Issue

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<u>BY HAND DELIVERY</u>

Mr. Barry Andrews
Florida Department of
Environmental Regulation
2600 Blair Stone Road
Tallahassee, Fl 32399-2400

Dear Barry:

Thank you for taking the time to meet with me this morning. The Best Available Control Technology analysis you are preparing will have far-reaching effects on our cogeneration project, and I enjoyed the opportunity to learn more about your review.

As we discussed, AES feels that SNCR (thermal denox) is not warranted for the Cedar Bay project for the following reasons:

- Proposed NO_x emissions from the cogeneration plant are 0.36 lb/MMBtu; well below the NSPS level of 0.6 lb/MMBtu.

- At 0.36 lb/MMBtu, the cogeneration plant will actually <u>improve</u> ambient NO_x concentrations in the surrounding area.

- Costs for SNCR control would be around $1600/ton of additional NO_x removal -- well above the $1000/ton guideline that has been used previously.

- The proposed project will also improve air quality for other pollutants -- while providing new electrical capacity needed for Florida's growth. If this project does not go forward, another new power plant will have to be built to supply the state's demand for power. Any other power plant would surely have much more impact on the environment than the Cedar Bay project.

AES/Cedar Bay Inc.

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Florida Rules specify that BACT should be considered by the Department on a case by case basis taking into account energy, environmental and economic impacts. The "top down" approach, although not yet incorporated into Florida law, is not necessarily in conflict with Florida's rule that consider all three of these imports. I urge you to consider that:

- From an energy standpoint this project will provide needed electricity at significant savings to ratepayers. National and state policy encourages cogeneration projects like AES Cedar Bay because they are thermodynamically efficient. The Florida Public Service Commission favors coal plants like this one as a way to reduce Florida's dependence on imported oil.

- This project is a net benefit to the environment. It is located at an existing industrial site, and will improve air quality in the area. If the cogeneration plant is not built, the paper mill will continue to run their old, environmentally outdated boilers.

- There are many economic benefits associated with the construction and operation of this project. Hundreds of jobs will be created, and the plant will contribute millions of dollars each year in taxes. Florida ratepayers will benefit from power provided below the utility "avoided cost".

Installation and operation of a SNCR system would result in additional costs to AES Cedar Bay of over $4 million each year. The cogeneration project is no longer economically viable if this additional cost is factored in. Lenders would not be willing to loan AES the money for the plant; therefore we would have to cancel the project. We believe these costs for a SNCR system is not justified under the DER rules on the EPA top down analysis when energy, environmental and the above cuts are considered.

I think you will agree that it doesn't make sense to cancel a project that offers so much for Florida -- particularly when it would be the cleanest coal plant in the state!

In the spirit of compromise we are willing, for purposes of settling this issue, to offer to reduce our emission rate to 0.29 lb/MMBtu over an annual averaging period. I believe this proposal would eliminate any question on the issue of SNCR, while still allowing the project to move forward.

Please let me know what you think of this proposal. I look forward to hearing from you soon.

Sincerely,

Terry Cole for

Jeffrey V. Swain
Project Director

cc: Hamilton S. Oven

Cedar Bay

ogen dioxide to particulate nitrites; and by sulfur dioxide when it converts to particulate sulfates.

The frequency distribution of the visibility observed at Jacksonville Imeson Airport over a five-year period is summarized in the application. The average quarterly background visibility at Jacksonville Airport is seldom greater than twelve miles or less than two miles. Visibility conditions greater than or equal to those measured at Jacksonville can be expected at St. Augustine (70 km southeast) and the Okefenokee Class I area (60-70 km northwest). Using equations, the background conditions may be calculated and the SO_4 (sulfate) and TSP impacts at the Okefenokee Class I and St. Augustine historical areas may be estimated st that the visibility impacts at these areas may also be estimated. For purposes of this simplified analysis, it was necessary to assume that SO_4 and TSP are the only pollutants contributing to visibility reduction. It was also assumed that the background visibility is twelve miles. The calculated new visibility due to the SJRPP was 10.8 miles.

This corresponds to a reduction of approximately ten percent in the visual range at the Okefenokee Class I area during worst-case conditions.

4. Best Available Control Technology

Two applicants propose to install an integrated cogeneration power plant complex at the Seminole Kraft Corporation facility located in Jacksonville, Florida. The power complex will consist of three coal/bark fired circulating fluidized bed (CFB) boilers, the respective coal handling equipment and limestone dryers, to be owned and operated by AES Cedar Bay, Inc. and a kraft recovery boiler to be owned and operated by the Seminole Kraft Corporation.

The CFB boiler, rated at 3,189 MMBtu will burn fuel made up of approximately 96 percent coal and 4 percent bark. The boilers will generate steam to produce power from a turbine generator set. The CBCP will generate 225 MW of electricity for sale to FPL as well as low pressure process steam for SKC.

The recovery boiler, rated at 1,125 MMBtu/hr will replace three old recovery boilers. Also included in the project is the installation of a new smelt dissolving tank and a new set of evaporators which will replace three old smelt dissolving tanks and three old sets of evaporators, respectively.

EPA has determined that although the CFB cogeneration complex is being constructed on the Seminole Kraft Corporation's property, that the cogeneration facility and the kraft recovery boiler should be reviewed as two separate projects for air quality impact purposes.

The applicants have indicated that the maximum net total annual tonnage of regulated air pollutants emitted from the projects based on 8,760 hours per year operation and 93% capacity factor for the CFB complex to be as follows:

Pollutant	Maximum Net Increase in Emissions (TPY) AES Cedar Bay	Seminole Kraft	PSD Signif. Emiss. Rate (TPY)
TSP	268	-140.7	25
PM10	265	-138.6	15
SO_2	4029	6.4	40
NOx	4683	1296.4	40
CO	2470	-160.0	100
VOC	208	-92.3	40
TRS	-	-53.3	10
Pb	91	-0.16	0.6
Be	1.5	-0.012	0.004
Hg	3.4	-	0.1
H_2SO_4	308	-5.8	7
Fl	1122	-	3

Rule 17-2.500(2)(f)(3) of the Florida Administrative Code (F.A.C.) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table. The NOx emissions from the smelt dissolving tank and the multiple effect evaporators are negligible and will not be considered as part of the BACT analysis. The emissions of heavy metals, H_2SO_4, VOC's, and fluorides from the limestone dryers are also negligible compared to that emitted from the CFB boiler and will not be considered in the BACT analysis for the AES CBCP.

BACT Determinations Requested by the Applicants

AES Cedar Bay

Pollutant	Determination
TSP	0.02
PM10	0.02
SO_2	0.6 (3 hour average)
	0.31 (12 month rolling average)
NOx	0.36
CO	0.19
VOC	0.016
Pb	0.007
Be	0.00011
Hg	0.00026
H_2SO_4	0.024
Fl	0.086

Seminole Kraft Corporation

Pollutant	Determination
NOx	180 ppm (corrected to 8% oxygen)

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-2, Air Pollution, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from cogeneration facilities can be grouped into categories based upon what control equipment and techniques that are available to control emissions from these facilities. Using this approach, the emissions are classified as follows:

- Combustion Products (Particulates and Heavy Metals). Controlled generally by particulate control devices.

- Products of Incomplete Combustion (CO, VOC, Toxic Organic Compounds). Control is largely achieved by proper combustion techniques.

- Acid Gases (SOx, NOx, HCl, Fl). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilities the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutants (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT Analysis

Combustion Products

The CBCP complexes' projected emissions of particulate matter, PM10, lead, beryllium, and mercury surpass the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2. A review of the BACT/LAER Clearinghouse indicates that the particulate emission rates range from 0.011 (LAER) to 0.05 lb/MMbtu for other CFB boilers permitted in the United States. As this is the case, the applicants proposal for particulate emissions (0.02 lb/MMBtu) is representative of the most stringent BACT determinations and is thereby justified as being BACT for this facility.

