REPORT

BART DETERMINATION FOR CRYSTAL RIVER POWER PLANT UNITS 1 AND 2

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1.0 INTRODUCTION

This submission is made in a cooperative effort to address regional haze rule (RHR) implementation issues resulting from recent regulatory developments related to EPA's Clean Air Interstate Rule (CAIR) and its successor, the Cross-State Air Pollution Rule (CSAPR). CSAPR is currently stayed, and CAIR remains in effect, pending judicial review of CSAPR. Depending on the court's decision on CSAPR, Progress may revisit, revise, or withdraw this proposal.

Progress Energy Florida, Inc. (PEF) owns and operates the Crystal River Power Plant (Facility ID No. 0170004) located on Power Line Road, West of U.S. Highway 19, Crystal River, in Citrus County, Florida. A Best Available Retrofit Technology (BART) determination analysis for particulate matter (PM) emissions from the BART-eligible emissions units (i.e., Unit No. 1 and Unit No. 2) at the Crystal River Power Plant was previously submitted to the Florida Department of Environmental Protection (FDEP) in 2007. This current report presents a revised BART determination analysis, which includes BART determinations for nitrogen oxides (NO_x) and sulfur dioxide (SO_2) emissions from the BART-eligible emissions units at the Crystal River Plant.

Pursuant to Section 403.061(35), Florida Statutes, the federal Clean Air Act (CAA), and the regional haze regulations contained in Title 40, Part 51 of the Code of Federal Regulations (40 CFR 51), Subpart P – Protection of Visibility, the Florida Department of Environmental Protection (FDEP) is required to ensure that certain sources of visibility impairing pollutants in Florida use BART to reduce the impact of their emissions on regional haze in federal Prevention of Significant Deterioration (PSD) Class I areas. Requirements for individual source BART control technology determinations and for BART exemptions are contained in Rule 62-296.340 of the Florida Administrative Code (F.A.C.), which states that a BART-eligible source may demonstrate that it is exempt from the requirement for BART determination for all pollutants by performing an individual source attribution analysis in accordance with the procedures contained in 40 CFR 51, Appendix Y. A BART-eligible source is exempt from BART determination requirements if its contribution to visibility impairment, as determined below, does not exceed 0.5 deciview (dv) above natural conditions in any Class I area [Rule 62-296.340(5)(c), F.A.C.].

The previous BART analysis for PM was based on Rule 62-296.340(5)(c), F.A.C., which states that, for electric generating units subject to the Clean Air Interstate Rule (CAIR) Program, the source attribution analysis need only consider PM emissions (including primary sulfate) for comparison with the contribution threshold. A BART permit was issued on February 25, 2009 (permit No. 0170004-017-AC), which imposed a revised allowable PM emission limit. Specifically, PM emissions from Units 1 and 2 combined are not to exceed 0.04 lb/mmBtu on a weighted average basis of the total heat input during steady state operations and 0.12 lb/mmBtu on a weighted average basis of the total heat input (not to exceed 3 hours in any 24-hour period) during steady state operations. Compliance with these revised standards is to be demonstrated no later than December 31, 2013. Further, the permit assumes that Units 1 and 2 will cease to be operated as coal-fired units by December 31, 2020. The permit requires PEF to notify the

Department of any developments that would delay the shutdown (or repowering) of Units 1 and 2 beyond this date.

On July 6, 2011, EPA finalized the Cross-State Air Pollution Rule (CSAPR), which was to replace CAIR starting in 2012. CSAPR has different emission requirements for NO_x and SO_2. Under CSAPR, the understanding under CAIR that compliance with CAIR requirements satisfied BART requirements for EGUs is no longer valid. EPA is developing a rule that would determine whether CSAPR is better than BART using a two-prong test and appropriate air quality modeling. The Federal Register notice for the final rule of CSAPR said that “EPA has not conducted any technical analysis to determine whether compliance with the Transport Rule would satisfy Reasonably Available Control Technology (RACT) requirements for EGUs in any nonattainment areas or Regional Haze BART-related requirements. For that reason, EPA is neither making determinations nor establishing any presumptions that compliance with the Transport Rule satisfies any RACT- or BART-related requirements for EGUs.”

However, on December 30, 2011, the United States Court of Appeals for the D.C. Circuit issued its ruling to stay CSAPR pending judicial review. As a result, CAIR has been put back into effect. The court set a speedy path to hear the legal arguments in the case, which were presented to the U.S. Court of Appeals in Washington, D.C. on April 13, 2012. However, a final ruling on CSAPR may not come until later this year or possibly in 2013.

It is expected that CSAPR is most likely to be reinstated in principal with the similar provisions as currently promulgated. If CSAPR is determined to be an alternative program that may substitute for source-specific BART, then the same BART modeling analyses for the Crystal River Power Plant conducted in 2007 should still be valid. However, the current version of CSAPR has different requirements for different states. For example, in Florida, it does not regulate SO_2 emissions and only has ozone-season NO_x emissions requirements. As a result, the BART exemption analysis for the Crystal River Power Plant, which was previously based on visibility impacts due to PM emissions only, needs to be re-evaluated, including PM, NO_x and SO_2 and sulfate emissions.

A description of the BART-eligible emissions units, a description of the modeling methodology, and the results of the BART exemption analysis are presented in Section 2.0. Regulatory requirements for the BART determination (control options) analysis are presented in Section 3.0. The BART determination analysis is presented in Section 4.0.

The source information and methodologies used for the BART determination are the same as those presented in the document entitled “Air Modeling Protocol to Evaluate Best Available Retrofit Technology (BART) Options for Affected Progress Energy Florida Plants”, commonly known as the “BART Protocol”. The BART Protocol was previously submitted to FDEP in January 2007.

2.0 DESCRIPTION OF BART-ELIGIBLE EMISSIONS UNITS

The BART-eligible emissions units at the Crystal River Power Plant include two fossil fuel steam generators (FFSGs), further characterized as pulverized coal dry bottom, tangentially-fired boilers, designated as Unit No. 1 and Unit No. 2. Unit No. 1 is a nominal 440.5 megawatt (MW) class (electric) steam generator while Unit No. 2 is a nominal 523.8 MW class (electric) steam generator. The units may burn bituminous coal or a bituminous coal and bituminous coal briquette mixture. Distillate fuel oil may be burned as a startup fuel.

The Crystal River Power plant is located at Universal Transverse Mercator (UTM) coordinates: 334.3 kilometers (km) East, 3,204.5 km North in UTM Zone 17. An area map showing the Plant and PSD Class I areas located within 300 km of the plant is presented in Figure 1-1 of the BART Protocol. The PSD Class I areas which were evaluated include:

- Saint Marks NWA - 174 km
- Chassahowitzka National Wilderness Area (NWA) - 21 km
- Wolf Island NWA - 293 km
- Okefenokee NWA- 178 km

The PSD Class I of the Bradwell Bay NWA is located within 300 km of the Crystal River Power Plant; however visibility impairment is not required to be addressed for this area.

The stack, operating, and PM emission data, including PM speciation, for the BART-eligible emissions units were presented in detail in the BART Protocol previously submitted to FDEP. The emissions units are regulated under Acid Rain-Phase II, Fossil Fuel Steam Generators with more than 250 million Btu per Hour Heat Input (Rule 62-296.405, F.A.C.), Best Available Retrofit Technology (BART) requirements (Rule 62-296.340, F.A.C.) and the Clean Air Interstate Rule (CAIR) requirements under 62-296.470, F.A.C.

As noted in the BART protocol and based on discussions with FDEP, building downwash effects were considered for the Crystal River Power Plant as the facility is located within 50 km of the closest PSD Class I area.

2.1 EMISSION RATES

Emission rates used in the Crystal River BART analysis were presented in the BART Protocol previously submitted to FDEP (only PM emission rates were included). This revised BART analysis includes SO_2 and NO_x emissions in addition to the PM emissions.

The EPA BART guidelines indicate that the emission rate to be used for BART modeling is the highest 24-hour actual emission rate representative of normal operations for the modeling period. Depending on

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the availability of the source data, the source emissions information should be based on the following, in order of priority based on the BART common protocol:

- 24-hour maximum emissions based on continuous emission monitoring (CEM) data for the period 2001 to 2003
- Facility stack test emissions
- Potential to emit
- Allowable permit limits
- AP-42 emission factors

Table 1A presents the stack data, operating parameters, and emissions of SO_2, NO_x, and PM for the baseline (i.e., exemption) scenario. The SO_2 and NO_x emission rates are based on the maximum actual 24-hour average rate from the period 2001 to 2003 which were obtained from the CEM data.

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

The PM emissions from the BART-eligible units at the Crystal River plant were speciated into the recommended size and species categories using EPA's Compilation of Air Pollutant Emission Factors, AP-42 (fifth edition). The species categories for Crystal River Units 1 and 2 were determined from the speciation profile for a "dry bottom boiler burning pulverized coal with ESP" provided in Table 1.1-5 in AP-42. The different size categories were determined from particle size distribution for "dry bottom PC boilers with ESP" provided in Table 1.1-6 in AP-42. The PM speciation data for the exemption scenario are presented in Table 2A (also presented with the BART Protocol previously submitted to FDEP).

2.2 MODELING METHODOLOGY

The CALPUFF model, Version 5.756, also known as the "BART Version CALPUFF", was used to predict the maximum visibility impairment at each of the four PSD Class I areas located within 300 km of the Crystal River Power Plant identified above. This version of CALPUFF, together with the post-processing programs associated with the BART Version of CALPUFF (i.e., POSTUTIL, CALPOST), were also used in the current BART modeling which includes SO_2 and NO_x emissions.

The methods and assumptions used in the CALPUFF model were previously presented in the BART Protocol. The 4-km spacing Florida domain was used for the BART exemption. The refined CALMET domain used for the BART modeling analysis has been provided by FDEP. The major features used in preparing these CALMET data have also been described in Section 4.0 of the BART Protocol.

Based on FDEP guidelines, the 98th percentile, i.e., the 8th highest 24-hour average visibility impairment value in any year or the 22nd highest 24-hour average visibility impairment value over 3 years combined, whichever is higher, is compared to 0.5 dv in the source attribution analysis.

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

Month	Saint Marks NWA	Chassahowitzka NWA	Wolf Island NWA	Okefenokee NWA
January	3.7	3.8	3.4	3.5
February	3.4	3.5	3.1	3.2
March	3.4	3.4	3.0	3.1
April	3.4	3.2	3.0	3.0
May	3.5	3.3	3.3	3.6
June	4.0	3.9	3.7	3.7
July	4.1	3.9	3.7	3.7
August	4.4	4.2	4.1	4.1
September	4.2	4.1	4.0	4.0
October	3.8	3.9	3.7	3.8
November	3.7	3.7	3.5	3.5
December	3.8	3.9	3.5	3.6

Method 6 requires input of natural background (BK) concentrations of ammonium sulfate (BKSO4), ammonium nitrate (BKNO3), coarse particulates (BKPMC), organic carbon (BKOC), soil (BKSOIL), and elemental carbon (BKEC) in micrograms per cubic meter (µg/m^3). The model then calculates the natural background light extinction and haze index based on these values.

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

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

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

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

- Saint Marks NWA – 21.53 Mm-1 (equivalent to 7.67 dv); 11.53 µg/m^3;
- Chassahowitzka NWA – 21.45 Mm-1 (equivalent to 7.63 dv); 11.45 µg/m^3;
- Wolf Island – 21.33 Mm-1 (equivalent to 7.58 dv); 11.33 µg/m^3; and
- Okefenokee NWA – 21.40 Mm-1 (equivalent to 7.61 dv); 11.40 µg/m^3.

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

Visibility impacts were predicted at the PSD Class I areas using receptors provided by the National Park Service (NPS).

2.3 BART EXEMPTION MODELING RESULTS

Summaries of the maximum visibility impairment values for the Crystal River BART-eligible emission units estimated using the new IMPROVE algorithm, are presented in Tables 3A and 4A. The 98th percentile (i.e., 8th highest) 24-hour average visibility impairment values for the years 2001, 2002, and 2003, and the 22nd highest 24-average visibility impairment values over the three years, are presented in Table 3A. The 8th highest visibility impairment values predicted at each PSD Class I area for each year are presented in Table 4A.

