	0.35	8800
Colorado	3.494	0.50	11700

For the sub-bituminous coals (PRB and Indonesian) with much lower heat content, it was assumed that the McIntosh boiler would have to be derated. Based on experience burning PRB at another Southern Company facility that was also not designed to burn this lower heat content fuel, it is projected that the derate would be at least 8%.

The cost effectiveness of each of the alternative fuels was calculated compared to the baseline fuel. To do this, the total annual fuel cost and SO_2 emissions for each fuel (baseline and alternatives) were calculated. Then the difference in the annual cost associated with using a given alternative fuel relative to the baseline fuel was divided by the difference in annual SO_2 emissions relative to the baseline to give the cost effectiveness in dollars-per-ton for each of the alternative fuels. Table 3-6 summarizes the results of these calculations.

Table 3-6 Summary of Cost Effectiveness for Alternative Coals

Coal Types	Annual Boiler Heat Input [mmBtu]	Annual Fuel Cost [$]	Annual SO_2 Emissions [tons]	Delta Fuel Cost Relative to Baseline [$]	Annual Capacity Penalty [$}	Heat Rate Penalty [$]	Annual Capital Recovery for Fuel Switch [$]	Annual O&M Adder Associated With Fuel Switch [$]	Total Annual Cost Delta [$]	Delta SO_2 Emissions Relative to Baseline [tons]	Cost Effectiveness Relative to Baseline [$/ton]
Baseline:											
Colombian	3,510,303	9,610,960	1816.16	Base	Base	Base	Base	Base	Base	Base	Base
Alternatives:											
CAPP	3,510,303	10,990,056	2062.18	1,379,096	n/a	n/a	n/a	n/a	1,379,096	246.02	n/a
Indonesian	3,510,303	14,140,546	1263.03	4,529,585	806,332	n/a	n/a	n/a	5,335,917	(553.13)	9,647
Russian	3,510,303	12,744,313	1096.10	3,133,354	n/a	n/a	n/a	n/a	3,133,354	(720.06)	4,352
PRB	3,510,303	10,603,600	1352.14	992,641	806,332	964,577	324,718	40,000	3,128,268	(464.02)	6,742
Colorado	3,510,303	12,264,823	1456.13	2,653,864	n/a	n/a	n/a	n/a	2,653,864	(360.03)	7,371

For those fuels that require a boiler derate, the maximum continuous rating of the unit was reduced by 8%. An indirect capacity penalty associated with this derate was calculated. The 8% derate represents 12,000 kW of lost capacity that would be made up by additional capacity constructed to offset the reduction. It is estimated that the cost of this capacity would be about $600/kW and that this capital would be recovered under the same financial assumptions used for the WFGD option.

For PRB coal, it is also estimated that the heat rate of the unit will be impacted due to the much higher moisture content of the fuel. A 6% heat rate penalty was assumed. This 6% reduction in heat rate means that for the same total heat input to the boiler, the energy output is reduced. It was assumed that this energy will be made up by purchasing makeup power at an average cost of $0.05/kWh.

In addition, switching to PRB will require investment in additional dust collection and dust suppression systems, installation of wash down systems (because even small amounts of PRB cannot sit uncompacted for more than 7 days), and investment in additional fire protection systems (because of the ignitibility of PRB). The estimated capital cost for installing a dust suppression system ($1,475,000) and a fire protection system ($1,482,500) is included in the analysis for switching to PRB. The O&M cost for the dust suppression system ($40,000 per year) is also included in the analysis. These estimates were obtained from consultants with a great deal of experience in dust suppression and fire protection for PRB conversions at power plants. While the consultants were not able to conduct a detailed engineering analysis in the time provided, they were able to provide approximate estimates based on their experience and on drawings and data related to the coal handling system at Plant McIntosh provided by GPC.[5] It could also be necessary to modify, add, or replace soot blowers and to modify bunkers or replace them with silos. The cost of any of these requirements would be substantial, but these costs have not been included in the coal switching analysis.

It should be noted that use of the lower heat-content coals such as Indonesian and PRB will result in greater mass and volumes of coal being handled and will likely result in increased O&M costs. These added O&M costs have not been factored into the coal switching cost analysis.

Coal Washing Cost Analysis

Currently the coal being delivered to McIntosh Unit 1 is sourced out of Colombia, South America, and is not washed. In preparation for this study, the supplier of this coal was contacted about data concerning sulfur-removal performance using washing techniques for this coal. At this time, no coal-washing performance data are available for this coal. In fact, the supplier indicated that each coal is unique and therefore would require separate study to ascertain sulfur removal capability. Also, there is no washing facility available for the coal without incurring increased transportation cost. Therefore, it was assumed for this study that GPC would be responsible for funding the construction of any required washing facility.

Given the lack of data on the sulfur removal performance of washing, available industry papers and data were researched to estimate the range of removal performance. Research shows that washing has the greatest effect on the pyritic sulfur contained within the coal.[6] Internal studies have shown that if the coal is ground to a very fine powder, up to 85% of the pyritic sulfur can be removed from high sulfur fuels. However, finely ground wet coal will form a paste, and the technology to handle this paste at volumes sufficient to power the full load of McIntosh Unit 1 is currently not available and therefore beyond the scope of this study. Therefore, it was assumed that the coal will not be crushed and that washing will affect only the pyritic sulfur available to the surface of the coal nugget.

Figure 3-2 shows the relationship between the amount of pyritic sulfur and the total sulfur content of the coal. Although the plot confirms that each coal is unique, it can be seen that the pyritic sulfur content increases as the total sulfur content increases. The graph indicates that the percent pyritic sulfur content for coals with sulfur content similar to that of the coal used at this unit (0.62 percent total sulfur) would be about 20-50%.