In general, the BACT/LAER clearinghouse does not contain specific emission limits for lead, beryllium, and mercury from CFB boilers. BACT for heavy metals from these facilities is typicaly represented by the level of particulate control. As this is the case, the applicants proposal of 0.02 lb/MMBtu for particulate matter and PM10 is judged to represent BACT for lead, beryllium and mercury.

A review of the coal handling facilities indicates that all practical measures will be employed to control fugitive dust emissions. Fugitive dust associated with the handling of coal will be controlled with enclosures, water sprays, compaction, and bag filter dust collection. All coal conveyers not located underground or within enclosed buildings will have covers.

The control measures employed to minimize the fugitive dust measures from coal handling is judged to represent BACT for the facility.

Products of Incomplete Combustion

The emissions of carbon monoxide, volatile organic compounds and other organics from coal fired boilers are largely dependent upon the completeness of combustion. A review of the BACT/LAER Clearinghouse indicates that the emission levels of 0.19 lb/MMBtu and 0.016 lb/MMBtu for carbon monoxide and volatile organic compounds, respectively, are representatives of previous BACT determinations. In each case the BACT was represented by combustion control and proper bed operation. The emissions of carbon monoxide could be reduced by increasing the combustion temperatures in the CFB boiler. This, however, would lead to higher nitrogen oxides emissions and additional limestone would be needed for acid gas reduction resulting in a cost which would not warrant the additional carbon monoxide control. The use of combustion control in conjunction with the proposed acid gas control is also deemed as representing BACT for the other organic compounds which would be emitted from the facility.

Acid Gases

The emissions of sulfur dioxide, nitrogen dioxide, fluorides, and sulfuric acid mist, as well as other acid gases which are not "regulated" under the PSD Rule, represent significant potential pollutants which must be subjected to appropriate control. Sulfur dioxide emissions from coal fired boilers are directly related to the sulfur content of the coal which is combusted. The addition of "add on" control equipment and the utilization of combustion technolgies which serve to control sulfur dioxide emissions in the combustion chamber itself are other techniques that can be used to minimize emissions.

The applicant has proposed the use of a CFB boiler to control sulfur dioxide emissions. Sulfur dioxide is removed in a CFB boiler by injecting limestone into the boiler bed. The limestone calcines to calcium oxide at the temperatures present in the fluidized bed. The calcium oxide then reacts with the SO_2 in the flue gas to form calcium sulfate. Sulfur dioxide is removed in this manner with efficiencies up to 90 percent based on a 30-day rolling average.

In keeping with the "top down" BACT approach the applicant has identified three alternative technologies that would control sulfur dioxide emissions.

1) Pulverized coal fired boiler followed by a wet limestone scrubber system designed for a maximum of 94 percent SO_2 removal on a 30-day rolling average basis.

2) Pulverized coal fired boiler followed by a wet limestone scrubber system designed for a maximum of 90 percent SO_2 removal on a 30-day rolling average basis.

3) Pulverized coal fired boiler followed by a lime spray dryer system designed for a maximum of 90 percent SO_2 removal on a 30-day rolling average basis.

A review of alternatives 2 and 3 indicates that the level of sulfur dioxide control would be equivalent to that proposed by the applicant and no further review is needed. Alternative 1, however, would provide additional control of SO_2, thus a cost benefit analysis of using this type of control is warranted.

In order to justify the cost effectiveness of any air pollution control, the EPA has developed cost guidelines to obtain the highest reduction of emissions per dollar invested. Achievement of maximum emission reductions for capital invested is a major consideration when New Source Performance Standards (NSPS) are developed by the EPA. For SO_2 emissions, EPA has determined that cost of up to $2,000 per ton of emissions controlled ($1.00/lb) is reasonable for NSPS.

The use of a wet limestone scrubber having an efficiency of 94% has a levelized total annual cost (capital and operating) which is $7.72 million dollars greater than that of the proposed CFB boiler by the applicant. The applicant has indicated that the additional sulfur dioxide removal from using the wet scrubber would be 3,353 tons per year based on a 94% efficiency. In addition, the use of a wet limestone scrubber would eliminate the need for lime dryers which are expected to emit 38 tons per year of sulfur dioxide. Taking these reductions into consideration with the increased annual cost, the cost per ton of SO_2 controlled is approximately $2,277. This increased cost is not unreasonable based on the NSPS guideline of $2,000 per ton removal.

Another control alternative that should be considered is the use of coal with a lower sulfur content. A review of the BACT/LAER Clearinghouse indicates that BACT for CFB boilers has been established in some cases by limiting both the mass emission rate and the sulfur content of the fuel.

The applicant has indicated that the CFB boiler will fire coal with a sulfur content ranging from 1.7 to 3.3 percent which will result in the proposed SO_2 emission rates of 0.6 lb/MMBtu heat input and 0.31 lb/MMBtu heat input on a three hour and 12-month rolling average, respectively.

The BACT/LAER Clearinghouse indicates that the lowest determination for coal sulfur content is 0.5 percent for a CFB boiler, with other determinations ranging up to 3.0 percent taking into the consideration the availability of low sulfur coal.

Based on the previous cost benefit anlaysis of the wet scrubber alternative, it seems reasonable to investigate the cost of using a coal with a lower than proposed sulfur content which would result in the same emission rate as the wet scrubber option.

In order to provide the same level of control as the wet scrubber alternative, it has been determined that the CFB boiler would need to utilize coal with a sulfur content ranging from 1.0 to 2.0 percent. This would result in sulfur dioxide emission rate of 0.36 lb/MMBtu and 0.186 lb/MMBtu for a three-hour and 12-month rolling average, respectively.

Based on the capacity factor of 93 percent as provided by the applicant, the use of coal with an average annual sulfur content of 1.0 percent would result in an sulfur dioxide emission reduction of 1,653 tons/year. When this reduction is taken into consideration wit the increased cost of purchasing coal with a lower sulfur content the cost per ton of sulfur dioxide reduction can be determined.

In a recent application in which the cost of switching to a lower sulfur content coal was evaluated, the cost of switching from a 2.0 to 1.0% sulfur coal was determined to be $4.90 greater per ton of coal purchased. Using this figure as an approximation of using coal with an annual average sulfur content of 1.0% as compared to the proposed 1.7% the cost benefit analysis is computed as follows. Based on the applicant's maximum consumption rate of 248,000 lbs/hr and the 93% capacity factor, the increased cost of using 1.0% sulfur coal would be approximately $4.95 million. Taking this cost into consideration with the expected reduction the cost per ton of control would be $2,995. The actual cost would be slightly less than $2,995 when taking into consideration the greater heating value from lower sulfur content coal but would still be well above the $2,000 per ton guideline.

The emissions of nitrogen oxides from coal fired boilers are controlled by combustion control and post combustion control equipment. In a CFB boiler, low combustion temperatures coupled with staged combustion effectively limit the formation of NOx. Low combustion temperatures primarily limit the formation of thermal NOx, and staged combustion (creating a reducing atmosphere in the lower portion of the boiler) inhibits the formation of fuel NOx.

The applicant has proposed the use of the CFB boiler with an emission limit of 0.36 lb/MMBtu as BACT for nitrogen oxides. The alternatives to further reduce NOx emissions are discussed and evaluated on a cost/benefit basis as follows:

> Post-combustion NOx control processes are based on the reaction of ammonia or urea with conversion of NOx to form nitrogen and water. Selective noncatalytic reduction and selective catalytic reduction NOx reduction technologies are the only technologies adequately demonstrated to be considered for installation on CFB boilers.
>
> Selective catalytic reduction (SCR) is a post-combustion method for control of NOx emissions which is being developed by a number of companies, principally in Japan and Europe. The SCR process combines vaporized ammonia with NOx in the presence of a catalyst to form nitrogen and water. The SCR process can achieve between 80 and 90 percent reduction of NOx. The vaporized ammonia is injected into the exhaust gases prior to passage through a catalyst bed. The optimum flue gas temperature range for SCR operation is approximately 700 to 850°F. The SCR catalyst is housed in a reactor vessel which is separate from the boiler.
>
> Selective noncatalytic reduction (SNCR) is another post-combustion method controlling NOx emissions. The process selectively reduces NOx by reaction with ammonia or urea without the use of a catalyst bed. A SNCR system could potentially reduce NOx emissions generated by a coal fired CFB boiler by 40 to 60 percent.