As shown in Tables 3A and 4A, the 8th highest visibility impairment values predicted for each year at all of the PSD Class I areas using the 1999 IMPROVE algorithm are greater than 0.5 dv. The 22nd highest visibility impairment value predicted over the 3-year period at this PSD Class I area is also greater than 0.5 dv. As a result, the Crystal River Power Plant is subject to the BART requirements, and a BART determination analysis for PM, SO_2, and NO_x is required for each of the BART-eligible emissions units at the plant.

3.0 REQUIREMENTS FOR ANALYSIS OF BART CONTROL OPTIONS

The visibility regulations define BART as follows:

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

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

(1) The available retrofit control options;

(2) Any pollution control equipment in use at the source (which affects the availability of options and their impacts);

(3) The costs of compliance with control options;

(4) The remaining useful life of the facility;

(5) The energy and non-air quality environmental impacts of control options; and

(6) The visibility impacts analysis.

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

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

STEP 1 – Identify All Available Retrofit Control Technologies

STEP 2 – Eliminate Technically Infeasible Options

STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies

STEP 4 – Evaluate Impacts and Document the Results

STEP 5 – Evaluate Visibility Impacts

Based on descriptions provided in 40 CFR 51 Appendix Y, Guidelines for BART Determinations Under the Regional Haze Rule, each of these steps is described briefly in the following sections.

STEP 1 – Identify All Available Retrofit Control Technologies

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

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

Where a New Source Performance Standard (NSPS) exists for a source category (which is the case for most of the categories affected by BART), a level of control equivalent to the NSPS as one of the control options should be included. The NSPS standards are codified in 40 CFR 60.

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

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

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

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

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

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

STEP 2 – Eliminate Technically Infeasible Options

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

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

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

STEP 3 – Evaluate Control Effectiveness of Remaining Control Technologies

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

(1) Ensuring that the degree of control is expressed using a metric that ensures an "apples to apples" comparison of emissions performance levels among options

(2) Giving appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels

This issue is especially important when comparing inherently lower-polluting processes to one another or to add-on controls. In such cases, it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed, such as pounds of emissions per million British thermal units (lb/MMBtu) of heat input.

Many control techniques, including both add-on controls and inherently lower polluting processes, can perform at a wide range of levels. Scrubbers and high and low efficiency electrostatic precipitators (ESPs) are two of the many examples of such control techniques that can perform at a wide range of levels. It is important that in analyzing the technology one take into account the most stringent emission control level that the technology is capable of achieving. Recent regulatory decisions and performance data (e.g., manufacturer's data, engineering estimates and the experience of other sources) should be considered when identifying an emissions performance level or levels to evaluate.

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

STEP 4 – Evaluate Impacts and Document the Results

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

- Costs of compliance
- Energy impacts
- Non-air quality environmental impacts
- Remaining useful life

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

Costs of Compliance

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

(1) Identify the emissions units being controlled

(2) Identify design parameters for emission controls

(3) Develop cost estimates based upon those design parameters

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

Once the control technology alternatives and achievable emissions performance levels have been identified, the source must develop estimates of capital and annual costs. The basis for equipment cost estimates should also be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Sixth Edition, February 2002). To maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option.

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

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

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

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

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

> Incremental Cost Effectiveness (dollars per incremental ton removed) =
> [(Total annualized costs of control option) − (Total annualized costs of next control option)] ÷
> [(Control option annual emissions) − (Next control option annual emissions)]

Energy Impacts

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

The energy impact analysis should consider only direct energy consumption and not indirect energy impacts. The energy requirements of the control options should be shown in terms of total (and in certain cases, also incremental) energy costs per ton of pollutant removed. Then these units can be converted into dollar costs and, where appropriate, can be factored into the control cost analysis. Indirect energy impacts (such as energy to produce raw materials for construction of control equipment) are generally not considered.

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

Non-Air Quality Environmental Impacts

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

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

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

Remaining Useful Life

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

The remaining useful life is the difference between:

(1) The date that controls will be put in place (capital and other construction costs incurred before controls are put in place can be rolled into the first year, as suggested in EPA’s OAQPS Control Cost Manual); and

(2) The date the facility permanently stops operations. Where this affects the BART determination, this date should be assured by a federally- or State-enforceable restriction preventing further operation.

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

STEP 5 – Evaluate Visibility Impacts

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

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

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

- Develop a modeling protocol.
- For each source, run the model at pre-control and post-control emission rates according to the accepted methodology in the protocol. Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in dv compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hour pre-control emission rate is 100 pounds per hour (lb/hr) of SO_2 and the control efficiency being evaluated is 95 percent, then the post-control rate is 5 lb/hr.
- Make the net visibility improvement determination. Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. The assessment of visibility improvements due to BART controls is flexible and can be done by one or more methods. The frequency, magnitude, and duration components of impairment may be considered. Suggestions for making the determination are:
  - Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g., the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing a given percentage change in improvement).
  - Compare the 98th percentile days for the pre- and post-control runs.

Each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

Selecting the "Best" Alternative

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

(1) Expected emission rate (tons per year, lb/hr)

(2) Emissions performance level (e.g., percent pollutant removed, emissions per unit product, lb/MMBtu, parts per million)

(3) Expected emissions reductions (tons per year)

(4) Costs of compliance – total annualized costs ($), cost effectiveness ($/ton), incremental cost effectiveness ($/ton), and/or any other cost-effectiveness measures (such as $/dv)

(5) Energy impacts

(6) Non-air quality environmental impacts

(7) Modeled visibility impacts

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

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

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

4.0 BART ANALYSIS

4.1 SO_2 Emissions

As shown in Table 3A, the highest 8th highest visibility impact due to Units 1 and 2 is 7.93 dv, more than 90 percent of which is due to sulfate particles. Since sulfate particles are formed due to SO_2 and sulfuric acid mist (SAM) emissions, reduction of SO_2 emissions from Units 1 and 2 is the most effective way to reduce visibility impacts due to the BART-eligible emissions units at the site. The SO_2 emissions from the two boilers are currently not controlled.

The BART control analysis, which is similar to the BACT analysis under PSD regulations, is presented in the following sections for SO_2 emissions from the two units. The analysis includes consideration of the available retrofit control technologies, analyzing the feasibility of these technologies, evaluating control effectiveness of the feasible control technologies, evaluating the impacts from cost of compliance, energy, non air-quality environmental, remaining useful life, and finally evaluating the improvement in visibility that may result from the control technology.

4.1.1 Available Retrofit Control Technologies

As part of the BART analysis, a review of previous SO_2 BACT determinations for coal-fired utility and large industrial-sized boilers was performed using the RACT/BACT/LAER Clearinghouse (RBLC) on EPA's webpage. Numerous examples are available in the RBLC database for large coal-fired boilers, which typically use flue gas desulfurization (FGD) as the BACT for SO_2 emissions. However, it should be noted that this database does not reflect the use of FGD systems as a retrofit to existing units. For existing units, the use of lower sulfur fuels is much more cost-effective than the retrofit of an FGD system. These determinations are presented in Table 5.

4.1.2 Control Technology Feasibility

The following control technologies were analyzed:

Low Sulfur Fuel

Units 1 and 2 currently burn bituminous coal. Sulfur content of bituminous coal can range from 0.3 percent to more than 3 percent. Switching to a lower-sulfur coal can reduce SO_2 emissions; however, the cost of compliance depends on the following:

- Cost difference of low sulfur coal and the coal currently used
- Difference in delivery cost for the lower-sulfur coal
- Costs associated with modifications to the units to enable use of lower sulfur coals

Use of low sulfur fuel is considered to be a technically feasible option to reduce SO_2 emissions.

Flue Gas Desulfurization

FGD systems are post-combustion control technologies that rely on chemical reactions within the control device to reduce the concentration of SO_2 in the flue gas. The chemical reaction with an alkaline chemical, which can be performed in a wet or dry contact system, converts SO_2 to sulfite or sulfate salts. In a wet FGD system, a reagent is slurried with water and sprayed into the flue gas stream in an absorber vessel. The SO_2 is removed from the flue gas by sorption and reaction with the slurry. The by-products of the sorption and reaction are in a wet form upon leaving the system and must be dewatered prior to transport/disposal.

The most widely used system for large-scale SO_2 removal is the calcium-based wet lime/limestone FGD system. SO_2 control efficiencies for wet limestone FGD range from 50 to 98 percent, depending on the type of device and design, with an average of 90 percent.

In a dry FGD system, SO_2-containing flue gas comes into contact with an alkaline sorbent such as lime. The sorbent can be delivered to flue gas in an aqueous slurry form (lime spray drying process) or as a dry powder (sorbent injection process). After the sorption and reaction process, a dry waste is produced which is similar to fly ash. The by-product is subsequently captured in a downstream particulate collection device, typically an ESP or a baghouse.

A dry scrubber can use either lime or sodium carbonate as reagent. A typical dry scrubber will use lime as the reagent because it is more readily available than sodium carbonate and the sodium-based reactions produce a soluble by-product that requires special handling.

Lime spray drying efficiency ranges from 70 to 96 percent, with an average of 90 percent. The use of a PM control device after the dry scrubber differs from the wet scrubber system, in which the slurry leaving the wet system must be dewatered and the gas cooled to adiabatic saturation temperature, which requires the particulate control device to be located upstream of the scrubber. The dry byproduct from the dry scrubber system is generally not marketable, since the byproducts includes fly ash and reacted SO_2 and calcium compounds. In contrast, the wet limestone FGD system can produce a marketable byproduct (i.e., gypsum).

Because the dry scrubber absorber construction material is usually carbon steel, the capital costs are usually less expensive as compared with wet scrubbers. However, the necessary use of lime in the process increases its annual operational costs. Based on the EPA Fact Sheet on FGD systems, typical industrial applications of FGD systems are stationary coal and oil-fired combustion units such as utility and industrial boilers.

The RBLC database review also shows that post-combustion controls are typically applied to coal-fired boilers. The EPA Fact Sheet mentions the high capital cost of an FGD system as a disadvantage.

4.1.3 Control Effectiveness of Options

The effectiveness of SO_2 emissions control by the use of an FGD system is assumed to result in approximately 95 percent control. PEF has preliminary estimates of the costs to retrofit dry FGD (DFGD) systems on Units 1 and 2, based on a Worley Parsons (WP) study conducted in 2010. The effectiveness of SO_2 emissions control by the use of low sulfur coal depends on the sulfur content of the lower sulfur coal that is available and economically feasible.

4.1.4 Impacts of Control Technology Options

LOW SULFUR FUELS

To achieve SO_2 emissions below current levels, Units 1 and 2 would require use of lower sulfur coal. The annual average fuel sulfur level for Crystal River Units 1 and 2 during the baseline years was approximately 1.02 percent. Based on the highest average fuel sulfur of 1.02 percent and an average fuel heating value of approximately 12,000 Btu/lb, an average baseline SO_2 emission rate of 1.7 lb/mmBtu was achieved. PEF has indicated that commercially available coal sulfur contents are as follows:

- 0.68 percent sulfur (equivalent to 1.2 lb/mmBtu, based on a fuel heating value of 12,000 Btu/lb)
- 0.35 percent sulfur (equivalent to 0.8 lb/mmBtu, based on a fuel heating value of 8,500 Btu/lb)

However, it is important to note that the 0.35 percent sulfur coal is representative of sub-bituminous coal, also referred to as Powder River Basin (PRB) coal. This coal requires special handling and modifications to existing equipment. While lower sulfur coal is potentially available from the Powder River Basin (PRB), PRB coal is sub-bituminous coal that has unique combustion characteristics requiring specific boiler designs and modifications to existing coal transport, handling and storage equipment. Moreover, the transportation of this coal from Wyoming to Florida would not only add significant cost but involve considerable secondary environmental impacts from unit trains travelling such a distance.

Based on information provided by PEF, the current delivered fuel (1.02 percent sulfur) cost is $4.25 per mmBtu of heating value. The cost of compliance to use reduced sulfur coal is represented by the additional cost of the lower sulfur coal versus the current 1.02 percent sulfur coal used in the boilers, plus any other capital costs that may be associated with the conversion to a different coal. According to PEF, reduced sulfur coal with 0.68 percent and 0.35 percent sulfur costs $4.37 per mmBtu and $4.04 per mmBtu, respectively, excluding additional capital and operating costs.

