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Golder Associates

May 30, 2008

0838-7514

Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention: Mr. Jeffery Koerner, Administrator

RE: GLADES SUGAR HOUSE
PROJECT NO. 0990026-014-AC
BART PROJECT
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION NO. 1

Dear Mr. Koerner:

Sugar Cane Growers Cooperative of Florida (SCGCF) has received a request for additional information (RAI) from the Florida Department of Environmental Protection (FDEP) dated February 29, 2008, regarding the Best Available Retrofit Technology (BART) determination analysis submitted in January 2008. Each of FDEP's requests is answered below, in the same order as they appear in the RAI letter.

Reduced Sulfur Fuel Oil (1%, 0.5%, 0.05% and 0.0015%)

Comment 1. **Please provide a schematic for the various fuel oil tanks and connections to Boilers 1, 2, 3, 4, 5 and 8. Identify which tank is capable of providing fuel to which boiler(s), the fuel storage capacity of each tank in gallons, pump locations and flow meter locations (schematically).**

Response 1: There is only one fuel tank that supplies fuel to all the boilers. A flow meter is located at each boiler.

Comment 2. **The cost effectiveness worksheet (Table 5-3) indicates capital costs for new tanks, pumps, piping, installation and contingencies as well as new oil guns for the 0.05% and 0.0015% reduced sulfur cases.**

a. **Capital Costs: Annual operating reports indicate that the average fuel sulfur content for all boilers (1, 2, 3, 4, 5 and 8) was 1% by weight in 1998, 1999, 2000, 2002 and 2003. Therefore, all of the boilers can currently fire 1% fuel oil without any changes. Fuel oil fired in Boiler 8 must be replaced in the shared tanks with fuel oil containing no more than 1% by weight. Therefore, only Boiler 3 would have a fuel sulfur content greater than 1%, which is the smallest boiler at the mill. Explain why new tanks, pumps and piping would be necessary. This equipment accounts for $2.5 - $2.7 million in total capital investment, which adds $278,500 to $304,414 in annual costs through capital recovery. Note that the life of this equipment was assumed to be only 15 years.**

Response 2a: Boiler Nos. 1, 2, 4, and 5, the four BART-eligible emissions units at the SCGCF Belle Glade facility, are permitted to burn No. 6 fuel oil with a maximum sulfur content of 2.4 percent. Table 5-3 of the BART determination report presented cost-effectiveness calculations for using different types of fuels in Boiler Nos. 4 and 5. From 2001 through 2006, Boiler Nos. 4 and 5 have used No. 6 fuel oil with a sulfur content varying from 1.0 to 2.17 percent. If these two boilers are limited to burn 1-percent sulfur No. 6 oil, SCGCF will need a new tank dedicated for these boilers so that the flexibility to use higher sulfur fuel in other boilers (Boiler Nos. 1, 2, 3, and 8) can be maintained. Due to similar reasons, a new fuel tank is considered for the scenarios of burning lower sulfur (0.0015 and 0.05 percent) No. 2 fuel oil.

All four BART-eligible boilers could be switched to 1.0 percent sulfur oil, as well as Boiler No. 3. In this case, a new fuel oil tank would not be needed, nor would new pumps or piping be required. However, the visibility reduction of such a change must also be considered by the Department. As discussed in the BART Control Analysis report, Boiler Nos. 1 and 2 contribute negligible visibility impacts at the Everglades National Park (ENP). Therefore, in order to assess this case, cost estimates for this case were developed as well as the visibility reduction, and are presented and attached in Table 1. The visibility impacts are summarized and attached in Table 5-11 (revised). As shown, this control option results in a cost effectiveness of \$1,160/ton SO_2 removed, and \$1.3 million/dv to \$1.8 million/dv visibility improvement. The deciview reduction for this option range is between 0.020 and 0.061deciview, depending on the boiler. These economic impacts are considered unreasonable, considering the very small deciview reduction and therefore, are rejected as BART.

b. Direct Operating Costs: Please explain why "additional" annual costs for operating labor, maintenance labor and maintenance materials would be necessary for the oil firing systems. The boilers currently have oil firing systems and already incur these costs. These items account for approximately \$70,000 in additional annual operating costs and should be removed.

Response 2b: Apart from differential fuel cost, there will be some direct operating costs associated with the new fuel tank for the following services:

- Perform routine tank tests and inspections.
- Maintain, and repair when necessary, computer electronics and communications for fuel level monitoring and leak detection.
- Coordinate tank repairs and upgrades.
- Document and record tank system status, and maintain files.

Since there is no reference available for the exact operating and maintenance labor hours, a 1 hour per shift assumption was used in the original calculation. Table 5-3 has been revised for a minimum of 15 minutes of operating labor per shift.

c. Indirect Operating Costs: Please explain why the following costs were included in this analysis: overhead, property taxes, insurance, and administration fees. These items account for approximately \$150,000 in additional annual operating costs and should be removed.

Response 2c: The indirect operating costs are all based on standard EPA factors from the EPA Air Pollution Control Cost Manual, as defined in Sections 2.5.5.7 and 2.5.5.8 of the Control Cost Manual. The overhead cost is tied to the operating, supervisory, and maintenance labor. Property taxes, insurance, and administrative changes are factored from the system capital investment. These costs are part of the total cost of installing and operating capital projects.

d. Since reducing the fuel oil sulfur content will only reduce sulfur dioxide (SO_2) emissions from firing oil, identify the baseline SO_2 emissions from firing 2.4% sulfur by weight No. 6 oil. For example:`

SO_2 (2.4%) = (594,000 gal/year)(8.1 lb oil/gal)(0.024 lb S/lb oil) (2 lb SO_2/lb S)(ton/2000 lb) = 115.5 ton/yr

Similarly, provide the calculation for each of the reduced fuel sulfur cases.

Response 2d: The calculations are as follows:

SO_2 (2.4%) = (594,000 gal/year) x (8.1 lb oil/gal) x (0.024 lb S/lb oil) x (2 lb SO_2/lb S) x (ton/2000 lb) = 115.5 TPY.

SO_2 (1.0%) = (594,000 gal/year) x (8.0 lb oil/gal) x (0.01 lb S/lb oil) x (2 lb SO_2/lb S) x (ton/2000 lb) = 47.5 TPY.

SO_2 (0.05%) = (640,000 gal/year) x (7.2 lb oil/gal) x (0.0005 lb S/lb oil) x (2 lb SO_2/lb S) x (ton/2000 lb) = 2.3 TPY.

SO_2 (0.0015%) = (640,000 gal/year) x (7.2 lb oil/gal) x (0.000015 lb S/lb oil) x (2 lb SO_2/lb S) x (ton/2000 lb) = 0.07 TPY.

The changes have been made and a revised Table 5-3 is attached.

e. Based on the application, the estimated annual fuel cost differential in switching from 2.4% to 1% sulfur by weight is \$29,700 per year. Assuming SO_2 emissions from oil firing would be reduced from 115.5 tons/year to 46.9 tons/year, this results in a cost effectiveness of:

CE = (\$29,700/year) / (115.5 – 46.9 tons/year) = \$433/ton of SO_2 removed

In addition to the 0.05% and 0.0015% reduced sulfur cases, the application provides modeled visibility impacts from firing 0.5% sulfur by weight fuel oil. Similar to the 1% reduced sulfur case discussed above, provide revised cost effectiveness estimates for the remaining reduced fuel sulfur cases (0.5%, 0.05% and 0.0015%) excluding costs for new tanks, pumps, piping, etc. Costs associated with new burners may be included for these cases; however, provide supporting information from the current burner vendor of the limitations on firing low sulfur fuels (e.g., density, heating value, etc.). Cost estimates should assume a 7% interest rate and 20-year life.

Response 2e: The revised Table 5-3 shows cost-effectiveness calculations using a cost recovery factor based on 7-percent interest rate and 20-year equipment life. Following is a summary of the revisions made to Table 5-3:

- Cost recovery factor based on 7-percent interest rate and 20-year equipment life.
- Operating labor has been reduced from 1 hour to 15 minutes per shift.
- Baseline SO_2 emissions calculated based on 594,000 gallons of No. 6 fuel oil with 2.4-percent sulfur content.

Revised Table 5-3 includes cost-effectiveness estimates for reduced sulfur No. 2 fuel oil with sulfur contents of 0.05 percent and 0.0015 percent. Cost information for 0.5-percent sulfur oil was not available. These include the cost-effectiveness calculations considering the visibility impacts of the scenarios.

Cost information for the new burners was provided in Appendix B of the BART Determination Report submitted in January 2008. The information is contained in an email from Babcock & Wilcox Company, dated March 5, 2007.

f. Provide the revised cost effectiveness estimates for all reduced sulfur cases (1%, 0.5%, 0.05% and 0.0015%) for Boilers 1 and 2.

Response 2f: The estimates have been developed for Boiler Nos. 1 and 2 and a revised Table 5-3 and a new Table 1 are attached with the results.

Section Conclusion: As shown in the revised Table 5-3, cost effectiveness of switching to lower sulfur fuel oil is very high both in terms of $/ton of SO_2 removed or $/dv of visibility improvement. Table 1 shows that the cost effectiveness of switching all boilers to 1 percent sulfur fuel oil is also very high in terms of $/dv. Therefore, switching to a lower sulfur fuel oil is not a viable option.

<u>New Wet Scrubber System (Venturi with Micro Mist)</u>

Comment 3. Indirect Capital Costs: The project contingency for retrofit assumes a factor of 20% of the total direct and indirect capital costs. This factor appears high for this project. The EPA cost manual states that, "A contingency factor should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system." Please provide supporting information for this high factor and revise downward.

Response 3: The project contingency for retrofit is intended for existing facilities for which control equipment is being added and is to cover unexpected costs such as the cost of unexpected delays, the cost of re-engineering and re-fabrication, the cost of correcting design errors, and the underestimating of actual costs. The retrofit cost considerations are explained in Section 2.5.4.2 of Chapter 2 of the Control Cost Manual. The Control Cost Manual states that because of the lack of sufficient information to fully assess the potential hidden costs of installing a control system in an existing facility, a retrofit factor as high as 50 percent can be justified. Because the retrofit cost estimate is subjective and varies across the spectrum of control devices, a factor of only 20 percent was used to cover potential unforeseen issues associated with installing additional controls at the Belle Glade facility, which is on the lower end of the range, and therefore is certainly acceptable.

As explained in the Control Cost Manual, the retrofit factor applies not only to the equipment cost, but also to the direct installation costs and the indirect capital costs. Therefore, the 20-percent retrofit factor was applied to the total capital cost (direct plus indirect).

Comment 4. Direct Operating Costs: Show the calculations for estimating the following annual costs: operating labor, caustic material, water, electricity and waste disposal. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary ($/hour, $/ton caustic, $/1000 gallons, etc.).

Response 4: The calculations are explained below:

- Caustic material – Calculation for caustic is based on the actual SO_2 emissions reported for the boiler from 2001 to present and the chemical equilibrium equation that requires 2 moles of NaOH to absorb 1 mole of SO_2. The cost calculation for caustic in Table 5-4 submitted with the BART Determination Analysis (submitted in January 2008) had an error in it as the spreadsheet cell was erroneously linked to the cell that calculated waste generated by the absorption process. The cost calculation is revised as follows and based on the current U.S. caustic cost of $470 to 520/dry ton:

  Highest actual SO_2 emissions from Boiler No. 4 – 113.2 TPY.

  NaOH requirement – 113.2 TPY of SO_2 × 2(MW_{NaOH}, 40)/MW_{SO2}, 64 = 141.5 TPY.

  Unit cost of NaOH = $470 to 520/dry ton (source: www.icis.com).

  Cost of NaOH = $500/dry ton × 141.5 TPY = $70,750.

- Waste disposal – The by-product of the caustic absorption process is sodium sulfate (Na_2SO_4), which is a solid and must be disposed of. Cost of Na_2SO_4 disposal is calculated as follows:

  Highest actual SO_2 emissions from Boiler No. 4 – 113.2 TPY.

  Na_2SO_4 produced – 113.2 TPY of SO_2 × 0.985 × MW_{Na2SO4}, 142/MW_{SO2}, 64 = 247.4 TPY.

  Cost of disposal = $40/ton × 247.4 TPY = $9,900.

- Water makeup – The makeup water requirement is calculated based on the vendor quote (Andritz, Appendix B, BART Determination Report, January 2008) for a system with inlet SO_2 emission rate of 2,200 lb/hr and prorating for the inlet conditions of Boiler Nos. 4 and 5:

  Andritz data – 250 gpm for inlet condition of 2,200 lb/hr.

  Boiler No. 4 inlet SO_2 – 500 lb/hr.

  Makeup water required for Boiler No. 4 = 250 gpm / 2,200 lb/hr × 500 lb/hr = 56.8 gpm.

  Cost of makeup water = $2.36/1,000 gallon × 56.82 gpm × 60 min/hr × 24 hr/day × 180 days/yr = $34,760.

- Electricity – The power requirement for the scrubbing system is based on the Andritz Piping & Instrumentation Diagram (P&ID), which shows two 125-hp quench pumps and a blowdown pump. One of the quench pumps is standby. However, the size of the blowdown pump was not available and only one quench pump was used in the power requirement estimation. Table 5-4 has been revised for the power requirement of just one quench pump.

  Electrical power requirement = 125 hp = 93 kW.

  Cost of electricity = 93 kW × 24 hr/day × 180 days/yr × $0.06/KWh = $24,100.

Comment 5. **The revised cost estimate should assume a 7% interest rate and 20-year life.**

Response 5: A revised Table 5-4 is submitted with capital recovery cost based on 7-percent interest and 20-year equipment life.

Comment 6. **Show the calculation of the annual SO_2 emissions rate used as the baseline emissions.**

Response 6: Annual SO_2 emissions used as baseline emissions are summarized below. The emissions calculations are provided in Table 2. These calculations include SO_2 due to fuel oil burning as well as bagasse burning. Note that in some cost estimating tables, only the SO_2 due to fuel oil burning is considered.

Year	Boiler 1	Boiler 2	Boiler 4	Boiler 5
2001	56.0	55.3	113.2	83.4
2002	40.0	6	86.5	56.6
2003	41.2	6	90.9	61.3
2004	5	41.7	96.4	61.8
2005	35.2	37.0	87.8	60.3
2006	9	4	56.0	38.6

Comment 7. **As indicated in the vendor quote, the wet scrubber will reduce particulate matter (PM) emissions in addition to SO_2 emissions. Provide a vendor quote for the PM control efficiency. Revise the cost estimate if necessary. Revise the cost effectiveness analysis to include the reduction of both SO_2 and PM emissions.**

Response 7: The vendor data (Andritz) for the scrubber system is focused on the SO_2 emissions control and indicates that PM emissions control is to be determined later through stack tests. The Envirocare website (www.envirocare.com) provides a typical PM control efficiency of > 99.5 percent for MicroMist scrubbers. However, it will not be able to achieve a further reduction of 99.5 percent on the exhaust stream of the existing wet scrubber. This is because the exhaust stream of the first control device will be composed of mainly smaller size particles. In addition, there would be operating difficulties in adding the ESP after the wet scrubber (i.e., high moisture levels, low temperature affecting resistivity, etc.).

Using the 99.5-percent control for PM, Table 5-4 has been revised to include PM emissions reduction and cost effectiveness based on the total SO_2 and PM emissions reduction calculated. As shown, the cost effectiveness ranges from 3,800 to 4,600 $/ton and the visibility cost effectiveness ranges from 9.2 million to 12.6 million $/dv for the bagasse and fuel oil firing scenario.

Section Conclusion: Revised Table 5-4 shows the cost-effectiveness for a new wet scrubber system based on revised baseline SO_2 emissions, direct operating labor and material cost, and capital recovery cost, which is very high. The cost-effectiveness values also include the PM emissions reduction in addition to SO_2. Therefore, a new wet scrubber is not a practical solution for additional visibility reduction. Table 5-4 shows that the visibility reduction achieved in the bagasse-only firing scenario is less than 0.005 dv, practically zero.

New Caustic Injection System for Existing Wet Impingement Scrubber

Comment 8. **Describe the caustic injection system (including equipment) intended for this option. The estimated total capital investment of $510,000 appears very high for such a system. The existing boilers currently use wet impingement scrubbers for particulate control. Typically, these systems include multiple levels of injectors with substantial scrubber water flow rates. Why couldn't the scrubbing media be treated prior to injection through the existing injectors?**

Response 8: A description of the caustic injection system is provided in Page 7 of the Andritz budget proposal. Equipment included in the caustic injection system is described in Page 10 of the budget proposal and includes a caustic buffer tank, dosage/control system, dual pH probe, and transmitters. The budget proposal does not break out this specific equipment and, therefore, a factor of 20-percent of the entire system cost was assumed for the caustic injection system. The cost analysis presented in Table 5-5 of the BART Determination Report did not include any installation cost. Table 5-5 has now been revised to include an installation cost, which is 20 percent of the installation cost of $1.5 million for the entire system.

Comment 9. **Capital Costs: Provide supporting information for the equipment cost estimate of $261,707 as well as "foundations, structural steel and lighting" at $34,938. Provide supporting information for the 20% contingency factor and revise downward.**

Response 9: As explained in Response 8, the caustic injection system cost of $261,707 is based on assuming 20 percent of the equipment cost from the budget proposal from Andritz and adjusted for the exhaust flow of Boiler No. 4 ($230,217 for Boiler No. 5).

- Andritz equipment cost = $1,235,000.
- 20% of equipment cost = $247,000.
- Andritz system inlet air flow = 284,000 acfm at 462°F.
- Boiler No. 4 exhaust flow = 203,000 acfm at 162°F.
- Adjusted 20 percent equipment cost = $247,000 / (284,000 x (460+162) / (460+462)) x 203,000 = $261,707.

As indicated in the budget proposal, the cost of foundation for the caustic injection system (includes tank, pump, dosage/control system) is not included and was estimated based on a factor of 12 percent of total equipment cost (OAQPS Cost Manual, 6th Edition, January 2002, Section 5).

The justification for using the 20-percent contingency factor is described in Comment 3.

Comment 10. **Operating Costs: Show the calculations for estimating the following annual costs: operating labor, caustic material, water, electricity and waste disposal. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary ($/hour, $/ton caustic, $/1000 gallons, etc.).**

Response 10: The operating labor, caustic material, water, electricity, and waste disposal costs are same as those calculated for the new Micro Mist wet scrubber system and described in Response 4. Adjustments have been made in Table 5-5 to account for 180 days per year operation.

Comment 11. **The revised cost estimate should assume a 7% interest rate and 20-year life.**

Response 11: The cost calculation has been revised and a revised Table 5-5 is attached.

Section Conclusion: As shown in revised Table 5-5, the cost effectiveness for adding a caustic injection system to the existing wet scrubber range from \$5,500/ton to \$6,500/ton and \$5.7 million/dv to \$8.5 million/dv for the bagasse and fuel oil firing scenario, which is very high and visibility reduction achieved in the bagasse-only firing scenario is 0.003 dv or less.

<u>New Electrostatic Precipitator</u>

Comment 12. **The cost estimate in Table 5-9 indicates a PM control efficiency of only 84% for the ESP added after the wet scrubber. Does this suggest that the ESP would be added after the existing wet impingement scrubber? The PPC cost quote in the Appendix states that the ESP will reduce emissions from 492 to 6.8 kg/hour, which is a control efficiency of 98.6%. This is more typical for a modern ESP design. Assuming a control efficiency of approximately 85% for the existing wet impingement scrubber and baseline emissions for Boiler 4 of 118.8 tons/year, uncontrolled emissions would be 792 tons/year. Assuming 98.6% reduction with the ESP to replace the existing wet impingement scrubber, controlled emissions would be only 11 tons/year. Please comment and revise the cost analysis accordingly also assuming 7% interest rate and 20-year life.**

Response 12: The ESP considered in the BART PM control technology analysis would replace the existing wet impingement scrubber. The control efficiency is based on the baseline PM emissions and not uncontrolled PM emissions for firing bagasse. Based on the vendor (PPC Industries) design data, the ESP is able to achieve a control efficiency of 98.6 percent. However, if used in series with a wet impingement scrubber control device, it will not be able to achieve a further reduction of 98.6 percent on the exhaust stream of the first control device. This is because the exhaust stream of the first control device will be composed of mainly smaller size particles. In addition, there would be operating difficulties in adding the ESP after the wet scrubber (i.e., high moisture levels, low temperature affecting resitivity, etc.).