The applicant has indicated that a SCR system would remove an additional 4,525 tons of nitrogen oxides per year. When this removal rate is taken into consideration with the total levelized annual cost (capital and operating) of $14.35 million, the cost per ton of nitrogen oxides controlled is approximately $3,171. This is well above the NSPS guideline of $1,000 per ton, yet less than previous BACT determinations in which post-combustion nitrogen oxides control was justified at costs up to approximately $4,200 per ton.

For SNCR the applicant has indicated that an additional 3,017 tons of nitrogen oxides per year would be controlled at a total levelized annual cost of $4.11 million. This results in a cost per ton of nitrogen oxides controlled of approximately $1,362 which is just slightly above the NSPS guideline and well below the cost of previous BACT determinations.

For the kraft recovery boiler, a review of recent BACT determinations for nitrogen oxides indicates that the emissions rate proposed by the applicant does not represent BACT. The rationale for establishing BACT at a lower than proposed level is presented as follows:

The applicant has indicated that an emission rate of 180 ppm corrected to 8% oxygen is representative of BACT taking into consideration guarantees common to all potential manufacturers, the black liquor fuel analysis, and performance deterioration based on a 24-hour average.

A review of the BACT/LAER Clearinghouse indicates a wide range of NOx limitations. Although several of the most recent BACT determinations range from 50-80 ppm corrected to 8% oxygen, none of the facilities listed utilize NOx reduction systems operating downstream from a kraft recovery boiler. However, in keeping with the "top down" BACT analysis, "add on" control equipment will be evaluated as part of the analysis.

The two types of control that are typically utilized for NOx reduction are selective catalytic reduction (SCR) and Thermal De NOx. Each of these technologies utilizes ammonia injection as the means to react with and thereby reduce the concentrations of NOx in the gas stream. Although these technologies have not been utilized for this type of application the economics of using such equipment should be addressed.

The applicant has indicated that using Thermal DeNOx as a control increase for NOx results in a cost of $2,000 per ton of NOx reduced. Although this costs is not excessive compared to recent BACT determinations in which NOx removal was justified at costs up to approximately $4,200 per ton, the use of Thermal DeNOx as a control measure has not been demonstrated on Kraft recovery boilers and hence has not been seriously considered as BACT for recent determinations. Similarly SCR has not been used in Kraft recovery boiler applications and should not be considered as BACT for these facilities.

Although "add on" NOx controls have not been utilized for kraft recovery boilers, a survey of the most recent BACT determinations indicates that kraft recovery boiler manufacturers are capable of limiting NOx emissions to suprisingly low levels (generally 53 to 75 ppm @ 8% oxygen) by equipment design.

Discussions with the BACT coordinators from other states which have pulp and paper industry indicate that all of the known manufacturers of kraft recovery boilers have proposed or agreed to meet NOx emission limitations which fall within the range discussed above. Although many of these facilities were just recently permitted and have yet to be constructed and tested, there is sufficient data available to suggest that these limitations can indeed be met.

In a technical study completed by the National Council of the Paper Industry for Air and Stream Improvement, Inc. (NCASI), several large kraft recovery furnaces (boilers) were tested for NOx emissions. The publication entitled "A Study of Nitrogen

Oxides Emissions from Large Kraft Recovery Furnaces" provides evidence that NOx emissions can be held to levels which are now being proposed by kraft recovery boiler manufacturers.

The NCASI report focused on the NOx emissions from four large kraft recovery boilers, with three of the units being located in the southeastern United States. The size of the units tested ranged from firing rates of 3.18 - 4.06 million pounds of black liquor solids (BLS) per day. This is comparable to the proposed kraft recovery boiler which has a firing of 4.1 million pounds of BLS per day.

Based on the NOx emission studies completed, the NCASI report concluded the following:

1) NOx emissions from large kraft recovery boilers were not size dependent.

2) NOx emissions ranged from 0.06 to 0.11 lbs/million Btu heat input.

Based on the applicant's maximum BLS input of 4.1×10^6 lb/day (170,833.3 lb/hr) a comparison of the proposed NOx emission limit can be made with the NCASI test results.

The applicant has estimated the maximum hourly NOx emission to be 369.3 pounds. Taking this into account with the BLS heating value of 4,522 Btu per pound, the calculated emission rate on a heat input basis is approximately 0.48 lbs per million Btu. This emission level ranges from approximately 4 to 8 times greater than that observed by the NCASI study.

Environmental Impact Analysis

A review of the impacts associated with the proposed CBCP and the recovery boiler installation indicates that there will be a reduction in the maximum annual impacts. This reduction in the impacts will be attributed to the replacement of three old power boilers and there old recovery boilers which are now exhibiting higher impacts than what will be expected from the new cogeneration/recovery boiler complex.

Discussion

The Department has determined that the levels of control proposed by the applicant for the CFB cogeneration facility represents BACT in most cases. The review indicates that the level of particulate control clearly is justified as BACT for particulate matter, PM_{10}, and other heavy metals. In addition, the levels of control proposed for the coal handling facilities, and for products of incomplete combustion is also representation of BACT.

A review of the proposed control for sulfur dioxide indicates that the inherent removal efficiency provided by the CFB boiler represents BACT. The analyses of alternative control technologies indicates that both the cost of using wet scrubbers and switching to a lower sulfur content coal are cost prohibitive based on BACT cost of control guidelines. In addition to the greater cost of using wet scrubbing, such an alternative has the disadvantage of having to handle and dispose of the scrubber sludge produced. In addition to the greater cost of using a lower sulfur coal, such an alternative presents the difficulties encountered to establish a coal contract which allows for the handling and transport of ash produced by the CFB boiler.

Section 17-2.03 Florida Administrative Code (FAC) and Section 169, 424SC 7401 require evaluation of proposed air pollutant emission control equipment and a determination as to whether or not an applicant will utilize the Best Available Control Technology (BACT) for each pollutant.

The installation of a high efficiency Fabric Filter to control particulate emission from the boilers, bag filters to control particulate emissions from fly ash handling, and liquid spray and bag filter systems to control particulate emissions from coal handling and lime and limestone handling all represent BACT.

The use of washed low sulfer coal and the fluidized bed boiler using limestone to achieve a 90% reduction of the potential sulfur oxide emissions would comply with requirements under 40 CFR Part 60, Federal New Source Performance Standards.

The use of boiler design controls which limit flame temperature and oxygen availability in order to control the formation of nitrogen oxides in the boiler to 0.6 pounds per million BTU is considered to be BACT. Likewise, the use of boiler controls to limit the emission of carbon monoxide is also considered BACT.

The Department of Environmental Regulation, having considered (a) all available scientific, engineering and technical material, (b) existing emission control standards of other states, and (c) the social and economic impact of the application to be used by AES to be the Best Available Control Technology, as shown in the following:

The proposed facility will consist of three 85.3 megawatt coal-fired electric utility steam generating

units to be located in Jacksonville, Florida. The units will be designed for coal and wood wask firing.

Kraft recovery boiler emissions of total reduced sulfur (TRS), SO_2, NO_x, CO and VOC will be controlled by proper boiler design and combustion controls. Particulate emissions will be controlled by an electrostatic precipitator.

Gas from the smelt dissolving tank will be vented to a wet scrubber for particulate and TRS emission control. The smelt dissolving tank will not emit significant quantities of SO_2, NO_x and CO.

Best Available Control Technology Analysis Summary:

The following is a summary of results from the BACT analysis:

- The pollutant applicability analysis concluded that the criteria pollutants--SO_2, NO_x, CO, and lead--requires a BACT analysis. The noncriteria pollutants--beryllium, mercury, flourides, and sulfuric acid mist--also require a BACT analysis.
- BACT determinations are based on the use of a "top-down" approach.
- No_x emission limiting techniques of lowering combustion temperatures and excess combustion air are counterproductive relative to CO emissions.

