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DIVISION OF AIR
RESOURCE MANAGEMENT

REPORT

BART DETERMINATION FOR TURKEY POINT POWER PLANT

Florida Power & Light Company

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Table of Contents

List of Tables

1.0 INTRODUCTION

Florida Power & Light Company (FPL) owns and operates the Turkey Point Power Plant (PTF) in Miami-Dade 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 PTF was previously submitted to the Florida Department of Environmental Protection (FDEP) in 2008. 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 PTF 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 April 14, 2009 (permit No. 0250003-008-AC), which requires FPL to install or modify air pollution control equipment to achieve the specified BART standards for PM. The permit also limits the sulfur content of the fuel effective December 31, 2013. However, the U.S. Environmental Protection Agency (EPA) has recently finalized the Cross State Air Pollution Rule (CSAPR), which replaces CAIR (CSAPR has currently been stayed pending litigation). CSAPR has different emission requirements for NO_x and SO_2. Compliance with CAIR requirements was understood to satisfy BART requirements for electric generating units; however, a similar understanding for CSAPR may not apply to NO_x and SO_2 emissions and a revised BART determination is required including SO2 and NOX

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 "Revised Air Modeling Protocol to Evaluate Best Available Retrofit Technology (BART) Options for FPL Facilities", 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 PTF are the two oil- and natural gas-fired conventional steam electric generating units, designated as Unit No. 1 and Unit No. 2. Each steam unit is a nominal 400-megawatt (MW) class (electric) steam generator which drives a single reheat turbine generator.

PTF is located 9.5 miles east of Florida City on SW 344th Street, Florida City, Dade County. The general location of the Plant, in Universal Transverse Mercator (UTM) coordinates, is 567.4 kilometers (km) East, 2,813.5 km North, Zone 17. An area map showing the PTF Plant and PSD Class I areas located within 300 km of the plant is presented in Figure 1-1 of the BART Protocol. The only PSD Class I area located within 300 km of the plant is the Everglades National Park (NP), located about 21 km to the west of the plant.

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.) and Reasonable Achievable Control Technology (RACT) Requirements for Major VOC- and NO_x-Emitting Facilities (Rule 62-296.570, F.A.C.).

The stacks for Units No. 1 and No. 2 at PTF are at Good Engineering Practice (GEP) height with no or minimal downwash effects. Therefore, building downwash effects were not included in the analysis.

2.1 EMISSION RATES

Emission rates used in the PTF 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 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 1 presents the stack data, operating parameters, and emissions of SO_2, NO_x, and PM. 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. correct years?

The PM emissions rates are based on stack test data. The PM speciation data is presented in Table 2 (also presented with the BART Protocol previously submitted to FDEP). These species categories were generally based on the speciation profile provided by the Visibility Improvement State and Tribal Association of the Southeast (VISTAS) for Uncontrolled Utility Residual Oil Boiler. The condensable PM emission rates were estimated based on emission factors for oil combustion presented in Table 1.3-2 of AP-42, while the different PM particle size categories were determined from particle size distribution for utility boilers firing residual oil provided in Table 1.3-4 of AP-42. The PM elemental carbon emission rates were based on data provided in EPA's January 2002 draft "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon".

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 the Everglades NP PSD Class I area located within 300 km of the PTF Plant. 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 4km? 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.

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 area using receptors provided by the National Park Service.

2.3 BART EXEMPTION MODELING RESULTS

Summaries of the maximum visibility impairment values for the PTF BART-eligible emission units estimated using the new IMPROVE algorithm, are presented in Tables 3 and 4. 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 value over the three years, are presented in Table 3. This table also presents the number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv. The 8th highest visibility impairment values predicted at the Everglades NP PSD Class I area for each year are presented in Table 4.

As shown in Tables 3 and 4, the 8th highest visibility impairment values predicted for each year at the Everglades NP PSD Class I area 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, PTF 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

(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, Fifth Edition, February 1996, EPA 453/B–96–001). 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

4.4 SO_2 Emissions

As shown in Table 3, the highest 8th highest visibility impact due to Units 1 and 2 is 5.96 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 PTF. 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 identical 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.