A typical ESP-controlled PM emission rate for Boiler Nos. 4 and 5 would be 0.02 lb/MMBtu. As explained in Section 5.4 of the BART Determination Report, current PM emission rates are 0.124 and 0.15 lb/MMBtu for Boiler Nos. 4 and 5, respectively, which means the ESP will reduce the PM emissions compared to the existing wet scrubber by 84 and 87 percent, respectively.

Outlet emissions = 0.02 lb/MMBtu.
Inlet emissions = 0.124 lb/MMBtu.
Emissions control = 1 - 0.02/0.124 = 84 percent.

The cost recovery factor in Table 5-9 was revised to be based on 20 years of equipment life at 7-percent interest.

Comment 13. **Capital Costs: Provide supporting information for the 20% contingency factor and revise downward.**

Response 13: The explanation for using the 20-percent contingency factor is described in Response 3.

Comment 14. **Operating Costs: Show the calculations for estimating the following annual costs: operating labor, caustic material, water, electricity and waste disposal. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary ($/hour, $/ton caustic, $/1000 gallons, etc.).**

Response 14: There are no cost estimates for caustic material, water, and waste disposal in Table 5-9. The costs of operating labor and electricity are explained below:

- Operating labor – Operating labor cost estimates are based on Section 6, Particulate Matter Control of the OAQPS Control Cost Manual. Section 3.4.1.1, Chapter 3 of Section 6 describes operating and supervisory labor estimates associated with ESPs. It is assumed that 25 percent of the coordinator's total time will be required for the ESP. Total annual cost for the coordinator, who typically is an engineer, was assumed to be $70,000. Operating labor is recommended to be ½ to 2 hours per shift and 1 hour/shift was used in the calculation. As recommended in Chapter 3, supervisory labor is taken as 15 percent of operating labor.
- Electricity – The power requirement for the ESP system is based on the budget proposal from PPC Industries, which shows the power consumption to be 132 kilovolt-ampere (kVA). Table 5-9 submitted with the BART Determination Report used the 132 kVA as 132 kW. Table 5-9 has been revised to use 106 kW, which is equivalent to 132 kVA.

Electrical power requirement = 132 kVA = 106 kW.
Cost of electricity = 106 kW x 24 hr/day x 180 days/yr x $0.06/kW = $27,500.

Comment 15. **Provide a cost estimate for a secondary wet scrubber (such as a wet venturi scrubber) to remove additional particulate after the existing wet impingement scrubber. Assume a 7% interest rate and 20-year life.**

Response 15: A cost estimate was generated for a secondary wet scrubber to remove additional PM after the existing wet impingement scrubber. The cost estimate, which is summarized in Table 3, is based on the same Andritz/Envirocare Micro Mist wet scrubber system used in the SO_2 control technology analysis, but without the caustic injection system. Since the cost of the caustic injection system used in the SO_2 control technology analysis was assumed to be 20 percent of the total system cost, 80 percent of the total system cost was used in this case for the scrubber without the caustic injection system.

Section Conclusion: Cost-effectiveness numbers presented in the revised Table 5-9 and Table 3 are very high in terms of both $/ton of PM removal and $/dv visibility improvement. Therefore, both control options for additional PM control, ESP (Table 5-9), and scrubber (Table 3) are not feasible.

<u>Mobotec System for Multi-Pollutant Reduction (ROFA + Rotomix)</u>

Comment 16. **Capital Costs: Provide supporting information for the 20% contingency factor and revise downward as necessary.**

Response 16: The justification for using the 20-percent contingency factor is described in Response 3.

Comment 17. **Operating Costs: Show the calculations for estimating the following annual costs: operating labor, urea, water and electricity. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary ($/hour, $/ton caustic, $/1000 gallons, etc.). Revise the maintenance cost factor to 1.5% of the total capital investment.**

Response 17: The cost estimates for operating labor, urea, water, and electricity are explained below:

- Operating labor – Operating labor cost estimate is based on an estimated 20 hours per week or about 1 hour per shift for the operating labor. Supervisory labor is taken as 15 percent of the operating labor according to the Control Cost Manual.
- Electricity – The,power requirement for the ROFA system is not directly available from the budget proposal from Mobotec. The Mobotec equipment list describes the ROFA fan as 300 to 400 hp. Based on data from commercial electric motor vendors on the internet (www.baldor.com), a 300-hp electric motor requires 224 kW of electric power. Tables 5-6 and 5-7 were revised to include the 224-kW power for the ROFA fan.

  Electrical power requirement = 224 kW.

  Cost of electricity = 224 kW x 24 hr/day x 180 days/yr x $0.06/kW = $58,100.
- Urea – Calculation for urea is based on the urea consumption of 0.25 gpm from the Mobotec budget proposal. The Mobotec urea usage, which is for a 423-MMBtu/hr boiler with uncontrolled NO_x emissions of 311 TPY, was prorated to match the NO_x emisisons of Boiler Nos. 4 and 5. Based on current industry data, the cost of 50 percent urea solution is $298/ton.

  Mobotec urea consumption = 0.25 gpm (NO_x emissions of 311 TPY).

  Boiler No. 4 NO_x emissions = 344 TPY (highest actual emissions for 2001 to present).

  Estimated urea consumption for Boiler No. 4 = 0.25 gpm x 344/311 x 60 min/hr = 16.6 gph.

  Unit cost of 50 percent urea solution = $298/ton = $1.65/gallon (based on density of urea, 11.1 lb/gallon).

  Annual cost of urea = 16.6 gph x 2 x 24 hr/yr x 180 days/yr x $1.65/gallon = $236,300.
- Water – The water usage for the ROTAMIX system is based on the water consumption of 1.25 gpm from the Mobotec budget proposal. The Mobotec water usage, which is for a 423-MMBtu/hr boiler with uncontrolled NO_x emissions of 311 TPY, was prorated to match the estimated urea usage of Boiler Nos. 4 and 5.

  Mobotec data = 1.25 gpm (urea usage = 15 gpm).

  Estimated urea usage of Boiler No. 4 = 16.6 gpm.

  Estimate water requirement for Boiler No. 4 = 1.25 gpm x 16.6/15 x 60 min/hr = 99.5 gph.

  Cost of water = $2.36/1,000 gallon x 99.5 gph x 24 hr/day x 180 days/yr = $1,000.

In the Control Cost Manual, a maintenance cost of 1.5 percent is used for control systems with little or no moving parts, such as the SCR and SNCR systems with few pumps and motors (Section 4 of the Control Cost Manual, page 2-45). Since the ROFA and ROTAMIX systems have moving parts, the maintenance cost was doubled to 3 percent.

Comment 18. **As indicated in the vendor quote in the Appendix, the Mobotec system will control PM and SO_2 emissions in addition to nitrogen oxides (NO_x). Provide a vendor quote for a system to control NO_x, PM and SO_2 (related costs, control efficiencies, etc.). Revise the cost effectiveness analysis to also include the reduction of NO_x, SO_2 and PM emissions.**

Response 18: A cost-effectiveness analysis has been performed for using the Mobotec system to control PM and SO_2 emissions in addition to controlling NO_x emissions for Boiler Nos. 4 and 5. The analyses are presented in Tables 4 and 5, respectively. The cost for the Mobotec Furnace Sorbent Injection (FSI) system has been added, which is the Mobotec system for SO_2 reduction and involves the injection of limestone sorbent into the furnace. The consumption of limestone is taken from the Mobotec budget proposal and prorated for the expected SO_2 emissions from Boiler Nos. 4 and 5 when burning 2.4 percent sulfur fuel oil. According to Mobotec, an additional installation cost of $210,000 has been added for the FSI system.

Based on the range of SO_2 control efficiency quoted by Mobotec for the FSI system, 55-percent control efficiency was used in the analysis. For PM, a control efficiency of 35-percent was used, which is based on Mobotec's expectation of reducing PM emissions from the furnace from 10 to 6.5 lb/MMBtu.

Comment 19. **Revise the cost estimate as indicated above and assuming a 7% interest rate and 20-year life.**

Response 19: The cost estimates have been revised based on 7-percent interest and 20-year equipment life in the revised Tables 5-6 and 5-7.

Section Conclusion: Revised Tables 5-6 and 5-7 show cost effectiveness of a ROFA system range from $6,300/ton to more than $10,000/ton of NO_x removed for Boiler Nos. 4 and 5, respectively, which is very high. Cost effectiveness of visibility improvement is in excess of $26 million/dv for each boiler, which is extremely high. Cost effectiveness for the consideration of reducing all three pollutants, NO_x, SO_2, and PM (Tables 4 and 5) is also very high. Therefore, further reduction of NO_x emissions is not practical.

<u>Fuel Tech Selective Non-Catalytic Reduction</u>

Comment 20. **Capital Costs: Provide supporting information for the 20% contingency factor and revise downward as necessary.**

Response 20: The justification for using the 20-percent contingency factor is described in Comment 3.

Comment 21. **Operating Costs: Show the calculations for estimating the following annual costs: operating labor, NOxOut reagent cost, water and electricity. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary ($/hour, $/ton caustic, $/1000 gallons, etc.).**

Response 21: The cost estimate for operating labor, NOxOut reagent cost, water, and electricity are explained below:

- Operating labor – Operating labor cost estimate is based on an estimated 1 hour per shift for the operating labor. Supervisory labor is taken as 15-percent of the operating labor. Annual maintenance labor and material cost is taken as 1.5-percent of total capital investment. These are based on the Control Cost Manual.
- NOxOUT Reagent – Calculation for NOxOUT reagent is based on the average reagent consumption of 19.3 gph provided by the Fuel Tech budget proposal. The Fuel Tech reagent usage, which is for a 423 MMBtu/hr boiler with uncontrolled NO_x emissions of 315 TPY, was prorated to match the NO_x emissions of Boiler Nos. 4 and 5. NOxOUT reagent is a 50 percent (by weight) aqueous urea solution with other additives. Therefore, a unit cost of $1.65/gallon is used for the NOxOUT reagent, which is similar to the 50% urea solution cost.

  Reagent consumption = 19.35 gph (NO_x emissions of 315 TPY).

  Boiler No. 4 NO_x emissions = 344 TPY (highest actual emissions for 2001-present).

  Estimated reagent consumption for Boiler No. 4 = 19.35 gph x 344/315 = 21.1 gph.

  Unit cost of reagent = $1.65/gallon.

  Annual cost of reagent = 21.1 gph x 24 hr/day x 180 days/yr x $1.65/gal = $150,600.

- Water – The water usage for the NOxOUT SNCR system is based on the average dilution water flow of 10.9 gpm provided by the Fuel Tech budget proposal. The Fuel Tech estimate, which is for a 423 MMBtu/hr boiler with uncontrolled NO_x emissions of 315 TPY, was prorated to match the estimated NOxOUT reagent usage for NO_x emissions of 344 TPY.

  Dilution water flow from Fuel Tech = 10.9 gpm (NO_x emissions of 315 TPY).

  Boiler No. 4 NO_x emissions = 344 TPY (highest actual emissions for 2001 to present).

  Estimate water requirement for Boiler No. 4 = 10.9 gpm x 21.1/19.35 x 60 min/hr = 712.1 gph.

  Cost of water = $2.36/1,000 gallon x 712.1 gph x 24 hr/day x 180 days/yr = $7,300.

- Electricity – The power requirement for the NOxOUT SNCR system is based on the budget proposal from Fuel Tech, which estimates the power requirement to be 35 kW for a boiler with 423 MMBtu/hr heat input and uncontrolled NO_x emissions rate of 315 TPY. The power requirement was prorated for the NO_x emissions of Boiler Nos. 4 and 5.

  NOxOUT SNCR system power requirement = 35 kW (NO_x emissions of 315 TPY).

  Boiler No. 4 NO_x emissions = 344 TPY (highest actual emissions for 2001 to present.

Adjusted power requirement = 35 kW x (21.1/19.35) = 38.2 kW.

Cost of electricity = 38.2 kW x 24 hr/day x 180 days/yr x \$0.06/kW = \$9,900.

Comment 22. **Revise the cost estimate as indicated above and assuming a 7% interest rate and 20-year life.**

Response 22: The cost estimates have been revised based on 7-percent interest and 20-year equipment life in the revised Table 5-8.

Section Conclusion: The cost effectiveness of adding a SNCR system for the additional control of NO_x emissions presented in the revised Table 5-8 are \$8,100/ton to \$11,500/ton and \$32 million/dv to over \$51 million/dv, which are very high, both in terms of \$/ton of NO_x reduction and \$/dv visibility improvement. Therefore, SNCR is not a viable control option for the SCGCF Boiler Nos. 4 and 5.

Visibility Modeling

Comment 23. **Provide revised visibility impact analyses for all BART-eligible boilers operating under each of the reduced sulfur scenarios (1%, 0.5%, and 0.0015%). Optionally, provide a revised visibility impact analysis for all BART-eligible boiler operating under a given reduced sulfur scenario that results in a visibility impact of less than 0.5 deciviews.**

Response 23: Visibility impacts for all BART-eligible boilers operating with 1-, 0.05-, and 0.0015-percent sulfur fuel oil are presented in the revised Table 5-11.

Comment 24. **For each control option with a revised emissions reduction, provide a corresponding revised visibility impact analysis. Visibility impacts must be determined for each BART-eligible unit.**

Response 24: Visibility impacts for each control option were determined and are presented in the visibility cost-effectiveness calculation in the cost calculation summary tables for each control option.

Thank you for your consideration of this information. A P.E. signature page is attached. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

DB/sl

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Professional Engineer Certification

1.	Professional Engineer Name: **David A. Buff** Registration Number: **19011**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 336-5600** ext.**545** Fax: **(352) 336-6603**
4.	Professional Engineer Email Address: **dbuff@golder.com**
5.	Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff — 5/30/08

Signature — Date

(seal)

* Attach any exception to certification statement.

** **Board of Professional Engineers Certificate of Authorization #00001670**

TABLE 5-3 (Revised 052808)
COST EFFECTIVENESS OF FUEL SWITCHING FOR NO. 4 OR NO. 5 BOILER

Cost Items	Cost Factors	No. 2 Oil (0.0015% S) Cost ($)	No. 2 Oil (0.05% S) Cost ($)	No. 6 Oil (1.0% S) Cost ($)
DIRECT CAPITAL COSTS (DCC):				
(1) Equipment Cost				
(a) New Fuel Oil Storage tank	See Footnote "a"	807,000	807,000	807,000
(b) Pumps, piping, etc.	See Footnote "a"	800,000	800,000	1,200,000
(c) New oil guns/atomizer sprayer plates	Babcock& Wilcox -- excludes installation[b]	175,000	175,000	0
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	111,375	111,375	125,438
Subtotal: Total Equipment Cost (TEC)		1,893,375	1,893,375	2,132,438
(3) Direct Installation Costs	85% of TEC (for new oil guns)	148,750	148,750	0
Total DCC:		2,042,125	2,042,125	2,132,438
INDIRECT CAPITAL COSTS (ICC):[c]				
(1) Indirect Installation Costs	SCGCF estimate	430,000	430,000	640,000
(a) Engineering	10% of TEC (for new oil guns)	17,500	17,500	Included Above
(b) Construction & Field Expenses	10% of TEC (for new oil guns)	17,500	17,500	Included Above
(c) Construction Contractor Fee	10% of TEC (for new oil guns)	17,500	17,500	Included Above
(d) Contingencies	3% of TEC (for new oil guns)	5,250	5,250	Included Above
(2) Other Indirect Costs				
(a) Startup	1% of TEC (for new oil guns)	1,750	1,750	Included Above
(b) Performance Test'	3% of TEC (for new oil guns)	5,250	5,250	Included Above
Total ICC:		494,750	494,750	640,000
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	2,536,875	2,536,875	2,772,437.5
DIRECT OPERATING COSTS (DOC):[d]				
(1) Operating Labor				
Operator	15 min/shift, $30/hr, 3 shifts/day, 180 days/yr	4,050	4,050	4,050
Supervisor	15% of operator cost	608	608	608
(2) Maintenance				
Labor	Equivalent to One-Half Operating Labor	2,025	2,025	2,025
Materials	100% of maintenance labor	2,025	2,025	2,025
(3) Utilities				
(4) Fuels				
Existing Fuel Cost (No. 6 fuel oil with 2.4%S)	$2.114/gal, 594,000 gal/yr	1,602,196	1,602,196	1,602,196
Proposed Fuel Cost (fuel with lower sulfur content)	See Footnote "e"	2,593,600	2,483,840	1,681,020
Differential Fuel Cost (Proposed - Existing)	Proposed fuel cost - existing fuel cost	991,404	881,644	78,824
Total DOC:		1,000,111	890,351	87,531
INDIRECT OPERATING COSTS (IOC):[d]				
(1) Overhead	60% of oper. labor & maintenance	5,225	5,225	5,225
(2) Property Taxes	1% of total capital investment	25,369	25,369	27,724
(3) Insurance	1% of total capital investment	25,369	25,369	27,724
(4) Administration	2% of total capital investment	50,738	50,738	55,449
Total IOC:		106,700	106,700	116,122
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	239,481	239,481	261,718
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**1,346,292**	**1,236,532**	**465,371**
BASELINE SO_2 EMISSIONS (TPY):	594,000 gal/yr, 2.4%S, 8.1 lb/gal No. 6 Oil (Highest annual usage for either Nos. 4 or 5 boiler for 2001-present)	115.5	115.5	115.5
MAX SO_2 EMISSIONS WITH PROPOSED FUEL (TPY):	640K gal/yr 0.05%S or 0.0015%S No. 2 oil or 594K gal/yr 1% S No. 6 Fuel Oil (8.0 lb/gal)	0.07	2.3	47.5
REDUCTION IN SO_2 EMISSONS (TPY):		115.4	113.2	68.0
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	**11,666**	**10,926**	**6,848**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10	0.284	0.284	0.284
CONTROLLED VISIBILITY IMPACT (dv)	Table 5-11, Lowest impact - Boiler 4 or 5	0.16	0.161	0.183
REDUCTION IN VISIBILITY IMPACT (dv):	Baseline - Controlled	0.124	0.123	0.101
COST EFFECTIVENESS OF VISIBILITY REDUCTION ($/dv):	AC/Reduction in visibility	***10,857,192***	***10,053,104***	***4,607,638***

Footnotes:

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

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

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

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

[e] Fuel cost per SCGCF: No. 6 Oil @ 2.4%S - $2.6973/gal, No. 6 Oil @ 1%S - $2.83/gal, No. 2 Oil @ 0.0015%S - $4.05/gal, No. 2 Oil @ 0.05%S - $3.88/gal. Fuel oil usage is 594,000 gal/yr based on actual fuel oil usage from the period 2001-2006. 594,000 gal of No. 6 oil is equivalent to 640,000 gal of No. 2 oil based on 151,000 Btu/gal for No. 6 oil and 140,000 Btu/gal for No. 2 oil.