Cogeneration Plant:

- The Cedar Bay Cogeneration Plant will generate 2,300,00 lb/h of steam at the maximum design conditions. The largest commercial CFB boiler produces 925,000 lb/h of steam. There are numerous pulverized coal (PC) fired boilers operating that are larger than three CFB boilers (each providing 33 percent of the total capacity), to a single full-capacity PC boiler.
- Flue gas desulfurization alternatives are evaluated on a total air quality control system (AQCS) basis. The AQCS contains FGD and particulate removal equipment, as well as waste disposal. SO_2 removal alternatives evaluated consistent with a top-down approach include the following.
  ---One PC boiler followed by a wet limestone scrubber system designed for 94% SO_2 removal.
  ---Three CFB boilers designed for 90% SO_2 removal.
  ---PC boiler followed by a wet limestone scrubber system designed for 90% SO_2 removal.
  ---PC boiler followed by a lime spray dryer system designed for 90% SO_2 removal.
- A PC boiler/wet limestone scrubber air quality control system (AQCS) designed to meet 94% SO_2 removal requirement has the highest total levelized annual cost. Additional costs result in an incremental removal cost of $2,300 per ton to go from 90% percent with a CFB boiler AQCS to 94% SO_2 removal. Based on economics, energy, and environmental considerations, a CFB boiler AQCS designed to meet a 90% SO_2 removal requirement represents BACT. BACT regarding noncriteria pollutants is accomplished as a result of FGD and particulate removal operations.
- CFB boilers have lower NO_x emission levels than PC boilers (0.36 lb/MBtu as compared to 0.40 lb/MBtu). A CFB or a PC boiler should be capable of meeting a CO emission rate of 0.19

lb/MBtu (CFB boiler) or 0.11 lb/MBtu (PC boiler) while meeting previously discussed NO_x and SO_2 emission levels.

- Selective catalytic reduction (SCR), and selective noncatalytic reduction (Thermal DeNOx) NO_x emission control technologies are the only technologies adequately demonstrated to be considered for installation. There is no publicly available operating experience with the use of either of these two technologies downstream of a coal fired CFB boiler. Problems presented by the use of these systems include equipment fouling, poor control and distribution of the ammonia injected, ammonia slip and the subsequent release of ammonia to the environment, and limited equipment life. Despite lack of experience and technical problems, a technical and economic analysis was performed for thoroughness of analysis.
- Installation of a 90% efficient SCR system on a CFB or PC boiler would result in an incremental NO_x reduction cost of \$6,800.00 and \$6,200.00 per ton, respectively. Installation of a 60% efficient Thermal DeNOx system on a CFB or PC boiler would result in an incremental NO_x reduction cost of \$1,400.00 and \$1,200.00 per ton, respectively.
- Consideration of environmental factors also supports the selection of combustion controls as BACT for NO_x. Use of an SCR or a Thermal DeNOx system will result in the emission of various amine compounds formed by the unreacted ammonia exiting these NO_x reduction systems. This represents a potential adverse human health effect, since many amine compounds are known or suspected carcinogens. Therefore, based on economic, energy, and environmental considerations, BACT for NO_x and CO emissions from the cogeneration plant is a CFB boiler with combustion controls to meet an NO_x and CO emission requirement of 0.36 lb/MBtu and 0.19 lb/MBtu, respectively.

Kraft Recovery Boiler

- Sulfur dioxide emissions from the kraft recovery boiler (KRB) are controlled by creating conditions (vigorous burning at high temperature) which minimize the initial SO_2 release from the black liquor, and by simultaneously creating conditions (vigorous burning and high lower furnace temperature) which are favorable for capturing SO_2 by reaction with alkaline sodium carbonate (NA_2CO_3) particles. Relatively large quatities of NA_2CO_3 are released during black liquor combustion.
- Manufacturers indicate that current KRB designs can consistently meet an SO_2 emission requirement of 180 ppmvd corrected to 8 percent oxygen (approximately 0.48 lb/MBtu).
- In addition to combustion controls, SO_2 emissions can be controlled by a flue gas desulferization system. Currently, there are no kraft recovery boilers with supplemental FGD systems. A wet sodium scrubber FGD system designed for 90 percent SO_2 removal would result in an incremental removal cost of \$2,900 per additional ton of SO_2 removed. Therefore, based on economics and energy use, an SO_2 emission limit of 180 ppmvd corrected to 8 percent oxygen represents BACT.

• Despite a complete lack of operating experience, a Thermal DeNOx nitrogen oxide reduction system is evaluated for use downstream of the KRB. Differential levelized annual costs result in an incremental NO_x reduction cost of $2,000 per ton. As previously discussed, the consideration of environmental factors also supports the selection of combustion controls as BACT. Therefore, based on economics, energy and environmental considerations, a NO_x emission limit of 180 ppmvd corrected to 8 percent oxygen represents BACT.

• BACT for CO emissions from the KRB is proper boiler design and operation (consistent with previously proposed NO_x and SO_2 emission requirements) to meet a CO emission limit of 400 ppmvd corrected to 8 percent oxygen.

Pollutant	Emission Limit
Pulp Mill-Recovery Boiler	
Particulate Matter	0.044 gr/dscf
SO_2	180 ppmvd @ 8% O_2
NO_x	180 ppmvd @ 8% O_2
CO	400 ppmvd @ 8% O_2
TRS	5 ppmvd @ 8% O_2
Smelt Dissolving Tank	
Particulate	0.2 lb/ton BLS
TRS	0.033 lb/ton BLS
Multiple Effects Evaporators	
TRS	5 ppmvd @ 10% O_2

The plant will be located in Duval County which is classified nonattainment for the pollutant Ozone (17-2.16(1)(c) F.A.C.). It will be located in the area of influence of the Jacksonville particulate nonattainment area (17-2.13(1)(b) F.A.C.), however, the plant will not significantly impact the nonattainment area and is, therefore exempt from the requirements of Section 17-2, 17 & 18 & 19 with respect to particulate emissions. The facility must comply with the provisions of 17-2.04 F.A.C. (Prevention of Significant Deterioration).

The proposed level of control for nitrogen oxides from both the CFB cogeneration facility and the kraft recovery boiler, however, are not representative of BACT. The review of the costs associated with using post combustion controls indicates that the cost per ton of using selective noncatalytic reduction (SNCR) for NOx removal from CFB boiler just slightly exceeds the $1,000 guideline that is used for NSPS and is well below that which has been justified as BACT for other facilities.

In general, the use of post combustion NOx controls has been a strategy which has been evaluated in every BACT review since the "top down" BACT policy was introduced by the EPA in December 1987. In each case, the use of post combustion controls was rejected due to being cost prohibitive, or on the basis that there was not sufficient operating experience for a particular technical application to demonstrate that the specific application was proven.

For the cases in which the use of post combustion controls was rejected because of being cost prohibitive, the cogeneration unit was being constructed for peaking purposes only. As this was the case, the facility in question would be operated well below full capacity (peaking units), thereby resulting in cost per ton figures which were well above what has been established as justifiable for BACT.

With regard to the technology being proven, both SCR and SNCR have had operating experience in both Japan and Europe. More recently, several facilities in California have been permitted with SNCR. Compliance testing has indicated that one of the facilities which is now operating (Corn Products) has passed its compliance test. Another operating facility (Cogeneration National) has had trouble meeting the NOx emission limitation while also maintaining compliance with the CO and SO_2 emission requirements. This plant has continued with adjustments targeted at achieving coincidental compliance.

The applicant has stated that SNCR systems emit various amine compounds formed by unreacted ammonia which represents a potential adverse human health effect. Although it has been demonstrated that ammonia slip does occur this does not indicate that the technology has not been proven. The use of both SCR and SNCR as representing BACT is becoming more and more prevalent for internal combustion engines, boilers, and turbines. Based on the experience that has been demonstrated on other facilities and the cost effectiveness, it has been determined that the Cedar Bay Cogeneration facility should incorporate SNCR as BACT for nitrogen oxides control.