Therefore, to make the coal washing calculation for the Colombian coal, the following optimistic assumptions were made for the high removal scenario:

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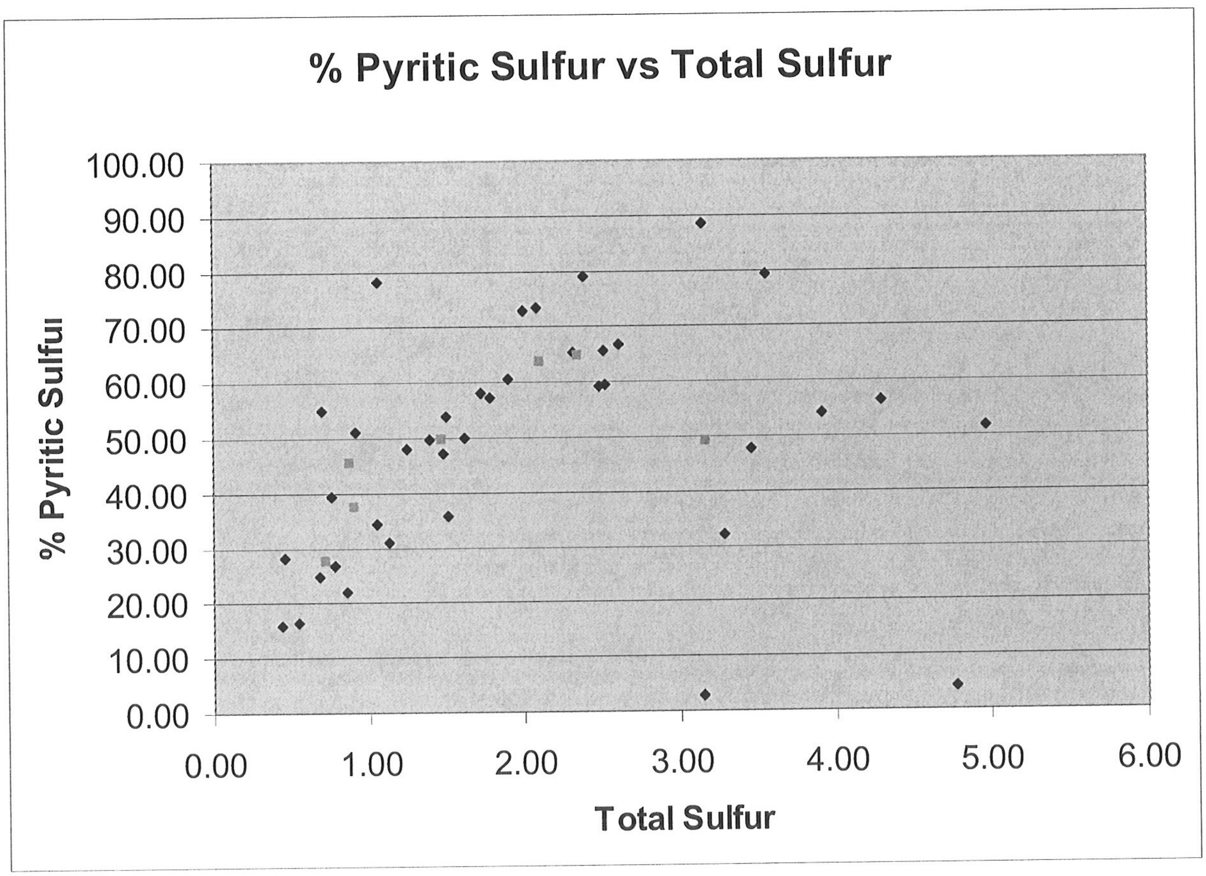
[5] For the dust suppression estimate: letter from Robert Coburn, Benetech, Inc., to Rosa Chi, GPC, dated June 25, 2007. For the fire protection estimate: letter from Tim Bator, TRM, to Rosa Chi, GPC, dated June 21, 2007.

[6] James C. Hower and B.K. Parekh, "Chemical/Physical Properties and Marketing," in Joseph Leonard III and Byron C. Hardinge, eds., *Coal Preparation*, 5th ed. (Littleton, CO: Society for Mining, Metallurgy and Exploration, 1991), p 72.

- 40% of the coal sulfur is pyritic.
- 30% of the pyritic sulfur is available to be removed by washing.
- 50% of the available pyritic sulfur is removed by washing.

After sizing a washing facility for a particular throughput, the O&M cost (based on vendor estimates) for the coal washing facility would be in the range of $1.50 to $2.00 per ton of coal.[7] Table 3-7 summarizes the O&M portion of the washing cost for a high removal case (using the above assumptions) and for a low removal case. For the high removal case it is determined that 0.000744 lb of SO_2 is removed for every lb of coal washed or it takes 1,344 tons of coal being washed to remove one ton of SO_2. Accordingly, at $2.00 per ton of coal, the operating cost alone is $2,688 per ton of SO_2 removed for the high removal case. For a low removal case, much more coal has to be washed to remove one ton of SO_2, and at $1.75 per ton of coal, the operating cost alone is $56,452 per ton of SO_2 removed.

Figure 3-2 Comparison of Pyritic Sulfur vs. Total Sulfur in Coal



[7] Peter Bethel, Director of Coal Preparation - Arch Coal Company, personal communication with Ricky Olive, Southern Company Services, April 23, 2007.

Table 3-7 Summary of Coal Washing O&M Costs

Assumptions Case	Total Sulfur [%]	Pyritic Sulfur as of Total [%]	Pyritic Sulfur Available for Washing [%]	Amount of Available Pyritic Removed [%]	Pyritic Sulfur Removed [%]	Percent of Total Sulfur Removed [%]	SO_2 Removed per lb of Coal [lb]	Tons Coal to Remove One Ton SO_2 [tons]	O&M Cost per Ton Washed [$/ton]	O&M Only - Removal Cost per Ton of SO_2 [$/ton]
High Removal	0.62	40	30	50	15	0.037	0.000744	1,344	2.00	2,688
Low Removal	0.62	5	10	50	5	0.002	0.000031	32,258	1.75	56,452

The capital cost of building a coal washing facility is unknown, as Southern Company has not undertaken a detailed cost analysis for such a project. However, using estimates for the capital and operating expenses obtained through vendors, cost ranges have been created that should encompass the actual costs should a facility be constructed.

The preliminary design criteria were set such that the coal washing facility could handle 110% of full load of the unit by running 8 to 14 hours per day and 28 days per month. This throughput suggested a design size, and using the vendor supplied estimates a capital cost estimate was determined. Using the same capital recovery assumptions that were used for the WFGD analysis, the annualized capital cost was determined. Table 3-8 summarizes the capital cost and the total removal cost for a high removal/low capital cost case and a low removal/high capital cost case.