TABLE 5-4 (Revised 052808)
CAPITAL AND ANNUAL COSTS FOR BOILER SO_2 CONTROL USING A SCRUBBER SYSTEM

Cost Items	Cost Factors	Boiler No. 4 Scrubber System Cost ($)	Boiler No. 5 Scrubber System Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Based on Vendor Quote	1,308,535	1,151,086
(a) Separator/Scrubber/Mist Eliminator		included	included
(b) Caustic Injection		included	included
(c) Devices/Instrumentation		included	included
(g) Access & Platform		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	81,783	71,943
(3) Equipment Freight Cost	5% of Equipment Cost	65,427	57,554
Subtotal: Total Equipment Cost (TEC)		1,455,745	1,280,583
(3) Installation Costs [a]			
(a) Vendor Quote - Installation of Equipment and Piping		1,500,000	1,500,000
(b) Foundations, Structural Steel, Lighting	12% of TEC	174,689	153,670
(c) Piping		Included	Included
(d) Drains/Heat Tracing/Insulation	1% of TEC	14,557	12,806
(e) Electrical - Motor Starters/Wiring/DCS	1% of TEC	14,557	12,806
(f) Painting	1% of TEC	14,557	12,806
(g) Documentation/Engineering		included	included
(h) Start-up and Commissioning		included	included
(i) Inlet Ductwork and Connecting Ductwork	Estimate	150,000	150,000
Total DCC:		3,324,106	3,122,671
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) Performance Testing	Typical Value: 1% of Total Equipment Cost	14,557	12,806
(2) Other Indirect Costs (a)			
Engineering	10% of TEC	145,574	128,058
Construction and field expenses	10% of TEC	145,574	128,058
Contractor Fees	10% of TEC	145,574	128,058
Startup & Testing	Typical Value: 1% of TEC	Included	Included
Total ICC:		451,281	396,981
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	755,077	703,930
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	4,530,465	4,223,582
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	$30/hr, 1.0 hr/shift, 3 shifts/day, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	8,100	8,100
Materials	100% of maintenance labor	8,100	8,100
(3) Operating Material			
Caustic	$500/ton dry caustic (No. 4 - 139 TPY, No. 5 - 102 TPY) [b]	69,500	51,000
Water makeup	$2.36/1000 gal (No. 4 - 56.8 gpm, No. 5 - 43.6 gpm), 180 days/yr [c]	34,756	26,693
Solid Waste Disposal	$40/ton (No. 4 - 243 TPY, No. 5 - 179 TPY) [d]	9,896	7,291
(4) Electricity	1x125 hp (1 Quench pump), 93 KW, $0.06/KW-hr, 180 days/yr	24,106	24,106
Total DOC:		173,088	143,919
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	20,898	20,898
(2) Property Taxes	1% of total capital investment	45,305	42,236
(3) Insurance	1% of total capital investment	45,305	42,236
(4) Administration	2% of total capital investment	90,609	84,472
Total IOC:	(1) + (2) + (3) + (4)	202,117	189,841
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	427,676	398,706
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**802,880**	**732,467**
BASELINE SO_2 EMISSIONS (TPY), (see Table 2) :	Highest actual emissions in 2001-present	113.2	83.4
CONTROLLED SO_2 EMISSIONS (TPY) :	98% Removal by the Scrubber (vendor specification)	2.3	1.7
REDUCTION IN SO_2 EMISSIONS (TPY):	Baseline - Controlled	110.9	81.7
BASELINE PM EMISSIONS (TPY) :	Highest actual emissions in 2001-present	118.8	90.0
CONTROLLED PM EMISSIONS (TPY) :	0.02 lb/MMBtu, Highest MMBtu from AORs for 2001-present	17.0	11.7
REDUCTION IN PM EMISSIONS (TPY):	Baseline - Controlled	101.8	78.3
TOTAL REDUCTION IN EMISSIONS (SO_2+PM,TPY) :	Reduction of SO_2 + Reduction of PM	212.7	160.1
COST EFFECTIVENESS:	$ per ton of SO_2 & PM Removed	**3,774**	**4,576**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.197	0.158
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.087	0.058
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**9,228,508**	**12,628,735**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.231	0.191
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.002	0.004
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**401,440,109**	**183,116,662**

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

TABLE 5-5 (Revised 052808)
CAPITAL AND ANNUAL COSTS FOR BOILER SO_2 CONTROL USING CAUSTIC IN EXISTING SCRUBBER SYSTEM

Cost Items	Cost Factors	Boiler No. 4 Scrubber System Cost ($)	Boiler No. 5 Scrubber System Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Based on Vendor Quote	0	0
(a) Separator/Scrubber/Mist Eliminator		included	included
(b) Caustic Injection System (tank, pump, control, DCS)	Assumed 20% of Vendor Quote for Total System	261,707	230,217
(c) Devices/Instrumentation		included	included
(g) Access & Platform		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	16,357	14,389
(3) Equipment Freight Cost	5% of Equipment Cost	13,085	11,511
Subtotal: Total Equipment Cost (TEC)		291,149	256,117
(3) Installation Costs [a]			
(a) Vendor Quote - Installation of Equipment and Piping	20% of total scrubbing system installation	300,000	300,000
(b) Foundations, Structural Steel, Lighting	12% of TEC	34,938	30,734
(c) Piping		Included	Included
(d) Drains/Heat Tracing/Insulation	1% of TEC	2,911	2,561
(e) Electrical - Motor Starters/Wiring/DCS	1% of TEC	2,911	2,561
(f) Painting	1% of TEC	2,911	2,561
(g) Documentation/Engineering		included	included
(h) Start-up and Commissioning		included	included
(i) Inlet Ductwork and Connecting Ductwork	Estimate	0	0
Total DCC:		634,821	594,534
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) Performance Testing	Typical Value: 1% of Total Equipment Cost	2,911	2,561
(2) Other Indirect Costs (a)			
Engineering	10% of TEC	29,115	25,612
Construction and field expenses	10% of TEC	29,115	25,612
Contractor Fees	10% of TEC	29,115	25,612
Startup & Testing	Typical Value: 1% of TEC	Included	Included
Total ICC:		90,256	79,396
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	145,015	134,786
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	870,093	808,716
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	$30/hr, 1.0 hr/shift, 3 shifts/day, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	8,100	8,100
Materials	100% of maintenance labor	8,100	8,100
(3) Operating Material			
Caustic	$500/ton dry caustic (No. 4 - 139 TPY, No. 5 - 102 TPY) [b]	69,500	51,000
Water makeup	$2.36/1000 gal (No. 4 - 56.8 gpm, No. 5 - 43.6 gpm), 180 days/yr [c]	34,756	26,693
Solid Waste Disposal	$40/ton (No. 4 - 243 TPY, No. 5 - 179 TPY) [d]	9,896	7,291
(4) Electricity	1x125 hp (1 Quench pump), 93 KW, $0.06/KW-hr, 180 days/yr	24,106	24,106
Total DOC:		173,088	143,919
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	20,898	20,898
(2) Property Taxes	1% of total capital investment	8,701	8,087
(3) Insurance	1% of total capital investment	8,701	8,087
(4) Administration	2% of total capital investment	17,402	16,174
Total IOC	(1) + (2) + (3) + (4)	55,702	53,247
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	82,137	76,343
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**310,926**	**273,509**
BASELINE SO_2 EMISSIONS (TPY), (see Table 2) :	Highest actual emissions in 2001-present	113.2	83.4
CONTROLLED SO_2 EMISSIONS (TPY) :	50% Removal by Existing Scrubber (assumed)	56.6	41.7
REDUCTION IN SO_2 EMISSIONS (TPY):	Baseline - Controlled	56.6	41.7
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	**5,493**	**6,559**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.229	0.184
REDUCTION IN VISIBILITY IMPACT (dv):	Baseline - Controlled	0.055	0.032
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**5,653,205**	**8,547,147**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.232	0.192
REDUCTION IN VISIBILITY IMPACT (dv):	Baseline - Controlled	0.001	0.003
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**310,926,257**	**91,169,566**

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

TABLE 5-6 (Revised 052808)
COST EFFECTIVENESS OF MOBOTEC FOR NO_x CONTROL, BOILER NO. 4

Cost Items	Cost Factors[a]	NO_x Control for Boiler No. 4 ROFA Only Cost ($)	 ROFA + ROTAMIX Cost ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	126,590	126,590
ROFA System	Vendor quote[b]	2,330,476	3,317,676
Emissions Monitoring	15% of equipment cost	349,571	497,651
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	186,438	265,414
Freight	5% of Equipment Cost	116,524	165,884
Taxes	Florida sales tax, 6.25%	145,655	207,355
Purchased Equipment Cost (PEC)		3,285,254	4,610,570
ROTAMIX Installataion	Vendor quote[b]	0	340,000
Total DCC		3,285,254	4,950,570
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	98,158	98,158
Electrical and Controls	Vendor quote[b]	33,712	33,712
General Facilities	5% of DCC	164,263	247,528
Engineering and home office fees	10% of DCC	328,525	495,057
Process Contingency	5% of DCC	164,263	247,528
Total ICC		788,921	1,121,984
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	814,835	1,214,511
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	4,889,009	7,287,064
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 180 days/yr	15,429	15,429
Supervisor	15% of operator cost	2,314	2,314
Maintenance	3% of TCI	146,670	218,612
Electricity	224 kW, $0.06/kW-hr, 180 days/yr	58,061	58,061
Water usage	99.5 gal/hr, 180 days/yr; $2.36/1000gal[c]	0	1,014
Urea	16.6 gph X $1.65/gal (50% sol) X 24 hr/day, 180 days/yr[c]	0	236,294
Total DOC:		222,474	531,723
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	98,648	141,813
Property Taxes	1% of TCI	48,890	72,871
Insurance	1% of TCI	48,890	72,871
Administration	2% of TCI	97,780	145,741
		294,208	433,295
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	461,522	687,899
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**978,205**	**1,652,918**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions in last 5 years	343.9	343.9
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	189.1	137.6
REDUCTION IN NO_x EMISSONS (TPY):		154.8	206.3
COST EFFECTIVENESS:	**$ per ton of NO_x Removed**	**6,321**	**8,011**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.284
CONTROLLED VISIBILITY IMPACT (dv)		0.255	0.246
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.029	0.038
VISIBILITY COST EFFECTIVENESS ($/dv) :		**33,731,196**	**43,497,833**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.233
CONTROLLED VISIBILITY IMPACT (dv)		0.196	0.178
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.037	0.055
VISIBILITY COST EFFECTIVENESS ($/dv) :		**26,437,965**	**30,053,049**

Footnotes:

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

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

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

TABLE 5-7 (Revised 052808)
COST EFFECTIVENESS OF MOBOTEC FOR NO_x CONTROL, BOILER NO. 5

		NO_x Control for Boiler No. 5	
		ROFA Only	ROFA + ROTAMIX
Cost Items	**Cost Factors[a]**	**Cost ($)**	**Cost ($)**
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	97,059	97,059
ROFA System	Vendor quote[b]	1,786,820	2,774,020
Emissions Monitoring	15% of equipment cost	268,023	416,103
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	142,946	221,922
Freight	5% of Equipment Cost	89,341	138,701
Taxes	Florida sales tax, 6.25%	111,676	173,376
Purchased Equipment Cost (PEC)		2,525,865	3,851,181
ROFA Installataion	Vendor quote[b]	345,250	685,250
Total DCC		2,871,115	4,536,431
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	75,259	75,259
Electrical and Controls	Vendor quote[b]	25,848	25,848
General Facilities	5% of DCC	143,556	226,822
Engineering and home office fees	10% of DCC	287,112	453,643
Process Contingency	5% of DCC	143,556	226,822
Total ICC		675,330	1,008,393
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	709,289	1,108,965
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	4,255,734	6,653,789
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 180 days/yr	15,429	15,429
Supervisor	15% of operator cost	2,314	2,314
Maintenance	3% of TCI	127,672	199,614
Electricity	224 kW, $0.06/kW-hr, 180 days/yr	58,061	58,061
Water usage	51.6 gal/hr, 180 days/yr; $2.36/1000gal [c]	0	527
Urea	16.6 gph X $1.65/gal (50% sol) X 24 hr/day, 180 days/yr [c]	0	122,716
Total DOC:		203,476	398,660
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	87,249	130,414
Property Taxes	1% of TCI	42,557	66,538
Insurance	1% of TCI	42,557	66,538
Administration	2% of TCI	85,115	133,076
		257,478	396,566
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	401,741	628,118
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**862,695**	**1,423,343**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions in last 5 years	178.6	178.6
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	98.2	71.4
REDUCTION IN NO_x EMISSONS (TPY):		80.4	107.2
COST EFFECTIVENESS:	**$ per ton of NO_x Removed**	**10,734**	**13,282**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.216	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.198	0.192
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.018	0.024
VISIBILITY COST EFFECTIVENESS ($/dv) :		**47,927,518**	**59,305,969**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.195	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.167	0.153
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.028	0.042
VISIBILITY COST EFFECTIVENESS ($/dv) :		**30,810,547**	**33,889,125**

Footnotes:

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

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

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

TABLE 5-8 (Revised 052808)
COST EFFECTIVENESS OF FUEL TECH FOR NO_x CONTROL, BOILER NOS. 4 AND 5

Cost Items	Cost Factors	SNCR System for Boiler No. 4 Cost ($)	SNCR System for Boiler No. 5 Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Based on Vendor Quote [b]	1,225,708	939,446
(a) NOxOUT SNCR Basic Process		included	included
(b) 8,000 Gallon FRP Storage Tank		included	included
(c) Circulation Module and Enclosure		included	included
(d) Urea and Dilution water Metering Module		included	included
(e) Urea Distribution Module, Injectors, Control Panel		included	included
(f) Temperature Monitoring, Engineering Designs		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	76,607	58,715
(3) Equipment Freight Cost	5% of Equipment Cost	61,285	46,972
Subtotal: Total Equipment Cost (TEC)		1,363,600	1,045,133
(4) Installation Costs [a]			
(a) Vendor quotes for similar boilers (equal to basic process equipment cost)		1,225,708	939,446
(b) Tank Foundation and Structural Support	5% of TEC	68,180	52,257
(c) Piping and Wiring	Engineering Estimate	100,000	100,000
(d) Electrical and Controls	Engineering Estimate	100,000	100,000
(h) NOxOUT Supply - First Fill	No. 4-8,800 gal, No. 5-4,600.gal. 5, $1.65/gal [c]	8,800	4,600
Total DCC:		2,866,288	2,241,436
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) General Facilities	5% of TEC	68,180	52,257
(b) Engineering and Home Office Fees	10% of TEC	136,360	104,513
(c) Process Contingency	5% of TEC	68,180	52,257
(2) Other Indirect Costs			
(a) NO_x, Ammonia, and CO Monitoring	Estimate	20,000	20,000
(b) Performance Testing	Based on historical testing	45,000	45,000
(c) Spare Parts	Engineering Estimate, 2% of TEC	27,272	20,903
(d) Contractor Fees	10% of TEC	136,360	104,513
Total ICC:		501,352	399,443
PROJECT CONTINGENCY (Retrofit installation)	20% of (DCC+ICC)	673,528	528,176
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	4,041,168	3,169,054
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	1.0 hr/shift, $30/hr, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance	Engineering estimate, 1.5% of TCI	60,618	47,536
(3) Annual NOxOut Cost	No. 4-21.4 gph, No. 5-11.1 gph, $1.65/gal [c]	150,597	78,211
(4) Electricity	No. 4-39 KW, No. 5 - 20 KW, $0.06/KW-hr [c]	9,905	5,144
(5) Water Consumption	No. 4-12 gpm, No.5-6 gpm, $2.36/1000 gal [c]	7,260	3,770
Total DOC:		247,010	153,291
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	47,549	39,699
(2) Property Taxes	1% of total capital investment	40,412	31,691
(3) Insurance	1% of total capital investment	40,412	31,691
(4) Administration	2% of total capital investment	80,823	63,381
Total IOC:	(1) + (2) + (3) + (4)	209,195	166,462
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	381,486	299,159
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**837,692**	**618,912**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions from 2001 to present	343.9	178.6
CONTROLLED NO_x EMISSIONS (TPY) :	SNCR NOx Reduction (30%)	240.7	125.0
REDUCTION IN NO_x EMISSIONS (TPY):		103.2	53.6
COST EFFECTIVENESS:	**$ per ton of NOx Removed**	**8,120**	**11,551**
BASELINE VISIBILITY IMPACT	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.265	0.204
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.019	0.012
VISIBILITY COST EFFECTIVENESS ($/dv) :		**44,089,052**	**51,575,969**
BASELINE VISIBILITY IMPACT	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.207	0.181
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.026	0.014
VISIBILITY COST EFFECTIVENESS ($/dv) :		**32,218,923**	**44,207,973**

Notes:

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

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

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

TABLE 5-9 (Revised 052808)
CAPITAL AND ANNUAL COSTS FOR BOILER PM CONTROL USING ESP

Cost Items	Cost Factors	ESP for Boiler No. 4 Cost ($)	ESP for Boiler No. 5 Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) ESP + auxiliary equipment	Based on Vendor Quote	1,657,000	1,657,000
(2) Instrumentation	10% of Equipment Cost	included	included
(3) Sales Tax	3% of Equipment Cost	49,710	49,710
(4) Equipment Freight Cost	5% of Equipment Cost	included	included
Subtotal: Total Equipment Cost (TEC)		1,706,710	1,706,710
(5) Direct Installation Costs [a]			
(a) Vendor Quote - Installation	Described below	0	0
(b) Foundation (Support included)	2% of TEC (4% for foundation & support)	34,134	34,134
(c) Handling & Erection	50% of TEC	853,355	853,355
(d) Electrical	8% of TEC	136,537	136,537
(e) Piping	1% of TEC	17,067	17,067
(f) Painting	2% of TEC	17,067	17,067
(g) Insulation for Ductwork	2% of TEC	included	included
Total DCC:		2,764,870	2,764,870
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Engineering	20% of TEC	341,342	341,342
(2) Construction and field expenses	20% of TEC	341,342	341,342
(3) Contractor Fees	10% of TEC	170,671	170,671
(4) Startup	1% of TEC	17,067	17,067
(5) Performance Test	1% of TEC	17,067	17,067
Total ICC:		887,489	887,489
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	730,472	730,472
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	4,382,831	4,382,831
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Coordinator	25% Time spent on ESP, Annual Salary 70K	17,500	17,500
Operator	$30/hr, 1 hr/shift, 3 shifts/day, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	8,100	8,100
Materials	100% of maintenance labor	8,100	8,100
(3) Operating Material	None	0	0
(4) Electricity	132 kVA, 106 KW, $0.06/KW-hr, 180 days/yr	27,475	27,475
(5) Water Usage	None, dry ESP	0	0
(6) Wastewater Treatment	None, dry ESP	0	0
Total DOC:		62,305	62,305
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	20,898	20,898
(2) Property Taxes	1% of total capital investment	43,828	43,828
(3) Insurance	1% of total capital investment	43,828	43,828
(4) Administration	2% of total capital investment	87,657	87,657
Total IOC:	(1) + (2) + (3) + (4)	196,211	196,211
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	413,739	413,739
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**672,256**	**672,256**
BASELINE PM EMISSIONS (TPY) :	Highest actual emissions in 2001-present (from AORs)	118.8	90.0
CONTROLLED PM EMISSIONS (TPY) :	No. 4: 0.124 → 0.02 lb/MMBtu, No. 5: 0.15 → 0.02 lb/MMBtu	19.0	11.7
REDUCTION IN PM EMISSONS (TPY):	Baseline - Controlled	99.8	78.3
COST EFFECTIVENESS:	$ per ton of PM Removed	**6,735**	**8,586**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.174	0.130
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.110	0.086
VISIBILITY COST EFFECTIVENESS ($/dv) :		**6,111,416**	**7,816,927**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.101	0.064
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.132	0.131
VISIBILITY COST EFFECTIVENESS ($/dv) :		**5,092,846**	**5,131,723**

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

TABLE 5-11 (Revised 052908)
SUMMARY OF VISIBILITY IMPACTS AT BASELINE AND CONTROLLED 24-HOUR AVERAGE EMISSION RATES

				SO_2 Control Scenario Impacts					NO_x Control Scenario Impacts			PM Control Impacts
Source	EU ID	Model ID	Baseline Impacts (dv)	No. 6 Oil (1% S Content) (dv)	No. 2 Oil (0.05%S) (dv)	No. 2 Oil (0.0015%S) (dv)	SO_2 Scrubber (98% Control) (dv)	Caustic (50% Control) (dv)	ROFA (45% Control) (dv)	ROFA+ROTAMIX (60% Control) (dv)	SNCR (30% Control) (dv)	ESP (98.6% Control) (dv)
Bagasse-Firing Only												
Boiler No. 4	004	SGC4	0.233	--	--	--	0.231	0.232	0.196	0.178	0.207	0.101
Boiler No. 5	005	SGC5	0.195	--	--	--	0.191	0.192	0.167	0.153	0.181	0.064
Maximum Fuel Oil w/Remainder Bagasse												
Boiler No. 1	001	SGC1	0.086	0.066	0.053	0.053	--	--	--	--	--	--
Boiler No. 2	002	SGC2	0.081	0.057	0.043	0.042	--	--	--	--	--	--
Boiler No. 4	004	SGC4	0.284	0.223	0.198	0.198	0.197	0.229	0.255	0.246	0.265	0.174
Boiler No. 5	005	SGC5	0.216	0.183	0.161	0.160	0.158	0.184	0.198	0.192	0.204	0.130
Total Boiler Nos. 1 -	--	--	0.578	0.495	0.446	0.442	--	--	--	--	--	--

Note: 8th Highest maximum visibility impacts from 2003.