4.4.1 Available Retrofit Control Technologies

As part of the BART analysis, a review of previous SO_2 BACT determinations for natural gas and liquid fossil-fuel fired utility and large industrial-sized boilers was performed using the RACT/BACT/LAER Clearinghouse (RBLC) on EPA's webpage. The RBLC database provides no recent (within the past 5 years) SO_2 BACT examples for large size natural gas or oil-fired boilers. Only four determinations were found for large industrial boilers burning fuel oil, and from the review of these BACT determinations, it is evident that SO_2 BACT determinations for large industrial boilers and boilers firing fuel oil have only been based on use of low-sulfur fuels. These determinations are presented in Table 5.

SO_2 BACT determinations for large biomass-fired boilers where oil is used as backup fuel have typically been a restriction on the fuel sulfur content as well. Numerous examples are available in the RBLC database for large coal-fired boilers, which use flue gas desulfurization (FGD) as the BACT for SO_2 emissions.

4.4.2 Control Technology Feasibility

The following control technologies were analyzed:

Low Sulfur Fuel

Units 1 and 2 currently burn natural gas and distillate (No. 2) or residual (No. 6) fuel oil. Although the sulfur content of natural gas is typically very low, sulfur content of liquid fossil fuels such as No. 6 fuel oil can be high. Sulfur content of residual oil can range from 0.3 percent to more than 2 percent. On the other hand, sulfur content of distillate oil can be as low as 0.0015 percent (also known as ultra low-sulfur diesel). Switching to a lower-sulfur fuel oil can reduce SO_2 emissions; however, the cost of compliance depends on the following:

- Cost difference of low sulfur fuel oil and fuel oil currently used
- Difference in delivery cost for the lower-sulfur fuel oil

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 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. Use of a wet or dry FGD system for oil-fired boilers similar in size to PTF Units 1 and 2 is not common. The EPA Fact Sheet also mentions the high capital cost of an FGD system as a disadvantage. Based on the cost range provided by EPA in the Fact Sheet for FGD system, the capital cost of a wet FGD system for Units 1 and 2 may range between $40 million to $100 million. This high capital cost and expected high retrofit cost, which would be required to install a FGD system for the existing Units 1 and 2, will be cost prohibitive. Therefore, a FGD system is not considered any further for Units 1 and 2.

4.4.3 Control Effectiveness of Options

The effectiveness of SO_2 emissions control by the use of low sulfur fuel oil depends on the sulfur content of the lower sulfur oil that is available and economically feasible. Since Units 1 and 2 primarily burn fuel oil, switching to an even lower sulfur content fuel oil option is best suited for these units. This is also the control method with no additional capital investment. Wet or dry FGD systems are typically used for coal-fired boilers, would be cost-prohibitive for Units 1 and 2, and have not been determined as BACT for large fuel oil-fired boilers in last 10 years.

4.4.4 Impacts of Control Technology Options

Cost of Compliance

To achieve SO_2 emissions below current levels, Units 1 and 2 would require use of lower sulfur fuel oil. Since the units currently burn 1-percent sulfur oil, lower sulfur contents of 0.7 percent and 0.3 percent were analyzed for this unit.

Based on information provided by FPL, the current fuel (1-percent sulfur) cost is $109.05 per barrel (bbl) (42 gallons). The cost of compliance to use reduced sulfur fuel oil is represented by the additional cost of the lower sulfur fuel oil versus $109.05/bbl for the current 1-percent sulfur fuel oil used in the boilers. According to FPL, reduced sulfur fuel oil with 0.7-percent and 0.3-percent sulfur costs $114.63/bbl and $124.63/bbl, respectively.

The cost analysis was prepared following EPA's Control Cost Manual, and is presented in Table 6. A new fuel oil tank will not be needed since the facility already burns fuel oil and the existing storage tanks will be able to store the lower sulfur oil. Since there are no equipment costs or indirect capital costs for using lower sulfur fuel oil, the total capital investment is zero. No operation or maintenance costs were used in the cost analysis because no change is expected to these costs. There are no indirect operating costs since these costs depend on either operating labor and maintenance or on capital investment. As a result, the only cost involved with using lower sulfur fuel oil is the annual differential fuel cost.

As shown in Table 6, the total annual cost of switching Units 1 and 2 from the fuel oil currently used to 0.7-percent sulfur fuel oil is more than $33 million, and from the fuel oil currently used to 0.3-percent sulfur fuel oil is more than $94 million. The capital recovery cost is zero because there is no capital investment. Thus, the total annual cost includes only the direct operating cost, which in this case is the differential fuel cost.