The cost analysis for the lower sulfur fuel options was prepared following EPA's Control Cost Manual, and is presented in Table 6 for Units 1 and 2. There are additional equipment costs and indirect capital costs for using the lower sulfur bituminous coal (i.e., the 0.68 percent sulfur case), that could be required due to the anticipated reduction in control efficiency of the ESPs while burning lower sulfur coal. It is unknown at this time if ESP upgrades will be required to meet the current BART PM limit of 0.04 lb/mmBtu normal operation and 0.12 lb/mmBtu limit for soot blowing operation after a switch to compliance coal. The high-level cost estimates provided are based on previous analyses to meet the lowered PM BART limit while burning coal with the current sulfur content. Additional analyses would be required to determine unit-specific modifications needed to maintain reliable ESP operation at this same PM BART limit, but taking into account the reduced efficiency expected while burning a lower sulfur coal.

Given the above qualifications on the cost estimates, Table 6 presents the total capital and annualized costs of switching Units 1 and 2 from the coal currently used to 0.68 percent sulfur coal. Annualized operating costs are estimated at more than $97 million, resulting in an average cost effectiveness of approximately $8,665 per ton of SO_2 removed if 0.68 percent sulfur fuel is used instead of the current coal.

To calculate the emissions reduction due to the control options, an apples-to-apples comparison of baseline emissions and controlled emissions were calculated based on future projected actual fuel usage. For the remaining useful life of these units, PEF has estimated annual fuel usage to be approximately 45,000,000 mmBtu/yr for both units combined. This represents a capacity factor of approximately 60 percent for these units.

Regarding the PRB coal option, there would be additional equipment costs and indirect capital costs for using the lower sulfur sub-bituminous coal (i.e., the 0.35 percent sulfur case), that could be required due to the anticipated reduction in control efficiency of the ESPs while burning lower sulfur coal, as well as the additional capital costs required for other equipment modifications. This cost estimate is based on a 2005 Sargent and Lundy Crystal River 4 & 5 study on costs of converting to 100 percent PRB. Significant increased scope is not included in this estimate, as an engineering evaluation would have to be completed to accurately define the required scope. Excluded scope includes, but is not limited to, pressure part modifications, ESP modifications, electrical system upgrades, and fan modifications. The 2005 costs were escalated to 2012 costs using the Global Insight Ash and Coal Handling cost category. In addition this cost estimate does not include any O&M, reagent, byproduct or fuel cost impacts, nor does it include a risk adjustment for potential safety hazards and associated issues related to the use of PRB coal at the Crystal River site.

Given the above qualifications and exclusions from the cost estimates, Table 6 presents the capital and annualized costs of switching Units 1 and 2 from the coal currently used to 0.35 percent sulfur coal.

Annualized operating costs are estimated at more than $296 million, resulting in an average cost effectiveness of approximately $14,652 per ton of SO_2 removed from the current base case and an incremental cost effectiveness of approximately $22,137 per ton of SO_2 removed when compared to the 0.68 percent sulfur case.

However, it should be noted that the Mercury and Air Toxics Standards (MATS) or Utility MACT, was issued with an effective date of April 16, 2012 and requires the installation of maximum achievable control technology (MACT). For existing EGUs, MATS contains an alternative, surrogate emission limit for PM with a compliance deadline of April 16, 2015, and an optional possibility of two one-year extensions. Relating MATS to BART, EPA has stated in 40 CFR Part 51, Appendix Y that facilities may rely on the MACT standards for purposes of BART. Ultimately, MATS will require the installation of controls on Crystal River Units 1 & 2 or force their retirement.

Energy Impacts

There are energy impacts associated with using lower sulfur coals, such as PRB coal, since the heating value of the PRB coal is much lower than the current coals being used (e.g., 8,500 Btu/lb versus 12,000 Btu/lb).

Non-Air Quality Environmental Impacts

Use of low or reduced sulfur coal does not result in any non-air quality environmental impacts.

Remaining Useful Life

A BART permit was issued for these units on February 25, 2009 (permit No. 0170004-017-AC), which imposed a revised allowable PM emission limit. The permit assumes that Units 1 and 2 will cease to be operated as coal-fired units by December 31, 2020. The permit requires PEF to notify the Department of any developments that would delay the shutdown (or repowering) of Units 1 and 2 beyond this date.

For the low sulfur fuel control options, it is assumed that some level of capital improvement will be required for ESP upgrades to accommodate the 0.68 percent sulfur coal, and that replacement of the ESPs with baghouses and other equipment modifications would be required for the firing of PRB coal. For this analysis, it is assumed that ESP upgrades or replacements and other equipment modifications would not be complete until 2018. Since the proposed unit retirement date is the end of 2020, this would result in a useful control option equipment life of two years.

FLUE GAS DESULFURIZATION

PEF has preliminary estimates of the costs to retrofit dry FGD (DFGD) systems on Units 1 and 2, based on a Worley Parsons (WP) study conducted in 2010. This estimate is characterized as a Class 5 estimate with an approximate accuracy rate of +/- 30 percent. The study also has several qualifications on the cost estimates, which are not included in this report, as follows:

- Based on the location at Crystal River for construction (i.e. site constraints, conditions of the current units, etc), a 20 percent productivity factor is recommended to be added to the EPC
- Estimate does not provide funds for transformers
- Reasonable Progress Energy owner's cost would be approximately 2.5 percent
- Add owner's contingency on the EPC contract at 5 percent
- This estimate does not factor in any escalation - assume 5 percent per year
- This estimate is project view and does not include any AFUDC, burdens or allocations. A rough estimate for financial view (AFUDC, burdens, allocations) costs would be approximately 8 percent

It is estimated that the capital costs for installation of DFGD systems are approximately $445 million for Units 1 and 2 combined. As shown in Table 7, the total annualized cost for installation and operation of the DFGD systems is $364 million for Units 1 and 2 combined. These annualized costs represent the annualized capital cost, as well as recurring annual operating costs for each unit.

To calculate the emissions reduction due to the DFGD control option, an apples-to-apples comparison of baseline emissions and controlled emissions were calculated based on future projected actual fuel usage. For the remaining useful life of these units, PEF has estimated annual fuel usage to be approximately 45,000,000 mmBtu/yr for both units combined. This represents a capacity factor of approximately 60 percent for these units. In addition, it is assumed that the baseline sulfur coal will continue to be fired and that the design DFGD control efficiency will be 95 percent.

As shown in Table 7, the average cost effectiveness is calculated to be approximately $10,034 per ton of SO_2 removed for Units 1 and 2 combined.

Energy Impacts

There are energy impacts associated with operation of DFGD systems. These additional energy impacts, due to use of auxiliary power and additional pressure drop in the system, are factored into the control cost analysis.

Non-Air Quality Environmental Impacts

Non-air quality impacts would potentially include increased energy use, increased water use and generation of additional solid wastes.

Remaining Useful Life

A BART permit was issued for these units on February 25, 2009 (permit No. 0170004-017-AC), which imposed a revised allowable PM emission limit. The permit assumes that Units 1 and 2 will cease to be operated as coal-fired units by December 31, 2020. The permit requires PEF to notify the Department of any developments that would delay the shutdown (or repowering) of Units 1 and 2 beyond this date.

Installation of DFGD controls for Units 1 and 2 would require time for project design and construction, as well as consideration for scheduling that allows for the continued operation to allow PEF to supply reliable electric power to its customers. For this analysis, it is assumed that these upgrades would not be complete until 2018. This would result in a useful control option equipment life of two years.

4.1.5 Visibility Impacts

To calculate the visibility improvement due to the lower sulfur content fuel and the DFGD control options, first the baseline visibility impacts were estimated based on the maximum 8th highest 24-hour average visibility impacts presented in Table 3A, which is 7.93 dv. Since sulfate particles contributed to more than 90-percent of the total visibility impact, instead of using just the sulfate contribution, the total impact (due to all pollutants) was used as a baseline.

Future or controlled visibility impacts were estimated based on modeling the reduced SO_2 emissions rates, which will result from the burning of lower sulfur coal and the installation of FGD systems of 95 percent control efficiency. These emission rates were calculated by multiplying the SO_2 emissions rates used in the baseline impact analysis by the ratio of: 1) the specific sulfur content (0.68 percent or 0.35 percent) and the baseline sulfur content (estimated to be 1.02 percent) for the fuel sulfur option and 2) by the uncontrolled baseline and the estimated control efficiency of the add on control equipment for the FGD option. The SO_2, NO_x and PM emission rates for the 0.68 percent sulfur coal, 0.35 percent sulfur coal and FGD systems scenarios are provided in Tables 1B, 1C and 1D, respectively. The PM speciation profiles for the 0.68 percent sulfur coal, 0.35 percent sulfur coal and FGD unit scenarios are shown in Tables 1B, 1C and 1D, respectively. Visibility improvements were determined by subtracting future dv impacts from the baseline dv impacts. Tables 3B, 3C and 3D provide a summary of the BART modeling results, including the relative contributions of SO2, NOx and PM, for the 0.68 percent sulfur coal, 0.35 percent sulfur coal and FGD systems cases, respectively. Tables 4B, 4C and 4D show the visibility rankings at each Class I area for 0.68 percent sulfur coal, 0.35 percent sulfur coal and FGD unit scenarios, respectively.

The visibility cost effectiveness numbers were calculated from the annual costs and the visibility improvement in dv. Visibility cost effectiveness numbers for the two units together are also presented in Table 6. As shown, visibility cost effectiveness for switching from the approximate 1.02 percent sulfur currently used to 0.68 percent sulfur is more than $40.4 million/dv for a total visibility improvement of 2.41 dv. Incremental visibility cost effectiveness for switching to 0.35 percent sulfur fuel is $145 million/dv for an additional improvement of 1.37 dv. Finally, the visibility cost effectiveness for installation of an DFGD system on Units 1 and 2 combined is $79.4 million/dv for an additional improvement of 4.59 dv. This visibility improvement is extremely small for a very large cost.

4.1.6 Selection of BART

As the pollutant and visibility cost effectiveness values above indicate, the cost of improvement is extremely high for switching from the current coal to 0.68 or 0.35 percent sulfur coal. As a result, switching to either of these lower sulfur coals has been determined to be cost prohibitive. Further, the capital cost and annual operating costs associated with retrofitting FGD systems on Units 1 and 2 was also demonstrated to be prohibitive.

In addition, it should be noted that the Mercury and Air Toxics Standards (MATS) or Utility MACT, was issued with an effective date of April 16, 2012 and requires the installation of maximum achievable control technology (MACT). For existing EGUs, MATS contains an alternative, surrogate emission limit for PM with a compliance deadline of April 16, 2015, and an optional possibility of two one-year extensions. Relating MATS to BART, EPA has stated in 40 CFR Part 51, Appendix Y that facilities may rely on the MACT standards for purposes of BART. Ultimately, MATS will require the installation of controls on Crystal River Units 1 & 2 or force their retirement.

4.2 NO_x Emissions

PEF has actual capital and annual operating costs for the SCR systems that were installed at Crystal River for Units 4 and 5. These are actual costs for retrofit SCR systems at existing coal-fired units at Crystal River and are considered representative, when scaled to MW capacity, of the costs to install and operate SCR systems for Units 1 and 2. It is estimated that the capital costs for installation of SCR systems are approximately $83 MM and $99 MM for Units 1 and 2, respectively. These are significant costs and cannot be justified for an approximate two years of useful control equipment life (i.e., 2018 until retirement in 2020).

Further, due to recent regulatory developments related to EPA's Clean Air Interstate Rule (CAIR) and its successor, the Cross-State Air Pollution Rule (CSAPR), CSAPR is currently stayed, and CAIR remains in effect, pending judicial review of CSAPR. PEF believes that compliance with CAIR (and CSAPR, depending on the court's decision) will serve to demonstrate compliance with applicable NOx standards under the BART program.

In addition, as shown in Table 3A, the visibility contribution of nitrate particles (which are formed by NO_x emissions) corresponding to the maximum 8th highest 24-hour average visibility impact is only 7.0 percent. Therefore, control of NO_x emissions will provide minimal effect in reducing visibility impacts due to Units 1 and 2 at the receptor corresponding to the maximum 8th highest visibility impact at the nearest Class I area (i.e., Chassohowitzka NRA).

Additional add-on control technologies, such as a selective catalytic reduction (SCR) system, will require a direct capital investment, as well as continuing annual operating costs for each unit, which will not result in any meaningful reduction in visibility. As demonstrated by modeling, the visibility contribution of nitrate particles is not significant. Further, PEF believes that compliance with CAIR (and CSAPR, depending on the court's decision) will serve to demonstrate compliance with applicable NOx standards under the BART program. As a result, PEF proposes that existing combustion processes, low NO_x burners, and good combustion practices be considered as BART for NO_x emissions for Units 1 and 2.