Table 3-8 Summary of Coal Washing Capital and Total Cost Effectiveness

Assumptions Case	Capital Cost of Coal Wash Plant [$/ton/hr]	Capital Cost of Support Systems [$/ton/hr]	Design Size of Facility [ton/hr]	Wash Plant Capital Estimate [mm$]	Annual Capital Recovery [mm$]	Annual Coal Burn [tons]	Tons of SO_2 Removed [tons]	Capital Only - Cost per Ton of SO_2 [$/ton]	Total SO_2 Removal Cost Including O&M [$/ton]
Low Capital and High Removal	12,000	13,000	39	0.96	0.11	150,013	37.2	2,846	5,534
High Capital and Low Removal	20,000	15,000	68	2.36	0.26	150,013	4.65	55,785	112,236

The range of capital cost estimates for the coal washing facility is from $0.96 to $2.36 million. After adding this capital cost the total washing cost is in the range of $5,534 per ton of SO_2 removed for the high removal/low capital cost case and up to $112,236 per ton of SO_2 removed for the low removal/high capital cost case.

Summary of Cost Analyses

Table 3-9 summarizes the cost analyses for each of the control options considered.

Table 3-9 Summary of Cost Analysis Results

Control Option	Cost Effectiveness [$/ton]
WFGD	
Capital Cost Cases:	
EPA Minimum	5,745
Industry Curve Fit minus 30%	5,105
Industry Curve Fit	7,115
Industry Curve Fit plus 70%	12,205
EPA Maximum	28,747
Coal Switching	
Baseline:	
Columbian	Base
Alternatives:	
CAPP	n/a
Indonesian	9,647
Russian	4,352
PRB	6,742
Colorado	7,371
Coal Washing	
Low Capital & High Removal	5,534
High Capital & Low Removal	112,236

Table 3-10 shows the weighted average cost effectiveness, in dollars-per-ton-reduced, for all of the WFGD systems currently under construction or planned to be built by GPC to comply with the Georgia Multipollutant Rule. The table also shows the percentage of the total SO_2 projected to be emitted by GPC plants in 2018 that will be reduced by these WFGD systems. The weighted average cost effectiveness of these planned and in-construction WFGD systems is about $743 per ton reduced, and they will remove about 93% of the total SO_2 projected to be emitted in 2018.[8] The remainder of Table 3-10 shows the control options considered in the cost analysis along with the incremental additional reduction in total SO_2 emissions that each of these controls would achieve if implemented at Plant McIntosh Unit 1. For purposes of this comparison, the industry curve fit capital cost assumption for WFGD is used.

[8] The WFGD costs used in this analysis are based on current GPC budget estimates, which reflect varying levels of certainty. The costs of future WFGD projects are less certain, and likely would be higher, than the costs of WFGD projects currently under construction.

Table 3-10 Removal Costs vs. Percent Reduction in Projected 2018 GPC SO_2 Emissions

	Wtd. Average Cost Effectiveness [$/ton]	SO_2 Tons Removed [%]
All Currently Planned GPC WFGD Retrofits	743	93
CONTROL OPTION	Cost Effectiveness [$/ton]	Incremental SO_2 Reduction [%]
WFGD		
Industry Curve Fit	7,115	0.2786
Coal Switching		
Baseline:		
Columbian	Base	n/a
Alternatives:		
CAPP	n/a	n/a
Indonesian	9,647	0.0872
Russian	4,352	0.1135
PRB	6,742	0.0732
Colorado	7,371	0.0568
Coal Washing		
Low Capital & High Removal	5,534	0.0059
High Capital & Low Removal	112,236	0.0007

As demonstrated by the information in Table 3-10, the cost per ton of SO_2 reduced for each of these control options at Plant McIntosh Unit 1 is extremely high relative to the weighted average cost effectiveness for all of GPC's currently planned and in-construction WFGD systems. In fact, the projected WFGD cost-per-ton-reduced for Plant McIntosh Unit 1 is nearly an order of magnitude higher than the weighted average cost effectiveness for all currently planned and in-construction WFGD systems. Moreover, all of the fuel switching options for Plant McIntosh Unit 1 are at least 5 times higher in cost-per-ton, and the coal washing option is from 7 times to well over 100 times higher in cost-per-ton, than the weighted average cost effectiveness of the WFGD systems currently planned or in construction by GPC. In addition, as Table 3-10 also shows, each of these options would further reduce total 2018 SO_2 emissions by only a fraction of a percent.

Indeed, because of recent (and anticipated future) rapid escalation in control-technology costs for reasons noted earlier in this report, it can be expected that any future WFGD or other control-technology installations at units such as McIntosh Unit 1 would be even more expensive -- perhaps much more expensive -- than is suggested by current estimates, which are based on historical data.

3.5.2 Factor b: Time Necessary for Compliance

Flue Gas Desulfurization

Based on GPC's experience to date on its large units, in general, total project schedules for WFGD from decision through permitting, engineering, procurement, construction, and startup have required approximately 5 years under conditions of normally balanced supply and demand of resources. Installing environmental controls requires significant craft skills. Based on the labor projections in the Southeast, craft workers with the types of skills needed to perform tasks associated with GPC's environmental construction program will be in high demand over the next six to eight years. Since the same market of craft laborers must be tapped for both environmental compliance projects and previously scheduled maintenance outages at all GPC plants, as well as major construction projects throughout the Southeast and nation, we must plan ahead to ensure that adequate resources are available. We recognize that other utilities across the country and in the Southeast, such as TVA, Duke Energy, Progress Energy, and Florida Power & Light, will also be engaged in very similar environmental compliance activities and, thus, will be competing for workers from this same labor pool. Compounding the short-supply problems in the Southeast are the labor and equipment needs of other industries, new generation projects, and the rebuilding along the Gulf Coast following the destruction of infrastructure and industrial facilities caused by Hurricane Katrina.

With all of this ongoing work and the requirements of the Georgia Multipollutant Rule, completion of a WFGD at McIntosh before January 1, 2016, is not considered feasible. In contrast to the larger power-plant installations of WFGD currently in construction or in planning stages, this plant's small size means that very few details can be known concerning issues with locating physically large pollution controls at Plant McIntosh.