For the kraft recovery boiler, it has been determined that NOx emission limitation of 75 ppm by volume, corrected to 8% oxygen, is representative of the levels that are being proposed in recent applications as BACT for boilers supplied by all known manufacturers. In addition, this level is supported by the NCASI report which showed NOx emissions ranging from 37 to 60 ppm, corrected to 8% oxygen, for all of the facilities tested over a three hour period.

In addition to the reasons stated above, the use of better than proposed nitrogen oxides control is further substantiated based on the location of the proposed Cedar Bay/Seminole Kraft cogeneration venture. The Seminole Kraft Corporation is located in an area which is designated as being nonattainment for ozone. Nitrogen oxides are known to be a precursor to ozone and should be controlled to the greatest extent which is deemed to be justified.

<u>BACT Determination by DER</u>

Based on the information presented in the preceeding analysis, the Department determines that the circulized fluidized bed boiler in conjunction with a baghouse and selective noncatalytic reduction represents BACT for the Cedar Bay Facility. The emission limits for the Cedar Bay cogeneration facility and the Seminole Kraft Corporation recovery boiler are established as follows:

AES Cedar Bay

Pollutant	Determination (lb/MM Btu)
TSP	0.02
PM10	0.02
SO_2	0.6 (3 hour average)
	0.31 (12 month rolling average)
NOx	0.144*
CO	0.19
VOC	0.016
Pb	0.007
Be	0.00011
Hg	0.00026
H_2SO_4	0.024
Fl	0.086

Seminole Kraft Corporation

Pollutant	Determination
NOx	75 ppm by vol., corrected to 8% oxygen

*Limitation based on using selective non catalytic reduction with a NOx removal efficiency of 60 percent.

Fugitive Dust

Fugitive dust is produced by a number of sources associated with the project. These include the coal handling system, limestone and spent limestone handling system, and pelletized waste handling systems. Also since fresh water cooling towers will be used, EPA has indicated that dissolved and suspended solids in the small droplets fraction (less than 50 microns diameter) of cooling tower drift would be considered fugitive dust in the impact assessment. The following paragraphs describe the control systems and/or methods proposed as BACT for these fugitive dust sources.

Coal Handling Fugitive Dust Collection

Control and collection of fugitive particulates in the coal handling system will be accomplished by several different methods, including totally enclosed conveying systems, water spray dust suppression systems, and dust collection systems utilizing fabric filters.

The coal unloading facility will have dry dust collection systems capable of 99.9 percent control efficiency on the unloader receiving hoppers. All conveyors will be totally enclosed and each transfer point fitted with dry dust collection systems, with the exception of the stacker-reclaimer which eill be fitted with a water spray dust suppression system capable of 97 percent efficiency.

Coal will be unloaded at the plant site by a rotary car dumper which will be housed in an unloading building with a wet dust suppression system. This is expected to have a dust control efficiency of 97 percent. From the delivery point, totally enclosed belt conveyors will be used to transport the coal to the coal handling building. Surge bins in the coal handling building will be vented with fabric filter dust collectors (efficiency of 99.9 percent), and similar collectors will be located at all conveyor discharge points. Conveyors between the coal handling building and the stacker-reclaimer will be enclosed, but coal dust associated with these conveyors will be controlled by a water spray dust suppresion system. Dust releases in the stacker-reclaimer area (active coal pile) will be ocntrolled by wetting agents for an efficiency of 90 percent. Dust releases from the inactive coal pile will also be controlled by wetting agents.

All conveyors from the coal handling building to the power house will be enclosed, and fabric filter dust collectors will be utilized to vent the storage silos in the power house and all conveyor transfer points. Tripper conveyors will be enclosed in a gallery.

Limestone Fugitive Dust Collection

Control and collection of fugitive dust particulates from the limestone addition system for the boilers will be accomplished by appropriate types of fabric filter dust collectors.

Limestone will be transported at the site by totally enclosed belt conveyors. All silos and hoppers utilized by the limestone system will be vented to fabric filter dust collectors. Similar collectors will be located at all conveyor discharge points.

All fabric filter dust collectors in the lime or limestone additive system will have an efficienct of 99.9 percent.

Control and Collection of Fugitive Fly Ash Particulates

In the fly ash handling system, fugitive fly ash particulate will be controlled at all transfer and discharge locations by fabric filters. The fly ash handling system consists essentially of ash hoppers located beneath the flue gas particulate collection equipment. Pneumatic conveyors are utilized to transfer fly ash to and from ash storage silos, and to mixers which prepare the ash and FGD wastes for disposal. Pneumatic conveyors are by their nature enclosed. Discharge for the conveyor's blower(s) will be equipped with fabric filters with greater than 99 percent collection efficienct.

Cooling Tower Drift

The dissolved and suspended solids in the small droplet size fraction of fresh water cooling tower drift is considered by EPA to contribute to total suspended particulates. This contribution is minimized by using high efficiency drift eliminators in the two natural draft towers (which limit drift to approximately .005 percent of circulating water flow) and by maintaining the cycles of concentration of the circulating water to a low level such as a maximum of 1.5. Additionally, a drift eliminator will be provided to mitigate the potential effects of blow-through. Upon reviewing the preceeding information, the Department also finds that the CBCP will not contribute to significant adverse air quality impacts.

5. Acid Rain

In recent years the increase of rainfall acidity levels across Florida and other parts of the country has been ascribed in part to the air emissions from coal-fired power plants. Hence the requirement for emission controls on these plants, designed to reduce the potential acid causing factors. Generally, sulfur dioxide and oxides of nitrogen are believed to be the primary anthropogenic agents contributing to rainfall acidification. However, a great deal remains unknown about the amount that these two gases contribute to the problem, as well as how and where the acidification takes place.

It should be noted that rainfall under unpolluted conditions tends to be somewhat acidic, on the order of pH 5.6-5.7. This is due to the absorption of water in the atmosphere. Also, neither sulfur dioxide nor nitrogen dioxide in and of themselves are acidic. It appears that after a certain amount of time, estimated to be on the order of 3-4 days, these gases interact with sunlight, water vapor, ammonia, and many other chemical compounds in the atmosphere, which converts them to sulfuric aqcid and nitric acid. Scientists around the world are studying the rate of these reactions, which catalytic aids (sunlight, water, etc.) have the most effect driving the conversion, ways to prevent the end acidic product from affecting the environment, where the end product eventually makes it's impacts, and numerous other questions relating to the conversion reactions. It is universally agreed that the entire cause-effect-control relationship is very complex.

There are three issues relevant to the licensing of the Cedar Bay/Seminole Kraft Projects as emission sources in relation to acidic rainfall. These are: (1) why is the problem of concern, (2) what will be the projects contribution to the regional, state and country wide problem, and (3) what controls are required to mitigate the problem?

First, the following effects have been ascribed to above-normal acidic rainfall. Acid rain is listed as a cause for destabilization of clay minerals, reduction of soil cation exchange capacity, promotion of chemical denudation of soils, and promotion of runoff. Vegetational effects tend to be quite varied, ranging from a few cases of reported beneficial effects, to the more prevalent harmful effects. The harmful effects include foilage damage, alteration of responses to pathogens, symbionts and saprophytes, leaching of essential materials from

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State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Steve Smallwood

FROM: Clair Fancy

DATE: November 21, 1989

SUBJ: Applied Energy Services

This is to update you on the status of the application for the cogeneration project at Applied Energy Services (AES).

About one year ago, Seminole Kraft and Applied Energy Services submitted applications under the Power Plant Siting Act to construct a cogeneration facility to replace the old boilers at Seminole Kraft and also to rehabilitate the recovery boilers and associated equipment for compliance with the TRS rule. Due to the time constraints in complying with the TRS rule, Seminole Kraft pulled from the site certification the TRS portion of the application. This is currently being reviewed and the Intent to Issue should go out this week.

With regards to the AES project, EPA informed the Department recently that there may be some complications in issuing this permit. Since that time, there has been some positive developments that may allow for the issuance of the permit.