TABLE 1A
BART MODELING DATA INPUT
CRYSTAL RIVER POWER PLANT, UNITS 1 & 2
BASELINE (EXEMPTION) SCENARIO

Parameter	Units	Value			
Emission Unit		Unit 1		Unit 2	
Location					
UTM Coordinates[a]					
East	km	334.30		334.30	
North	km	3,204.50		3,204.50	
Zone		17		17	
Lambert Conformal Coordinates [a]					
x	km	1,398.50		1,398.50	
y	km	-1,116.10		-1,116.10	
Stack Data					
Height	ft (m)	499	(152.1)	502	(153.0)
Diameter	ft (m)	15	(4.57)	16.0	(4.88)
Base elevation	ft (m)	3.3	(1.00)	3.3	(1.00)
Hourly heat input[b]	MMBtu/hr	3630.0	-	4390.0	-
Operating Data					
Exit gas temperature	^{o}F (K)	291	(417)	300	(422)
Exit gas velocity	ft/s (m/s)	132.7	(40.5)	160.0	(48.8)
Emission Data[c,d,e,f]					
SO_2	lb/hr (g/s)	7,238.4	(912.0)	8,968.1	(1130.0)
NO_x	lb/hr (g/s)	1,601.2	(201.7)	2,913.0	(367.0)
PM Filterable	lb/hr (g/s)	140.8	(17.7)	115.2	(14.5)
SO_4	lb/hr (g/s)	50.4	(6.4)	61.0	(7.7)

Notes:

a. Based on common location using UTM coordinates of: East 567.4 km; North 2,813.5 km

b. Hourly heat input for each unit corresponds to the maximum hourly PM emissions for 2001 - 2006.

c. SO_2 emissions data based on CEMS data for 2001 - 2003.

d. NO_x emissions data based on CEMS data for 2001 - 2003.

e. PM filterable emissions data based on monitoring data from 2001 - 2006.

f. SO_4 emissions data calculated based on 0.8% conversion of sulfur to H_2SO_4 and 37% removal of H_2SO_4 in electrostatic precipitator (Southern Company methodology).

TABLE 2A
PM SPECIATION SUMMARY - PEF CRYSTAL RIVER POWER PLANT, UNIT 1
BASELINE (EXEMPTION) SCENARIO

PM Category	Emission Unit [a]	Units	Total	Coarse PM	Soil (Fine PM)	Elemental Carbon (EC)	Inorganic (as H_2SO_4)	Organic
PM Filterable [b]	Unit 1	lb/hr	140.8	78.23	60.27	2.32	NA	NA
		%	100%	56%	43%	1.6%	NA	NA
PM Condensable [c]	Unit 1	lb/hr	283.14	NA	NA	NA	50.4	232.7
		%	100%	NA	NA	NA	18%	82%
Total PM_{10} (filterable+condensable)	Unit 1	lb/hr	424.0	78.23	60.27	2.32	50.43	232.7
		%	100%	18.5%	14.2%	0.5%	11.9%	54.9%
Total PM_{10} (filterable+Organic Condensable PM)	Unit 1	lb/hr	373.5	78.23	60.27	2.32	0.0	232.7
Modeled PM Speciation % (SO_4 modeled separately)		%	100%	20.9%	16.1%	0.6%	0.0%	62.3%

PM Particle Size Distribution for CALPUFF Assessment

Species	Size Distribution by Category (%)					Emission Rate (lb/hr)		
	AP-42 (Table 1.1-6)		Cumulative	Individual Categories				
Name	Particle Size (microns)	Cumulative (%)	Normalized PM10 (%)	Filterable (%)	Organic Condensable	Filterable	Organic Condensable	Total
Total PM_{10}						140.8	232.7	373.5
PM0063	0.63	18.5%	33.3%	33.3%	50.0%	46.9	116.4	163.2
PM0100	1	0.0%	0.0%	0.0%	50.0%	0.0	116.4	116.4
PM0125	1.25	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM0250	2.5	25.9%	46.6%	13.3%	0	18.7	0.0	18.7
PM0600	6	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM1000	10	55.6%	100.0%	53.4%	0	75.2	0.0	75.2
Totals				100.0%	100.0%	140.8	232.7	373.5

Total Modeled PM_{10} 373.5

[a] Heat input rate for unit and fuel heat content 3,630 MMBtu/hr 3,630 Unit 1
1.08 sulfur content (%)

[b] PM fine consists of PM soil and PM elemental carbon lb/1000 gal
PM fine based on ratio of PM2.5 (fine) to PM10 (filterable) PM2.5 0.24 lb/ton Ratio = 0.44 PM2.5/PM10
emission factor (Table 1.1-5, AP-42) PM10 0.54 lb/ton

PM elemental carbon based on EPA's "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", Table 5, January 2002 DRAFT
0.037 of PM2.5

PM elemental carbon 0.016 PM elemental carbon/PM10
PM soil= PM2.5 - PM elemental carbon 0.43 PM soil/PM10
PM2.5 0.44 PM2.5/PM10
PM coarse= PM10 - PM2.5

[c] Condensable PM (Table 1.1-6, AP-42) lb/MMBtu
Total 0.1 x S - 0.03
0.08

TABLE 2A (CONTINUED)
PM SPECIATION SUMMARY - PEF CRYSTAL RIVER POWER PLANT, UNIT 2
BASELINE (EXEMPTION) SCENARIO

PM Category	Emission Unit [a]	Units	Total	Coarse PM	Soil (Fine PM)	Elemental Carbon (EC)	Inorganic (as H_2SO_4)	Organic
PM Filterable [b]	Unit 1	lb/hr	115.2	64.00	49.31	1.89	NA	NA
		%	100%	56%	43%	1.6%	NA	NA
PM Condensable [c]	Unit 1	lb/hr	342.42	NA	NA	NA	61.0	281.4
		%	100%	NA	NA	NA	18%	82%
Total PM_{10} (filterable+condensable)	Unit 1	lb/hr	457.6	64.00	49.31	1.89	61.0	281.4
		%	100%	14.0%	10.8%	0.4%	13.3%	61.5%
Total PM_{10} (filterable+Organic Condensable PM)	Unit 1	lb/hr	396.6	64.00	49.31	1.89	0.0	281.44
Modeled PM Speciation % (SO_4 modeled separately)		%	100%	16.1%	12.4%	0.5%	0.0%	71.0%

PM Particle Size Distribution for CALPUFF Assessment

Species	Size Distribution by Category (%)					Emission Rate (lb/hr)		
	AP-42 (Table 1.1-6)		Cumulative	Individual Categories				
Name	Particle Size (microns)	Cumulative (%)	Normalized PM10 (%)	Filterable (%)	Organic Condensable	Filterable	Organic Condensable	Total
Total PM_{10}						115.2	281.4	396.6
PM0063	0.63	18.5%	33.3%	33.3%	50.0%	38.3	140.7	179.0
PM0100	1	0.0%	0.0%	0.0%	50.0%	0.0	140.7	140.7
PM0125	1.25	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM0250	2.5	25.9%	46.6%	13.3%	0	15.3	0.0	15.3
PM0600	6	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM1000	10	55.6%	100.0%	53.4%	0	61.5	0.0	61.5
Totals				100.0%	100.0%	115.2	281.4	396.6

Total Modeled PM_{10} 396.6

[a] Heat input rate for unit and fuel heat content 4,390 MMBtu/hr 4,390 Unit 1
1.08 sulfur content (%)

[b] PM fine consists of PM soil and PM elemental carbon lb/1000 gal
PM fine based on ratio of PM2.5 (fine) to PM10 (filterable) PM2.5 0.24 lb/ton Ratio = 0.44 PM2.5/PM10
emission factor (Table 1.1-5, AP-42) PM10 0.54 lb/ton

PM elemental carbon based on EPA's "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", Table 5, January 2002 DRAFT
0.037 of PM2.5

PM elemental carbon 0.016 PM elemental carbon/PM10
PM soil= PM2.5 - PM elemental carbon 0.43 PM soil/PM10
PM2.5 0.44 PM2.5/PM10
PM coarse= PM10 - PM2.5

[c] Condensable PM (Table 1.1-6, AP-42) lb/MMBtu
Total 0.1 x S - 0.03
0.08

TABLE 3A
SUMMARY OF BART BASELINE (EXEMPTION) MODELING RESULTS WITH NEW IMPROVE ALGORITHM
CRYSTAL RIVER POWER PLANT - UNITS 1 AND 2 - COAL FIRING

Class I Area	Distance (km) of Source to Nearest Class I Area Boundary	Visibility Impact >0.5 dv 2001	2001 8th Highest Impact (dv)	2002	2002 8th Highest Impact (dv)	2003	2003 8th Highest Impact (dv)	22nd Highest Impact (dv) Over 3-Yr Period
Saint Marks NWA	174		4.08		3.40		3.99	3.96
Pollutant Contribution		Sulfate	88.1%	Sulfate	89.8%	Sulfate	85.2%	
		Nitrate	9.2%	Nitrate	7.5%	Nitrate	10.1%	
		Particulate Matter	2.7%	Particulate Matter	2.6%	Particulate Matter	4.8%	
Chassahowitzka NWA	21		7.93		7.18		6.43	6.97
Pollutant Contribution		Sulfate	90.4%	Sulfate	47.8%	Sulfate	42.6%	
		Nitrate	7.0%	Nitrate	23.8%	Nitrate	29.5%	
		Particulate Matter	2.7%	Particulate Matter	28.4%	Particulate Matter	27.9%	
Wolf Island NWA	293		1.23		1.22		1.78	1.52
Pollutant Contribution		Sulfate	96.7%	Sulfate	96.2%	Sulfate	94.4%	
		Nitrate	2.2%	Nitrate	2.3%	Nitrate	1.8%	
		Particulate Matter	1.1%	Particulate Matter	1.5%	Particulate Matter	3.7%	
Okefenokee NWA	178		2.50		2.82		2.14	2.70
Pollutant Contribution		Sulfate	95.3%	Sulfate	83.4%	Sulfate	95.0%	
		Nitrate	3.3%	Nitrate	13.1%	Nitrate	3.0%	
		Particulate Matter	1.4%	Particulate Matter	3.5%	Particulate Matter	2.0%	

TABLE 4A
VISIBILITY IMPACT RANKINGS AT PSD CLASS I AREAS
WITH NEW IMPROVE ALGORITHM, BASELINE (EXEMPTION) ANALYSIS
CRYSTAL RIVER POWER PLANT - UNITS 1 AND 2

Class I Area	Rank	2001 Predicted Impact (dv)	2002 Predicted Impact (dv)	2003 Predicted Impact (dv)
Saint Marks NWA	1	8.14	7.93	5.09
	2	6.13	5.75	4.99
	3	5.57	4.26	4.98
	4	5.27	4.14	4.69
	5	4.74	3.63	4.64
	6	4.46	3.50	4.56
	7	4.24	3.42	4.44
	8	4.08	3.40	3.99
Chassahowitzka NWA	1	10.59	9.82	9.21
	2	9.85	9.29	9.19
	3	9.58	8.21	8.26
	4	9.56	7.84	7.65
	5	8.79	7.84	6.97
	6	8.62	7.56	6.66
	7	8.36	7.56	6.47
	8	7.93	7.18	6.43
Wolf Island NWA	1	3.31	3.59	2.62
	2	2.26	2.90	2.51
	3	2.14	2.14	2.39
	4	1.54	1.80	2.35
	5	1.52	1.54	2.16
	6	1.43	1.48	1.94
	7	1.38	1.34	1.81
	8	1.23	1.22	1.78
Okefenokee NWA	1	4.66	4.53	4.57
	2	3.99	4.37	3.98
	3	3.55	3.29	3.96
	4	2.98	3.15	3.44
	5	2.83	3.02	3.35
	6	2.83	2.90	2.81
	7	2.55	2.85	2.78
	8	2.50	2.82	2.14

TABLE 1B
BART MODELING DATA INPUT
CRYSTAL RIVER POWER PLANT, UNITS 1 & 2
COMPLIANCE COAL, 0.68 WEIGHT % SULFUR

Parameter	**Units**	**Value**			
Emission Unit		Unit 1		Unit 2	
Location					
UTM Coordinates[a]					
East	km	334.30		334.30	
North	km	3,204.50		3,204.50	
Zone		17		17	
Lambert Conformal Coordinates [a]					
x	km	1,398.50		1,398.50	
y	km	-1,116.10		-1,116.10	
Stack Data					
Height	ft (m)	499	(152.1)	502	(153.0)
Diameter	ft (m)	15	(4.57)	16.0	(4.88)
Base elevation	ft (m)	3.3	(1.00)	3.3	(1.00)
Hourly heat input[b]	MMBtu/hr	3630.0	-	4390.0	-
Operating Data					
Exit gas temperature	^oF (K)	291	(417)	300	(422)
Exit gas velocity	ft/s (m/s)	132.7	(40.5)	160.0	(48.8)
Emission Data[c,d,e,f]					
SO_2	lb/hr (g/s)	4,356.0	(548.9)	5,268.0	(663.8)
NO_x	lb/hr (g/s)	1,601.2	(201.7)	2,913.0	(367.0)
PM Filterable	lb/hr (g/s)	140.8	(17.7)	115.2	(14.5)
SO_4	lb/hr (g/s)	33.6	(4.2)	40.7	(5.1)

Notes:

a. Based on common location using UTM coordinates of: East 567.4 km; North 2,813.5 km

b. Hourly heat input for each unit corresponds to the maximum hourly PM emissions for 2001 - 2006.

c. SO_2 emissions calculated based on vendor SO_2 emission factor and hourly heat input

d. NO_x emissions data based on CEMS data for 2001 - 2003.

e. PM filterable emissions data based on monitoring data from 2001 - 2006.

f. SO_4 emissions data calculated based on 0.8% conversion of sulfur to H_2SO_4 and 37% removal of H_2SO_4 in electrostatic precipitator (Southern Company methodology).