3.5.3 Factor c: Energy and Non Air Quality Environmental Impacts

The following section discusses the energy and non air quality related environmental impacts of the control options that were evaluated:

WFGD (LSFO)

The parasitic steam or electrical power requirements for wet scrubbers on coal-fired boilers will depend on the unit's size and design but typically range from 1% to 2% of the total generation. Water consumption is on the order of 70 gal/MWh.

A WFGD system typically produces over 2.1 tons of gypsum for every ton of SO_2 removed from the flue gas. The gypsum byproduct can be sold or disposed on-site. Gypsum can be used in wallboard, agricultural, cement industry and other applications. When disposal is required, the gypsum can naturally dewater, is physically and chemically stable, and can be disposed in a similar manner to (and with) fly ash.

Coal Switching

Although it is possible to reduce the SO_2 emissions from a coal-fired boiler through switching to coals with lower sulfur content, the lower quality of some of these coals can potentially cause problems in an existing boiler. This is especially true for sub-bituminous coals like PRB and Indonesian since the significantly lower heat content and other characteristics of the fuel might result in a derate in generation capacity. For example, the low ash fusion temperature of PRB causes slagging and buildup in the furnace back passes. The lower heat content will possibly limit unit capability due to mill limitations. In addition, the PRB, and possibly other alternative coals, contain significantly more moisture than the higher quality bituminous coals. The need to evaporate this additional moisture can result in an efficiency decrease (heat rate increase).

Specifically, the Russian coal considered in this analysis was tested last year at two Southern Company plants. There were problems with extraneous materials found in the coal itself (including metal) that caused problems with pulverizers, feeders, and other coal handling equipment. This coal also was very soft and as a result it arrived at the plant in very fine particles and was extremely wet. All of these issues could result in derate and efficiency impacts on the boiler.

Coal Washing

Coal washing/preparation is the process by which ash is removed from raw coal in order to make it suitable for combustion in power plants. Incidental to ash removal, some sulfur in the form of pyrite is also removed. Modern coal washing plants incorporate several different washing processes. Coarser particles (+3/8ths inch in size) are removed in a heavy media bath. The lighter coal particles float in the heavy media solution while the heavier ash (rocks) are allowed to sink. The heavier material is discarded. Finer material is cleaned in any of several different ways. Heavy media cyclones, which incorporate a heavy media solution and centrifugal force to provide for the separation, are typical in the 3/8ths x 28 mesh size fraction. Ultra fine (-28 mesh material) is typically cleaned by water-only methods. Sulfur, as pyrite, is more effectively cleaned from the smaller size fractions. The waste material from the coal cleaning process is stored on-site at the coal washing plant. Effluent from the ponds and impoundments where this material is stored is usually acidic in nature and must be treated in accordance with state and federal environmental laws before being allowed to return to any streams or tributaries.

4.0 Projected Visibility Improvement

Although it is not listed specifically as one of the statutory factors for states to consider in determining RPGs, the achievement of actual visibility improvement in mandatory Federal Class I areas is, of course, the regional haze rules' underlying objective. Indeed, that objective is the foundation for the rules' requirement that, in setting RPGs, a state consider the uniform rate of progress toward a return to natural visibility conditions. For example, if potential additional emission controls at an electric generating unit -- regardless of the degree of cost effectiveness of those controls on a dollar-per-ton basis and regardless of those controls' feasibility in other respects -- are not projected to be effective in achieving meaningful visibility improvement in relevant Class I areas, no sound basis would exist under the rules for requiring such controls at that unit.[9] Thus, any reasonable progress analysis of potential emission controls must take into account the degree to which those controls improve visibility in those areas. Accordingly, this section of the report presents projections of visibility improvement at relevant Class I areas that might result from additional SO_2 emission controls on Plant McIntosh Unit 1.

VISTAS and the VISTAS states are using a version of the CMAQ regional scale model to estimate the effectiveness of control strategies in achieving the glidepath RPG. This modeling begins with actual emissions in the base year (2002) and projections of emissions in a future year (2018), considering growth and controls from existing and projected control programs, such as CAIR. Unlike modeling to support BART, the emissions are based on realistic estimates, not maximum rates. Running the CMAQ model is resource intensive and, as a result, generally not used to model the effect of emissions from individual sources. Nevertheless, the analysis called for in the four-factor analysis is unit-specific. For the purposes of this discussion, the units identified for four-factor analysis by GEPD are Kraft Units 1, 2, and 3, McIntosh Unit 1, and Mitchell Unit 3 (hereinafter referred to as "the four-factor units"). Given available time and resources, GPC decided to use two different approaches in order to bound the estimate of visibility improvement that may result from controls on Plant McIntosh Unit 1.

First, the VISTAS version of CMAQ was used to simulate the effect of maximum controls on all units anticipated by GPC to be candidates for four-factor analysis. Because GPC began this work before it received GEPD's March 21, 2007 letter, and because the modeling was also designed to serve other purposes, the GPC units and pollutants assessed in this modeling were over-inclusive. That is, in addition to the four-factor units, Yates Units 2, 3, 4, & 5 were included. Furthermore, the controls assumed a zeroing-out of the emissions from the four-factor units (which overestimates the emissions reductions achievable from coal washing, coal-switching, and FGD) and assumed an FGD and SCR on Yates Units 2, 3, 4, & 5. Therefore, the visibility changes simulated in this modeling vastly overestimate the unit-control-specific benefits for Unit 1 at Plant McIntosh.

Second, in an attempt to gain unit-specific information on visibility impact, GPC ran the VISTAS version of CALPUFF for each of the four-factor units. Given the substantial effort involved in using actual (or projected actual) hourly emissions in this modeling, the BART maximum

[9] *See, e.g.,* Final Reasonable Progress Guidance at 5-2 (discussing importance of considering controls' effectiveness in achieving deciview improvements).

emissions rates were used, and the SO_2 emissions were reduced by 95%, in the control simulation. Due to time limitations, the effects of control options (i.e., coal washing and coal switching) that would produce fewer emission reductions were not evaluated. Keeping with the approach for reasonable progress, only the changes for the 20% worst days in 2002 were evaluated. Therefore, the visibility changes projected using this approach also overestimate the unit-control-specific benefits for Unit 1 at Plant McIntosh.