To calculate the emissions reduction due to the control options, the baseline emissions were based on the maximum actual annual SO_2 emissions for both Units 1 and 2 from the period 2001 to 2003. The controlled emissions were calculated based on future projected actual fuel usage, which is based on the permitted heat input rate of 4,000 MMBtu/hr for each unit and a projected actual annual operation of 6,825 hrs/yr for each. The projected annual operating hours are based on the maximum actual operation of any one unit over the most recent 5-year period (2007 – 2011).

As shown in Table 6, the average cost effectiveness is calculated to be approximately $19,000 per ton of SO_2 removed if 0.7-percent sulfur fuel is used instead of the current fuel oil. An additional $90 million would be required to switch from 0.7-percent sulfur to 0.3-percent sulfur fuel oil for an incremental average cost effectiveness of more than $16,000 per ton.

Energy Impacts

There are no energy impacts associated with using lower sulfur fuel oil since the heating value of the fuel oil is expected to remain the same with lower sulfur contents.

Non-Air Quality Environmental Impacts

Use of low or reduced sulfur fuel oils do not result in any non-air quality environmental impacts.

Remaining Useful Life

FPL has placed Unit 2 on Inactive Reserve and operates the unit as a synchronous condenser to provide voltage support to the electrical system in the southernmost portion of the FPL service territory. The electric generator is disconnected from the steam turbine and the boiler is inactive, burning no fuel. In addition, FPL plans to significantly reduce the #6 fuel oil burning capability of Unit 1 in the coming years.

4.4.5 Visibility Impacts

To calculate the visibility improvement due to the lower sulfur content fuel, first the baseline visibility impacts were estimated based on the maximum 8th highest 24-hour average visibility impacts presented in Table 6, which is 5.96 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 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 oil. These rates were calculated by multiplying the SO_2 emissions rates used in the baseline impact analysis by the ratio of the specific sulfur content (0.7% or 0.3%) and the baseline sulfur content (estimated to be 1-percent). Visibility improvements were determined by subtracting future dv impacts from the baseline dv impacts.

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-percent sulfur currently used to 0.7-percent sulfur is more than $33 million/dv for a total visibility improvement of 1.5 dv. Incremental visibility cost effectiveness for switching to 0.3-percent sulfur fuel is $35 million/dv for an additional improvement of 2.5 dv. These visibility improvements are extremely small for a very large cost.

4.4.6 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 fuel oil to 0.7- or 0.3-percent sulfur fuel oil. As a result, switching to either of these lower sulfur fuel oils should be cost prohibitive. However, based on the existing BART permit No. 0250003-008-AC, PTF Units 1 and 2 are already subject to a BART limit of 0.7-percent sulfur fuel oil effective on December 31, 2013. Therefore, FPL proposes the currently permitted and soon to be implemented use of 0.7-percent sulfur fuel oil as the BART for SO2 emissions..

FPL recently requested FDEP to modify the existing BART permit (FDEP Project No. 0250003-018-AC) to include additional SO2 emission control measures FPL is proposing –

- Unit 2 will be designated as a permanent synchronous condenser and would no longer burn fossil fuels.
- Unit 1 fuel oil firing will be limited to 25-percent of the current capacity starting December 31, 2013 until June 1, 2017 or the effective date of the Mercury Air Toxics Rule (MATS), whichever is sooner.
- When the MATS Rule is effective, FPL will limit fuel oil firing of Unit 1 to the proposed definition of a "limited use unit" which is approximately 8-percent of the current capacity.

These additional SO2 emission control measures in addition to the proposed use of 0.7-percent sulfur fuel oil will significantly reduce actual SO2 emissions from the PTF BART-eligible emissions units, which will lower visibility impacts at the Everglades NP. Therefore, additional reduction of fuel sulfur content lower than 0.7-percent is not required.

4.5 NO_x Emissions

As shown in Table 3, a maximum of 2.8 percent of the total visibility impact was due to nitrate particles, which are formed by NO_x emissions. Therefore, control of NO_x emissions will provide minimal effect in reducing visibility impacts due to Units 1 and 2.

The units are currently equipped with Low-NOx burners for controlling NOx emissions. Additional add-on control technologies, such as a selective catalytic reduction (SCR) system, will require a direct capital investment between $10 and $20 million for each unit, which will not result in any meaningful reduction in visibility. As a result, FPL proposes that existing combustion processes, Low NOx burners, and good combustion practice be considered as BART for NO_x emissions for Units 1 and 2.