TABLE 2B
PM SPECIATION SUMMARY - PEF CRYSTAL RIVER POWER PLANT, UNIT 1
COMPLIANCE COAL, 0.68 WT% SULFUR

PM Category	Emission Unit [a]	Units	Total	Coarse PM	Soil (Fine PM)	Elemental Carbon (EC)	Inorganic (as H_2SO_4)	Organic
PM Filterable [b]	Unit 1	lb/hr	140.8	78.23	60.27	2.32	NA	NA
		%	100%	56%	43%	1.6%	NA	NA
PM Condensable [c]	Unit 1	lb/hr	137.94	NA	NA	NA	33.6	104.3
		%	100%	NA	NA	NA	24%	76%
Total PM_{10} (filterable+condensable)	Unit 1	lb/hr	278.8	78.23	60.27	2.32	33.62	104.3
		%	100%	28.1%	21.6%	0.8%	12.1%	37.4%
Total PM_{10} (filterable+Organic Condensable PM)	Unit 1	lb/hr	245.1	78.23	60.27	2.32	0.0	104.3
Modeled PM Speciation % (SO_4 modeled separately)		%	100%	31.9%	24.6%	0.9%	0.0%	42.6%

PM Particle Size Distribution for CALPUFF Assessment

Species	Size Distribution by Category (%)					Emission Rate (lb/hr)		
	AP-42 (Table 1.1-6)		Cumulative	Individual Categories				
Name	Particle Size (microns)	Cumulative (%)	Normalized PM10 (%)	Filterable (%)	Organic Condensable	Filterable	Organic Condensable	Total
Total PM_{10}						140.8	104.3	245.1
PM0063	0.63	18.5%	33.3%	33.3%	50.0%	46.9	52.2	99.0
PM0100	1	0.0%	0.0%	0.0%	50.0%	0.0	52.2	52.2
PM0125	1.25	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM0250	2.5	25.9%	46.6%	13.3%	0	18.7	0.0	18.7
PM0600	6	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM1000	10	55.6%	100.0%	53.4%	0	75.2	0.0	75.2
Totals				100.0%	100.0%	140.8	104.3	245.1

Total Modeled PM_{10} 245.1

[a] Heat input rate for unit and fuel heat content 3,630 MMBtu/hr 3,630 Unit 1
0.68 sulfur content (%)

[b] PM fine consists of PM soil and PM elemental carbon lb/1000 gal
PM fine based on ratio of PM2.5 (fine) to PM10 (filterable) PM2.5 0.24 lb/ton Ratio = 0.44 PM2.5/PM10
emission factor (Table 1.1-5, AP-42) PM10 0.54 lb/ton

PM elemental carbon based on EPA's "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", Table 5, January 2002 DRAFT
0.037 of PM2.5

PM elemental carbon 0.016 PM elemental carbon/PM10
PM soil= PM2.5 - PM elemental carbon 0.43 PM soil/PM10
PM2.5 0.44 PM2.5/PM10
PM coarse= PM10 - PM2.5

[c] Condensable PM (Table 1.1-6, AP-42) lb/MMBtu
Total 0.1 x S - 0.03
0.04

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TABLE 2B (CONTINUED)
PM SPECIATION SUMMARY - PEF CRYSTAL RIVER POWER PLANT, UNIT 2
COMPLIANCE COAL, 0.68 WT% SULFUR

PM Category	Emission Unit [a]	Units	Total	Coarse PM	Soil (Fine PM)	Elemental Carbon (EC)	Inorganic (as H_2SO_4)	Organic
PM Filterable [b]	Unit 1	lb/hr	115.2	64.00	49.31	1.89	NA	NA
		%	100%	56%	43%	1.6%	NA	NA
PM Condensable [c]	Unit 1	lb/hr	166.82	NA	NA	NA	40.7	126.2
		%	100%	NA	NA	NA	24%	76%
Total PM_{10} (filterable+condensable)	Unit 1	lb/hr	282.0	64.00	49.31	1.89	40.7	126.2
		%	100%	22.7%	17.5%	0.7%	14.4%	44.7%
Total PM_{10} (filterable+Organic Condensable PM)	Unit 1	lb/hr	241.4	64.00	49.31	1.89	0.0	126.16
Modeled PM Speciation % (SO_4 modeled separately)		%	100%	26.5%	20.4%	0.8%	0.0%	52.3%

PM Particle Size Distribution for CALPUFF Assessment

Species	Size Distribution by Category (%)					Emission Rate (lb/hr)		
	AP-42 (Table 1.1-6)		Cumulative	Individual Categories				
Name	Particle Size (microns)	Cumulative (%)	Normalized PM10 (%)	Filterable (%)	Organic Condensable	Filterable	Organic Condensable	Total
Total PM_{10}						115.2	126.2	241.4
PM0063	0.63	18.5%	33.3%	33.3%	50.0%	38.3	63.1	101.4
PM0100	1	0.0%	0.0%	0.0%	50.0%	0.0	63.1	63.1
PM0125	1.25	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM0250	2.5	25.9%	46.6%	13.3%	0	15.3	0.0	15.3
PM0600	6	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM1000	10	55.6%	100.0%	53.4%	0	61.5	0.0	61.5
Totals				100.0%	100.0%	115.2	126.2	241.4

Total Modeled PM_{10} 241.4

[a] Heat input rate for unit and fuel heat content 4,390 MMBtu/hr 4,390 Unit 1
0.68 sulfur content (%)

[b] PM fine consists of PM soil and PM elemental carbon lb/1000 gal
PM fine based on ratio of PM2.5 (fine) to PM10 (filterable) PM2.5 0.24 lb/ton Ratio = 0.44 PM2.5/PM10
emission factor (Table 1.1-5, AP-42) PM10 0.54 lb/ton

PM elemental carbon based on EPA's "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", Table 5, January 2002 DRAFT
0.037 of PM2.5

PM elemental carbon 0.016 PM elemental carbon/PM10
PM soil= PM2.5 - PM elemental carbon 0.43 PM soil/PM10
PM2.5 0.44 PM2.5/PM10
PM coarse= PM10 - PM2.5

[c] Condensable PM (Table 1.1-6, AP-42) lb/MMBtu
Total 0.1 x S - 0.03
0.04

Golder Associates

TABLE 3B
SUMMARY OF COMPLIANCE COAL MODELING RESULTS WITH NEW IMPROVE ALGORITHM
CRYSTAL RIVER POWER PLANT - UNITS 1 AND 2 - COAL FIRING

Class I Area	Distance (km) of Source to Nearest Class I Area Boundary	Visibility Impact >0.5 dv	2001 8th Highest Impact (dv)		2002 8th Highest Impact (dv)		2003 8th Highest Impact (dv)	22nd Highest Impact (dv) Over 3-Yr Period
Saint Marks NWA	174		2.89		2.22		2.67	2.66
Pollutant Contribution		Sulfate	64.1%	Sulfate	95.6%	Sulfate	80.0%	
		Nitrate	33.6%	Nitrate	2.7%	Nitrate	16.1%	
		Particulate Matter	2.2%	Particulate Matter	1.7%	Particulate Matter	3.8%	
Chassahowitzka NWA	21		5.52		5.22		4.62	4.97
Pollutant Contribution		Sulfate	86.3%	Sulfate	81.4%	Sulfate	78.8%	
		Nitrate	11.5%	Nitrate	11.8%	Nitrate	16.3%	
		Particulate Matter	2.2%	Particulate Matter	6.8%	Particulate Matter	4.8%	
Wolf Island NWA	293		0.76		0.79		1.11	0.95
Pollutant Contribution		Sulfate	95.5%	Sulfate	81.2%	Sulfate	63.5%	
		Nitrate	3.7%	Nitrate	17.3%	Nitrate	34.6%	
		Particulate Matter	0.8%	Particulate Matter	1.5%	Particulate Matter	1.9%	
Okefenokee NWA	178		1.64		1.81		1.39	1.71
Pollutant Contribution		Sulfate	66.5%	Sulfate	90.2%	Sulfate	81.1%	
		Nitrate	27.4%	Nitrate	6.4%	Nitrate	16.5%	
		Particulate Matter	6.1%	Particulate Matter	3.4%	Particulate Matter	2.4%	

TABLE 4B
VISIBILITY IMPACT RANKINGS AT PSD CLASS I AREAS
WITH NEW IMPROVE ALGORITHM, COMPLIANCE COAL ANALYSIS
CRYSTAL RIVER POWER PLANT - UNITS 1 AND 2

Class I Area	Rank	2001 Predicted Impact (dv)	2002 Predicted Impact (dv)	2003 Predicted Impact (dv)
Saint Marks NWA	1	5.61	5.63	3.46
	2	4.33	4.00	3.33
	3	4.01	2.74	3.24
	4	3.62	2.68	3.05
	5	3.10	2.32	3.02
	6	2.94	2.24	2.97
	7	2.91	2.23	2.91
	8	2.89	2.22	2.67
Chassahowitzka NWA	1	7.51	7.08	6.49
	2	6.94	6.96	6.41
	3	6.80	6.03	5.75
	4	6.68	6.00	5.31
	5	6.13	5.81	4.95
	6	5.95	5.36	4.95
	7	5.94	5.27	4.63
	8	5.52	5.22	4.62
Wolf Island NWA	1	2.11	2.36	1.66
	2	1.50	1.83	1.63
	3	1.34	1.35	1.59
	4	0.96	1.15	1.49
	5	0.93	1.04	1.34
	6	0.88	1.04	1.23
	7	0.87	0.82	1.18
	8	0.76	0.79	1.11
Okefenokee NWA	1	3.00	3.14	2.96
	2	2.74	2.94	2.66
	3	2.27	2.13	2.51
	4	1.93	2.09	2.29
	5	1.85	1.90	2.12
	6	1.84	1.89	1.78
	7	1.71	1.82	1.78
	8	1.64	1.81	1.39

TABLE 1C
BART MODELING DATA INPUT
CRYSTAL RIVER POWER PLANT, UNITS 1 & 2
POWDER RIVER BASIN COAL, 0.35 WEIGHT % SULFUR

Parameter	Units	Value			
Emission Unit		Unit 1		Unit 2	
Location					
UTM Coordinates[a]					
East	km	334.30		334.30	
North	km	3,204.50		3,204.50	
Zone		17		17	
Lambert Conformal Coordinates [a]					
x	km	1,398.50		1,398.50	
y	km	-1,116.10		-1,116.10	
Stack Data					
Height	ft (m)	499	(152.1)	502	(153.0)
Diameter	ft (m)	15	(4.57)	16.0	(4.88)
Base elevation	ft (m)	3.3	(1.00)	3.3	(1.00)
Hourly heat input[b]	MMBtu/hr	3630.0	-	4390.0	-
Operating Data					
Exit gas temperature	^oF (K)	291	(417)	300	(422)
Exit gas velocity	ft/s (m/s)	132.7	(40.5)	160.0	(48.8)
Emission Data[c,d,e,f]					
SO_2	lb/hr (g/s)	2,904.0	(365.9)	3,512.0	(442.5)
NO_x	lb/hr (g/s)	1,601.2	(201.7)	2,913.0	(367.0)
PM Filterable	lb/hr (g/s)	140.8	(17.7)	115.2	(14.5)
SO_4	lb/hr (g/s)	23.1	(2.9)	27.9	(3.5)

Notes:

a. Based on common location using UTM coordinates of: East 567.4 km; North 2,813.5 km

b. Hourly heat input for each unit corresponds to the maximum hourly PM emissions for 2001 - 2006.

c. SO_2 emissions calculated based on vendor SO_2 emission factor and hourly heat input

d. NO_x emissions data based on CEMS data for 2001 - 2003.

e. PM filterable emissions data based on monitoring data from 2001 - 2006.

f. SO_4 emissions data calculated based on 0.8% conversion of sulfur to H_2SO_4 and 37% removal of H_2SO_4 in electrostatic precipitator (Southern Company methodology).