TABLE 1
COST EFFECTIVENESS OF FUEL SWITCHING FOR BOILER NOS. 1 TO 4

Cost Items	Cost Factors	Boiler No. 1 (1.0% S Oil) Cost ($)	Boiler No. 2 (1.0% S Oil) Cost ($)	Boiler No. 3 (1.0% S Oil) Cost ($)	Boiler No. 4 (1.0% S Oil) Cost ($)
DIRECT CAPITAL COSTS (DCC):					
(1) Equipment Cost					
(a) New Fuel Oil Storage tank	See Footnote "a"	None	None	None	None
(b) Pumps, piping, etc.	See Footnote "a"	None	None	None	None
(c) New oil guns/atomizer sprayer plates	Babcock& Wilcox -- excludes installation[b]	0	0	0	0
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	0	0	0	0
Subtotal: Total Equipment Cost (TEC)		0	0	0	0
(3) Direct Installation Costs	85% of TEC (for new oil guns)	0	0	0	0
Total DCC:		0	0	0	0
INDIRECT CAPITAL COSTS (ICC):[c]					
(1) Indirect Installation Costs	SCGCF estimate	0	0	0	0
(a) Engineering	10% of TEC (for new oil guns)	0	0	0	0
(b) Construction & Field Expenses	10% of TEC (for new oil guns)	0	0	0	0
(c) Construction Contractor Fee	10% of TEC (for new oil guns)	0	0	0	0
(d) Contingencies	3% of TEC (for new oil guns)	0	0	0	0
(2) Other Indirect Costs					
(a) Startup	1% of TEC (for new oil guns)	0	0	0	0
(b) Performance Test'	3% of TEC (for new oil guns)	0	0	0	0
Total ICC:		0	0	0	0
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	0	0	0	0
DIRECT OPERATING COSTS (DOC):[d]					
(1) Operating Labor					
Operator	15 min/shift, $30/hr, 7296 hrs/yr	0	0	0	0
Supervisor	15% of operator cost	0	0	0	0
(2) Maintenance					
Labor	Equivalent to One-Half Operating Labor	0	0	0	0
Materials	100% of maintenance labor	0	0	0	0
(3) Utilities					
(4) Fuels					
Existing Fuel Cost (No. 6 fuel oil with 2.4%S)	See Footnote "e"	736,363	717,482	1,602,196	1,051,947
Proposed Fuel Cost (No. 6 fuel oil with 1% S)	$2.6973/gal, SCGCF data	772,590	752,780	1,681,020	1,103,700
Differential Fuel Cost (Proposed - Existing)	Proposed fuel cost - existing fuel cost	36,227	35,298	78,824	51,753
Total DOC:		36,227	35,298	78,824	51,753
INDIRECT OPERATING COSTS (IOC):[d]					
(1) Overhead	60% of oper. labor & maintenance	0	0	0	0
(2) Property Taxes	1% of total capital investment	0	0	0	0
(3) Insurance	1% of total capital investment	0	0	0	0
(4) Administration	2% of total capital investment	0	0	0	0
Total IOC:		0	0	0	0
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	0	0	0	0
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**36,227**	**35,298**	**78,824**	**51,753**
BASELINE SO_2 EMISSIONS (TPY) :	Baseline usage[e], 2.4%S, 8.1 lb/gal No. 6 Oil	53.1	51.7	115.5	75.8
MAX SO_2 EMISSIONS WITH PROPOSED FUEL (TPY):	1.0%S, 8.0 lb/gal No. 6 Oil	21.8	21.3	47.5	31.2
REDUCTION IN SO_2 EMISSONS (TPY):		31.2	30.4	68.0	44.6
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	**1,160**	**1,160**	**1,160**	**1,160**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10	0.086	0.081	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)	Table 5-11 (Revised 052208)	0.066	0.057	0.223	0.183
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.020	0.024	0.061	0.033
COST EFFECTIVENESS OF VISIBILITY REDUCTION ($	AC/Reduction in visibility	**1,811,355**	**1,470,758**	**1,292,193**	**1,568,273**

Footnotes:

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

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

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

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

[e] Fuel cost per SCGCF is $2.114/gal. Baseline oil usage: Boiler 1 - 273,000 gal, Boiler 2 - 266,000 gal, Boiler 4 - 594,000 gal, and Boiler 5 - 390,000 gal. Baseline oil usage based on maximum oil usage from the AORs for the period 2001 to present.

TABLE 2
BASELINE SO_2 EMISSIONS FOR BOILER NOS. 1, 2, 3, and 4

Year	Oil Usage [1] (gallons)	MMBtu [2]	S Content [1]	Density (lb/gal)	SO_2 [3]	Bagasse Usage [1]	MMBtu [2]	SO_2 (0.06 lb/MMBtu) [4]	Total Heat Input	Total SO_2
Boiler 1										
2001	267,090	40,331	1.64	8.1	35.5	42,683	682,936	20.5	723,266	56.0
2002	272,500	41,148	1.00	8.0	21.8	37,959	607,341	18.2	648,488	40.0
2003	239,600	36,180	1.00	8.0	19.2	45,901	734,416	22.0	770,596	41.2
2004	213,860	32,293	1.44	8.0	24.6	41,402	662,429	19.9	694,722	44.5
2005	119,810	18,091	2.00	8.1	19.4	32,943	527,088	15.8	545,179	35.2
2006	31,540	4,763	2.17	8.1	5.5	34,155	546,479	16.4	551,241	21.9
Boiler 2										
2001	265,760	40,130	1.64	8.1	35.3	41,761	668,177	20.0	708,307	55.3
2002	247,760	37,412	1.00	8.0	19.8	34,858	557,725	16.7	595,137	36.6
2003	200,790	30,319	1.00	8.0	16.1	40,727	651,632	19.5	681,951	35.6
2004	187,218	28,270	1.44	8.0	21.6	41,974	671,587	20.1	699,857	41.7
2005	124,900	18,860	2.00	8.1	20.2	35,008	560,127	16.8	578,986	37.0
2006	34,020	5,137	2.17	8.1	6.0	36,256	580,089	17.4	585,226	23.4
Boiler 4										
2001	520,650	78,618	1.64	8.1	69.2	91,843	1,469,495	44.1	1,548,113	113.2
2002	594,160	89,718	1.00	8.0	47.5	81,257	1,300,107	39.0	1,389,825	86.5
2003	528,130	79,748	1.00	8.0	42.3	101,307	1,620,912	48.6	1,700,660	90.9
2004	448,610	67,740	1.44	8.0	51.7	93,260	1,492,168	44.8	1,559,908	96.4
2005	293,280	44,285	2.00	8.1	47.5	83,867	1,341,874	40.3	1,386,159	87.8
2006	81,620	12,325	2.17	8.1	14.3	86,773	1,388,363	41.7	1,400,688	56.0
Boiler 5										
2001	389,960	58,884	1.64	8.1	51.8	65,784	1,052,545	31.6	1,111,429	83.4
2002	372,480	56,244	1.00	8.0	29.8	55,917	894,665	26.8	950,909	56.6
2003	348,550	52,631	1.00	8.0	27.9	69,537	1,112,592	33.4	1,165,223	61.3
2004	262,510	39,639	1.44	8.0	30.2	65,835	1,053,352	31.6	1,092,991	61.8
2005	201,180	30,378	2.00	8.1	32.6	57,820	925,112	27.8	955,491	60.3
2006	56,030	8,461	2.17	8.1	9.8	59,825	957,196	28.7	965,656	38.6

[1] From 2001 - 2006 AORs.

[2] Fuel oil heat content of 151,000 Btu/gal and bagasse heat content of 16 MMBtu/ton used in calculation.

[3] SO_2 = gallons x density, lb/gallon x % sulfur/100 x (64/32) x ton/2000 lb.

[4] Based on industry data.

TABLE 3
CAPITAL AND ANNUAL COSTS FOR BOILER PM CONTROL USING A SCRUBBER SYSTEM

Cost Items	Cost Factors	Boiler No. 4 Scrubber System Cost ($)	Boiler No. 5 Scrubber System Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Assumed 80% of Vendor Quote for total system[b]	1,046,828	920,869
(a) Separator/Scrubber/Mist Eliminator		included	included
(b) Caustic Injection		Not considered	Not considered
(c) Devices/Instrumentation		included	included
(g) Access & Platform		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	65,427	57,554
(3) Equipment Freight Cost	5% of Equipment Cost	52,341	46,043
Subtotal: Total Equipment Cost (TEC)		1,164,596	1,024,467
(3) Installation Costs[a]			
(a) Vendor Quote - Installation of Equipment and Piping		1,200,000	1,200,000
(b) Foundations, Structural Steel, Lighting	12% of TEC	139,751	122,936
(c) Piping		Included	Included
(d) Drains/Heat Tracing/Insulation	1% of TEC	11,646	10,245
(e) Electrical - Motor Starters/Wiring/DCS	1% of TEC	11,646	10,245
(f) Painting	1% of TEC	11,646	10,245
(g) Documentation/Engineering		included	included
(h) Start-up and Commissioning		included	included
(i) Inlet Ductwork and Connecting Ductwork	Estimate	150,000	150,000
Total DCC:		2,689,285	2,528,137
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) Performance Testing	Typical Value: 1% of Total Equipment Cost	11,646	10,245
(2) Other Indirect Costs (a)			
Engineering	10% of TEC	116,460	102,447
Construction and field expenses	10% of TEC	116,460	102,447
Contractor Fees	10% of TEC	116,460	102,447
Startup & Testing	Typical Value: 1% of TEC	Included	Included
Total ICC:		361,025	317,585
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	610,062	569,144
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	3,660,372	3,414,866
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	$30/hr, 1 hr/shift, 3 shifts/day, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	8,100	8,100
Materials	100% of maintenance labor	8,100	8,100
(3) Operating Material			
Water makeup	$2.36/1000 gal (No. 4 - 56.8 gpm, No. 5 - 43.6 gpm), 180 days/yr[c]	152,928	34,756
(4) Electricity	1x125 hp (1 Quench pump), 93 KW, $0.06/KW-hr, 180 days/yr	24,106	24,106
Total DOC:		211,864	93,692
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	20,898	20,898
(2) Property Taxes	1% of total capital investment	36,604	34,149
(3) Insurance	1% of total capital investment	36,604	34,149
(4) Administration	2% of total capital investment	73,207	68,297
Total IOC:	(1) + (2) + (3) + (4)	167,313	157,493
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	345,539	322,363
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	724,716	573,548
BASELINE PM EMISSIONS (TPY):	Highest actual emissions in 2001-present (from AORs)	118.8	90.0
CONTROLLED PM EMISSIONS (TPY):	No. 4: 0.124 → 0.02 lb/MMBtu, No. 5: 0.15 → 0.02 lb/MMBtu	19.0	11.7
REDUCTION IN PM EMISSONS (TPY):	Baseline - Controlled	99.8	78.3
COST EFFECTIVENESS:	$ per ton of PM Removed	7,261	7,325
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.174	0.130
REDUCTION IN VISIBILITY IMPACT (dv):	Baseline - Controlled	0.110	0.086
VISIBILITY COST EFFECTIVENESS ($/dv):		**6,588,323**	**6,669,162**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.101	0.064
REDUCTION IN VISIBILITY IMPACT (dv):	Baseline - Controlled	0.132	0.131
VISIBILITY COST EFFECTIVENESS ($/dv):		**5,490,269**	**4,378,228**

Notes:
(a) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002, Section 5
(b) Vendor quote from Andritz/Envirocare International, received in March 2007.
(c) Water makeup calculated from vendor data for inlet condition of 2,200 lb/hr and prorating for SQ emission rates of 500 lb/hr and 384 lb/hr, for Nos. 4 and 5, respectively.

TABLE 4
COST EFFECTIVENESS OF MOBOTEC FOR NO_x+SO_2+PM CONTROL, BOILER NO. 4

Cost Items	Cost Factors[a]	NO_x Control for Boiler No. 4 ROFA+FSI Cost ($)	ROFA+ROTAMIX+FSI Cost ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	126,590	126,590
ROFA System + FSI	Vendor quote[b]	3,207,876	3,207,876
ROTAMIX	Vendor quote[c]	--	987,200
Emissions Monitoring	15% of equipment cost	481,181	629,261
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	256,630	335,606
Freight	5% of Equipment Cost	160,394	209,754
Taxes	Florida sales tax, 6.25%	200,492	262,192
Purchased Equipment Cost (PEC)		4,463,163	5,788,479
Installataion for FSI and Rotamix	Vendor quote[c]	210,000	550,000
Total DCC		4,673,163	6,338,479
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	98,158	98,158
Electrical and Controls	Vendor quote[b]	33,712	33,712
General Facilities	5% of DCC	233,658	316,924
Engineering and home office fees	10% of DCC	467,316	633,848
Process Contingency	5% of DCC	233,658	316,924
Total ICC		1,066,503	1,399,566
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	1,147,933	1,547,609
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	6,887,599	9,285,654
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 180 days/yr	15,429	15,429
Supervisor	15% of operator cost	2,314	2,314
Maintenance	3% of TCI	206,628	278,570
Electricity	224 kW, $0.06/kW-hr, 180 days/yr	58,061	58,061
Water usage	99.5 gal/hr, 180 days/yr; $2.36/1000gal [d]	0	1,014
Urea	16.6 gph X $1.65/gal (50% sol) X 24 hr/day, 180 days/yr [d]	0	236,294
Limestone for FSI	398 lb/hr X $20/ton X 24 hr/day, 180 days/yr [d]	17,204	17,204
Total DOC:		299,636	608,885
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	134,622	177,787
Property Taxes	1% of TCI	68,876	92,857
Insurance	1% of TCI	68,876	92,857
Administration	2% of TCI	137,752	185,713
		410,126	549,214
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	650,189	876,566
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**1,359,951**	**2,034,664**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions 2001 - present	343.9	343.9
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	189.1	137.6
REDUCTION IN NO_x EMISSONS (TPY):		154.8	206.3
BASELINE SO_2 EMISSIONS (TPY), (see Table 5-4) :	Highest actual emissions 2001 - present	113.2	113.2
Maximum controlled SO_2 Emissions (TPY) :	55% reduction for FSI, Range 50-60%	50.9	50.9
REDUCTION IN SO_2 EMISSONS (TPY):		62.3	62.3
BASELINE PM EMISSIONS (TPY), (see Table 5-9):	Highest actual emissions 2001 - present	118.8	118.8
Maximum controlled PM Emissions (TPY) :	35% reduction, 10 lb/MMBtu → 6.5 lb/MMBtu	77.2	77.2
REDUCTION IN PM EMISSONS (TPY):		41.6	41.6
TOTAL REDUCTION OF NO_x + SO_2 + PM (TPY):		258.6	310.2
COST EFFECTIVENESS:	**$ per ton of pollutant removed**	**5,259**	**6,560**

Footnotes:

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

[b] Vendor quote from Mobotec, May and June, 2007, adjusted for specific heat input rate of Boiler No. 4. $877,400 added for the cost of FSI

[c] Vendor quote from Mobotec, May and June, 2007, Rotamix cost $987,200. Installation cost: FSI - $210,000, Rotamix - $340,000.

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

TABLE 5
COST EFFECTIVENESS OF MOBOTEC FOR NO_x+SO_2+PM CONTROL, BOILER NO. 5

Cost Items	Cost Factors[a]	NO_x Control for Boiler No. 5 ROFA+FSI Cost ($)	 ROFA+ROTAMIX+FSI Cost ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	97,059	97,059
ROFA System + FSI	Vendor quote[b]	2,664,220	2,664,220
ROTAMIX	Vendor quote[c]	--	987,200
Emissions Monitoring	15% of equipment cost	399,633	547,713
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	213,138	292,114
Freight	5% of Equipment Cost	133,211	182,571
Taxes	Florida sales tax, 6.25%	166,514	228,214
Purchased Equipment Cost (PEC)		3,703,775	5,029,091
Installataion for FSI and Rotamix	Vendor quote[c]	210,000	550,000
Total DCC		3,913,775	5,579,091
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	75,259	75,259
Electrical and Controls	Vendor quote[b]	25,848	25,848
General Facilities	5% of DCC	195,689	278,955
Engineering and home office fees	10% of DCC	391,377	557,909
Process Contingency	5% of DCC	195,689	278,955
Total ICC		883,862	1,216,925
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	959,527	1,359,203
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	5,757,164	8,155,219
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 180 days/yr	15,429	15,429
Supervisor	15% of operator cost	2,314	2,314
Maintenance	3% of TCI	172,715	244,657
Electricity	224 kW, $0.06/kW-hr, 180 days/yr	58,061	58,061
Water usage	51.6 gal/hr, 180 days/yr; $2.36/1000gal[d]	0	527
Urea	8.6 gph X $1.65/gal (50% sol) X 24 hr/day, 180 days/yr[d]	0	122,716
Limestone for FSI	290 lb/hr X $20/ton X 24 hr/day, 180 days/yr[d]	12,518	12,518
Total DOC:		261,036	456,221
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	114,275	157,440
Property Taxes	1% of TCI	57,572	81,552
Insurance	1% of TCI	57,572	81,552
Administration	2% of TCI	115,143	163,104
		344,561	483,648
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	543,476	769,853
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**1,149,074**	**1,709,722**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions 2001 - present	178.6	178.6
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	98.2	71.4
REDUCTION IN NO_x EMISSONS (TPY):		80.4	107.2
BASELINE SO_2 EMISSIONS (TPY), (see Table 5-4):	Highest actual emissions 2001 - present	83.4	83.4
Maximum controlled SO_2 Emissions (TPY) :	55% reduction for FSI, Range 50-60%	37.5	37.5
REDUCTION IN SO_2 EMISSONS (TPY):		45.9	45.9
BASELINE PM EMISSIONS (TPY), (see Table 5-9):	Highest actual emissions 2001 - present	90.0	90.0
Maximum controlled PM Emissions (TPY) :	35% reduction, 10 lb/MMBtu → 6.5 lb/MMBtu	58.5	58.5
REDUCTION IN PM EMISSONS (TPY):		31.5	31.5
TOTAL REDUCTION OF NO_x + SO_2 + PM (TPY):		157.7	184.5
COST EFFECTIVENESS:	**$ per ton of pollutant removed**	**7,285**	**9,265**

Footnotes:
[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Cost Control Manual, Sixth Edition (EPA/452/B-02-001, Jan. 2002).
[b] Vendor quote from Mobotec, May and June, 2007, adjusted for specific heat input rate of Boiler No. 5. $877,400 added for the cost of FSI
[c] Vendor quote from Mobotec, May and June, 2007, Rotamix cost $987,200. Installation cost: FSI - $210,000, Rotamix - $340,000.
[d] Vendor operational parameters of water flow (90 gph), urea usage (15 gph), and limestone usage adjusted for specific heat input rate of Boiler No. 5.

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May 30, 2008

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BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention: Mr. Jeffery Koerner, Administrator

RE: GLADES SUGAR HOUSE
PROJECT NO. 0990026-014-AC
BART PROJECT
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION NO. 1

Dear Mr. Koerner:

Sugar Cane Growers Cooperative of Florida (SCGCF) has received a request for additional information (RAI) from the Florida Department of Environmental Protection (FDEP) dated February 29, 2008, regarding the Best Available Retrofit Technology (BART) determination analysis submitted in January 2008. Each of FDEP's requests is answered below, in the same order as they appear in the RAI letter.

Reduced Sulfur Fuel Oil (1%, 0.5%, 0.05% and 0.0015%)

Comment 1. **Please provide a schematic for the various fuel oil tanks and connections to Boilers 1, 2, 3, 4, 5 and 8. Identify which tank is capable of providing fuel to which boiler(s), the fuel storage capacity of each tank in gallons, pump locations and flow meter locations (schematically).**

Response 1: There is only one fuel tank that supplies fuel to all the boilers. A flow meter is located at each boiler.