There are three issues as to whether or not the Applied Energy Services cogeneration project is subject to PSD review. These are contiguous plant property, SIC grouping, and common control. It is clear that the AES project and the Seminole Kraft facility are on contiguous property. EPA has suggested that if 50 percent of the steam produced by AES goes to the pulp mill, then they would be under the pulp and paper SIC code. If not, it would be under a different SIC code and would therefore be subject to PSD. Seventy-eight percent (78%) of the steam will go for outside power generation and twenty two percent (22%) will go for Seminole Kraft. However, it is my understanding that the heat distribution will be appoximately 50-50. EPA is looking into this now. Seminole Kraft and AES are not under common financial control, however, since they will be sharing the facility and

Seminole Kraft will not be able to operate without AES supplying steam, this may be considered common control by EPA. EPA Region IV personnel are going to discuss both of these issues with Headquarters next week. Wayne Aronson, of EPA Region IV, agrees that AES should be permitted as it will cause an air quality improvement in the Jacksonville area. He also agrees that EPA should take a look at cogeneration facilities not being subject to PSD review and intends to ask Headquarters to investigate this. We sent the modeling parameters to EPA and they will do a screening analysis this week.

If the facility is subject to PSD, it now appears as though it will be permittable. 40 CFR 51 165 (b) states that if the contribution of SO_2 from a source exceeds one microgram per cubic meter on an annual basis that it is considered significant and that the modeling needs to be done. Fortunately, this regulation allows the issuance of the PSD permit, even if air quality standards are being exceeded, if it can be clearly demonstrated that there will be an offset in ambient concentration and an overall improvement in air quality. This project clearly meets this criteria so the modeled nonattainment status, if it exists, will not prohibit the issuance of the PSD permit. The other major criteria with the PSD regulations is the BACT analysis. EPA feels that the cogeneration facility with the fluidized bed is BACT for a boiler of this type. The only question would be whether or not DeNox would be required.

I intend to closely monitor this situation with EPA, BAR staff, and the Siting Coordination Section to attempt to meet all the necessary dates. If some of these issues cannot be resolved prior to the detailed site certification's required public notice date, we can include some general information with regards to air quality and have more information to present at the hearing. As all sources certified under the Power Plant Siting Act also need PSD permits, I feel confident that the BAR can prepare a PSD permit that can be approved simultaneously with the approval of the site certification, probably in April or May.

CHF/kt

cc: B. Oven
B. Andrews
B. Thomas
P. Raval

CONDITION OF CERTIFICATION

1. Common Control

This certification and any individual air permits issued subsequent to the final order of the Board certifying the power plant site under 403.509, F.S., shall require, as a federally enforceable condition, any source offered for contemporaneous emission reduction credits (offsets) to be permanently removed from operation. That requirement shall operate as a joint and individual requirement to assure common control for purpose of insuring that all contemporaneous emission reductions relied on are in fact made.

Features of Common Control

This certification and any individual permits issued by the Secretary, as a joint application for site certification, is found to be on the same piece or contiguous property and provides for the retirement of the same type of sources as offsets or reduction credits for the construction of new sources. Old kraft recovery boilers, evaporators, smelt dissolving tanks, power and bark boilers will be retired after NSPS recovery boilers, smelt tanks, evaporators and cogeneration power boilers are brought on line.

- This project will be certified jointly under one set of conditions.

- Seminole Kraft dictates steam extraction from AES Cedar Bay's turbine.

- Seminole Kraft owns the land on which the cogeneration facility will be built.

- AES Cedar Bay leases land from Seminole Kraft for the power plant site.

- AES Cedar Bay relies on bark from Seminole for boiler fuel.

- AES Cedar Bay also intends to use surplus lime from the paper making process for injection to react with SO_2, if practicable.

- AES Cedar Bay uses Seminole Kraft rail lines and rights-of-way.

- AES Cedar Bay relies on Seminole Kraft deep wells for water supply.

- Seminole Kraft relies on AES Cedar Bay for demineralizer water.

- AES Cedar Bay relies on Seminole Kraft for lime softened water.

- AES Cedar Bay relies on Seminole Kraft for a potion of wastewater treatment.

- AES Cedar Bay is not economically feasible without the sale of steam to Seminole Kraft.

The overall design of the project will make Seminole Kraft and AES Cedar Bay integral and inseparable parts of each other, therefore constituting common control.

<u>Precedent</u>

Precedent exists for new source review of two companies as a single facility under EPA approved rules. In California, Sacrament Municipal Utility District and Campbell Soup Company were considered a single facility in their PSD review and analysis dated August 9, 1988 issued in EPA Region IX. The conditions of this permit are similar and pertinent to the Cedar Bay Cogeneration Project.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

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NOV 14 1989

Mr. Clair H. Fancy, P.E., Deputy Chief
Bureau of Air Quality Management
Florida Department of Environmental
Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Seminole Kraft/AES Cedar Bay Cogeneration Project

Dear Mr. Fancy:

Through our review of the joint application submitted for a Power Plant Site Certification by the above facilities, an issue has arisen which may greatly impact upon the Prevention of Significant Deterioration (PSD) review performed by your Agency for this project.

As our information indicates, Seminole Kraft has jointly applied with AES Cedar Bay, Inc., (Cedar Bay) to perform several modifications. Namely, to construct a new kraft recovery boiler and smelt tank (while simultaneously shutting down various steam boilers, three old recovery boilers and smelt tanks) and also to construct a new power facility using circulating fluidized bed (CFB) boilers. The new recovery boiler/smelt tank would be owned and operated by Seminole Kraft while the new power facility would be owned and operated by Cedar Bay. Our review of the application for the site certification submitted jointly by Seminole Kraft and Cedar Bay indicates that netting credits from the shutdown of existing pulp mill sources are being used for both the new recovery boiler/smelt tank and the new power facility modifications. EPA Region IV disagrees with this action because netting credits can only be applied within a "facility", which is defined under federal regulations as: "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel.

Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-00176-0, respectively.)"

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET
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Mr. Clair H. Fancy, P.E., Deputy Chief
Bureau of ~~Air Quality~~ Management
Florida Department of Environmental
Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

The modifications to the Seminole Kraft pulp mill are categorized under the "Major Group" 26-Paper and Allied Products. The cogeneration project is categorized under the "Major Group" 49-Electric, Gas, and Sanitary Services. Moreover, it is clearly stated in the Site Certification Application that the new recovery boiler/smelt tank will be owned and operated by Seminole Kraft, and the new power facility will be owned and operated by Cedar Bay.

In discussing this matter with your staff, it was discovered that DER's general definition of "facility" (17-2.100) is different than the federal definition in that the requirement for the pollutant emitting activities to belong to the same industrial grouping is not included in DER's definition. However, our review of DER's PSD rules, 17-2.500, clearly indicates this "Major Group" criteria in determining applicability for new major sources. Our review of this section of the federally approved regulations for Florida suggests that DER's PSD applicability criteria for a new "facility" is premised upon the same factors as the federal regulations. Therefore, we have concluded that no deficiency exists in DER's PSD rules regarding the applicability of a new "facility".

Based on the above facts, we have concluded that Seminole Kraft and Cedar Bay are two separate and distinct facilities and may not "net" interchangeably under the federally approved Prevention of Significant Deterioration (PSD) rules for Florida. However, for purposes of nonattainment new source review (NSR) requirements, offset credit may be used by either facility as long as the reductions in volatile organic compound (VOC) emissions are made federally enforceable. (Offset credit should not be confused with "netting" as defined under both sets of regulations, i.e., in determining applicability.)

If you have any questions concerning this matter, please call Mark Armentrout of my staff at (404) 347-2864.

Sincerely yours,

Wayne J. Aronson / for

Bruce P. Miller, Chief
Air Programs Branch
Air, Pesticides, and Toxics
Management Division

copied: P. Raval
B. Andrews
M. Linn
G. Kettyman, NE Dist.
S. Pace, BESD
CHF/BT

YELLOW FILE COPY.