TABLE 2C
PM SPECIATION SUMMARY - PEF CRYSTAL RIVER POWER PLANT, UNIT 1
POWDER RIVER BASIN (PRB) COAL, 0.35 WEIGHT % SULFUR

PM Category	Emission Unit [a]	Units	Total	Coarse PM	Soil (Fine PM)	Elemental Carbon (EC)	Inorganic (as H_2SO_4)	Organic
PM Filterable [b]	Unit 1	lb/hr	140.8	78.23	60.27	2.32	NA	NA
		%	100%	56%	43%	1.6%	NA	NA
PM Condensable [c]	Unit 1	lb/hr	36.30	NA	NA	NA	23.1	13.2
		%	100%	NA	NA	NA	64%	36%
Total PM_{10} (filterable+condensable)	Unit 1	lb/hr	177.1	78.23	60.27	2.32	23.07	13.2
		%	100%	44.2%	34.0%	1.3%	13.0%	7.5%
Total PM_{10} (filterable+Organic Condensable PM)	Unit 1	lb/hr	154.0	78.23	60.27	2.32	0.0	13.2
Modeled PM Speciation % (SO_4 modeled separately)		%	100%	50.8%	39.1%	1.5%	0.0%	8.6%

PM Particle Size Distribution for CALPUFF Assessment

Species	Size Distribution by Category (%)					Emission Rate (lb/hr)		
	AP-42 (Table 1.1-6)		Cumulative	Individual Categories				
Name	Particle Size (microns)	Cumulative (%)	Normalized PM10 (%)	Filterable (%)	Organic Condensable	Filterable	Organic Condensable	Total
Total PM_{10}						140.8	13.2	154.0
PM0063	0.63	18.5%	33.3%	33.3%	50.0%	46.9	6.6	53.5
PM0100	1	0.0%	0.0%	0.0%	50.0%	0.0	6.6	6.6
PM0125	1.25	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM0250	2.5	25.9%	46.6%	13.3%	0	18.7	0.0	18.7
PM0600	6	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM1000	10	55.6%	100.0%	53.4%	0	75.2	0.0	75.2
Totals				100.0%	100.0%	140.8	13.2	154.0

Total Modeled PM_{10} 154.0

[a] Heat input rate for unit and fuel heat content 3,630 MMBtu/hr 3,630 Unit 1
0.35 sulfur content (%)

[b] PM fine consists of PM soil and PM elemental carbon lb/1000 gal
PM fine based on ratio of PM2.5 (fine) to PM10 (filterable) PM2.5 0.24 lb/ton Ratio = 0.44 PM2.5/PM10
emission factor (Table 1.1-5, AP-42) PM10 0.54 lb/ton

PM elemental carbon based on EPA's "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", Table 5, January 2002 DRAFT
0.037 of PM2.5

PM elemental carbon 0.016 PM elemental carbon/PM10
PM soil= PM2.5 - PM elemental carbon 0.43 PM soil/PM10
PM2.5 0.44 PM2.5/PM10
PM coarse= PM10 - PM2.5

[c] Condensable PM (Table 1.1-6, AP-42) lb/MMBtu
0.010 for sulfur content =< 0.4% wt

TABLE 2C (CONTINUED)
PM SPECIATION SUMMARY - PEF CRYSTAL RIVER POWER PLANT, UNIT 2
POWDER RIVER BASIN (PRB) COAL, 0.35 WEIGHT % SULFUR

PM Category	Emission Unit [a]	Units	Total	Coarse PM	Soil (Fine PM)	Elemental Carbon (EC)	Inorganic (as H_2SO_4)	Organic
PM Filterable [b]	Unit 1	lb/hr	115.2	64.00	49.31	1.89	NA	NA
		%	100%	56%	43%	1.6%	NA	NA
PM Condensable [c]	Unit 1	lb/hr	43.90	NA	NA	NA	27.9	16.0
		%	100%	NA	NA	NA	64%	36%
Total PM_{10} (filterable+condensable)	Unit 1	lb/hr	159.1	64.00	49.31	1.89	27.9	16.0
		%	100%	40.2%	31.0%	1.2%	17.5%	10.1%
Total PM_{10} (filterable+Organic Condensable PM)	Unit 1	lb/hr	131.2	64.00	49.31	1.89	0.0	16.00
Modeled PM Speciation % (SO_4 modeled separately)		%	100%	48.8%	37.6%	1.4%	0.0%	12.2%

PM Particle Size Distribution for CALPUFF Assessment

Species	Size Distribution by Category (%)					Emission Rate (lb/hr)		
	AP-42 (Table 1.1-6)		Cumulative	Individual Categories				
Name	Particle Size (microns)	Cumulative (%)	Normalized PM10 (%)	Filterable (%)	Organic Condensable	Filterable	Organic Condensable	Total
Total PM_{10}						115.2	16.0	131.2
PM0063	0.63	18.5%	33.3%	33.3%	50.0%	38.3	8.0	46.3
PM0100	1	0.0%	0.0%	0.0%	50.0%	0.0	8.0	8.0
PM0125	1.25	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM0250	2.5	25.9%	46.6%	13.3%	0	15.3	0.0	15.3
PM0600	6	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM1000	10	55.6%	100.0%	53.4%	0	61.5	0.0	61.5
Totals				100.0%	100.0%	115.2	16.0	131.2

Total Modeled PM_{10} 131.2

[a] Heat input rate for unit and fuel heat content — 4,390 MMBtu/hr — 4,390 Unit 1
0.35 sulfur content (%)

[b] PM fine consists of PM soil and PM elemental carbon — lb/1000 gal
PM fine based on ratio of PM2.5 (fine) to PM10 (filterable) — PM2.5 0.24 lb/ton — Ratio = 0.44 PM2.5/PM10
emission factor (Table 1.1-5, AP-42) — PM10 0.54 lb/ton

PM elemental carbon based on EPA's "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", Table 5, January 2002 DRAFT
0.037 of PM2.5

PM elemental carbon — 0.016 PM elemental carbon/PM10
PM soil= PM2.5 - PM elemental carbon — 0.43 PM soil/PM10
PM2.5 — 0.44 PM2.5/PM10
PM coarse= PM10 - PM2.5

[c] Condensable PM (Table 1.1-6, AP-42) — lb/MMBtu
0.010 for sulfur content =< 0.4% wt

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TABLE 3C
SUMMARY OF PRB COAL MODELING RESULTS WITH NEW IMPROVE ALGORITHM
CRYSTAL RIVER POWER PLANT - UNITS 1 AND 2 - COAL FIRING

Class I Area	Distance (km) of Source to Nearest Class I Area Boundary	Visibility Impact >0.5 dv 2001	2001 8th Highest Impact (dv)	Visibility Impact >0.5 dv 2002	2002 8th Highest Impact (dv)	Visibility Impact >0.5 dv 2003	2003 8th Highest Impact (dv)	22nd Highest Impact (dv) Over 3-Yr Period
Saint Marks NWA	174		2.17		1.60		1.95	1.90
Pollutant Contribution		Sulfate	45.0%	Sulfate	81.4%	Sulfate	75.3%	
		Nitrate	53.7%	Nitrate	17.6%	Nitrate	22.9%	
		Particulate Matter	1.3%	Particulate Matter	1.0%	Particulate Matter	1.8%	
Chassahowitzka NWA	21		4.15		3.79		3.43	3.92
Pollutant Contribution		Sulfate	78.6%	Sulfate	79.7%	Sulfate	74.3%	
		Nitrate	20.4%	Nitrate	17.0%	Nitrate	23.5%	
		Particulate Matter	1.0%	Particulate Matter	3.3%	Particulate Matter	2.3%	
Wolf Island NWA	293		0.59		0.56		0.85	0.66
Pollutant Contribution		Sulfate	42.7%	Sulfate	94.9%	Sulfate	72.3%	
		Nitrate	54.8%	Nitrate	4.7%	Nitrate	26.1%	
		Particulate Matter	2.5%	Particulate Matter	0.4%	Particulate Matter	1.6%	
Okefenokee NWA	178		1.23		1.25		1.01	1.23
Pollutant Contribution		Sulfate	60.1%	Sulfate	92.6%	Sulfate	75.8%	
		Nitrate	37.3%	Nitrate	6.6%	Nitrate	23.2%	
		Particulate Matter	2.5%	Particulate Matter	0.8%	Particulate Matter	1.0%	

TABLE 4C
VISIBILITY IMPACT RANKINGS AT PSD CLASS I AREAS
WITH NEW IMPROVE ALGORITHM, PRB COAL ANALYSIS
CRYSTAL RIVER POWER PLANT - UNITS 1 AND 2

Class I Area	Rank	2001 Predicted Impact (dv)	2002 Predicted Impact (dv)	2003 Predicted Impact (dv)
Saint Marks NWA	1	4.13	4.32	2.56
	2	3.31	3.03	2.40
	3	3.14	1.90	2.25
	4	2.69	1.89	2.13
	5	2.29	1.76	2.12
	6	2.24	1.62	2.09
	7	2.18	1.60	2.07
	8	2.17	1.60	1.95
Chassahowitzka NWA	1	5.63	5.56	4.87
	2	5.16	5.21	4.72
	3	5.15	4.76	4.29
	4	4.95	4.43	3.94
	5	4.57	4.38	3.92
	6	4.55	4.11	3.55
	7	4.30	3.93	3.49
	8	4.15	3.79	3.43
Wolf Island NWA	1	1.46	1.69	1.29
	2	1.11	1.26	1.11
	3	0.93	0.93	1.11
	4	0.66	0.82	1.02
	5	0.63	0.82	0.91
	6	0.60	0.79	0.87
	7	0.60	0.57	0.86
	8	0.59	0.56	0.85
Okefenokee NWA	1	2.09	2.39	2.08
	2	2.08	2.16	1.95
	3	1.59	1.60	1.73
	4	1.37	1.45	1.68
	5	1.37	1.40	1.47
	6	1.34	1.29	1.26
	7	1.32	1.26	1.22
	8	1.23	1.25	1.01

TABLE 1D
BART MODELING DATA INPUT
CRYSTAL RIVER POWER PLANT, UNITS 1 & 2
WITH FLUE GAS DESULFURIZATION (FGD) UNIT

Parameter	**Units**	**Value**			
Emission Unit		Unit 1		Unit 2	
Location					
UTM Coordinates[a]					
East	km	334.30		334.30	
North	km	3,204.50		3,204.50	
Zone		17		17	
Lambert Conformal Coordinates [a]					
x	km	1,398.50		1,398.50	
y	km	-1,116.10		-1,116.10	
Stack Data					
Height	ft (m)	499	(152.1)	502	(153.0)
Diameter	ft (m)	15	(4.57)	16.0	(4.88)
Base elevation	ft (m)	3.3	(1.00)	3.3	(1.00)
Hourly heat input[b]	MMBtu/hr	3630.0	-	4390.0	-
Operating Data					
Exit gas temperature	^oF (K)	291	(417)	300	(422)
Exit gas velocity	ft/s (m/s)	132.7	(40.5)	160.0	(48.8)
FGD unit control efficiency	%	95.0	-	95.0	-
Emission Data[c,d,e,f]					
SO_2	lb/hr (g/s)	361.9	(45.6)	448.4	(56.5)
NO_x	lb/hr (g/s)	1,601.2	(201.7)	2,913.0	(367.0)
PM Filterable	lb/hr (g/s)	140.8	(17.7)	115.2	(14.5)
SO_4	lb/hr (g/s)	50.4	(6.4)	61.0	(7.7)

Notes:

a. Based on common location using UTM coordinates of: East 567.4 km; North 2,813.5 km

b. Hourly heat input for each unit corresponds to the maximum hourly PM emissions for 2001 - 2006.

c. SO_2 emissions calculated based on vendor SO_2 emission factor, hourly heat input and FGD control efficiency

d. NO_x emissions data based on CEMS data for 2001 - 2003.

e. PM filterable emissions data based on monitoring data from 2001 - 2006.

f. SO_4 emissions data calculated based on 0.8% conversion of sulfur to H_2SO_4 and 37% removal of H_2SO_4 in electrostatic precipitator (Southern Company methodology).