Each of the modeling approaches is summarized below. Section 4.1 describes the CMAQ modeling. Section 4.2 describes the CALPUFF modeling. Finally, section 4.3 summarizes the modeling results.

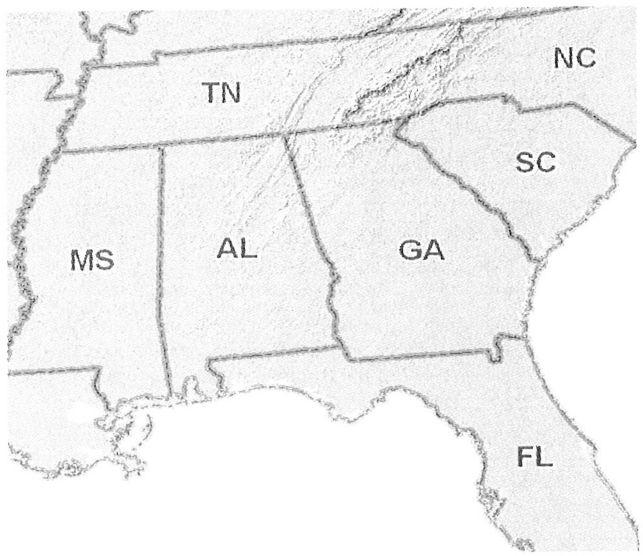
4.1 CMAQ Modeling

Air quality modeling was conducted to assess the effects on simulated visibility in Class I areas of hypothetical further reductions in SO_2 and NO_x emissions resulting from potential controls (e.g., SCR and FGD) at Southern Company sources. For this analysis, modeling inputs were obtained from VISTAS; these are the latest versions of the inputs being used for the VISTAS regional haze modeling of the southeastern U.S. The VISTAS CMAQ modeling system (Version 4.5.1 with AERO4 and SOA mods) and associated input databases, including the Base_G2 emissions for 2002 and 2018, were utilized. Annual simulations were conducted on a 36-km resolution grid (Figure 4-1) covering the southeastern U.S. centered on Alabama and Georgia (i.e., the ALGA-36 domain) for the following scenarios:

Description
2002 VISTAS G2 Base Case
2018 VISTAS G2 Future baseline
2018 SoCo Baseline
2018 SoCo + Georgia Power Company (GPC) full control or retirement

To investigate the impact of pollution controls, the emissions for selected Southern Company units in the 2018 VISTAS files were modified to establish a SoCo 2018 baseline reflecting expected future controls on various units that were not included in the VISTAS 2018 baseline. More specifically, the 2018 SoCo Baseline includes the zeroing out of SO_2 emissions from Plant McDonough (reflecting its planned retirement and replacement by gas-fired capacity) and a series of NOx emissions changes, including adding and deleting SCRs, and correcting VISTAS errors in seasonality on several GPC units. Since NOx emissions play such a small role in visibility in the Southeast, the NOx changes are not expected to affect the analysis. The projected visibility differences between the 2018 VISTAS G2 and 2018 SoCo are largely driven by the McDonough SO_2 changes, and are very small.

Figure 4-1 Depiction of the ALGA 36-km Resolution CMAQ Grid Used for the Southern Company Emission Reduction Sensitivity Analysis



The 2002 G2 base case simulation was conducted to provide the basis for calculating relative reduction factors of $PM_{2.5}$ species between the base and future-year scenarios. These factors were used to calculate expected future year visibility estimates. We also reran the VISTAS future year baseline simulation for 2018 using the 2018 G2 emissions. This allowed us to test our ability to reproduce the VISTAS projections.

Emissions for several GPC units in the SoCo 2018 baseline were subsequently modified to reflect intended full control or retirement. As stated above, the emissions from each of the five four-factor units were set to zero, while both FGD and SCR systems were applied to Yates Units 2, 3, 4, & 5. With the addition of wet scrubbers to the units, the exit stack temperature was reduced and set to 169°F. This temperature reduction may have lowered the effective plume rise for these units compared to the 2002 base case, but the effects on simulated concentrations are likely small compared to the effects from the emissions reductions.

The results of the modeling are summarized in terms of three metrics consistent with achieving reasonable progress. The metrics are described below:

Future Mean Visibility (FMV): Future year mean visibility is calculated for each IMPROVE site based on estimates of the future-year concentrations for each species using the new IMPROVE equation. The species concentrations are calculated using the average observed values for the 20 percent best and (separately) 20 percent worst visibility days for the 2000-2004 baseline period. These are multiplied by species-specific RRFs. For this metric, the RRFs are calculated using the simulation results for both the 20 percent best and worst days (observed) during the simulation period.

Glidepath Progress: For a given future year, the glidepath target is calculated as the amount of visibility improvement needed to maintain a linear deciview reduction to natural background by 2064. The percent of this needed reduction that is achieved by the future-year scenario is calculated for each IMPROVE site using the new IMPROVE equation. This metric applies to the 20 percent worst days only.

4.2 CALPUFF Modeling

Single-source modeling of Plant McIntosh was conducted for this analysis using the CALPUFF modeling system. The analysis utilized inputs and methodologies established by VISTAS for the recently completed modeling analysis of BART-eligible sources as part of the visibility and regional haze analysis of the Southeast U.S.

For this exercise, CALPUFF Version 5.754 and CALMET Version 5.7 were used. These model versions can be obtained at http://www.src.com/verio/download/download.htm#VISTAS_VERSION. These versions contain enhancements funded by the Minerals Management Service (MMS) and VISTAS. They are maintained on TRC's Atmospheric Studies Group CALPUFF website for public access. This release includes CALMET, CALPUFF, CALPOST, CALSUM, and POSTUTIL as well as CALVIEW.

The CALPUFF modeling presented here used inputs developed by VISTAS for regional haze BART modeling. VISTAS generated the 4-km grid meteorological inputs to CALPUFF by applying CALMET to its 12-km 2002 MM5 meteorological model simulation (see http://vistas-sesarm.org/documents/BARTModeling_Protocol_rev3.2_31Aug06.pdf).