TABLES

TABLE 1
BART MODELING DATA INPUT
FPL TURKEY POINT PLANT

Parameter	Units	Value			
Emission Unit		Unit 1		Unit 2	
Location					
UTM Coordinates					
East	km	567.41		567.41	
North	km	2,813.41		2,813.56	
Zone		17		17	
Lambert Conformal Coordinates [a]					
x	km	1,700.37		1,700.37	
y	km	-1,467.79		-1,467.79	
Stack Data					
Height	ft (m)	400	(122.0)	400	(122.0)
Diameter	ft (m)	18.1	(5.52)	18.1	(5.52)
Base elevation	ft (m)	16	(4.88)	16	(4.88)
Operating Data					
Exit gas temperature	^{o}F (K)	287	(415)	287	(415)
Exit gas velocity	ft/s (m/s)	63.8	(19.5)	62.7	(19.1)
Emission Data					
SO_2	lb/hr (g/s)	3,488	(439.5)	3,757	(473.4)
NO_x	lb/hr (g/s)	2,586	(325.8)	2,198	(276.9)
PM Filterable	lb/hr (g/s)	144.4	(18.2)	144.2	(18.2)

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

TABLE 2
PM SPECIATION SUMMARY - FPL TURKEY POINT

PM Category	Emission Unit [a]	Units	Total	Coarse PM	Soil (Fine PM)	Elemental Carbon (EC)	Inorganic (as H_2SO_4)	Organic
PM Filterable [b]	Units 1 & 2	lb/hr	288.6	78.26	194.77	15.56	NA	NA
		%	100%	27%	67%	5%	NA	NA
PM Condensable [c]	Units 1 & 2	lb/hr	80.00	NA	NA	NA	68.00	12.00
		%	100%	NA	NA	NA	85%	15%
Total PM_{10} (filterable+condensable)	Units 1 & 2	lb/hr	368.6	78.26	194.77	15.56	68.00	12.00
		%	100%	21.2%	52.8%	4.2%	18.4%	3.3%
Total PM_{10} (filterable+Organic Condensable PM)	Units 1 & 2	lb/hr	300.6	78.26	194.77	15.56	0.0	12.00
Modeled PM Speciation % (SO_4 modeled separately)		%	100%	26.0%	64.8%	5.2%	0.0%	4.0%

PM Particle Size Distribution for CALPUFF Assessment

Species Name	AP-42 (Table 1.3-4) Particle Size (microns)	AP-42 (Table 1.3-4) Cumulative (%)	Cumulative Normalized PM10 (%)	Individual Categories Filterable (%)	Individual Categories Organic Condensable	Emission Rate (lb/hr) Filterable	Emission Rate (lb/hr) Organic Condensable	Emission Rate (lb/hr) Total
Total PM_{10}						288.6	12.0	300.6
PM0063	0.63	20.0%	28.2%	28.2%	50.0%	81.3	6.0	87.3
PM0100	1	39.0%	54.9%	26.8%	50.0%	77.2	6.0	83.2
PM0125	1.25	43.0%	60.6%	5.6%	0	16.3	0.0	16.3
PM0250	2.5	52.0%	73.2%	12.7%	0	36.6	0.0	36.6
PM0600	6	58.0%	81.7%	8.5%	0	24.4	0.0	24.4
PM1000	10	71.0%	100.0%	18.3%	0	52.8	0.0	52.8
Totals				100.0%	100.0%	288.6	12.0	300.6

Total Modeled PM_{10} 300.6

[a] Heat input rate for unit and fuel heat content 8,000 MMBtu/hr 4000 PER UNIT
150,000 Btu/gal fuel oil

[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	4.3	x sulfur content factor	Ratio =	0.73 PM2.5/PM10
emission factor (Table 1.3-4, AP-42)	PM10	5.9	x sulfur content factor		

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

PM elemental carbon	0.054	PM elemental carbon/PM10
PM soil= PM2.5 - PM elemental carbon	0.67	PM soil/PM10
PM2.5	0.73	PM2.5/PM10
PM coarse= PM10 - PM2.5		

[c] Condensable PM (Table 1.3-2, AP-42)

	lb/1000 gal	lb/MMBtu	
Total	1.5	0.0100	
Inorganic	1.275	0.0085	(0.85 of Total)
Organic	0.225	0.0015	(0.15 of Total)