TABLE 2D
PM SPECIATION SUMMARY - PEF CRYSTAL RIVER POWER PLANT, UNIT 1
FLUE GAS DESULFURIZATION UNIT SCENARIO, 95% SO_2 EMISSIONS CONTROL

PM Category	Emission Unit [a]	Units	Total	Coarse PM	Soil (Fine PM)	Elemental Carbon (EC)	Inorganic (as H_2SO_4)	Organic
PM Filterable [b]	Unit 1	lb/hr	140.8	78.23	60.27	2.32	NA	NA
		%	100%	56%	43%	1.6%	NA	NA
PM Condensable [c]	Unit 1	lb/hr	283.14	NA	NA	NA	50.4	232.7
		%	100%	NA	NA	NA	18%	82%
Total PM_{10} (filterable+condensable)	Unit 1	lb/hr	424.0	78.23	60.27	2.32	50.43	232.7
		%	100%	18.5%	14.2%	0.5%	11.9%	54.9%
Total PM_{10} (filterable+Organic Condensable PM)	Unit 1	lb/hr	373.5	78.23	60.27	2.32	0.0	232.7
Modeled PM Speciation % (SO_4 modeled separately)		%	100%	20.9%	16.1%	0.6%	0.0%	62.3%

PM Particle Size Distribution for CALPUFF Assessment

Species	Size Distribution by Category (%)					Emission Rate (lb/hr)		
	AP-42 (Table 1.1-6)		Cumulative	Individual Categories				
Name	Particle Size (microns)	Cumulative (%)	Normalized PM10 (%)	Filterable (%)	Organic Condensable	Filterable	Organic Condensable	Total
Total PM_{10}						140.8	232.7	373.5
PM0063	0.63	18.5%	33.3%	33.3%	50.0%	46.9	116.4	163.2
PM0100	1	0.0%	0.0%	0.0%	50.0%	0.0	116.4	116.4
PM0125	1.25	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM0250	2.5	25.9%	46.6%	13.3%	0	18.7	0.0	18.7
PM0600	6	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM1000	10	55.6%	100.0%	53.4%	0	75.2	0.0	75.2
Totals				100.0%	100.0%	140.8	232.7	373.5

Total Modeled PM_{10} 373.5

[a] Heat input rate for unit and fuel heat content 3,630 MMBtu/hr 3,630 Unit 1
1.08 sulfur content (%)

[b] PM fine consists of PM soil and PM elemental carbon lb/1000 gal
PM fine based on ratio of PM2.5 (fine) to PM10 (filterable) PM2.5 0.24 lb/ton Ratio = 0.44 PM2.5/PM10
emission factor (Table 1.1-5, AP-42) PM10 0.54 lb/ton

PM elemental carbon based on EPA's "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", Table 5, January 2002 DRAFT
0.037 of PM2.5

PM elemental carbon 0.016 PM elemental carbon/PM10
PM soil= PM2.5 - PM elemental carbon 0.43 PM soil/PM10
PM2.5 0.44 PM2.5/PM10
PM coarse= PM10 - PM2.5

[c] Condensable PM (Table 1.1-6, AP-42) lb/MMBtu
Total 0.1 x S - 0.03
0.08

TABLE 2D (CONTINUED)
PM SPECIATION SUMMARY - PEF CRYSTAL RIVER POWER PLANT, UNIT 2
FLUE GAS DESULFURIZATION UNIT SCENARIO, 95% SO_2 EMISSIONS CONTROL

PM Category	Emission Unit [a]	Units	Total	Coarse PM	Soil (Fine PM)	Elemental Carbon (EC)	Inorganic (as H_2SO_4)	Organic
PM Filterable [b]	Unit 1	lb/hr	115.2	64.00	49.31	1.89	NA	NA
		%	100%	56%	43%	1.6%	NA	NA
PM Condensable [c]	Unit 1	lb/hr	342.42	NA	NA	NA	61.0	281.4
		%	100%	NA	NA	NA	18%	82%
Total PM_{10} (filterable+condensable)	Unit 1	lb/hr	457.6	64.00	49.31	1.89	61.0	281.4
		%	100%	14.0%	10.8%	0.4%	13.3%	61.5%
Total PM_{10} (filterable+Organic Condensable PM)	Unit 1	lb/hr	396.6	64.00	49.31	1.89	0.0	281.44
Modeled PM Speciation % (SO_4 modeled separately)		%	100%	16.1%	12.4%	0.5%	0.0%	71.0%

PM Particle Size Distribution for CALPUFF Assessment

Species	Size Distribution by Category (%)					Emission Rate (lb/hr)		
	AP-42 (Table 1.1-6)		Cumulative	Individual Categories				
Name	Particle Size (microns)	Cumulative (%)	Normalized PM10 (%)	Filterable (%)	Organic Condensable	Filterable	Organic Condensable	Total
Total PM_{10}						115.2	281.4	396.6
PM0063	0.63	18.5%	33.3%	33.3%	50.0%	38.3	140.7	179.0
PM0100	1	0.0%	0.0%	0.0%	50.0%	0.0	140.7	140.7
PM0125	1.25	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM0250	2.5	25.9%	46.6%	13.3%	0	15.3	0.0	15.3
PM0600	6	0.0%	0.0%	0.0%	0	0.0	0.0	0.0
PM1000	10	55.6%	100.0%	53.4%	0	61.5	0.0	61.5
Totals				100.0%	100.0%	115.2	281.4	396.6

Total Modeled PM_{10} 396.6

[a] Heat input rate for unit and fuel heat content — 4,390 MMBtu/hr — 4,390 Unit 1
1.08 sulfur content (%)

[b] PM fine consists of PM soil and PM elemental carbon — lb/1000 gal
PM fine based on ratio of PM2.5 (fine) to PM10 (filterable) — PM2.5 0.24 lb/ton — Ratio = 0.44 PM2.5/PM10
emission factor (Table 1.1-5, AP-42) — PM10 0.54 lb/ton

PM elemental carbon based on EPA's "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon", Table 5, January 2002 DRAFT
0.037 of PM2.5

PM elemental carbon — 0.016 PM elemental carbon/PM10
PM soil= PM2.5 - PM elemental carbon — 0.43 PM soil/PM10
PM2.5 — 0.44 PM2.5/PM10
PM coarse= PM10 - PM2.5

[c] Condensable PM (Table 1.1-6, AP-42) — lb/MMBtu
Total — 0.1 x S - 0.03
0.08

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TABLE 3D
SUMMARY OF BART FGD UNIT MODELING RESULTS WITH NEW IMPROVE ALGORITHM
CRYSTAL RIVER POWER PLANT - UNITS 1 AND 2 - COAL FIRING

Class I Area	Distance (km) of Source to Nearest Class I Area Boundary	Visibility Impact >0.5 dv 2001		2002		2003		22nd Highest Impact (dv) Over 3-Yr Period
			8th Highest Impact (dv)		8th Highest Impact (dv)		8th Highest Impact (dv)	
Saint Marks NWA	174		1.18		0.81		0.98	0.98
Pollutant Contribution		Sulfate	25.3%	Sulfate	16.0%	Sulfate	28.7%	
		Nitrate	63.9%	Nitrate	73.1%	Nitrate	54.9%	
		Particulate Matter	10.8%	Particulate Matter	10.9%	Particulate Matter	16.4%	
Chassahowitzka NWA	21		3.34		4.22		4.29	3.88
Pollutant Contribution		Sulfate	25.4%	Sulfate	25.2%	Sulfate	25.3%	
		Nitrate	42.9%	Nitrate	45.6%	Nitrate	42.4%	
		Particulate Matter	31.6%	Particulate Matter	29.2%	Particulate Matter	32.2%	
Wolf Island NWA	293		0.24		0.29		0.31	0.30
Pollutant Contribution		Sulfate	13.7%	Sulfate	38.9%	Sulfate	29.0%	
		Nitrate	75.8%	Nitrate	50.3%	Nitrate	57.9%	
		Particulate Matter	10.5%	Particulate Matter	10.9%	Particulate Matter	13.1%	
Okefenokee NWA	178		0.55		0.58		0.51	0.55
Pollutant Contribution		Sulfate	66.3%	Sulfate	48.4%	Sulfate	20.3%	
		Nitrate	15.5%	Nitrate	16.0%	Nitrate	67.9%	
		Particulate Matter	18.1%	Particulate Matter	35.6%	Particulate Matter	11.8%	

TABLE 4D
VISIBILITY IMPACT RANKINGS AT PSD CLASS I AREAS
WITH NEW IMPROVE ALGORITHM, FGD UNIT ANALYSIS
CRYSTAL RIVER POWER PLANT - UNITS 1 AND 2

Class I Area	Rank	2001 Predicted Impact (dv)	2002 Predicted Impact (dv)	2003 Predicted Impact (dv)
Saint Marks NWA	1	1.96	2.15	1.37
	2	1.91	1.48	1.24
	3	1.83	1.34	1.16
	4	1.67	1.11	1.10
	5	1.46	0.86	1.10
	6	1.41	0.82	1.05
	7	1.35	0.82	1.04
	8	1.18	0.81	0.98
Chassahowitzka NWA	1	5.44	7.21	5.54
	2	4.96	6.97	5.25
	3	3.94	6.75	5.23
	4	3.92	6.52	4.88
	5	3.88	5.81	4.42
	6	3.75	5.11	4.41
	7	3.57	4.40	4.32
	8	3.34	4.22	4.29
Wolf Island NWA	1	0.55	0.78	0.88
	2	0.50	0.54	0.54
	3	0.42	0.42	0.49
	4	0.31	0.42	0.37
	5	0.31	0.39	0.32
	6	0.30	0.37	0.32
	7	0.29	0.31	0.32
	8	0.24	0.29	0.31
Okefenokee NWA	1	1.04	1.19	0.94
	2	0.93	1.11	0.71
	3	0.90	1.03	0.71
	4	0.67	0.80	0.65
	5	0.66	0.74	0.58
	6	0.66	0.64	0.55
	7	0.61	0.59	0.53
	8	0.55	0.58	0.51

TABLE 5
SUMMARY OF SO_2 BACT DETERMINATIONS FOR COAL FUEL FIRED LARGE INDUSTRIAL BOILERS (>250 MMBTU/HR) (2007-2012)