Hourly measurements of ozone from all non-urban monitors, as generated by VISTAS and available on the VISTAS CALPUFF page on the Earth Tech web site (http://www.src.com/verio/download/sample_files.htm), were used as inputs to CALPUFF. For ammonia, a 0.5 ppb background value, as recommended by VISTAS, was used.

For this CALPUFF exercise we modeled SO_2, SO_4, NOx, SOA, PMF, PMC, and EC emissions. For the control scenario, a wet FGD with 95% SO_2 removal was applied, which also resulted in reductions in emission of SO_4, PMF, PMC, and EC, as indicated in Table 4-1. The SO_2 emissions were defined, as recommended in the VISTAS BART Modeling Protocol, using the maximum 24-hour CEMS emission rate during normal operation for the 2003-2005 period.

For the CALPUFF model options, the VISTAS common BART modeling protocol (Section 4.4.1), which was developed using IWAQM (EPA, 1998) guidance, was followed. Since the modeled facility is more than 50 km from the nearest Class I area, building downwash effects were not included in the CALPUFF modeling.

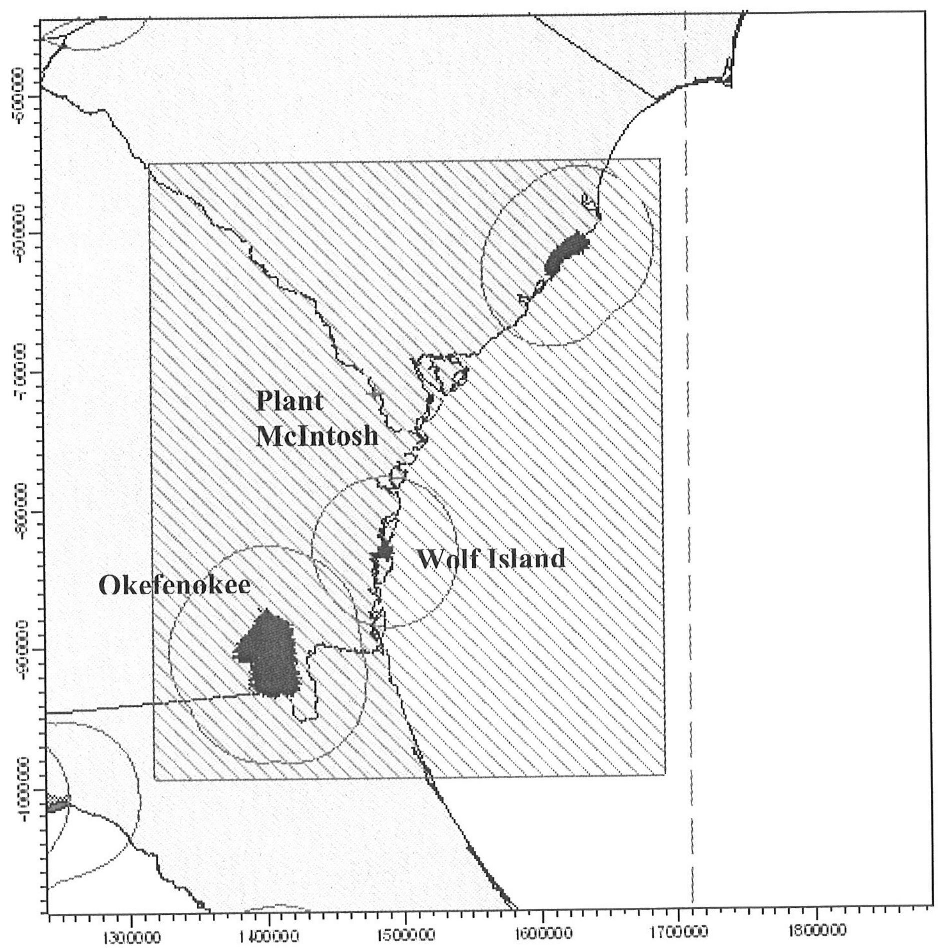
Table 4-1 Modeling Stack Parameters and Emissions Inputs

Plant Name and Case	Stack Parameters							Emissions								
	X UTM Coord	Y UTM Coord	Stack Height	Base Elev	Stack Diam	Exit Vel	Exit Temp	Emission Rates (g/s)								
	(km)	(km)	(m)	(m)	(m)	(m/s)	(deg. K)	SO2	SO4	NOx	HNO3	NO3	SOA	PMF	PMC	EC
McIntosh 1 Base	1481.13	-717.54	105.16	9.75	3.5	24.2	425.8	491.9	1.42	166.74	0	0	1.57	1.11	1.44	0.04
McIntosh 1 Controlled	1481.13	-717.54	105.16	9.75	3.5	24.2	425.8	24.59	0.85	166.74	0	0	1.57	0.22	0.29	0.01

The POSTUTIL utility program (VISTAS common protocol Section 4.4.2) was used to repartition HNO_3 and NO_3 using VISTAS-provided ammonia concentrations derived from previous 2002 CMAQ modeling conducted by EPA.

The CALPUFF runs used the sub-domain 4, 4-km CALMET data supplied by VISTAS, as discussed above. This domain includes all Class I areas within 300 km of the source, plus a 50-km buffer. The receptors used for each of the relevant Class I areas are based on the National Park Service database of Class I receptors, as recommended by the VISTAS common protocol (Section 4.3.3). For the Plant McIntosh four-factor analysis, receptors were modeled for the Okefenokee and Wolf Island Wilderness Areas. Cape Romain was not included since it was not identified as an area of concern from the GEPD's underlying analysis that identified Plant McIntosh Unit 1 for four-factor analysis. Figure 2 shows a map of the computational domain and Class I receptors utilized for modeling Plant McIntosh.

Figure 4-2 Plant McIntosh CALPUFF Computational Modeling Domain Showing Receptors for Okefenokee and Wolf Island Class I Areas.