MEMORANDUM

DATE: OCT 27 1989

SUBJECT: Use of Leftover Netting Credits

FROM: Bruce P. Miller, Chief
Air Programs Branch

TO: Gary McCutchen, Chief
New Source Review Section (MD-15)

We have been asked by KBN Engineering and Applied Sciences, Inc., a consulting firm representing the Seminole Kraft Company, to provide EPA's policy for addressing leftover emission credits not used during a netting transaction. Based on our conversations with other Regional Offices, it would appear that there is some inconsistency in EPA's position on this matter.

As you will see from the attached letter from KBN (October 2, 1989), Seminole Kraft is proposing to construct a new recovery boiler and smelt dissolving tank at its existing kraft pulp mill located in Jacksonville, Florida. As part of the project, three existing recovery boilers and smelt dissolving tanks will be shut down to generate contemporaneous emission decreases. From the table attached with KBN's letter, there will be a net decrease of several pollutants and a significant net emissions increase for only oxides of nitrogen. The Florida Department of Environmental Regulation (DER) has taken the position that the leftover emission decreases may not be carried over to be used in future netting/offsetting transactions and that the slate is wiped clean for those pollutants. This is based on their interpretation of 40 CFR 51.166(b)(3)(iii) which states that... "An increase or decrease in actual emissions is creditable only if the reviewing authority has not relied on it in issuing a permit for the source under regulations approved pursuant to this section, which permit is in effect when the increase in actual emissions from the particular change occurs."

In your review of this matter, we ask that you address the following questions:

1. Can the facility use the leftover contemporaneous emission reductions in future netting transactions? If yes, can these emission credits be sold or otherwise used by a separate facility (with a different major SIC number) under any circumstances? For example, if a new major power plant under separate ownership would locate on Seminole kraft property for the purpose of supplying power both to the pulp mill and to other facilities, could the leftover emission credits be used by the power plant under any circumstances?

2. If Seminole Kraft is allowed to use the leftover emission credits in future netting transactions, is the five year netting timeframe opened for all pollutants even though a future modification may be major for only a limited number of pollutants? For example, if a future project involves an increase of 35 tons of sulfur dioxide and 50 tons of particulate matter per year, would the facility be required to perform a PSD review for sulfur dioxide because of the previous contemporaneous increase of 6.4 tons per year?

Since we must provide KBN and the Florida DER a response to these issues as soon as possible, we request that you respond to these questions by November 10, 1989. If you need any additional information, please contact Mark Armentrout of my staff at (FTS) 257-2864.

Attachment

MARMENTROUT/CDW/10/23/89 DOC: 24-MB-GM
ARMENTROUT 10/20 ARONSON 10/20 MILLER 10/24

Briefing Paper for Winston Smith/Bruce Miller

ISSUE: The Florida DER is proposing to allow netting credits (created by the shutdown of existing pulp mill sources at Seminole kraft) to be used at a separate "facility" (AES/Cedar Bay) and thus net out of PSD. The Florida DER is allowing this action by misconstruing their definition of "facility" under the PSD rules.

BACKGROUND: Seminole kraft and AES/Cedar Bay have jointly applied for a permit under the Power Plant Siting Act to perform the following activities:

1. Shutdown three existing recovery boilers and associated smelt tanks and numerous steam boilers at Seminole kraft.

2. Construct one new recovery boiler and smelt tank.

3. Construct a power generation facility consisting of three circulating fluidized bed boilers for supplying process steam to Seminole kraft and 225 mw of electricity for sale to the JEA.

It is clearly stated in the application that the new recovery boiler/smelt tank will be owned and operated by Seminole kraft. It is also stated that the new power facility, to be constructed on Seminole kraft property, will be owned and operated by AES/Cedar Bay.

There is an inconsistency between the federal definition of "facility" and that of the Florida DER. EPA's definition includes the following criteria for defining a "facility": All pollutant emitting activities that are,

a) on contiguous or adjacent property,
b) under control of the same person (or persons under common control), and
c) belong to the same "Major Group", i.e., have the same first two digit SIC code.

Florida's definition of facility does not require that the pollutant emitting units belong to the same "Major Group"; otherwise, their regulation is identical.

By either definition and in review of the preamble to the promulgation of the term "facility", it is apparent that the kraft pulp mill and power facility should be considered two distinct "facilities". This is based on the meaning of "under control of the same person (or persons under common control)". Therefore, emission netting may only be applied within each separate facility.

Wayne (main)

Please prepare a response ASAP. Make sure that any response is coordinated (& agreed to) by Fla. prior to sent. Bruce

KBN

October 2, 1989
89026

AIR PROGRAMS BRANCH
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OCT 4 1989
EPA-REGION IV
ATLANTA, GA.

Bruce P. Miller, Chief
Air Programs Branch
U.S. Environmental Protection Agency Region IV
345 Courtland Street
Atlanta, GA 30365

Dear Mr. Miller:

The purpose of this letter is to solicit EPA opinion and comment on a PSD issue related to the accumulation of contemporaneous emission increases and decreases. A disagreement has risen recently with the Florida Department of Environmental Regulation (FDER) over the interpretation of PSD regulations in this area.

It should first be mentioned that FDER has repeatedly stated in the past that the Florida PSD rules were written with the intent of being equivalent to (not more stringent than) EPA PSD regulations. The question regarding accumulation has been raised on several past PSD projects, the most recent being Seminole Kraft's proposed recovery boiler application (submitted separately from the American Energy Services cogeneration application). I will use the Seminole Kraft application, submitted in August 1989, for example discussion purposes.

Applied

Seminole Kraft is proposing to construct a new recovery boiler (RB) and associated smelt dissolving tank (SDT). As part of the project, the three old RBs and SDTs will be shutdown, providing contemporaneous emission offsets. Review of the plant history for the last five years revealed only one additional contemporaneous change at the plant - the shutdown of an old lime slaker and construction of a new lime slaker. This change resulted in a net decrease in particulate matter (PM) emissions.

The construction of the new RB and SDT will cause emission increases for several pollutants, while the shutdown of the old RBs/SDTs will result in contemporaneous emission decreases. The resulting source applicability determination is shown in Table 4-4 attached. As indicated, there is a significant net increase in emissions of only nitrogen oxides (NO_x), and therefore NO_x is subject to PSD review. There is a net increase in emissions of sulfur dioxide (SO_2), but these increases are less than PSD significant emission rates, and therefore this pollutant is not subject to PSD review. There is a net decrease in emissions of all other regulated pollutants and therefore these pollutants are not subject to PSD review.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
P.O. Box 14288 5700 SW 34th Street Gainesville, FL 32604 904/375-8000 Telex: 984689 KBN ENG UD

KBN

The basic question to be resolved is whether the net decreases determined for the pollutants not requiring PSD review can be used in the future as contemporaneous reductions to offset increases due to other, separate projects at the Seminole Kraft plant. It is FDER's position that once a PSD permit is issued for the plant, the "slate is wiped clean", and all pollutant increase/decreases are set to zero. They claim that in issuing the PSD permit, they "relied upon" the emission decreases, and therefore they cannot be used in the future to offset other increases. Other than this reason, they provided no other justification or substantiation to support this position, either in their own rules or EPA PSD rules.

I disagree with this position, and in fact can find no basis for this position either in the PSD regulations (40 CFR 52.21) or in the preamble to the various PSD regulations issued by EPA in the past. First of all, PSD regulations only apply to PSD pollutants, in this case NO_x. It is agreed that the issuance of a PSD permit for NO_x results in "wiping the slate clean" for NO_x, and emissions of NO_x for future PSD applicability determinations is set to zero.