Facility Name	State	Permit Issued	Process Info	Fuel	Heat Input	Control Method	SO_2 Limit	Basis
John W. Turk Jr. Power Plant	AR	11/5/2008	PC Boiler	PRB Sub-Bit Coal	6,000 MMBtu/hr	Dry Flue Gas Desulfurization (Spray Dry Absorber)	0.08 LB/MMBTU	BACT-PSD
Ottumwa Generating Station	IA	2/27/2007	Boiler #1	Coal	6,370 MMBtu/hr	Low Sulfur Coal	1.2 LB/MMBTU	BACT-PSD
J.K. Smith Generating Station	KY	4/9/2010	Circulating Fluidized Bed Boiler Cfb1 And CFB2	Coal	3,000 MMBtu/hr	Limestone Injection (CFB) and a Flash Dryer Absorber with Fresh Lime Injection	0.075 LB/MMBTU	BACT-PSD
Karn Weadock Generating Complex	MI	12/29/2009	Boiler	PRB Coal Or 50/50 Blend	8,190 MMBtu/hr	Limestone Forced Oxidation, Wet Fluidized Gas Desulfurization (Fgd) and Low Sulfur Coal.	0.06 LB/MMBTU	BACT-PSD
Spiritwood Station	ND	9/14/2007	Atmospheric Circulating Fluidized Bed Boiler	Lignite	1,280 MMBtu/hr	Limestone injection into the unit with a Spray Dryer following.	0.06 LB/MMBTU	BACT-PSD
Smart Papers Holdings, Llc	OH	1/31/2008	Pulverized Dry Bottom Boiler	Coal	420 MMBtu/hr		1.7 LB/MMBTU	BACT-PSD
Hugo Generating Sta	OK	2/9/2007	Coal-Fired Steam EGU Boiler (HU-Unit 2)		2,561 MMBtu/hr	Wet Limestone Flue Gas Desulfurization	0.065 LB/MMBTU	BACT-PSD
Sunnyside Ethanol,Llc	PA	5/7/2007	CFB Boiler	Coal	497 MMBtu/hr	Limestone Injection and add on Dry Flue Gas Desulfedrization, CEM	0.2 LB/MMBTU	BACT-PSD
Coleto Creek Unit 2	TX	5/3/2010	Coal-Fired Boiler Unit 2	PRB Coal	6,670 MMBtu/hr	Spray Dry Adsorber/Fabric Filter	0.06 LB/MMBTU	BACT-PSD
White Stallion Energy Center	TX	12/16/2010	CFB Boiler	Coal & Pet Coke	3,300 MMBtu/hr	"Limestone Bed CFB and Lime Spray Dryer Permit Design Sulfur Content of Ill Basin Coal is 3.9 Wt% and of Pet Coke 4.3 Avg/6.0 Max	0.114 LB/MMBTU	BACT-PSD
Tenaska Trailblazer Energy Center	TX	12/30/2010	Coal-Fired Boiler	Sub-Bituminous Coal	8,307 MMBtu/hr	HI Weighting of Limits Used for Fuel Blending"	0.06 LB/MMBTU	BACT-PSD
Bonanza Power Plant Waste Coal Fired Unit	UT	8/30/2007	Circulating Fluidized Bed Boiler, 1445 MMbtu/Hr Waste Coal Fired	Waste Coal/Bituminous Blend	-- --	Wet Limestone Scrubber	0.055 LB/MMBTU	BACT-PSD
Virginia City Hybrid Energy Center	VA	6/30/2008	2 Circulating Fluidized Bed Boilers	Coal And Coal Refuse	3,132 MMBtu/hr		0.035 LB/MMBTU	BACT-PSD
Western Greenbrier Co-Generation, Llc	WV	4/26/2006	Circulating Fluidized Bed Boiler (CFB)	Waste Coal	1,070 MMBtu/hr	Dry SO2 Scrubber (Spray Dry Absorber)"	0.14 LB/MMBTU	BACT-PSD
Wygen 3	WY	2/5/2007	PC Boiler	Subbituminous Coal	1,300 MMBtu/hr	Good Combustion Practices Low Sulfur Content Coal and CEM System	0.09 LB/MMBTU	BACT-PSD
Dry Fork Station	WY	10/15/2007	PC Boiler (ES1-01)	Coal	-- --	Limestone Injection and Flue Gas Desulfurization and CEM System	0.07 LB/MMBTU	BACT-PSD

Source: EPA 2012 (RBLC database)

TABLE 6
COST EFFECTIVENESS OF FUEL SWITCHING
PEF CRYSTAL RIVER POWER PLANT, UNITS 1 AND 2

Cost Items	Cost Factors	Baseline Current Fuel Cost ($)	Projected Future 0.68% S Fuel Cost ($)	Projected Future 0.35% S Fuel Cost ($)
DIRECT CAPITAL COSTS (DCC):				
(1a) Equipment Cost - Upgrade ESP for 0.68%S Coal			100,000,000	
(1b) Equipment Cost - Performance, Coal Handling Performance, Safety for 0.35% Coal [(a)]				82,500,000
(1c) Equipment Cost - Replace ESP with Baghouse for 0.35%S Coal				250,000,000
(3) Sales Tax	NA	0.0	0.0	0.0
Subtotal: Total Equipment Cost (TEC)		0.0	100,000,000	332,500,000
(4) Direct Installation Costs	NA	0.0	0.0	0.0
Total DCC:		0.0	100,000,000	332,500,000
INDIRECT CAPITAL COSTS (ICC): [(b)]				
(1) Indirect Installation Costs				
(a) Engineering	10% of TEC	0.0	10,000,000	33,250,000
(b) Construction & Field Expenses	10% of TEC	0.0	10,000,000	33,250,000
(c) Construction Contractor Fee	10% of TEC	0.0	10,000,000	33,250,000
(d) Contingencies	3% of TEC	0.0	3,000,000	9,975,000
(2) Other Indirect Costs				
(a) Startup	1% of TEC	0.0	1,000,000	3,325,000
(b) Performance Test'	1% of TEC	0.0	1,000,000	3,325,000
Total ICC:		0.0	35,000,000	116,375,000
PROJECT CONTINGENCY	15% of (DCC+ICC)	0.0	20,250,000	67,331,250
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	0.0	155,250,000	516,206,250
DIRECT OPERATING COSTS (DOC):				
(1) Variable Operation & Maintenance Cost	Progress Energy Data	0	0	0
(3) Fuels				
Existing Fuel Cost (Coal with 1.0%S)	$4.25/mmBtu coal; 45,000,000 mmBtu/yr; 12,000 Btu/lb	191,250,000	--	--
Proposed Fuel Cost (Coal with 0.68%S)	$4.37/mmBtu coal; 45,000,000 mmBtu/yr; 12,000 Btu/lb	--	196,650,000	--
Proposed Fuel Cost (Coal with 0.35%S)	$4.04/mmBtu coal; 45,000,000 mmBtu/yr; 8,800 Btu/lb	--	--	181,800,000
Differential Fuel Cost (Proposed - Existing)	Proposed fuel cost - existing fuel cost		5,400,000	-9,450,000
Total DOC:			5,400,000	-9,450,000
INDIRECT OPERATING COSTS (IOC): [(b)]				
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	0.0	0.0	0.0
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	0.0	1,552,500	5,162,063
(3) Insurance	1% of total capital investment, CCM Chapter 2	0.0	1,552,500	5,162,063
(4) Administration	2% of total capital investment, CCM Chapter 2	0.0	3,105,000	10,324,125
Total IOC:	(1) + (2) + (3) + (4)	0.0	6,210,000	20,648,250
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.55309 times TCI (2 yrs @ 7%)	0.0	85,867,223	285,508,515
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	0.0	97,477,223	296,706,765
Baseline Emissions:	Based on projected operation for Units 1 & 2	38,250	38,250	38,250
Projected Future Emissions:	1.2 lb/mmBtu and 0.8 lb/mmBtu; 45,000,000 mmBtu/yr	--	27,000	18,000
Emissions Reduction (TPY)(AC):	Baseline - Future Projected (TPY)	--	11,250	20,250
Average Cost Effectiveness ($/ton):	AC/Emissions Reduction	--	8,665	14,652
Incremental Cost ($)	Incremental Cost for using 0.35% S instead of 0.68% S coal	--	--	199,229,542
Incremental Emissions Reduction (TPY):	Emissions Reduction 0.35% S coal - 0.68% S coal	--	--	9,000
Incremental Cost Effectiveness ($/ton):	Incremental Cost/Incremental Emissions Reduction	--	--	22,137
Modeled Baseline Visibility Impact - Haze Index (HI) (dv):	8th Highest Visibility Impact for Both Units 1 and 2	7.93	--	--
Modeled Visibility Impact w 0.68% & 0.35% S Coal - HI (dv	8th Highest Visibility Impact for Both Units 1 and 2	--	5.52	4.15
Improvement in Visibility (dv)	Future - Baseline	--	2.41	3.78
Average Visibility Improvement Cost Effectiveness ($/dv):	AC/Visibility Improvement	--	40,446,980	78,493,853
Incremental Visibility Improvement (dv):	Visibility Improvement 0.35% S coal - 0.68% S coal	--	--	1.37
Incremental Visibility Improvement Cost Effectiveness ($/dv	Incremental Cost/Incremental Visibility Improvement	--	--	145,423,024

Notes:

[(a)] This estimate is based on a 2005 Sargent and Lundy Crystal River 4 & 5 study on costs of converting to 100% PRB. Significant increased scope is not included in this estimate, as an engineering evaluation would have to be completed to accurately define the required scope. Excluded scope includes, but is not limited to, pressure part modifications, ESP modifications, electrical system upgrades, and fan modifications. The 2005 costs were escalated to 2012 costs using the Global Insight ash and coal handling cost category. In addition this cost estimate does not include any O&M, reagent, byproduct or fuel cost impacts, nor does it include a risk adjustment for potential safety hazards and associated issues related to the use of PRB coal at the Crystal River site.

[(b)] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 7
COST EFFECTIVENESS OF FUEL GAS DESULFURIZATION (FGD) SYSTEMS
PEF CRYSTAL RIVER POWER PLANT, UNITS 1 AND 2

Cost Items	Cost Factors	Baseline Uncontrolled Cost ($)	Projected Future FGD Systems Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Equipment Cost			286,653,406
(3) Sales Tax	NA	0.0	0.0
Subtotal: Total Equipment Cost (TEC)		0.0	286,653,406.0
(4) Direct Installation Costs	NA	0.0	0.0
Total DCC:		0.0	286,653,406.0
INDIRECT CAPITAL COSTS (ICC): [a]			
(1) Indirect Installation Costs			
(a) Engineering	10% of TEC	0.0	28,665,340.6
(b) Construction & Field Expenses	10% of TEC	0.0	28,665,340.6
(c) Construction Contractor Fee	10% of TEC	0.0	28,665,340.6
(d) Contingencies	3% of TEC	0.0	8,599,602.2
(2) Other Indirect Costs			
(a) Startup	1% of TEC	0.0	2,866,534.1
(b) Performance Test'	1% of TEC	0.0	2,866,534.1
Total ICC:		0.0	100,328,692.1
PROJECT CONTINGENCY	15% of (DCC+ICC)	0.0	58,047,314.7
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	0.0	445,029,412.8
DIRECT OPERATING COSTS (DOC): [a],[b]			
(1) Limestone	133,000 tpy x $32.8 per ton	0	4,362,400
(2) Filtered water	315 Mgal x $0.82 per 1000 gal	0	258,300
(3) Electrical power	1.9% of gross power production of Units 1 & 2 x 8760 hours x $0.05 per KWhr	0	71,111,490
(4) By-product disposal	380,000 tpy by-product x $65.6 per ton	0	24,928,000
Total DOC:		0	100,660,190
INDIRECT OPERATING COSTS (IOC): [c]			
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	0.0	0.0
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	0.0	4,450,294.1
(3) Insurance	1% of total capital investment, CCM Chapter 2	0.0	4,450,294.1
(4) Administration	2% of total capital investment, CCM Chapter 2	0.0	8,900,588.3
Total IOC:	(1) + (2) + (3) + (4)	0.0	17,801,176.5
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.55309 times Total Capital Cost (2 yrs @ 7%)	0.0	246,141,318
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	0.0	364,602,684
Baseline Emissions:	Based on projected operation for Units 1 & 2	38,250	38,250
Projected Future Emissions:	Assumes 95% control	--	1,913
Emissions Reduction (TPY)(AC):	Baseline - Future Projected (TPY)	--	36,338
Average Cost Effectiveness ($/ton):	AC/Emissions Reduction	--	10,034
Incremental Cost ($)	Incremental Cost for using FGD instead of 0.68% S coal	--	--
Incremental Emissions Reduction (TPY):	Emissions Reduction 0.35% S coal - 0.68% S coal	--	--
Incremental Cost Effectiveness ($/ton):	Incremental Cost/Incremental Emissions Reduction	--	--
Modeled Baseline Visibility Impact - Haze Index (HI) (dv):	8th Highest Visibility Impact for Both Units 1 and 2	7.93	--
Modeled Visibility Impact w FGD System - HI (dv):	8th Highest Visibility Impact for Both Units 1 and 2	--	3.34
Improvement in Visibility (dv)	Future - Baseline	--	4.59
Average Visibility Improvement Cost Effectiveness ($/dv):	AC/Visibility Improvement	--	79,434,136
Incremental Visibility Improvement (dv):		--	--
Incremental Visibility Improvement Cost Effectiveness ($/dv):	Incremental Cost/Incremental Visibility Improvement	--	--

Notes:

[a] Direct operating costs include primary cost elements only.

[b] Direct operating costs estimated based on "Dry Flue Gas Desulfurization (DFGD)/Puff Jet Fabric Filter (PJFF) and Selective Catalytic Reduction (SCR) System Retrofit and Conceptual Design and Cost Estimate" for Crystal River Units 1 & 2, Progress Energy Florida, July 2010; CRCA-0-LI-022-0006.

[c] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

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