TABLE 3
SUMMARY OF BART MODELING RESULTS, FPL TURKEY POINT PLANT
NEW IMPROVE ALGORITHM

Class I Area	Distance from Source to Nearest Class I Area Boundary (km)	Visibility Impact >0.5 dv						22nd Highest Impact (dv) Over 3-Yr Period
		2001		2002		2003		
			8th Highest Impact (dv)		8th Highest Impact (dv)		8th Highest Impact (dv)	
Everglades NP	21		5.619		5.086		5.956	5.774
Pollutant Contribution		Sulfate	94.1%	Sulfate	94.9%	Sulfate	93.9%	
		Nitrate	1.5%	Nitrate	1.3%	Nitrate	2.8%	
		Particulate Matter	4.3%	ticulate Matter	3.8%	ticulate Matter	3.3%	

TABLE 4
VISIBILITY IMPACT RANKINGS AT PSD CLASS I AREA
WITH NEW IMPROVE EQUATION
FPL TURKEY POINT PLANT

Class I Area	Rank	Predicted Impact (dv) 2001	2002	2003
Everglades NP	1	6.528	6.916	10.332
	2	6.375	6.363	8.825
	3	6.247	6.238	8.164
	4	6.173	5.856	7.341
	5	6.128	5.776	6.841
	6	5.866	5.502	6.801
	7	5.678	5.107	6.338
	8	5.619	5.086	5.956

TABLE 5
SUMMARY OF SO2 BACT DETERMINATIONS FOR LIQUID FUEL FIRED LARGE INDUSTRIAL BOILERS (>250 MMBTU/HR) (1999-2009)

Facility Name	State	Permit Issued	Process Info	Fuel	Heat Input	Control Method	SO_2 Limit	Basis
Longview Fibre Paper And Packaging, Inc	WA	11/01/2006	Power Boilers 12 And 13		444 MMBtu/hr, ea		100.00 PPMDV @ 7% O2	Other Case-by-Case
Longview Fibre Paper And Packaging, Inc	WA	11/01/2006	Power Boiler 16	Fuel Oil	525 MMBtu/hr		250.00 PPMDV @ 7% O2	Other Case-by-Case
Longview Fibre Paper And Packaging, Inc	WA	11/01/2006	Power Boiler 17	Fuel Oil	591 MMBtu/hr	Low Sulfur Fuel	250.00 PPMDV @ 7% O2	Other Case-by-Case
Longview Fibre Paper And Packaging, Inc	WA	11/01/2006	Power Boiler 20	Fuel Oil	900 MMBtu/hr	Low Sulfur Fuel	100.00 PPMDV @ 7% O2	Other Case-by-Case
Columbia Energy Center	SC	07/03/2003	Boiler, Fuel Oil	No. 2 Oil	550 MMBtu/hr	Low Sulfur Fuel	0.06 LB/MMBTU	BACT-PSD
International Paper - Mansfield Mill	LA	08/14/2001	Power Boiler #1 & #2, Oil	Fuel Oil	645 MMBtu/hr	Max S Content 0.7%	516.00 LB/H	BACT-PSD
International Paper - Mansfield Mill	LA	08/14/2001	Power Boiler #1 & #2, Combined Fuel	Combined Fuel	760 MMBtu/hr	Limit S Content		BACT-PSD
Columbia Energy LLC	SC	04/09/2001	Boilers, Fuel Oil (2)	No. 2 Oil	350 MMBtu/hr	Low Sulfur Fuel	21.00 LB/H	BACT-PSD

Source: EPA 2009 (RBLC database)