Following the VISTAS protocol, the CALPOST postprocessor was used to calculate effects on light extinction of the modeled source's sulfate concentrations. The formula currently contained in CALPOST has been revised because the original formula was shown to be inadequate in both its representation of light extinction from sea salt and its use of 1.4 as the organic-mass-to-carbon-mass ratio. Furthermore, guidance for this formula did not provide for site-specific Rayleigh scattering. In December 2005, the IMPROVE Steering Committee adopted a new formula for determining light extinction that addresses these and other shortcomings. Dr. Ivar Tombach (VISTAS' consultant) produced a spreadsheet tool (dated September 29, 2006, available at http://www.vistas-sesarm.org/BART/CALPOST-NewIMPROVEformulaCalculationNO2RevP_Dec92006.xls) to allow the new IMPROVE formula results to be derived from the basic CALPOST outputs. This revised version of the IMPROVE Equation was used in this four-factor analysis to calculate modeled visibility improvement. Also, since this CALPUFF four-factor analysis modeling only assessed the impact of SO_2 controls, NO_2 was set to zero in the new formula.

The assessment of visibility impacts at the Class I areas used CALPOST Method 6 (VISTAS common protocol Section 4.3.2). Each hour's source-caused extinction was calculated by first using the hygroscopic components of the source-caused concentrations, due to ammonium sulfate and nitrate, and monthly Class I area-specific f(RH) values. The contribution to the total source-caused extinction from ammonium sulfate and nitrate is then added to the other, non-hygroscopic components of the particulate concentration (from coarse and fine soil, secondary organic aerosols, and elemental carbon) to yield the total hourly source-caused extinction.

There is no guidance on the metrics to use in this analysis. Therefore, in an attempt to translate CALPUFF results into metrics aligned with the way reasonable progress is to be measured, the following metrics were calculated:

Delta-Delta Deciview: This metric represents the modeled visibility improvement obtained by adding controls to an emissions source. The number is calculated for each day of the modeled period by subtracting the base case (no controls) visibility impact of a source (measured in deciviews) from the case where emission controls have been applied. This metric was calculated for the 20% worst days. The average of those 20% worst days was also calculated.

Scaled Delta-Delta Deciview: This metric is similar to the delta-delta deciview metric, except that the daily modeled visibility improvement resulting from controls has been scaled by the ratio of the actual daily SO_2 emission rate to the modeled maximum emission rate.

4.3 Visibility Modeling Results

Although the GEPD's March 21, 2007 letter did not mention specific Class I areas, the underlying analysis identifying the four-factor units to be assessed included three Class I areas, Okefenokee and Wolf Island in Georgia and Saint Marks in Florida. Therefore, the modeling results for these three class I areas are summarized in this section. All results presented use the new IMPROVE equation.

4.3.1 CMAQ Modeling Results

The results of the CMAQ modeling are presented in Table 4-2. As stated earlier, these estimated changes in visibility vastly over-estimate the changes that would be expected from SO_2 emissions reductions at Plant McIntosh Unit 1. The maximum average benefit on the 20% worst days for the emissions reductions simulated is 0.15 dv at Wolf Island, and the glidepath progress improvement is less than 4%. Projected benefits from Unit 1 at Plant McIntosh alone would be far less than these results.

Table 4-2 CMAQ Modeling Results w/ New IMPROVE Equation

Class I Area	Metrics	Modeling Scenarios: 2000 - 2004 Baseline	2018g2 VISTAS	2018 SOCO	2018 SOCO + GPC Full Control or Retirement	Difference between 2018 SOCO & 2018 SOCO + GPC Full Control or Retirement
Okefenokee	Average of 20% Best (Deciview)	15.23	13.79	13.75	13.71	0.04
	Average of 20% Worst (Deciview)	23.49	23.80	23.76	23.62	**0.14**
	Glidepath Progress of Average of 20% Worst (Percent)	N/A	91.45	92.73	96.52	-3.79
Wolf Island	Average of 20% Best (Deciview)	15.23	13.88	13.84	13.77	0.07
	Average of 20% Worst (Deciview)	23.49	23.58	23.55	23.40	**0.15**
	Glidepath Progress of Average of 20% Worst (Percent)	N/A	97.68	98.56	102.48	-3.92
St. Marks	Average of 20% Best (Deciview)	14.37	12.99	12.78	12.75	0.03
	Average of 20% Worst (Deciview)	22.88	22.80	22.63	22.55	**0.08**
	Glidepath Progress of Average of 20% Worst (Percent)	N/A	102.30	107.38	109.86	-2.48

4.3.2 CALPUFF Modeling Results

The results of the CALPUFF modeling are presented in Table 4-3. Since the BART modeling was originally set up to assess visibility changes at Class I areas within 300 km, results for St. Marks are not included. As stated above, these estimated changes in visibility over-estimate the changes that would be expected from SO_2 emissions reductions at Plant McIntosh Unit 1. In an effort to estimate what the results might have been had actual hourly emissions rates been used, the CALPUFF results were scaled down using the ratio of the actual daily emissions rate (on the date for each 20% worst day in 2002) to the maximum rate. Since the emissions causing the impact on a given day may have been emitted on an earlier day, the actual rate on the day before the 20% worst date was also assessed. There was little difference in the results. Only the "day-of" results are presented in Table 4-3.

The maximum benefit for the average of the 20% worst days from an FGD using the maximum emissions rate is 0.20 dv at Wolf Island and 0.07 dv using the more realistic, scaled results.

Projected benefits from the smaller emissions reductions resulting from fuel options at Unit 1 at Plant McIntosh would be far less than these results.

Table 4-3 CALPUFF Modeling Results w/ New IMPROVE Equation for Plant McIntosh Unit 1

Class I Area	Max or Scaled	Minimum Change on Days w/ Change Delta-Delta Deciview	Maximum Change Delta-Delta Deciview	Average Change in 20% Worst Days Delta-Delta-Deciview
Okefenokee	Max	0.00	0.89	0.17
	Scaled	0.00	0.36	0.06
Wolf Island	Max	0.00	1.16	0.20
	Scaled	0.00	0.52	0.07

5.0 Reasonable Progress Recommendation for Plant McIntosh Unit 1

EPA's Reasonable Progress Guidance contains little guidance regarding how to determine whether and which controls are appropriate at individual units as part of a state plan for achieving reasonable progress on visibility improvement at Class I areas. The Guidance simply indicates that the costs of emissions reduction, the time necessary for compliance, the energy and non air quality environmental impacts of compliance, and the remaining useful life must be considered to the extent applicable. The Guidance recognizes that states have considerable discretion in considering these factors and making this determination. As part of its exercise of this discretion, GEPD requested, in a letter dated March 21, 2007, that GPC conduct a four-factor analysis for Plant McIntosh Unit 1.