Comment 2. **The cost effectiveness worksheet (Table 5-3) indicates capital costs for new tanks, pumps, piping, installation and contingencies as well as new oil guns for the 0.05% and 0.0015% reduced sulfur cases.**

a. **Capital Costs: Annual operating reports indicate that the average fuel sulfur content for all boilers (1, 2, 3, 4, 5 and 8) was 1% by weight in 1998, 1999, 2000, 2002 and 2003. Therefore, all of the boilers can currently fire 1% fuel oil without any changes. Fuel oil fired in Boiler 8 must be replaced in the shared tanks with fuel oil containing no more than 1% by weight. Therefore, only Boiler 3 would have a fuel sulfur content greater than 1%, which is the smallest boiler at the mill. Explain why new tanks, pumps and piping would be necessary. This equipment accounts for $2.5 - $2.7 million in total capital investment, which adds $278,500 to $304,414 in annual costs through capital recovery. Note that the life of this equipment was assumed to be only 15 years.**

Response 2a: Boiler Nos. 1, 2, 4, and 5, the four BART-eligible emissions units at the SCGCF Belle Glade facility, are permitted to burn No. 6 fuel oil with a maximum sulfur content of 2.4 percent. Table 5-3 of the BART determination report presented cost-effectiveness calculations for using different types of fuels in Boiler Nos. 4 and 5. From 2001 through 2006, Boiler Nos. 4 and 5 have used No. 6 fuel oil with a sulfur content varying from 1.0 to 2.17 percent. If these two boilers are limited to burn 1-percent sulfur No. 6 oil, SCGCF will need a new tank dedicated for these boilers so that the flexibility to use higher sulfur fuel in other boilers (Boiler Nos. 1, 2, 3, and 8) can be maintained. Due to similar reasons, a new fuel tank is considered for the scenarios of burning lower sulfur (0.0015 and 0.05 percent) No. 2 fuel oil.

All four BART-eligible boilers could be switched to 1.0 percent sulfur oil, as well as Boiler No. 3. In this case, a new fuel oil tank would not be needed, nor would new pumps or piping be required. However, the visibility reduction of such a change must also be considered by the Department. As discussed in the BART Control Analysis report, Boiler Nos. 1 and 2 contribute negligible visibility impacts at the Everglades National Park (ENP). Therefore, in order to assess this case, cost estimates for this case were developed as well as the visibility reduction, and are presented and attached in Table 1. The visibility impacts are summarized and attached in Table 5-11 (revised). As shown, this control option results in a cost effectiveness of \$1,160/ton SO_2 removed, and \$1.3 million/dv to \$1.8 million/dv visibility improvement. The deciview reduction for this option range is between 0.020 and 0.061deciview, depending on the boiler. These economic impacts are considered unreasonable, considering the very small deciview reduction and therefore, are rejected as BART.

b. **Direct Operating Costs: Please explain why "additional" annual costs for operating labor, maintenance labor and maintenance materials would be necessary for the oil firing systems. The boilers currently have oil firing systems and already incur these costs. These items account for approximately \$70,000 in additional annual operating costs and should be removed.**

Response 2b: Apart from differential fuel cost, there will be some direct operating costs associated with the new fuel tank for the following services:

- Perform routine tank tests and inspections.
- Maintain, and repair when necessary, computer electronics and communications for fuel level monitoring and leak detection.
- Coordinate tank repairs and upgrades.
- Document and record tank system status, and maintain files.

Since there is no reference available for the exact operating and maintenance labor hours, a 1 hour per shift assumption was used in the original calculation. Table 5-3 has been revised for a minimum of 15 minutes of operating labor per shift.

c. **Indirect Operating Costs: Please explain why the following costs were included in this analysis: overhead, property taxes, insurance, and administration fees. These items account for approximately \$150,000 in additional annual operating costs and should be removed.**

Response 2c: The indirect operating costs are all based on standard EPA factors from the EPA Air Pollution Control Cost Manual, as defined in Sections 2.5.5.7 and 2.5.5.8 of the Control Cost Manual. The overhead cost is tied to the operating, supervisory, and maintenance labor. Property taxes, insurance, and administrative changes are factored from the system capital investment. These costs are part of the total cost of installing and operating capital projects.

d. **Since reducing the fuel oil sulfur content will only reduce sulfur dioxide (SO_2) emissions from firing oil, identify the baseline SO_2 emissions from firing 2.4% sulfur by weight No. 6 oil. For example:`**

SO_2 (2.4%) = (594,000 gal/year)(8.1 lb oil/gal)(0.024 lb S/lb oil) (2 lb SO_2/lb S)(ton/2000 lb) = 115.5 ton/yr

Similarly, provide the calculation for each of the reduced fuel sulfur cases.

Response 2d: The calculations are as follows:

SO_2 (2.4%) = (594,000 gal/year) x (8.1 lb oil/gal) x (0.024 lb S/lb oil) x (2 lb SO_2/lb S) x (ton/2000 lb) = 115.5 TPY.

SO_2 (1.0%) = (594,000 gal/year) x (8.0 lb oil/gal) x (0.01 lb S/lb oil) x (2 lb SO_2/lb S) x (ton/2000 lb) = 47.5 TPY.

SO_2 (0.05%) = (640,000 gal/year) x (7.2 lb oil/gal) x (0.0005 lb S/lb oil) x (2 lb SO_2/lb S) x (ton/2000 lb) = 2.3 TPY.

SO_2 (0.0015%) = (640,000 gal/year) x (7.2 lb oil/gal) x (0.000015 lb S/lb oil) x (2 lb SO_2/lb S) x (ton/2000 lb) = 0.07 TPY.

The changes have been made and a revised Table 5-3 is attached.

e. **Based on the application, the estimated annual fuel cost differential in switching from 2.4% to 1% sulfur by weight is $29,700 per year. Assuming SO_2 emissions from oil firing would be reduced from 115.5 tons/year to 46.9 tons/year, this results in a cost effectiveness of:**

CE = ($29,700/year) / (115.5 – 46.9 tons/year) = $433/ton of SO_2 removed

In addition to the 0.05% and 0.0015% reduced sulfur cases, the application provides modeled visibility impacts from firing 0.5% sulfur by weight fuel oil. Similar to the 1% reduced sulfur case discussed above, provide revised cost effectiveness estimates for the remaining reduced fuel sulfur cases (0.5%, 0.05% and 0.0015%) excluding costs for new tanks, pumps, piping, etc. Costs associated with new burners may be included for these cases; however, provide supporting information from the current burner vendor of the limitations on firing low sulfur fuels (e.g., density, heating value, etc.). Cost estimates should assume a 7% interest rate and 20-year life.

Response 2e: The revised Table 5-3 shows cost-effectiveness calculations using a cost recovery factor based on 7-percent interest rate and 20-year equipment life. Following is a summary of the revisions made to Table 5-3:

- Cost recovery factor based on 7-percent interest rate and 20-year equipment life.
- Operating labor has been reduced from 1 hour to 15 minutes per shift.
- Baseline SO_2 emissions calculated based on 594,000 gallons of No. 6 fuel oil with 2.4-percent sulfur content.

Revised Table 5-3 includes cost-effectiveness estimates for reduced sulfur No. 2 fuel oil with sulfur contents of 0.05 percent and 0.0015 percent. Cost information for 0.5-percent sulfur oil was not available. These include the cost-effectiveness calculations considering the visibility impacts of the scenarios.

Cost information for the new burners was provided in Appendix B of the BART Determination Report submitted in January 2008. The information is contained in an email from Babcock & Wilcox Company, dated March 5, 2007.

f. Provide the revised cost effectiveness estimates for all reduced sulfur cases (1%, 0.5%, 0.05% and 0.0015%) for Boilers 1 and 2.

Response 2f: The estimates have been developed for Boiler Nos. 1 and 2 and a revised Table 5-3 and a new Table 1 are attached with the results.

Section Conclusion: As shown in the revised Table 5-3, cost effectiveness of switching to lower sulfur fuel oil is very high both in terms of \$/ton of SO_2 removed or \$/dv of visibility improvement. Table 1 shows that the cost effectiveness of switching all boilers to 1 percent sulfur fuel oil is also very high in terms of \$/dv. Therefore, switching to a lower sulfur fuel oil is not a viable option.

<u>New Wet Scrubber System (Venturi with Micro Mist)</u>

Comment 3. Indirect Capital Costs: The project contingency for retrofit assumes a factor of 20% of the total direct and indirect capital costs. This factor appears high for this project. The EPA cost manual states that, "A contingency factor should be reserved (and applied to) only those items that could incur a reasonable but unanticipated increase but are not directly related to the demolition, fabrication, and installation of the system." Please provide supporting information for this high factor and revise downward.

Response 3: The project contingency for retrofit is intended for existing facilities for which control equipment is being added and is to cover unexpected costs such as the cost of unexpected delays, the cost of re-engineering and re-fabrication, the cost of correcting design errors, and the underestimating of actual costs. The retrofit cost considerations are explained in Section 2.5.4.2 of Chapter 2 of the Control Cost Manual. The Control Cost Manual states that because of the lack of sufficient information to fully assess the potential hidden costs of installing a control system in an existing facility, a retrofit factor as high as 50 percent can be justified. Because the retrofit cost estimate is subjective and varies across the spectrum of control devices, a factor of only 20 percent was used to cover potential unforeseen issues associated with installing additional controls at the Belle Glade facility, which is on the lower end of the range, and therefore is certainly acceptable.

As explained in the Control Cost Manual, the retrofit factor applies not only to the equipment cost, but also to the direct installation costs and the indirect capital costs. Therefore, the 20-percent retrofit factor was applied to the total capital cost (direct plus indirect).

Comment 4. Direct Operating Costs: Show the calculations for estimating the following annual costs: operating labor, caustic material, water, electricity and waste disposal. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary (\$/hour, \$/ton caustic, \$/1000 gallons, etc.).

Response 4: The calculations are explained below:

- Caustic material – Calculation for caustic is based on the actual SO_2 emissions reported for the boiler from 2001 to present and the chemical equilibrium equation that requires 2 moles of NaOH to absorb 1 mole of SO_2. The cost calculation for caustic in Table 5-4 submitted with the BART Determination Analysis (submitted in January 2008) had an error in it as the spreadsheet cell was erroneously linked to the cell that calculated waste generated by the absorption process. The cost calculation is revised as follows and based on the current U.S. caustic cost of $470 to 520/dry ton:

  Highest actual SO_2 emissions from Boiler No. 4 – 113.2 TPY.

  NaOH requirement – 113.2 TPY of SO_2 × 2(MW_{NaOH}, 40)/MW_{SO2}, 64 = 141.5 TPY.

  Unit cost of NaOH = $470 to 520/dry ton (source: www.icis.com).

  Cost of NaOH = $500/dry ton × 141.5 TPY = $70,750.

- Waste disposal – The by-product of the caustic absorption process is sodium sulfate (Na_2SO_4), which is a solid and must be disposed of. Cost of Na_2SO_4 disposal is calculated as follows:

  Highest actual SO_2 emissions from Boiler No. 4 – 113.2 TPY.

  Na_2SO_4 produced – 113.2 TPY of SO_2 × 0.985 × MW_{Na2SO4}, 142/MW_{SO2}, 64 = 247.4 TPY.

  Cost of disposal = $40/ton × 247.4 TPY = $9,900.

- Water makeup – The makeup water requirement is calculated based on the vendor quote (Andritz, Appendix B, BART Determination Report, January 2008) for a system with inlet SO_2 emission rate of 2,200 lb/hr and prorating for the inlet conditions of Boiler Nos. 4 and 5:

  Andritz data – 250 gpm for inlet condition of 2,200 lb/hr.

  Boiler No. 4 inlet SO_2 – 500 lb/hr.

  Makeup water required for Boiler No. 4 = 250 gpm / 2,200 lb/hr × 500 lb/hr = 56.8 gpm.

  Cost of makeup water = $2.36/1,000 gallon × 56.82 gpm × 60 min/hr × 24 hr/day ×180 days/yr = $34,760.

- Electricity – The power requirement for the scrubbing system is based on the Andritz Piping & Instrumentation Diagram (P&ID), which shows two 125-hp quench pumps and a blowdown pump. One of the quench pumps is standby. However, the size of the blowdown pump was not available and only one quench pump was used in the power requirement estimation. Table 5-4 has been revised for the power requirement of just one quench pump.

  Electrical power requirement = 125 hp = 93 kW.

  Cost of electricity = 93 kW × 24 hr/day ×180 days/yr × $0.06/KWh = $24,100.

Comment 5. **The revised cost estimate should assume a 7% interest rate and 20-year life.**

Response 5: A revised Table 5-4 is submitted with capital recovery cost based on 7-percent interest and 20-year equipment life.

Comment 6. **Show the calculation of the annual SO_2 emissions rate used as the baseline emissions.**

Response 6: Annual SO_2 emissions used as baseline emissions are summarized below. The emissions calculations are provided in Table 2. These calculations include SO_2 due to fuel oil burning as well as bagasse burning. Note that in some cost estimating tables, only the SO_2 due to fuel oil burning is considered.

Year	Boiler 1	Boiler 2	Boiler 4	Boiler 5
2001	56.0	55.3	113.2	83.4
2002	40.0	6	86.5	56.6
2003	41.2	6	90.9	61.3
2004	5	41.7	96.4	61.8
2005	35.2	37.0	87.8	60.3
2006	9	4	56.0	38.6

Comment 7. **As indicated in the vendor quote, the wet scrubber will reduce particulate matter (PM) emissions in addition to SO_2 emissions. Provide a vendor quote for the PM control efficiency. Revise the cost estimate if necessary. Revise the cost effectiveness analysis to include the reduction of both SO_2 and PM emissions.**

Response 7: The vendor data (Andritz) for the scrubber system is focused on the SO_2 emissions control and indicates that PM emissions control is to be determined later through stack tests. The Envirocare website (www.envirocare.com) provides a typical PM control efficiency of > 99.5 percent for MicroMist scrubbers. However, it will not be able to achieve a further reduction of 99.5 percent on the exhaust stream of the existing wet scrubber. This is because the exhaust stream of the first control device will be composed of mainly smaller size particles. In addition, there would be operating difficulties in adding the ESP after the wet scrubber (i.e., high moisture levels, low temperature affecting resistivity, etc.).

Using the 99.5-percent control for PM, Table 5-4 has been revised to include PM emissions reduction and cost effectiveness based on the total SO_2 and PM emissions reduction calculated. As shown, the cost effectiveness ranges from 3,800 to 4,600 \$/ton and the visibility cost effectiveness ranges from 9.2 million to 12.6 million \$/dv for the bagasse and fuel oil firing scenario.

Section Conclusion: Revised Table 5-4 shows the cost-effectiveness for a new wet scrubber system based on revised baseline SO_2 emissions, direct operating labor and material cost, and capital recovery cost, which is very high. The cost-effectiveness values also include the PM emissions reduction in addition to SO_2. Therefore, a new wet scrubber is not a practical solution for additional visibility reduction. Table 5-4 shows that the visibility reduction achieved in the bagasse-only firing scenario is less than 0.005 dv, practically zero.

New Caustic Injection System for Existing Wet Impingement Scrubber

Comment 8. **Describe the caustic injection system (including equipment) intended for this option. The estimated total capital investment of $510,000 appears very high for such a system. The existing boilers currently use wet impingement scrubbers for particulate control. Typically, these systems include multiple levels of injectors with substantial scrubber water flow rates. Why couldn't the scrubbing media be treated prior to injection through the existing injectors?**

Response 8: A description of the caustic injection system is provided in Page 7 of the Andritz budget proposal. Equipment included in the caustic injection system is described in Page 10 of the budget proposal and includes a caustic buffer tank, dosage/control system, dual pH probe, and transmitters. The budget proposal does not break out this specific equipment and, therefore, a factor of 20-percent of the entire system cost was assumed for the caustic injection system. The cost analysis presented in Table 5-5 of the BART Determination Report did not include any installation cost. Table 5-5 has now been revised to include an installation cost, which is 20 percent of the installation cost of $1.5 million for the entire system.

Comment 9. **Capital Costs: Provide supporting information for the equipment cost estimate of $261,707 as well as "foundations, structural steel and lighting" at $34,938. Provide supporting information for the 20% contingency factor and revise downward.**

Response 9: As explained in Response 8, the caustic injection system cost of $261,707 is based on assuming 20 percent of the equipment cost from the budget proposal from Andritz and adjusted for the exhaust flow of Boiler No. 4 ($230,217 for Boiler No. 5).

- Andritz equipment cost = $1,235,000.
- 20% of equipment cost = $247,000.
- Andritz system inlet air flow = 284,000 acfm at 462°F.
- Boiler No. 4 exhaust flow = 203,000 acfm at 162°F.
- Adjusted 20 percent equipment cost = $247,000 / (284,000 x (460+162) / (460+462)) x 203,000 = $261,707.

As indicated in the budget proposal, the cost of foundation for the caustic injection system (includes tank, pump, dosage/control system) is not included and was estimated based on a factor of 12 percent of total equipment cost (OAQPS Cost Manual, 6th Edition, January 2002, Section 5).

The justification for using the 20-percent contingency factor is described in Comment 3.

Comment 10. **Operating Costs: Show the calculations for estimating the following annual costs: operating labor, caustic material, water, electricity and waste disposal. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary ($/hour, $/ton caustic, $/1000 gallons, etc.).**

Response 10: The operating labor, caustic material, water, electricity, and waste disposal costs are same as those calculated for the new Micro Mist wet scrubber system and described in Response 4. Adjustments have been made in Table 5-5 to account for 180 days per year operation.

Comment 11. **The revised cost estimate should assume a 7% interest rate and 20-year life.**

Response 11: The cost calculation has been revised and a revised Table 5-5 is attached.

Section Conclusion: As shown in revised Table 5-5, the cost effectiveness for adding a caustic injection system to the existing wet scrubber range from \$5,500/ton to \$6,500/ton and \$5.7 million/dv to \$8.5 million/dv for the bagasse and fuel oil firing scenario, which is very high and visibility reduction achieved in the bagasse-only firing scenario is 0.003 dv or less.

<u>New Electrostatic Precipitator</u>

Comment 12. **The cost estimate in Table 5-9 indicates a PM control efficiency of only 84% for the ESP added after the wet scrubber. Does this suggest that the ESP would be added after the existing wet impingement scrubber? The PPC cost quote in the Appendix states that the ESP will reduce emissions from 492 to 6.8 kg/hour, which is a control efficiency of 98.6%. This is more typical for a modern ESP design. Assuming a control efficiency of approximately 85% for the existing wet impingement scrubber and baseline emissions for Boiler 4 of 118.8 tons/year, uncontrolled emissions would be 792 tons/year. Assuming 98.6% reduction with the ESP to replace the existing wet impingement scrubber, controlled emissions would be only 11 tons/year. Please comment and revise the cost analysis accordingly also assuming 7% interest rate and 20-year life.**

Response 12: The ESP considered in the BART PM control technology analysis would replace the existing wet impingement scrubber. The control efficiency is based on the baseline PM emissions and not uncontrolled PM emissions for firing bagasse. Based on the vendor (PPC Industries) design data, the ESP is able to achieve a control efficiency of 98.6 percent. However, if used in series with a wet impingement scrubber control device, it will not be able to achieve a further reduction of 98.6 percent on the exhaust stream of the first control device. This is because the exhaust stream of the first control device will be composed of mainly smaller size particles. In addition, there would be operating difficulties in adding the ESP after the wet scrubber (i.e., high moisture levels, low temperature affecting resitivity, etc.).

A typical ESP-controlled PM emission rate for Boiler Nos. 4 and 5 would be 0.02 lb/MMBtu. As explained in Section 5.4 of the BART Determination Report, current PM emission rates are 0.124 and 0.15 lb/MMBtu for Boiler Nos. 4 and 5, respectively, which means the ESP will reduce the PM emissions compared to the existing wet scrubber by 84 and 87 percent, respectively.

Outlet emissions = 0.02 lb/MMBtu.
Inlet emissions = 0.124 lb/MMBtu.
Emissions control = 1 - 0.02/0.124 = 84 percent.

The cost recovery factor in Table 5-9 was revised to be based on 20 years of equipment life at 7-percent interest.

Comment 13. **Capital Costs: Provide supporting information for the 20% contingency factor and revise downward.**

Response 13: The explanation for using the 20-percent contingency factor is described in Response 3.