Table 6. Cost Effectiveness of Fuel Switching for FPL Turkey Point Units 1 and 2

Cost Items	Cost Factors	Baseline Current Fuel Cost ($)	Projected Future 0.7% S Fuel Cost ($)	Projected Future 0.3% S Fuel Cost ($)	
DIRECT CAPITAL COSTS (DCC):					
(1) Equipment Cost					
(a) New Fuel Oil Storage tank	New tank will not be needed	0.0	0.0	0.0	
(b) Pumps, piping, etc.	NA	0.0	0.0	0.0	
(c) New oil guns/atomizer sprayer plates	NA	0.0	0.0	0.0	
(3) Sales Tax	NA	0.0	0.0	0.0	
Subtotal: Total Equipment Cost (TEC)		0.0	0.0	0.0	
(4) Direct Installation Costs	NA	0.0	0.0	0.0	
Total DCC:		0.0	0.0	0.0	
INDIRECT CAPITAL COSTS (ICC): [a]					
(1) Indirect Installation Costs					
(a) Engineering	10% of TEC	0.0	0.0	0.0	
(b) Construction & Field Expenses	10% of TEC	0.0	0.0	0.0	
(c) Construction Contractor Fee	10% of TEC	0.0	0.0	0.0	
(d) Contingencies	3% of TEC	0.0	0.0	0.0	
(2) Other Indirect Costs					
(a) Startup	1% of TEC	0.0	0.0	0.0	
(b) Performance Test'	1% of TEC	0.0	0.0	0.0	
Total ICC:		0.0	0.0	0.0	
PROJECT CONTINGENCY	15% of (DCC+ICC)	0.0	0.0	0.0	
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	0.0	0.0	0.0	
DIRECT OPERATING COSTS (DOC):					
(1) Variable Operation & Maintenance Cost	FPL Data	0	0	0	
(3) Fuels					
Existing Fuel Cost (Fuel oil with 1.0%S)	$109.05/bbl, 4,000 MMBtu/hr, 145 MMBtu/10^3 gal, 6,825 hrs/yr	977,689,655	513858621 --	--	
Proposed Fuel Cost (Fuel oil with 0.7%S)	$114.63/bbl, 4,000 MMBtu/hr, 145 MMBtu/10^3 gal, 6,825 hrs/yr	--	~~1,027,717,241~~	--	558,656,24
Proposed Fuel Cost (Fuel oil with 0.3%S)	$124.63/bbl, 4,000 MMBtu/hr, 145 MMBtu/10^3 gal, 6,825 hrs/yr	--	--	1,117,372,414	
Differential Fuel Cost (Proposed - Existing)	Proposed fuel cost - existing fuel cost		50,027,586	139,682,759	
Total DOC:			50,027,586	139,682,759	
			- 163,831,035	419,003,998	
INDIRECT OPERATING COSTS (IOC): [a]					
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	0.0	0.0	0.0	
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	0.0	0.0	0.0	
(3) Insurance	1% of total capital investment, CCM Chapter 2	0.0	0.0	0.0	
(4) Administration	2% of total capital investment, CCM Chapter 2	0.0	0.0	0.0	
Total IOC:	(1) + (2) + (3) + (4)	0.0	0.0	0.0	
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	0.0	0.0	0.0	
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	0.0	50,027,586	139,682,759	
Baseline Emissions:	Max. 2001-2003 from CEM Data, Both Units 1 and 2	13,281	13,281	13,281	
Projected Future Emissions:	4,000 MMBtu/hr, 145 MMBtu/10^3 gal, 6,825 hrs/yr, Units 1 and 2	--	10,675	4,575	← ?
Emissions Reduction (TPY)(AC):	Baseline - Future Projected (TPY)	--	2,606	8,706	
Average Cost Effectiveness ($/ton):	AC/Emissions Reduction	--	19,197	16,044	
Incremental Cost ($)	Incremental Cost for using 0.3% S instead of 0.7% S oil	--	--	89,655,172	
Incremental Emissions Reduction (TPY):	Emissions Reduction 0.3% S oil - 0.7% S oil	--	--	6,100	
Incremental Cost Effectiveness ($/ton):	Incremental Cost/Incremental Emissions Reduction	--	--	14,697	
Modeled Baseline Visibility Impact - Haze Index (HI) (dv):	8th Highest Visibility Impact for Both Units 1 and 2	5.96	--	--	
Modeled Baseline Visibility Impact w 0.7% S Fuel - HI (dv):	8th Highest Visibility Impact for Both Units 1 and 2	--	4.45	1.91	
Improvement in Visibility (dv)	Future - Baseline	--	1.51	4.05	
Average Visibility Improvement Cost Effectiveness ($/dv):	AC/Visibility Improvement	--	33,130,852	34,465,256	
Incremental Visibility Improvement (dv):	Visibility Improvement 0.3% S oil - 0.7% S oil	--	--	2.54	
Incremental Visibility Improvement Cost Effectiveness ($/dv):	Incremental Cost/Incremental Visibility Improvement	--	--	35,257,652	

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

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