However, a PSD permit is not issued for non-PSD pollutants. Only a construction permit is issued for non-PSD pollutants - in Seminole Kraft's case, for all pollutants except NO_x. Therefore, emissions of these non-PSD pollutants were not "relied upon" in issuing a PSD permit. EPA states in the preamble to the PSD regulations (Federal Register, August 7, 1980) that "A reviewing authority "relies" on an increase or decrease when, after taking the increases or decreases into account, it concludes that the proposed project would not cause or contribute to a violation of an increment or ambient standard" (pg. 52699). In the case of a PSD pollutant, this criteria is satisfied since an air quality review is required for the PSD pollutant. However, for non-PSD pollutants, an air quality review is not required. Again, in Seminole Kraft's case, an air quality review is only required for the PSD pollutant- NO_x. What was relied upon in issuing the PSD permit is the shutdown of the existing RBs/SDTs. This will be required by a federally enforceable permit condition.

There is no regulatory basis for "wiping the slate clean" for non-PSD pollutants. The net emission reductions for these pollutants should be able to be applied during the future five-year contemporaneous period. These are not "paper" offsets, but reductions in real actual emissions.

This treatment of non-PSD pollutants is no different than any other non-PSD construction permit issued. For example, the replacement of slakers at Seminole Kraft in 1987 resulted in a net decrease in PM emissions. A FDER construction permit was required for the project. The net decrease in PM emissions was creditable and could be used in the future 5-year contemporaneous period to offset other PM increases at the plant. The net decreases resulting from the Seminole Kraft RB project should be treated no differently - they are non-PSD pollutants requiring only a construction

Mr. Bruce Miller
October 2, 1989
Page Three

permit. There is no regulatory authority or basis for "wiping the slate clean" for non-PSD pollutants.

The fact that FDER addresses all pollutants in the PSD permit is only for convenience. However, an additional benefit is that net emissions reductions can be documented. This documentation also prevents any possible "double counting" of emission decreases since the Technical Evaluation/Preliminary Determination and Final Determination document in writing the net emissions decreases resulting from the project.

EPA discusses the concept of "accumulation" in its preamble to the PSD regulations (Federal Register, August 7, 1980, pg. 52702). It is clear from this discussion that changes at a major stationary source are accumulated to determine if PSD review applies: "... a series of individually de minimis changes at a major stationary source would be accumulated within a contemporaneous time frame to see if a review would be required." This would be applied on a pollutant specific basis. Accumulation should apply to decreases as well as increases. Obviously, a change which results in a decrease in emissions would be a de minimis change.

Not true

It is also noted that the FDER's position of wiping the slate clean for all pollutants once a PSD permit is issued for any pollutant will actually be counter productive to reducing emissions and installing newer, less polluting equipment. This is because, if this policy is retained, sources will only shutdown the minimum number of sources necessary to just avoid PSD review. There will be no benefit whatsoever to shutting down additional units, since in effect no reduction credit will be given for these shutdowns.

EPA comment is solicited on these PSD aspects of accumulation and contemporaneous emissions changes. It is requested that legislative and regulatory citations be included to support EPA's position.

I would also like to take this opportunity to comment on one related aspect of PSD rules, that of using actual emissions as a basis for offset credit. The problem with using actual emissions is that this is a significant incentive for industry to emit as much as possible now, within the limits of their permits, so that their PSD emission baseline is higher. The higher baseline provides greater opportunity to escape future PSD review. There is no incentive whatsoever for minimizing emissions. Unfortunately, industry has come to realize this after being exposed to PSD regulations for the past ten years, and I am sure this has led to greater emissions that otherwise would have occurred. EPA should revise their rules to allow the use of allowable emissions, or some reasonable level above actual emissions, for PSD baseline purposes, or devise some other incentive for industry to minimize their current emissions without being penalized.

85.

Thank you for your consideration of this matter. I look forward to your response to these comments.

Sincerely,

David A. Buff

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

DAB:mah

cc: Curtis Barton
Terry Cole

September 12, 1989

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DER BAQM

Mr. Hamilton S. Oven
Department of Environmental Regulation
Siting Coordination Section
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Oven:

The following are responses to the questions and comments listed in the BESD letter of July 12, 1989 (copy enclosed), regarding the Environmental Assessment Report by Dames and Moore dated July 7, 1989.

1. Comment:
   BESD States that "There is presumptive evidence, based on the subject report results, that certain surface water quality standards (metals listed above) for Class III predominantly marine waters FAC Rule 17-3 are being exceeded at the boundary of Seminole Kraft property adjacent to the Broward River."

   Response:
   The report indicates that ground water standards are being exceeded at some wells in the area of the Seminole Kraft plant site. The report also states that ground water migration is toward the rivers (Broward River included). However, we have no evidence that surface water quality standards (Class III marine) are being exceeded near the plant boundary as a result of ground water migration or any plant activities.

2. Comment:
   BESD asks what tasks and/or laboratory procedures did Dames and Moore undertake to overcome the presence of dissolved gases which made certain results inconclusive in the earlier ERM-South report.

   Response:
   In order to determine what methods would be required to produce conclusive results, Dames & Moore sent to Savannah Labs preliminary samples taken December 8, 1988, from existing monitoring wells drilled for ERM. Savannah Labs ran tests on these samples and found, according to Janet Pruitt, that conclusive results could be obtained in each set of tests. Ms. Pruitt related that foaming and emulsions occurred, but Savannah Labs uses techniques which produce conclusive results, despite these tendencies, without raising detection limits.

AES/CedarBay Inc.
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Response:
Seminole Kraft's new lime mud process with clarifier will settle out lime wastes. The decant water will go to Seminole Kraft's industrial wastewater treatment system. Since the effluent from the lime mud settling ponds is currently being directed to Seminole Kraft's treatment system, this mode of operation is essentially unchanged. Therefore, the use of the planned clarifier will have no significant additional impact on heavy metals in the waste stream.

6. Comment:
BESD believes the minimum criteria for all ground water in FAC Rule 17-3.402 apply to the area of the southern most fuel oil tank and fuel oil contaminated soil which is not included in the AESCB project site.

Response:
Seminole Kraft has submitted a proposed cleanup program to DER. The program was approved by DER and plans for cleanup are underway.

Sincerely,

Julie Blunden
Development Manager

LRA:rs
Enclosure

cc: Robert S. Pace, BESD

Pradeep

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DER - BAQM

April 17, 1989

FEDERAL EXPRESS

Mr. Hamilton S. Oven, Jr.
Administrator, Siting Coordination Section
Division of Air Resources Management
Department of Environmental Regulation
2000 Blair Stone Road
Tallahassee, Florida 32399

Dear Mr. Oven:

Enclosed are responses to Florida DER comments on the Cedar Bay Cogeneration Project's Site Certification Application. An additional copy of each respective set of comments and responses is being sent separately to the originating group.

If you have any questions on this material, please let me know.

Sincerely,

Julie Blunden
Development Manager

LRA:rs
Enclosure

cc: Mr. Paul Darst, Florida Department of Community Affairs
Mr. Al Bishop, Florida DER, Point Source Evaluation Section
Mr. Richard S. Levin, St. Johns River Water Management District,
Marine Mammals Section, Florida Department of Natural Resources
Mr. Robert S. Pace, Jacksonville, Department of Health, Welfare, & Bio-Environmental Services
Mr. Daryll Joyner, Florida DER, Point Source Evaluation Section

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EMISSION COMPLIANCE TEST METHODS

	Performance Parameter	Referenced Test Code
1	Carbon Dioxide (CO)	40 CFR Part 60 Method 10
2	Nitrogen Oxides (NO_x)	40 CFR Part 60 Method 7
3	Sulfur Dioxide (SO_2)	40 CFR Part 60 Method 6
4	Total Suspended Particulate (TSP)	40 CFR Part 60 Method 5 or 17
5	Lead (Pb)	40 CFR Part 60 Method 12
6	Beryllium (Be)	40 CFR Part 61 Method 104
7	Mercury (Hg)	40 CFR Part 61 Method 101
8	Fluorine	40 CFR Part 60 Method 13A or 13B
9	Sulfuric Acid Mists (SO_3)	40 CFR Part 60 Method 8
10	Total Reduced Sulfur (TRS)	40 CFR Part 60 Method 16A
11	Non-Methane Hydrocarbons	40 CFR Part 60 Method 25A or 25B
12	Opacity	40 CFR Part 60 Method 9 or Appendix B Specification 1