Comment 14. **Operating Costs: Show the calculations for estimating the following annual costs: operating labor, caustic material, water, electricity and waste disposal. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary ($/hour, $/ton caustic, $/1000 gallons, etc.).**

Response 14: There are no cost estimates for caustic material, water, and waste disposal in Table 5-9. The costs of operating labor and electricity are explained below:

- Operating labor – Operating labor cost estimates are based on Section 6, Particulate Matter Control of the OAQPS Control Cost Manual. Section 3.4.1.1, Chapter 3 of Section 6 describes operating and supervisory labor estimates associated with ESPs. It is assumed that 25 percent of the coordinator's total time will be required for the ESP. Total annual cost for the coordinator, who typically is an engineer, was assumed to be $70,000. Operating labor is recommended to be ½ to 2 hours per shift and 1 hour/shift was used in the calculation. As recommended in Chapter 3, supervisory labor is taken as 15 percent of operating labor.
- Electricity – The power requirement for the ESP system is based on the budget proposal from PPC Industries, which shows the power consumption to be 132 kilovolt-ampere (kVA). Table 5-9 submitted with the BART Determination Report used the 132 kVA as 132 kW. Table 5-9 has been revised to use 106 kW, which is equivalent to 132 kVA.

Electrical power requirement = 132 kVA = 106 kW.
Cost of electricity = 106 kW x 24 hr/day x 180 days/yr x $0.06/kW = $27,500.

Comment 15. **Provide a cost estimate for a secondary wet scrubber (such as a wet venturi scrubber) to remove additional particulate after the existing wet impingement scrubber. Assume a 7% interest rate and 20-year life.**

Response 15: A cost estimate was generated for a secondary wet scrubber to remove additional PM after the existing wet impingement scrubber. The cost estimate, which is summarized in Table 3, is based on the same Andritz/Envirocare Micro Mist wet scrubber system used in the SO_2 control technology analysis, but without the caustic injection system. Since the cost of the caustic injection system used in the SO_2 control technology analysis was assumed to be 20 percent of the total system cost, 80 percent of the total system cost was used in this case for the scrubber without the caustic injection system.

Section Conclusion: Cost-effectiveness numbers presented in the revised Table 5-9 and Table 3 are very high in terms of both $/ton of PM removal and $/dv visibility improvement. Therefore, both control options for additional PM control, ESP (Table 5-9), and scrubber (Table 3) are not feasible.

<u>**Mobotec System for Multi-Pollutant Reduction (ROFA + Rotomix)**</u>

Comment 16. **Capital Costs: Provide supporting information for the 20% contingency factor and revise downward as necessary.**

Response 16: The justification for using the 20-percent contingency factor is described in Response 3.

Comment 17. **Operating Costs: Show the calculations for estimating the following annual costs: operating labor, urea, water and electricity. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary ($/hour, $/ton caustic, $/1000 gallons, etc.). Revise the maintenance cost factor to 1.5% of the total capital investment.**

Response 17: The cost estimates for operating labor, urea, water, and electricity are explained below:

- Operating labor – Operating labor cost estimate is based on an estimated 20 hours per week or about 1 hour per shift for the operating labor. Supervisory labor is taken as 15 percent of the operating labor according to the Control Cost Manual.
- Electricity – The power requirement for the ROFA system is not directly available from the budget proposal from Mobotec. The Mobotec equipment list describes the ROFA fan as 300 to 400 hp. Based on data from commercial electric motor vendors on the internet (www.baldor.com), a 300-hp electric motor requires 224 kW of electric power. Tables 5-6 and 5-7 were revised to include the 224-kW power for the ROFA fan.

  Electrical power requirement = 224 kW.

  Cost of electricity = 224 kW x 24 hr/day x 180 days/yr x $0.06/kW = $58,100.
- Urea – Calculation for urea is based on the urea consumption of 0.25 gpm from the Mobotec budget proposal. The Mobotec urea usage, which is for a 423-MMBtu/hr boiler with uncontrolled NO_x emissions of 311 TPY, was prorated to match the NO_x emisisons of Boiler Nos. 4 and 5. Based on current industry data, the cost of 50 percent urea solution is $298/ton.

  Mobotec urea consumption = 0.25 gpm (NO_x emissions of 311 TPY).

  Boiler No. 4 NO_x emissions = 344 TPY (highest actual emissions for 2001 to present).

  Estimated urea consumption for Boiler No. 4 = 0.25 gpm x 344/311 x 60 min/hr = 16.6 gph.

  Unit cost of 50 percent urea solution = $298/ton = $1.65/gallon (based on density of urea, 11.1 lb/gallon).

  Annual cost of urea = 16.6 gph x 2 x 24 hr/yr x 180 days/yr x $1.65/gallon = $236,300.
- Water – The water usage for the ROTAMIX system is based on the water consumption of 1.25 gpm from the Mobotec budget proposal. The Mobotec water usage, which is for a 423-MMBtu/hr boiler with uncontrolled NO_x emissions of 311 TPY, was prorated to match the estimated urea usage of Boiler Nos. 4 and 5.

  Mobotec data = 1.25 gpm (urea usage = 15 gpm).

  Estimated urea usage of Boiler No. 4 = 16.6 gpm.

  Estimate water requirement for Boiler No. 4 = 1.25 gpm x 16.6/15 x 60 min/hr = 99.5 gph.

  Cost of water = $2.36/1,000 gallon x 99.5 gph x 24 hr/day x 180 days/yr = $1,000.

In the Control Cost Manual, a maintenance cost of 1.5 percent is used for control systems with little or no moving parts, such as the SCR and SNCR systems with few pumps and motors (Section 4 of the Control Cost Manual, page 2-45). Since the ROFA and ROTAMIX systems have moving parts, the maintenance cost was doubled to 3 percent.

Comment 18. As indicated in the vendor quote in the Appendix, the Mobotec system will control PM and SO_2 emissions in addition to nitrogen oxides (NO_x). Provide a vendor quote for a system to control NO_x, PM and SO_2 (related costs, control efficiencies, etc.). Revise the cost effectiveness analysis to also include the reduction of NO_x, SO_2 and PM emissions.

Response 18: A cost-effectiveness analysis has been performed for using the Mobotec system to control PM and SO_2 emissions in addition to controlling NO_x emissions for Boiler Nos. 4 and 5. The analyses are presented in Tables 4 and 5, respectively. The cost for the Mobotec Furnace Sorbent Injection (FSI) system has been added, which is the Mobotec system for SO_2 reduction and involves the injection of limestone sorbent into the furnace. The consumption of limestone is taken from the Mobotec budget proposal and prorated for the expected SO_2 emissions from Boiler Nos. 4 and 5 when burning 2.4 percent sulfur fuel oil. According to Mobotec, an additional installation cost of $210,000 has been added for the FSI system.

Based on the range of SO_2 control efficiency quoted by Mobotec for the FSI system, 55-percent control efficiency was used in the analysis. For PM, a control efficiency of 35-percent was used, which is based on Mobotec's expectation of reducing PM emissions from the furnace from 10 to 6.5 lb/MMBtu.

Comment 19. Revise the cost estimate as indicated above and assuming a 7% interest rate and 20-year life.

Response 19: The cost estimates have been revised based on 7-percent interest and 20-year equipment life in the revised Tables 5-6 and 5-7.

Section Conclusion: Revised Tables 5-6 and 5-7 show cost effectiveness of a ROFA system range from $6,300/ton to more than $10,000/ton of NO_x removed for Boiler Nos. 4 and 5, respectively, which is very high. Cost effectiveness of visibility improvement is in excess of $26 million/dv for each boiler, which is extremely high. Cost effectiveness for the consideration of reducing all three pollutants, NO_x, SO_2, and PM (Tables 4 and 5) is also very high. Therefore, further reduction of NO_x emissions is not practical.

<u>Fuel Tech Selective Non-Catalytic Reduction</u>

Comment 20. Capital Costs: Provide supporting information for the 20% contingency factor and revise downward as necessary.

Response 20: The justification for using the 20-percent contingency factor is described in Comment 3.

Comment 21. Operating Costs: Show the calculations for estimating the following annual costs: operating labor, NOxOut reagent cost, water and electricity. These costs should be estimated on the same basis as the baseline emissions (e.g., 180 operating days). In addition, provide supporting information for the unit costs for each of the items and adjust as necessary ($/hour, $/ton caustic, $/1000 gallons, etc.).

Response 21: The cost estimate for operating labor, NOxOut reagent cost, water, and electricity are explained below:

- Operating labor – Operating labor cost estimate is based on an estimated 1 hour per shift for the operating labor. Supervisory labor is taken as 15-percent of the operating labor. Annual maintenance labor and material cost is taken as 1.5-percent of total capital investment. These are based on the Control Cost Manual.
- NOxOUT Reagent – Calculation for NOxOUT reagent is based on the average reagent consumption of 19.3 gph provided by the Fuel Tech budget proposal. The Fuel Tech reagent usage, which is for a 423 MMBtu/hr boiler with uncontrolled NO_x emissions of 315 TPY, was prorated to match the NO_x emissions of Boiler Nos. 4 and 5. NOxOUT reagent is a 50 percent (by weight) aqueous urea solution with other additives. Therefore, a unit cost of $1.65/gallon is used for the NOxOUT reagent, which is similar to the 50% urea solution cost.

  Reagent consumption = 19.35 gph (NO_x emissions of 315 TPY).

  Boiler No. 4 NO_x emissions = 344 TPY (highest actual emissions for 2001-present).

  Estimated reagent consumption for Boiler No. 4 = 19.35 gph x 344/315 = 21.1 gph.

  Unit cost of reagent = $1.65/gallon.

  Annual cost of reagent = 21.1 gph x 24 hr/day x 180 days/yr x $1.65/gal = $150,600.

- Water – The water usage for the NOxOUT SNCR system is based on the average dilution water flow of 10.9 gpm provided by the Fuel Tech budget proposal. The Fuel Tech estimate, which is for a 423 MMBtu/hr boiler with uncontrolled NO_x emissions of 315 TPY, was prorated to match the estimated NOxOUT reagent usage for NO_x emissions of 344 TPY.

  Dilution water flow from Fuel Tech = 10.9 gpm (NO_x emissions of 315 TPY).

  Boiler No. 4 NO_x emissions = 344 TPY (highest actual emissions for 2001 to present).

  Estimate water requirement for Boiler No. 4 = 10.9 gpm x 21.1/19.35 x 60 min/hr = 712.1 gph.

  Cost of water = $2.36/1,000 gallon x 712.1 gph x 24 hr/day x 180 days/yr = $7,300.

- Electricity – The power requirement for the NOxOUT SNCR system is based on the budget proposal from Fuel Tech, which estimates the power requirement to be 35 kW for a boiler with 423 MMBtu/hr heat input and uncontrolled NO_x emissions rate of 315 TPY. The power requirement was prorated for the NO_x emissions of Boiler Nos. 4 and 5.

  NOxOUT SNCR system power requirement = 35 kW (NO_x emissions of 315 TPY).

  Boiler No. 4 NO_x emissions = 344 TPY (highest actual emissions for 2001 to present.

Adjusted power requirement = 35 kW x (21.1/19.35) = 38.2 kW.

Cost of electricity = 38.2 kW x 24 hr/day x 180 days/yr x $0.06/kW = $9,900.

Comment 22. **Revise the cost estimate as indicated above and assuming a 7% interest rate and 20-year life.**

Response 22: The cost estimates have been revised based on 7-percent interest and 20-year equipment life in the revised Table 5-8.

Section Conclusion: The cost effectiveness of adding a SNCR system for the additional control of NO_x emissions presented in the revised Table 5-8 are \$8,100/ton to \$11,500/ton and \$32 million/dv to over \$51 million/dv, which are very high, both in terms of \$/ton of NO_x reduction and \$/dv visibility improvement. Therefore, SNCR is not a viable control option for the SCGCF Boiler Nos. 4 and 5.

Visibility Modeling

Comment 23. **Provide revised visibility impact analyses for all BART-eligible boilers operating under each of the reduced sulfur scenarios (1%, 0.5%, and 0.0015%). Optionally, provide a revised visibility impact analysis for all BART-eligible boiler operating under a given reduced sulfur scenario that results in a visibility impact of less than 0.5 deciviews.**

Response 23: Visibility impacts for all BART-eligible boilers operating with 1-, 0.05-, and 0.0015-percent sulfur fuel oil are presented in the revised Table 5-11.

Comment 24. **For each control option with a revised emissions reduction, provide a corresponding revised visibility impact analysis. Visibility impacts must be determined for each BART-eligible unit.**

Response 24: Visibility impacts for each control option were determined and are presented in the visibility cost-effectiveness calculation in the cost calculation summary tables for each control option.

Thank you for your consideration of this information. A P.E. signature page is attached. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

DB/sl

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Professional Engineer Certification

<table>
<tr><td>1. Professional Engineer Name: David A. Buff
Registration Number: 19011</td></tr>
<tr><td>2. Professional Engineer Mailing Address...
Organization/Firm: Golder Associates Inc.**
Street Address: 6241 NW 23rd Street, Suite 500
City: Gainesville State: FL Zip Code: 32653</td></tr>
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Telephone: (352) 336-5600 ext.545 Fax: (352) 336-6603</td></tr>
<tr><td>4. Professional Engineer Email Address: dbuff@golder.com</td></tr>
<tr><td>5. Professional Engineer Statement:
I, the undersigned, hereby certify, except as particularly noted herein*, that:
(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and
(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.
(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.
(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.
(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff   5/30/08
Signature   Date

(seal)</td></tr>
</table>

* Attach any exception to certification statement.

**** Board of Professional Engineers Certificate of Authorization #00001670**

TABLE 5-3 (Revised 052808)
COST EFFECTIVENESS OF FUEL SWITCHING FOR NO. 4 OR NO. 5 BOILER

Cost Items	Cost Factors	No. 2 Oil (0.0015% S) Cost ($)	No. 2 Oil (0.05% S) Cost ($)	No. 6 Oil (1.0% S) Cost ($)
DIRECT CAPITAL COSTS (DCC):				
(1) Equipment Cost				
(a) New Fuel Oil Storage tank	See Footnote "a"	807,000	807,000	807,000
(b) Pumps, piping, etc.	See Footnote "a"	800,000	800,000	1,200,000
(c) New oil guns/atomizer sprayer plates	Babcock& Wilcox -- excludes installation[b]	175,000	175,000	0
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	111,375	111,375	125,438
Subtotal: Total Equipment Cost (TEC)		1,893,375	1,893,375	2,132,438
(3) Direct Installation Costs	85% of TEC (for new oil guns)	148,750	148,750	0
Total DCC:		2,042,125	2,042,125	2,132,438
INDIRECT CAPITAL COSTS (ICC):[c]				
(1) Indirect Installation Costs	SCGCF estimate	430,000	430,000	640,000
(a) Engineering	10% of TEC (for new oil guns)	17,500	17,500	Included Above
(b) Construction & Field Expenses	10% of TEC (for new oil guns)	17,500	17,500	Included Above
(c) Construction Contractor Fee	10% of TEC (for new oil guns)	17,500	17,500	Included Above
(d) Contingencies	3% of TEC (for new oil guns)	5,250	5,250	Included Above
(2) Other Indirect Costs				
(a) Startup	1% of TEC (for new oil guns)	1,750	1,750	Included Above
(b) Performance Test'	3% of TEC (for new oil guns)	5,250	5,250	Included Above
Total ICC:		494,750	494,750	640,000
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	2,536,875	2,536,875	2,772,437.5
DIRECT OPERATING COSTS (DOC):[d]				
(1) Operating Labor				
Operator	15 min/shift, $30/hr, 3 shifts/day, 180 days/yr	4,050	4,050	4,050
Supervisor	15% of operator cost	608	608	608
(2) Maintenance				
Labor	Equivalent to One-Half Operating Labor	2,025	2,025	2,025
Materials	100% of maintenance labor	2,025	2,025	2,025
(3) Utilities				
(4) Fuels				
Existing Fuel Cost (No. 6 fuel oil with 2.4%S)	$2.114/gal, 594,000 gal/yr	1,602,196	1,602,196	1,602,196
Proposed Fuel Cost (fuel with lower sulfur content)	See Footnote "e"	2,593,600	2,483,840	1,681,020
Differential Fuel Cost (Proposed - Existing)	Proposed fuel cost - existing fuel cost	991,404	881,644	78,824
Total DOC:		1,000,111	890,351	87,531
INDIRECT OPERATING COSTS (IOC):[d]				
(1) Overhead	60% of oper. labor & maintenance	5,225	5,225	5,225
(2) Property Taxes	1% of total capital investment	25,369	25,369	27,724
(3) Insurance	1% of total capital investment	25,369	25,369	27,724
(4) Administration	2% of total capital investment	50,738	50,738	55,449
Total IOC:		106,700	106,700	116,122
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	239,481	239,481	261,718
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**1,346,292**	**1,236,532**	**465,371**
BASELINE SO_2 EMISSIONS (TPY) :	594,000 gal/yr, 2.4%S, 8.1 lb/gal No. 6 Oil (Highest annual usage for either Nos. 4 or 5 boiler for 2001-present)	115.5	115.5	115.5
MAX SO_2 EMISSIONS WITH PROPOSED FUEL (TPY):	640K gal/yr 0.05%S or 0.0015%S No. 2 oil or 594K gal/yr 1% S No. 6 Fuel Oil (8.0 lb/gal)	0.07	2.3	47.5
REDUCTION IN SO_2 EMISSONS (TPY):		115.4	113.2	68.0
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	**11,666**	**10,926**	**6,848**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10	0.284	0.284	0.284
CONTROLLED VISIBILITY IMPACT (dv)	Table 5-11, Lowest impact - Boiler 4 or 5	0.16	0.161	0.183
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.124	0.123	0.101
COST EFFECTIVENESS OF VISIBILITY REDUCTION ($/dv) :	AC/Reduction in visibility	**10,857,192**	**10,053,104**	**4,607,638**

Footnotes:

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

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

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

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

[e] Fuel cost per SCGCF: No. 6 Oil @ 2.4%S - $2.6973/gal, No. 6 Oil @ 1%S - $2.83/gal, No. 2 Oil @ 0.0015%S - $4.05/gal, No. 2 Oil @ 0.05%S - $3.88/gal. Fuel oil usage is 594,000 gal/yr based on actual fuel oil usage from the period 2001-2006. 594,000 gal of No. 6 oil is equivalent to 640,000 gal of No. 2 oil based on 151,000 Btu/gal for No. 6 oil and 140,000 Btu/gal for No. 2 oil.