Section 3.0 of this document summarizes GPC's analysis of which SO_2 control options are feasible for Plant McIntosh, their costs and associated factors, and their energy and non air quality environmental impacts. The results of this analysis demonstrate that, for this unit, the available, feasible control options for SO_2 are not cost effective and have considerable energy and non air quality environmental impacts. Moreover, for the reasons explained in section 4.0, none of the available control options would produce a perceptible or otherwise meaningful improvement in visibility at the relevant Class I areas.

Table 5-1 summarizes the cost effectiveness of each of the SO_2 control options assessed for McIntosh Unit 1. Table 5-2 shows the weighted average cost effectiveness for all of the WFGD systems currently under construction or planned to be built by GPC to comply with the Georgia Multipollutant Rule. The table also shows the percentage of the total SO_2 projected to be emitted by GPC plants in 2018 that will be reduced by these WFGD systems. The remainder of Table 5-2 shows the control options considered in the cost analysis along with the incremental additional reduction in total SO_2 emissions that each of these controls would achieve if implemented at Plant McIntosh Unit 1. This table illustrates that the cost of each of these controls is unreasonable compared to the cost of installing WFGD on the GPC units for which WFGD is currently planned or being built, that each of these controls would produce only negligible marginal reductions in 2018 SO_2 emissions, and therefore that none of these controls is cost effective.

Indeed, because of recent (and anticipated future) rapid escalation in control-technology costs for reasons noted in this report, it can be expected that any future WFGD or other control-technology installations at units such as McIntosh Unit 1 would be even more expensive -- perhaps much more expensive -- than is suggested by current estimates, which are based on historical data. Furthermore, a full budget-quality cost estimate for significant control installations such as those evaluated here takes far more time to prepare than the period given for this analysis. GPC has found that, when compared to estimated costs based on historical data, costs traditionally are significantly, if not drastically, higher when a full estimate is prepared that takes into account all site-specific information.

Table 5-1 Summary of Cost Analysis Results

Control Option	Cost Effectiveness [$/ton]
WFGD	
Capital Cost Cases:	
EPA Minimum	5,745
Industry Curve Fit minus 30%	5,105
Industry Curve Fit	7,115
Industry Curve Fit plus 70%	12,205
EPA Maximum	28,747
Coal Switching	
Baseline:	
Columbian	Base
Alternatives:	
CAPP	n/a
Indonesian	9,647
Russian	4,352
PRB	6,742
Colorado	7,371
Coal Washing	
Low Capital & High Removal	5,534
High Capital & Low Removal	112,236

Table 5-2 Removal Costs vs. Percent Reduction in Projected 2018 GPC SO_2 Emissions

	Wtd. Average Cost Effectiveness [$/ton]	SO_2 Tons Removed [%]
All Currently Planned GPC WFGD Retrofits	743	93
CONTROL OPTION	Cost Effectiveness [$/ton]	Incremental SO_2 Reduction [%]
WFGD		
Industry Curve Fit	7,115	0.2786
Coal Switching		
Baseline:		
Columbian	Base	n/a
Alternatives:		
CAPP	n/a	n/a
Indonesian	9,647	0.0872
Russian	4,352	0.1135
PRB	6,742	0.0732
Colorado	7,371	0.0568
Coal Washing		
Low Capital & High Removal	5,534	0.0059
High Capital & Low Removal	112,236	0.0007

Table 5-3 provides a summary of visibility modeling results that bound, on the high end, the visibility improvements that the evaluated control options might be able to produce at the relevant Class I areas. The following discussion analyzes this information.

Table 5-3 CMAQ and CALPUFF Modeling Results w/ New IMPROVE Equation

Class I Area	Metrics	Average Change in 20% Worst Days Delta-Delta-Deciview
Okefenokee	CMAQ	0.14
	CALPUFF-Scaled	0.06
Wolf Island	CMAQ	0.15
	CALPUFF-Scaled	0.07
St. Marks	CMAQ	0.08
	CALPUFF-Scaled	N/A

Although it is not listed specifically as one of the statutory factors for states to consider in determining RPGs, the achievement of actual visibility improvement in mandatory Federal Class I areas is, of course, the regional haze rules' underlying objective. Thus, any reasonable progress analysis of potential emission controls must take into account the degree to which those controls improve visibility in those areas. Accordingly, GPC conducted modeling to project visibility improvement at relevant Class I areas that might result from additional SO_2 emission controls on Plant McIntosh Unit 1. In this analysis, which used two different approaches that are described in detail in section 4.0, the visibility changes simulated in the modeling overestimate the unit-control-specific benefits from controls at Unit 1 at Plant McIntosh since a) many more units are controlled, b) pollutants in addition to SO2 are controlled, and/or c) the amount of control is overestimated. Results are presented in Table 5-3. The maximum average benefit on the 20% worst days for the emissions reductions simulated using CMAQ for aggregate emission reductions from several GPC units is 0.15 dv at Wolf Island. Projected benefits from Unit 1 at Plant McIntosh alone would be far less. The maximum benefit for the average of the 20% worst days from an FGD at Plant McIntosh Unit 1 using the scaled CALPUFF results of the simulated maximum emissions rate is 0.07 dv at Wolf Island. Projected benefits from the smaller emissions reductions that would result from fuel switching and coal washing options at Plant McIntosh Unit 1 would be far smaller even than this exceedingly low level of improvement.

In sum, the cost of each of the SO_2 controls evaluated for Plant McIntosh Unit 1 is unreasonably high, on a dollar-per-ton-reduced basis, and any of these extraordinarily expensive controls would in any event yield only negligible further reductions in GPC's SO_2 emissions. Moreover, there are additional energy and non air quality environmental impacts associated with these additional controls. In addition, any visibility improvement that would result from the small additional SO_2 reductions that any of these controls would produce is projected to be minimal and far below the level that would be perceptible at any of the relevant Class I areas. For all of these reasons, GPC believes that no additional controls to reduce SO_2 emissions at Plant McIntosh Unit 1 are necessary or appropriate for the purpose of setting or achieving the 2018 RPGs.