TABLE 5-4 (Revised 052808)
CAPITAL AND ANNUAL COSTS FOR BOILER SO_2 CONTROL USING A SCRUBBER SYSTEM

Cost Items	Cost Factors	Boiler No. 4 Scrubber System Cost ($)	Boiler No. 5 Scrubber System Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Based on Vendor Quote	1,308,535	1,151,086
(a) Separator/Scrubber/Mist Eliminator		included	included
(b) Caustic Injection		included	included
(c) Devices/Instrumentation		included	included
(g) Access & Platform		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	81,783	71,943
(3) Equipment Freight Cost	5% of Equipment Cost	65,427	57,554
Subtotal: Total Equipment Cost (TEC)		1,455,745	1,280,583
(3) Installation Costs [a]			
(a) Vendor Quote - Installation of Equipment and Piping		1,500,000	1,500,000
(b) Foundations, Structural Steel, Lighting	12% of TEC	174,689	153,670
(c) Piping		Included	Included
(d) Drains/Heat Tracing/Insulation	1% of TEC	14,557	12,806
(e) Electrical - Motor Starters/Wiring/DCS	1% of TEC	14,557	12,806
(f) Painting	1% of TEC	14,557	12,806
(g) Documentation/Engineering		included	included
(h) Start-up and Commissioning		included	included
(i) Inlet Ductwork and Connecting Ductwork	Estimate	150,000	150,000
Total DCC:		3,324,106	3,122,671
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) Performance Testing	Typical Value: 1% of Total Equipment Cost	14,557	12,806
(2) Other Indirect Costs (a)			
Engineering	10% of TEC	145,574	128,058
Construction and field expenses	10% of TEC	145,574	128,058
Contractor Fees	10% of TEC	145,574	128,058
Startup & Testing	Typical Value: 1% of TEC	Included	Included
Total ICC:		451,281	396,981
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	755,077	703,930
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	4,530,465	4,223,582
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	$30/hr, 1.0 hr/shift, 3 shifts/day, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	8,100	8,100
Materials	100% of maintenance labor	8,100	8,100
(3) Operating Material			
Caustic	$500/ton dry caustic (No. 4 - 139 TPY, No. 5 - 102 TPY) [b]	69,500	51,000
Water makeup	$2.36/1000 gal (No. 4 - 56.8 gpm, No. 5 - 43.6 gpm), 180 days/yr [c]	34,756	26,693
Solid Waste Disposal	$40/ton (No. 4 - 243 TPY, No. 5 - 179 TPY) [d]	9,896	7,291
(4) Electricity	1x125 hp (1 Quench pump), 93 KW, $0.06/KW-hr, 180 days/yr	24,106	24,106
Total DOC:		173,088	143,919
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	20,898	20,898
(2) Property Taxes	1% of total capital investment	45,305	42,236
(3) Insurance	1% of total capital investment	45,305	42,236
(4) Administration	2% of total capital investment	90,609	84,472
Total IOC:	(1) + (2) + (3) + (4)	202,117	189,841
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	427,676	398,706
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**802,880**	**732,467**
BASELINE SO_2 EMISSIONS (TPY), (see Table 2) :	Highest actual emissions in 2001-present	113.2	83.4
CONTROLLED SO_2 EMISSIONS (TPY) :	98% Removal by the Scrubber (vendor specification)	2.3	1.7
REDUCTION IN SO_2 EMISSIONS (TPY):	Baseline - Controlled	110.9	81.7
BASELINE PM EMISSIONS (TPY) :	Highest actual emissions in 2001-present	118.8	90.0
CONTROLLED PM EMISSIONS (TPY) :	0.02 lb/MMBtu, Highest MMBtu from AORs for 2001-present	17.0	11.7
REDUCTION IN PM EMISSIONS (TPY):	Baseline - Controlled	101.8	78.3
TOTAL REDUCTION IN EMISSIONS (SO_2+PM,TPY) :	Reduction of SO_2 + Reduction of PM	212.7	160.1
COST EFFECTIVENESS:	$ per ton of SO_2 & PM Removed	**3,774**	**4,576**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.197	0.158
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.087	0.058
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**9,228,508**	**12,628,735**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.231	0.191
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.002	0.004
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**401,440,109**	**183,116,662**

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

TABLE 5-5 (Revised 052808)
CAPITAL AND ANNUAL COSTS FOR BOILER SO_2 CONTROL USING CAUSTIC IN EXISTING SCRUBBER SYSTEM

Cost Items	Cost Factors	Boiler No. 4 Scrubber System Cost ($)	Boiler No. 5 Scrubber System Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Based on Vendor Quote	0	0
(a) Separator/Scrubber/Mist Eliminator		included	included
(b) Caustic Injection System (tank, pump, control, DCS)	Assumed 20% of Vendor Quote for Total System	261,707	230,217
(c) Devices/Instrumentation		included	included
(g) Access & Platform		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	16,357	14,389
(3) Equipment Freight Cost	5% of Equipment Cost	13,085	11,511
Subtotal: Total Equipment Cost (TEC)		291,149	256,117
(3) Installation Costs [a]			
(a) Vendor Quote - Installation of Equipment and Piping	20% of total scrubbing system installation	300,000	300,000
(b) Foundations, Structural Steel, Lighting	12% of TEC	34,938	30,734
(c) Piping		Included	Included
(d) Drains/Heat Tracing/Insulation	1% of TEC	2,911	2,561
(e) Electrical - Motor Starters/Wiring/DCS	1% of TEC	2,911	2,561
(f) Painting	1% of TEC	2,911	2,561
(g) Documentation/Engineering		included	included
(h) Start-up and Commissioning		included	included
(i) Inlet Ductwork and Connecting Ductwork	Estimate	0	0
Total DCC:		634,821	594,534
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) Performance Testing	Typical Value: 1% of Total Equipment Cost	2,911	2,561
(2) Other Indirect Costs (a)			
Engineering	10% of TEC	29,115	25,612
Construction and field expenses	10% of TEC	29,115	25,612
Contractor Fees	10% of TEC	29,115	25,612
Startup & Testing	Typical Value: 1% of TEC	Included	Included
Total ICC:		90,256	79,396
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	145,015	134,786
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	870,093	808,716
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	$30/hr, 1.0 hr/shift, 3 shifts/day, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	8,100	8,100
Materials	100% of maintenance labor	8,100	8,100
(3) Operating Material			
Caustic	$500/ton dry caustic (No. 4 - 139 TPY, No. 5 - 102 TPY) [b]	69,500	51,000
Water makeup	$2.36/1000 gal (No. 4 - 56.8 gpm, No. 5 - 43.6 gpm), 180 days/yr[c]	34,756	26,693
Solid Waste Disposal	$40/ton (No. 4 - 243 TPY, No. 5 - 179 TPY) [d]	9,896	7,291
(4) Electricity	1x125 hp (1 Quench pump), 93 KW, $0.06/KW-hr, 180 days/yr	24,106	24,106
Total DOC:		173,088	143,919
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	20,898	20,898
(2) Property Taxes	1% of total capital investment	8,701	8,087
(3) Insurance	1% of total capital investment	8,701	8,087
(4) Administration	2% of total capital investment	17,402	16,174
Total IOC:	(1) + (2) + (3) + (4)	55,702	53,247
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	82,137	76,343
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**310,926**	**273,509**
BASELINE SO_2 EMISSIONS (TPY), (see Table 2) :	Highest actual emissions in 2001-present	113.2	83.4
CONTROLLED SO_2 EMISSIONS (TPY) :	50% Removal by Existing Scrubber (assumed)	56.6	41.7
REDUCTION IN SO_2 EMISSIONS (TPY):	Baseline - Controlled	56.6	41.7
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	**5,493**	**6,559**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.229	0.184
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.055	0.032
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**5,653,205**	**8,547,147**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.232	0.192
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.001	0.003
VISIBILITY COST EFFECTIVENESS ($/dv) :	**AC/Reduction in visibility impact**	**310,926,257**	**91,169,566**

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

TABLE 5-6 (Revised 052808)
COST EFFECTIVENESS OF MOBOTEC FOR NO_x CONTROL, BOILER NO. 4

		NO_x Control for Boiler No. 4	
Cost Items	**Cost Factors**[a]	**ROFA Only Cost ($)**	**ROFA + ROTAMIX Cost ($)**
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	126,590	126,590
ROFA System	Vendor quote[b]	2,330,476	3,317,676
Emissions Monitoring	15% of equipment cost	349,571	497,651
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	186,438	265,414
Freight	5% of Equipment Cost	116,524	165,884
Taxes	Florida sales tax, 6.25%	145,655	207,355
Purchased Equipment Cost (PEC)		3,285,254	4,610,570
ROTAMIX Installataion	Vendor quote[b]	0	340,000
Total DCC		3,285,254	4,950,570
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	98,158	98,158
Electrical and Controls	Vendor quote[b]	33,712	33,712
General Facilities	5% of DCC	164,263	247,528
Engineering and home office fees	10% of DCC	328,525	495,057
Process Contingency	5% of DCC	164,263	247,528
Total ICC		788,921	1,121,984
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	814,835	1,214,511
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	4,889,009	7,287,064
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 180 days/yr	15,429	15,429
Supervisor	15% of operator cost	2,314	2,314
Maintenance	3% of TCI	146,670	218,612
Electricity	224 kW, $0.06/kW-hr, 180 days/yr	58,061	58,061
Water usage	99.5 gal/hr, 180 days/yr; $2.36/1000gal [c]	0	1,014
Urea	16.6 gph X $1.65/gal (50% sol) X 24 hr/day, 180 days/yr [c]	0	236,294
Total DOC:		222,474	531,723
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	98,648	141,813
Property Taxes	1% of TCI	48,890	72,871
Insurance	1% of TCI	48,890	72,871
Administration	2% of TCI	97,780	145,741
		294,208	433,295
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	461,522	687,899
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**978,205**	**1,652,918**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions in last 5 years	343.9	343.9
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	189.1	137.6
REDUCTION IN NO_x EMISSONS (TPY):		154.8	206.3
COST EFFECTIVENESS:	**$ per ton of NO_x Removed**	**6,321**	**8,011**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.284
CONTROLLED VISIBILITY IMPACT (dv)		0.255	0.246
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.029	0.038
VISIBILITY COST EFFECTIVENESS ($/dv) :		**33,731,196**	**43,497,833**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.233
CONTROLLED VISIBILITY IMPACT (dv)		0.196	0.178
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.037	0.055
VISIBILITY COST EFFECTIVENESS ($/dv) :		**26,437,965**	**30,053,049**

Footnotes:

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

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

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

TABLE 5-7 (Revised 052808)
COST EFFECTIVENESS OF MOBOTEC FOR NO_x CONTROL, BOILER NO. 5

		NO_x Control for Boiler No. 5	
Cost Items	Cost Factors[a]	ROFA Only Cost ($)	ROFA + ROTAMIX Cost ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	97,059	97,059
ROFA System	Vendor quote[b]	1,786,820	2,774,020
Emissions Monitoring	15% of equipment cost	268,023	416,103
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	142,946	221,922
Freight	5% of Equipment Cost	89,341	138,701
Taxes	Florida sales tax, 6.25%	111,676	173,376
Purchased Equipment Cost (PEC)		2,525,865	3,851,181
ROFA Installataion	Vendor quote[b]	345,250	685,250
Total DCC		2,871,115	4,536,431
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	75,259	75,259
Electrical and Controls	Vendor quote[b]	25,848	25,848
General Facilities	5% of DCC	143,556	226,822
Engineering and home office fees	10% of DCC	287,112	453,643
Process Contingency	5% of DCC	143,556	226,822
Total ICC		675,330	1,008,393
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	709,289	1,108,965
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	4,255,734	6,653,789
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 180 days/yr	15,429	15,429
Supervisor	15% of operator cost	2,314	2,314
Maintenance	3% of TCI	127,672	199,614
Electricity	224 kW, $0.06/kW-hr, 180 days/yr	58,061	58,061
Water usage	51.6 gal/hr, 180 days/yr; $2.36/1000gal[c]	0	527
Urea	16.6 gph X $1.65/gal (50% sol) X 24 hr/day, 180 days/yr[c]	0	122,716
Total DOC:		203,476	398,660
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	87,249	130,414
Property Taxes	1% of TCI	42,557	66,538
Insurance	1% of TCI	42,557	66,538
Administration	2% of TCI	85,115	133,076
		257,478	396,566
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	401,741	628,118
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**862,695**	**1,423,343**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions in last 5 years	178.6	178.6
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	98.2	71.4
REDUCTION IN NO_x EMISSONS (TPY):		80.4	107.2
COST EFFECTIVENESS:	**$ per ton of NO_x Removed**	**10,734**	**13,282**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.216	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.198	0.192
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.018	0.024
VISIBILITY COST EFFECTIVENESS ($/dv) :		**47,927,518**	**59,305,969**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.195	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.167	0.153
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.028	0.042
VISIBILITY COST EFFECTIVENESS ($/dv) :		**30,810,547**	**33,889,125**

Footnotes:

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

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

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

TABLE 5-8 (Revised 052808)
COST EFFECTIVENESS OF FUEL TECH FOR NO_x CONTROL, BOILER NOS. 4 AND 5

Cost Items	Cost Factors	SNCR System for Boiler No. 4 Cost ($)	SNCR System for Boiler No. 5 Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Based on Vendor Quote [b]	1,225,708	939,446
(a) NOxOUT SNCR Basic Process		included	included
(b) 8,000 Gallon FRP Storage Tank		included	included
(c) Circulation Module and Enclosure		included	included
(d) Urea and Dilution water Metering Module		included	included
(e) Urea Distribution Module, Injectors, Control Panel		included	included
(f) Temperature Monitoring, Engineering Designs		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	76,607	58,715
(3) Equipment Freight Cost	5% of Equipment Cost	61,285	46,972
Subtotal: Total Equipment Cost (TEC)		1,363,600	1,045,133
(4) Installation Costs [a]			
(a) Vendor quotes for similar boilers (equal to basic process equipment cost)		1,225,708	939,446
(b) Tank Foundation and Structural Support	5% of TEC	68,180	52,257
(c) Piping and Wiring	Engineering Estimate	100,000	100,000
(d) Electrical and Controls	Engineering Estimate	100,000	100,000
(h) NOxOUT Supply - First Fill	No. 4-8,800 gal, No. 5-4,600 gal. 5, $1.65/gal[c]	8,800	4,600
Total DCC:		2,866,288	2,241,436
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) General Facilities	5% of TEC	68,180	52,257
(b) Engineering and Home Office Fees	10% of TEC	136,360	104,513
(c) Process Contingency	5% of TEC	68,180	52,257
(2) Other Indirect Costs			
(a) NO_x, Ammonia, and CO Monitoring	Estimate	20,000	20,000
(b) Performance Testing	Based on historical testing	45,000	45,000
(c) Spare Parts	Engineering Estimate, 2% of TEC	27,272	20,903
(d) Contractor Fees	10% of TEC	136,360	104,513
Total ICC:		501,352	399,443
PROJECT CONTINGENCY (Retrofit installation)	20% of (DCC+ICC)	673,528	528,176
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	4,041,168	3,169,054
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	1.0 hr/shift, $30/hr, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance	Engineering estimate, 1.5% of TCI	60,618	47,536
(3) Annual NOxOut Cost	No. 4-21.4 gph, No. 5-11.1 gph, $1.65/gal [c]	150,597	78,211
(4) Electricity	No. 4-39 KW, No. 5 - 20 KW, $0.06/KW-hr[c]	9,905	5,144
(5) Water Consumption	No. 4-12 gpm, No.5-6 gpm, $2.36/1000 gal[c]	7,260	3,770
Total DOC:		247,010	153,291
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	47,549	39,699
(2) Property Taxes	1% of total capital investment	40,412	31,691
(3) Insurance	1% of total capital investment	40,412	31,691
(4) Administration	2% of total capital investment	80,823	63,381
Total IOC:	(1) + (2) + (3) + (4)	209,195	166,462
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	381,486	299,159
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**837,692**	**618,912**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions from 2001 to present	343.9	178.6
CONTROLLED NO_x EMISSIONS (TPY) :	SNCR NOx Reduction (30%)	240.7	125.0
REDUCTION IN NO_x EMISSIONS (TPY):		103.2	53.6
COST EFFECTIVENESS:	**$ per ton of NOx Removed**	**8,120**	**11,551**
BASELINE VISIBILITY IMPACT	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.265	0.204
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.019	0.012
VISIBILITY COST EFFECTIVENESS ($/dv) :		**44,089,052**	**51,575,969**
BASELINE VISIBILITY IMPACT	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.207	0.181
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.026	0.014
VISIBILITY COST EFFECTIVENESS ($/dv) :		**32,218,923**	**44,207,973**

Notes:
(a) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002, Section 4
(b) Vendor quote from Fuel Tech, Inc., received in March 2007.
(c) Vendor operational parameters of NOxOUT flow (19.35 gph average), dilution water flow (10.87 gpm average), and power requirement (35 kW) adjusted for the NOx emissions of Boiler Nos. 4 and 5.

TABLE 5-9 (Revised 052808)
CAPITAL AND ANNUAL COSTS FOR BOILER PM CONTROL USING ESP

Cost Items	Cost Factors	ESP for Boiler No. 4 Cost ($)	ESP for Boiler No. 5 Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) ESP + auxiliary equipment	Based on Vendor Quote	1,657,000	1,657,000
(2) Instrumentation	10% of Equipment Cost	included	included
(3) Sales Tax	3% of Equipment Cost	49,710	49,710
(4) Equipment Freight Cost	5% of Equipment Cost	included	included
Subtotal: Total Equipment Cost (TEC)		1,706,710	1,706,710
(5) Direct Installation Costs [(a)]			
(a) Vendor Quote - Installation	Described below	0	0
(b) Foundation (Support included)	2% of TEC (4% for foundation & support)	34,134	34,134
(c) Handling & Erection	50% of TEC	853,355	853,355
(d) Electrical	8% of TEC	136,537	136,537
(e) Piping	1% of TEC	17,067	17,067
(f) Painting	2% of TEC	17,067	17,067
(g) Insulation for Ductwork	2% of TEC	included	included
Total DCC:		2,764,870	2,764,870
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Engineering	20% of TEC	341,342	341,342
(2) Construction and field expenses	20% of TEC	341,342	341,342
(3) Contractor Fees	10% of TEC	170,671	170,671
(4) Startup	1% of TEC	17,067	17,067
(5) Performance Test	1% of TEC	17,067	17,067
Total ICC:		887,489	887,489
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	730,472	730,472
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	4,382,831	4,382,831
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Coordinator	25% Time spent on ESP, Annual Salary 70K	17,500	17,500
Operator	$30/hr, 1 hr/shift, 3 shifts/day, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	8,100	8,100
Materials	100% of maintenance labor	8,100	8,100
(3) Operating Material	None	0	0
(4) Electricity	132 kVA, 106 KW, $0.06/KW-hr, 180 days/yr	27,475	27,475
(5) Water Usage	None, dry ESP	0	0
(6) Wastewater Treatment	None, dry ESP	0	0
Total DOC:		62,305	62,305
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	20,898	20,898
(2) Property Taxes	1% of total capital investment	43,828	43,828
(3) Insurance	1% of total capital investment	43,828	43,828
(4) Administration	2% of total capital investment	87,657	87,657
Total IOC:	(1) + (2) + (3) + (4)	196,211	196,211
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	413,739	413,739
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**672,256**	**672,256**
BASELINE PM EMISSIONS (TPY) :	Highest actual emissions in 2001-present (from AORs)	118.8	90.0
CONTROLLED PM EMISSIONS (TPY) :	No. 4: 0.124 → 0.02 lb/MMBtu, No. 5: 0.15 → 0.02 lb/MMBtu	19.0	11.7
REDUCTION IN PM EMISSONS (TPY):	Baseline - Controlled	99.8	78.3
COST EFFECTIVENESS:	$ per ton of PM Removed	**6,735**	**8,586**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.174	0.130
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.110	0.086
VISIBILITY COST EFFECTIVENESS ($/dv) :		**6,111,416**	**7,816,927**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.101	0.064
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.132	0.131
VISIBILITY COST EFFECTIVENESS ($/dv) :		**5,092,846**	**5,131,723**

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

TABLE 5-11 (Revised 052908)
SUMMARY OF VISIBILITY IMPACTS AT BASELINE AND CONTROLLED 24-HOUR AVERAGE EMISSION RATES

Source	EU ID	Model ID	Baseline Impacts (dv)	SO_2 Control Scenario Impacts: No. 6 Oil (1% S Content) (dv)	No. 2 Oil (0.05%S) (dv)	No. 2 Oil (0.0015%S) (dv)	SO_2 Scrubber (98% Control) (dv)	Caustic (50% Control) (dv)	NO_x Control Scenario Impacts: ROFA (45% Control) (dv)	ROFA+ROTAMIX (60% Control) (dv)	SNCR (30% Control) (dv)	PM Control Impacts: ESP (98.6% Control) (dv)
Bagasse-Firing Only												
Boiler No. 4	004	SGC4	0.233	--	--	--	0.231	0.232	0.196	0.178	0.207	0.101
Boiler No. 5	005	SGC5	0.195	--	--	--	0.191	0.192	0.167	0.153	0.181	0.064
Maximum Fuel Oil w/Remainder Bagasse												
Boiler No. 1	001	SGC1	0.086	0.066	0.053	0.053	--	--	--	--	--	--
Boiler No. 2	002	SGC2	0.081	0.057	0.043	0.042	--	--	--	--	--	--
Boiler No. 4	004	SGC4	0.284	0.223	0.198	0.198	0.197	0.229	0.255	0.246	0.265	0.174
Boiler No. 5	005	SGC5	0.216	0.183	0.161	0.160	0.158	0.184	0.198	0.192	0.204	0.130
Total Boiler Nos. 1 -	--	--	0.578	0.495	0.446	0.442	--	--	--	--	--	--

Note: 8th Highest maximum visibility impacts from 2003.

TABLE 1
COST EFFECTIVENESS OF FUEL SWITCHING FOR BOILER NOS. 1 TO 4

Cost Items	Cost Factors	Boiler No. 1 (1.0% S Oil) Cost ($)	Boiler No. 2 (1.0% S Oil) Cost ($)	Boiler No. 3 (1.0% S Oil) Cost ($)	Boiler No. 4 (1.0% S Oil) Cost ($)
DIRECT CAPITAL COSTS (DCC):					
(1) Equipment Cost					
(a) New Fuel Oil Storage tank	See Footnote "a"	None	None	None	None
(b) Pumps, piping, etc.	See Footnote "a"	None	None	None	None
(c) New oil guns/atomizer sprayer plates	Babcock& Wilcox -- excludes installation[b]	0	0	0	0
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	0	0	0	0
Subtotal: Total Equipment Cost (TEC)		0	0	0	0
(3) Direct Installation Costs	85% of TEC (for new oil guns)	0	0	0	0
Total DCC:		0	0	0	0
INDIRECT CAPITAL COSTS (ICC):[c]					
(1) Indirect Installation Costs	SCGCF estimate	0	0	0	0
(a) Engineering	10% of TEC (for new oil guns)	0	0	0	0
(b) Construction & Field Expenses	10% of TEC (for new oil guns)	0	0	0	0
(c) Construction Contractor Fee	10% of TEC (for new oil guns)	0	0	0	0
(d) Contingencies	3% of TEC (for new oil guns)	0	0	0	0
(2) Other Indirect Costs					
(a) Startup	1% of TEC (for new oil guns)	0	0	0	0
(b) Performance Test'	3% of TEC (for new oil guns)	0	0	0	0
Total ICC:		0	0	0	0
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	0	0	0	0
DIRECT OPERATING COSTS (DOC):[d]					
(1) Operating Labor					
Operator	15 min/shift, $30/hr, 7296 hrs/yr	0	0	0	0
Supervisor	15% of operator cost	0	0	0	0
(2) Maintenance					
Labor	Equivalent to One-Half Operating Labor	0	0	0	0
Materials	100% of maintenance labor	0	0	0	0
(3) Utilities					
(4) Fuels					
Existing Fuel Cost (No. 6 fuel oil with 2.4%S)	See Footnote "e"	736,363	717,482	1,602,196	1,051,947
Proposed Fuel Cost (No. 6 fuel oil with 1% S)	$2.6973/gal, SCGCF data	772,590	752,780	1,681,020	1,103,700
Differential Fuel Cost (Proposed - Existing)	Proposed fuel cost - existing fuel cost	36,227	35,298	78,824	51,753
Total DOC:		36,227	35,298	78,824	51,753
INDIRECT OPERATING COSTS (IOC):[d]					
(1) Overhead	60% of oper. labor & maintenance	0	0	0	0
(2) Property Taxes	1% of total capital investment	0	0	0	0
(3) Insurance	1% of total capital investment	0	0	0	0
(4) Administration	2% of total capital investment	0	0	0	0
Total IOC:		0	0	0	0
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	0	0	0	0
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**36,227**	**35,298**	**78,824**	**51,753**
BASELINE SO_2 EMISSIONS (TPY) :	Baseline usage [e], 2.4%S, 8.1 lb/gal No. 6 Oil	53.1	51.7	115.5	75.8
MAX SO_2 EMISSIONS WITH PROPOSED FUEL (TPY):	1.0%S, 8.0 lb/gal No. 6 Oil	21.8	21.3	47.5	31.2
REDUCTION IN SO_2 EMISSONS (TPY):		31.2	30.4	68.0	44.6
COST EFFECTIVENESS:	$ per ton of SO_2 Removed	**1,160**	**1,160**	**1,160**	**1,160**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10	0.086	0.081	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)	Table 5-11 (Revised 052208)	0.066	0.057	0.223	0.183
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.020	0.024	0.061	0.033
COST EFFECTIVENESS OF VISIBILITY REDUCTION (	AC/Reduction in visibility	**1,811,355**	**1,470,758**	**1,292,193**	**1,568,273**

Footnotes:

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

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

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

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

[e] Fuel cost per SCGCF is $2.114/gal. Baseline oil usage: Boiler 1 - 273,000 gal, Boiler 2 - 266,000 gal, Boiler 4 - 594,000 gal, and Boiler 5 - 390,000 gal. Baseline oil usage based on maximum oil usage from the AORs for the period 2001 to present.

TABLE 2
BASELINE SO_2 EMISSIONS FOR BOILER NOS. 1, 2, 3, and 4

Year	Oil Usage [1] (gallons)	MMBtu [2]	S Content [1]	Density (lb/gal)	SO_2 [3]	Bagasse Usage [1]	MMBtu [2]	SO_2 (0.06 lb/MMBtu) [4]	Total Heat Input	Total SO_2
Boiler 1										
2001	267,090	40,331	1.64	8.1	35.5	42,683	682,936	20.5	723,266	56.0
2002	272,500	41,148	1.00	8.0	21.8	37,959	607,341	18.2	648,488	40.0
2003	239,600	36,180	1.00	8.0	19.2	45,901	734,416	22.0	770,596	41.2
2004	213,860	32,293	1.44	8.0	24.6	41,402	662,429	19.9	694,722	44.5
2005	119,810	18,091	2.00	8.1	19.4	32,943	527,088	15.8	545,179	35.2
2006	31,540	4,763	2.17	8.1	5.5	34,155	546,479	16.4	551,241	21.9
Boiler 2										
2001	265,760	40,130	1.64	8.1	35.3	41,761	668,177	20.0	708,307	55.3
2002	247,760	37,412	1.00	8.0	19.8	34,858	557,725	16.7	595,137	36.6
2003	200,790	30,319	1.00	8.0	16.1	40,727	651,632	19.5	681,951	35.6
2004	187,218	28,270	1.44	8.0	21.6	41,974	671,587	20.1	699,857	41.7
2005	124,900	18,860	2.00	8.1	20.2	35,008	560,127	16.8	578,986	37.0
2006	34,020	5,137	2.17	8.1	6.0	36,256	580,089	17.4	585,226	23.4
Boiler 4										
2001	520,650	78,618	1.64	8.1	69.2	91,843	1,469,495	44.1	1,548,113	113.2
2002	594,160	89,718	1.00	8.0	47.5	81,257	1,300,107	39.0	1,389,825	86.5
2003	528,130	79,748	1.00	8.0	42.3	101,307	1,620,912	48.6	1,700,660	90.9
2004	448,610	67,740	1.44	8.0	51.7	93,260	1,492,168	44.8	1,559,908	96.4
2005	293,280	44,285	2.00	8.1	47.5	83,867	1,341,874	40.3	1,386,159	87.8
2006	81,620	12,325	2.17	8.1	14.3	86,773	1,388,363	41.7	1,400,688	56.0
Boiler 5										
2001	389,960	58,884	1.64	8.1	51.8	65,784	1,052,545	31.6	1,111,429	83.4
2002	372,480	56,244	1.00	8.0	29.8	55,917	894,665	26.8	950,909	56.6
2003	348,550	52,631	1.00	8.0	27.9	69,537	1,112,592	33.4	1,165,223	61.3
2004	262,510	39,639	1.44	8.0	30.2	65,835	1,053,352	31.6	1,092,991	61.8
2005	201,180	30,378	2.00	8.1	32.6	57,820	925,112	27.8	955,491	60.3
2006	56,030	8,461	2.17	8.1	9.8	59,825	957,196	28.7	965,656	38.6

[1] From 2001 - 2006 AORs.

[2] Fuel oil heat content of 151,000 Btu/gal and bagasse heat content of 16 MMBtu/ton used in calculation.

[3] SO_2 = gallons x density, lb/gallon x % sulfur/100 x (64/32) x ton/2000 lb.

[4] Based on industry data.

TABLE 3
CAPITAL AND ANNUAL COSTS FOR BOILER PM CONTROL USING A SCRUBBER SYSTEM

Cost Items	Cost Factors	Boiler No. 4 Scrubber System Cost ($)	Boiler No. 5 Scrubber System Cost ($)
DIRECT CAPITAL COSTS (DCC):			
(1) Included Equipment Cost	Assumed 80% of Vendor Quote for total system [b]	1,046,828	920,869
(a) Separator/Scrubber/Mist Eliminator		included	included
(b) Caustic Injection		Not considered	Not considered
(c) Devices/Instrumentation		included	included
(g) Access & Platform		included	included
(2) Sales Tax	Florida Sales Tax: 6.25% of Equipment Cost	65,427	57,554
(3) Equipment Freight Cost	5% of Equipment Cost	52,341	46,043
Subtotal: Total Equipment Cost (TEC)		1,164,596	1,024,467
(3) Installation Costs [(a)]			
(a) Vendor Quote - Installation of Equipment and Piping		1,200,000	1,200,000
(b) Foundations, Structural Steel, Lighting	12% of TEC	139,751	122,936
(c) Piping		Included	Included
(d) Drains/Heat Tracing/Insulation	1% of TEC	11,646	10,245
(e) Electrical - Motor Starters/Wiring/DCS	1% of TEC	11,646	10,245
(f) Painting	1% of TEC	11,646	10,245
(g) Documentation/Engineering		included	included
(h) Start-up and Commissioning		included	included
(i) Inlet Ductwork and Connecting Ductwork	Estimate	150,000	150,000
Total DCC:		2,689,285	2,528,137
INDIRECT CAPITAL COSTS (ICC): (a)			
(1) Indirect Installation Costs			
(a) Performance Testing	Typical Value: 1% of Total Equipment Cost	11,646	10,245
(2) Other Indirect Costs (a)			
Engineering	10% of TEC	116,460	102,447
Construction and field expenses	10% of TEC	116,460	102,447
Contractor Fees	10% of TEC	116,460	102,447
Startup & Testing	Typical Value: 1% of TEC	Included	Included
Total ICC:		361,025	317,585
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC+ICC)	610,062	569,144
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+ Project Contingency	3,660,372	3,414,866
DIRECT OPERATING COSTS (DOC): (a)			
(1) Operating Labor			
Operator	$30/hr, 1 hr/shift, 3 shifts/day, 180 days/yr	16,200	16,200
Supervisor	15% of operator cost	2,430	2,430
(2) Maintenance			
Labor	Equivalent to One-Half Operating Labor	8,100	8,100
Materials	100% of maintenance labor	8,100	8,100
(3) Operating Material			
Water makeup	$2.36/1000 gal (No. 4 - 56.8 gpm, No. 5 - 43.6 gpm), 180 days/yr[(c)]	152,928	34,756
(4) Electricity	1x125 hp (1 Quench pump), 93 KW, $0.06/KW-hr, 180 days/yr	24,106	24,106
Total DOC:		211,864	93,692
INDIRECT OPERATING COSTS (IOC): (a)			
(1) Overhead	60% of oper. labor & maintenance	20,898	20,898
(2) Property Taxes	1% of total capital investment	36,604	34,149
(3) Insurance	1% of total capital investment	36,604	34,149
(4) Administration	2% of total capital investment	73,207	68,297
Total IOC:	(1) + (2) + (3) + (4)	167,313	157,493
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	345,539	322,363
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	**724,716**	**573,548**
BASELINE PM EMISSIONS (TPY) :	Highest actual emissions in 2001-present (from AORs)	118.8	90.0
CONTROLLED PM EMISSIONS (TPY) :	No. 4: 0.124 → 0.02 lb/MMBtu, No. 5: 0.15 → 0.02 lb/MMBtu	19.0	11.7
REDUCTION IN PM EMISSONS (TPY):	Baseline - Controlled	99.8	78.3
COST EFFECTIVENESS:	$ per ton of PM Removed	**7,261**	**7,325**
BASELINE VISIBILITY IMPACT (dv)	Table 3-10, No. 6 fuel oil firing	0.284	0.216
CONTROLLED VISIBILITY IMPACT (dv)		0.174	0.130
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.110	0.086
VISIBILITY COST EFFECTIVENESS ($/dv) :		**6,588,323**	**6,669,162**
BASELINE VISIBILITY IMPACT (dv)	Table 3-9, bagasse firing (normal operation)	0.233	0.195
CONTROLLED VISIBILITY IMPACT (dv)		0.101	0.064
REDUCTION IN VISIBILITY IMPACT (dv) :	Baseline - Controlled	0.132	0.131
VISIBILITY COST EFFECTIVENESS ($/dv) :		**5,490,269**	**4,378,228**

Notes:
(a) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002, Section 5
(b) Vendor quote from Andritz/Envirocare International, received in March 2007.
(c) Water makeup calculated from vendor data for inlet condition of 2,200 lb/hr and prorating for SO_2 emission rates of 500 lb/hr and 384 lb/hr, for Nos. 4 and 5, respectively.

TABLE 4
COST EFFECTIVENESS OF MOBOTEC FOR NO_x+SO_2+PM CONTROL, BOILER NO. 4

Cost Items	Cost Factors[a]	NO_x Control for Boiler No. 4 ROFA+FSI Cost ($)	ROFA+ROTAMIX+FSI Cost ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	126,590	126,590
ROFA System + FSI	Vendor quote[b]	3,207,876	3,207,876
ROTAMIX	Vendor quote[c]	--	987,200
Emissions Monitoring	15% of equipment cost	481,181	629,261
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	256,630	335,606
Freight	5% of Equipment Cost	160,394	209,754
Taxes	Florida sales tax, 6.25%	200,492	262,192
Purchased Equipment Cost (PEC)		4,463,163	5,788,479
Installataion for FSI and Rotamix	Vendor quote[c]	210,000	550,000
Total DCC		4,673,163	6,338,479
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	98,158	98,158
Electrical and Controls	Vendor quote[b]	33,712	33,712
General Facilities	5% of DCC	233,658	316,924
Engineering and home office fees	10% of DCC	467,316	633,848
Process Contingency	5% of DCC	233,658	316,924
Total ICC		1,066,503	1,399,566
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	1,147,933	1,547,609
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	6,887,599	9,285,654
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 180 days/yr	15,429	15,429
Supervisor	15% of operator cost	2,314	2,314
Maintenance	3% of TCI	206,628	278,570
Electricity	224 kW, $0.06/kW-hr, 180 days/yr	58,061	58,061
Water usage	99.5 gal/hr, 180 days/yr; $2.36/1000gal [d]	0	1,014
Urea	16.6 gph X $1.65/gal (50% sol) X 24 hr/day, 180 days/yr [d]	0	236,294
Limestone for FSI	398 lb/hr X $20/ton X 24 hr/day, 180 days/yr [d]	17,204	17,204
Total DOC:		299,636	608,885
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	134,622	177,787
Property Taxes	1% of TCI	68,876	92,857
Insurance	1% of TCI	68,876	92,857
Administration	2% of TCI	137,752	185,713
		410,126	549,214
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	650,189	876,566
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**1,359,951**	**2,034,664**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions 2001 - present	343.9	343.9
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	189.1	137.6
REDUCTION IN NO_x EMISSONS (TPY):		154.8	206.3
BASELINE SO_2 EMISSIONS (TPY), (see Table 5-4) :	Highest actual emissions 2001 - present	113.2	113.2
Maximum controlled SO_2 Emissions (TPY) :	55% reduction for FSI, Range 50-60%	50.9	50.9
REDUCTION IN SO_2 EMISSONS (TPY):		62.3	62.3
BASELINE PM EMISSIONS (TPY), (see Table 5-9):	Highest actual emissions 2001 - present	118.8	118.8
Maximum controlled PM Emissions (TPY) :	35% reduction, 10 lb/MMBtu → 6.5 lb/MMBtu	77.2	77.2
REDUCTION IN PM EMISSONS (TPY):		41.6	41.6
TOTAL REDUCTION OF NO_x + SO_2 + PM (TPY):		258.6	310.2
COST EFFECTIVENESS:	**$ per ton of pollutant removed**	**5,259**	**6,560**

Footnotes:

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

[b] Vendor quote from Mobotec, May and June, 2007, adjusted for specific heat input rate of Boiler No. 4. $877,400 added for the cost of FSI

[c] Vendor quote from Mobotec, May and June, 2007, Rotamix cost $987,200. Installation cost: FSI - $210,000, Rotamix - $340,000.

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

TABLE 5
COST EFFECTIVENESS OF MOBOTEC FOR NO_x+SO_2+PM CONTROL, BOILER NO. 5

Cost Items	Cost Factors[a]	NO_x Control for Boiler No. 5 ROFA+FSI Cost ($)	ROFA+ROTAMIX+FSI Cost ($)
DIRECT CAPITAL COSTS (DCC):			
Purchased Equipment Cost (PEC)			
CFD Modeling	Vendor quote[b]	97,059	97,059
ROFA System + FSI	Vendor quote[b]	2,664,220	2,664,220
ROTAMIX	Vendor quote[c]	--	987,200
Emissions Monitoring	15% of equipment cost	399,633	547,713
Geotechnical Engineering for Fan Foundation	Based on Engineering Estimate	30,000	30,000
Structure Support	8% of equipment cost	213,138	292,114
Freight	5% of Equipment Cost	133,211	182,571
Taxes	Florida sales tax, 6.25%	166,514	228,214
Purchased Equipment Cost (PEC)		3,703,775	5,029,091
Installataion for FSI and Rotamix	Vendor quote[c]	210,000	550,000
Total DCC		3,913,775	5,579,091
INDIRECT CAPITAL COSTS (ICC):			
Mechanical Installation	Vendor quote[b]	75,259	75,259
Electrical and Controls	Vendor quote[b]	25,848	25,848
General Facilities	5% of DCC	195,689	278,955
Engineering and home office fees	10% of DCC	391,377	557,909
Process Contingency	5% of DCC	195,689	278,955
Total ICC		883,862	1,216,925
PROJECT CONTINGENCY (RETROFIT):	20% of (DCC + ICC)	959,527	1,359,203
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC + PROJECT CONTINGENCY	5,757,164	8,155,219
DIRECT OPERATING COSTS (DOC):			
Operating Labor			
Operator	20 hours/week, $30/hr, 180 days/yr	15,429	15,429
Supervisor	15% of operator cost	2,314	2,314
Maintenance	3% of TCI	172,715	244,657
Electricity	224 kW, $0.06/kW-hr, 180 days/yr	58,061	58,061
Water usage	51.6 gal/hr, 180 days/yr; $2.36/1000gal [d]	0	527
Urea	8.6 gph X $1.65/gal (50% sol) X 24 hr/day, 180 days/yr [d]	0	122,716
Limestone for FSI	290 lb/hr X $20/ton X 24 hr/day, 180 days/yr [d]	12,518	12,518
Total DOC:		261,036	456,221
INDIRECT OPERATING COSTS (IOC):			
Overhead	60% of oper. labor & maintenance	114,275	157,440
Property Taxes	1% of TCI	57,572	81,552
Insurance	1% of TCI	57,572	81,552
Administration	2% of TCI	115,143	163,104
		344,561	483,648
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	543,476	769,853
ANNUALIZED COSTS (AC):	DOC + IOC + CRC	**1,149,074**	**1,709,722**
BASELINE NO_x EMISSIONS (TPY) :	Highest actual emissions 2001 - present	178.6	178.6
Maximum controlled NO_x Emissions (TPY) :	45% reduction for ROFA; 60% for ROTAMIX	98.2	71.4
REDUCTION IN NO_x EMISSONS (TPY):		80.4	107.2
BASELINE SO_2 EMISSIONS (TPY), (see Table 5-4):	Highest actual emissions 2001 - present	83.4	83.4
Maximum controlled SO_2 Emissions (TPY) :	55% reduction for FSI, Range 50-60%	37.5	37.5
REDUCTION IN SO_2 EMISSONS (TPY):		45.9	45.9
BASELINE PM EMISSIONS (TPY), (see Table 5-9):	Highest actual emissions 2001 - present	90.0	90.0
Maximum controlled PM Emissions (TPY) :	35% reduction, 10 lb/MMBtu → 6.5 lb/MMBtu	58.5	58.5
REDUCTION IN PM EMISSONS (TPY):		31.5	31.5
TOTAL REDUCTION OF NO_x + SO_2 + PM (TPY):		157.7	184.5
COST EFFECTIVENESS:	**$ per ton of pollutant removed**	**7,285**	**9,265**

Footnotes:
[a] Unless otherwise specified, factors and cost estimates reflect EPA Air Pollution Cost Control Manual, Sixth Edition (EPA/452/B-02-001, Jan. 2002).
[b] Vendor quote from Mobotec, May and June, 2007, adjusted for specific heat input rate of Boiler No. 5. $877,400 added for the cost of FSI
[c] Vendor quote from Mobotec, May and June, 2007, Rotamix cost $987,200. Installation cost: FSI - $210,000, Rotamix - $340,000.
[d] Vendor operational parameters of water flow (90 gph), urea usage (15 gph), and limestone usage adjusted for specific heat input rate of Boiler No. 5.