UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

145 COURTLAND STREET
ATLANTA. GEORGIA 30365

MEMORANDUM

DATE:

SUBJECT: Cedar Bay Cogeneration Facility, Jacksonville, Florida

FROM: Wayne J. Aronson, Chief
Program Support Section
Air Programs Branch

TO: Robert B. Howard, Chief
NEPA Compliance Branch

Per your request, we have reviewed the site certification application for the proposed construction of the Cedar Bay Cogeneration Facility to be located in Jacksonville, Florida. We offer the following comments:

Application Forms for Each Source

1. Circulating Fluidized Bed (CFB) Boilers

The application states that in addition to burning coal and wood, the CFB boilers will burn No. 2 fuel oil in the estimated amount of 160,000 gallons per year. This fuel will be used as backup/auxiliary fuel. To be more sufficient the application form for the CFB boilers should list No. 2 fuel oil in Section E (Fuels) along with the other fuels.

Section C (Airborne Contaminants Emitted) of the application form requires that all pollutants be listed and contain federally enforceable emission limits for regulated pollutants. Instead of listing the pollutants, the form states that a list of pollutants emitted from this source can be found in the text of the Site Certification Application. Such a reference is impractical. We recommend that all regulated pollutants, along with their federally enforceable limits, be included on the application form. Furthermore, when indicating the pollutants, include any air toxic substances that will be emitted due to the combustion of No. 2 fuel oil. According to the EPA publication titled "Control Technologies for Hazardous Air Pollutants," possible air toxics that might be emitted due to the combustion of oil are (* indicates regulated pollutants):

formaldehyde	*beryllium
polycyclic organic matter	cadmium
*fluoride	chromium
*mercury	cobalt
chlorine	copper
*arsenic	*lead
barium	manganese
zinc	nickel
vanadium	*radionuclides

1.

2.

1. The FDER application form (Section III Part E - Fuels) for the CFB boiler. will be revised to list No. 2 fuel oil as the backup/auxiliary fuel. The estimated quantity will be 160,000 gallons per year.

2. Because of the nature of the supplemental information, it was determined, that the data could be summarized more efficiently into a table. The SCA Table 3.4-2 information will be expanded to include regulated and air toxic emission estimates for various proposed sources. The expanded information is included as Attachment A (Tables 1, 2, and 3) to this submittal.

The application form should also specify that the boilers are subject to New Source Performance Standards (NSPS) for electric utility steam generating units (40 CFR Part 60, Subpart Da). In addition to emission limits for sulfur dioxide (SO_2), particulate matter (PM), and nitrogen oxides (NO_x), Subpart Da specifies that permits for electric utility steam generating units must have an opacity limit of 20 percent and contain requirements for the continuous monitoring of SO_2, NO_x, opacity, oxygen (O_2), and carbon monoxide (CO).

2. Kraft Recovery Boiler (KRB)

The application form for the KRB should list all regulated pollutants along with their federally enforceable emission limits, should state that the KRB will be subject to NSPS for kraft pulp mills (40 CFR Part 60, Subpart BB), and the NSPS for industrial-commercial-institutional steam generating units (40 CFR Part 60, Subpart Db), and should indicate that the emission limit of 5 ppm for total reduced sulfur (TRS) emissions will be standardized by correcting the volume, on a dry basis, to 8 percent O_2.

3. Smelt Dissolving Tank (SDT)

Like the application form for the KRB, this application form should state that this unit will be subject to 40 CFR Part 60, Subpart BB, and should list a federally enforceable emission limit for PM.

4. Lime Kiln (LK)

The application form should indicate that this unit will be subject to 40 CFR Part 60, Subpart BB. It should also state that the emission limit of 5 ppm for TRS will be standardized by correcting the dry volume to 10 percent O_2.

In addition to the requirements stated above, all the application forms should specify test methods to be used during compliance testing. The forms should also specify emissions limits that reflect best available control technology (BACT), which will be discussed later in this memorandum. Currently, most of the application forms only specify emission limits that meet the minimum emissions standards of NSPS.

Net Significant Emissions Calculations

Federal PSD regulations require that increases or decreases in pollutant emissions be determined by obtaining the difference in new allowable emissions and either old actual emissions or old allowable emissions, whichever is lower. In this case net emissions increases should be determined by using new allowable emissions and old actual emissions. The

RESPONSES

3. The application form (Section VI Part A) for the CFB boilers will be revised to list the additional NSPS Subpart Da requirements: opacity limit of 20 percent and continuous emission monitoring for SO_2, NO_x, opacity, oxygen (O_2), and carbon monoxide (CO).

4. The application form (Section VI Part A) for the Kraft Recovery Boiler (KRB) will be revised to indicate that the emission limit of 5 ppm for total reduced sulfur will be standardized by correcting the volume, on a dry basis, to 8 percent O_2.

   Approximately 250,000 gallons of oil will be used only for startup. Black liquor solids (BLS) will essentially be the only fuel burned in the KRB. Therefore, our understanding of the only requirements associated with 40 CFR Part 60 (Subpart Db) for the KRB will be to notify the appropriate regulatory agency and maintain a fuel log.

5. The application form (Section VI Part A) for the Smelt Dissolving Tank (SDT) will be revised. It will state that the SDT is subject 40 CFR Part 60, Subpart BB and a particulate emission limit of 0.2 lb particulate per ton of BLS (dry weight).

6. This comment was interpreted to actually be addressing the multiple-effect evaporator (MEE) and not the lime kiln. The lime kiln is an existing source and does not require permit modification. The application form will be revised for the MEE to list the applicable NSPS standards and emission rates.

7. Attachment B summarizes the test methods that will be used, as required, during compliance testing.

applicant's net emissions calculation results for PM and TRS are invalid because old actual emissions data were not used for these two pollutants. Actual emissions are defined in the PSD regulations as:

> "...the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which preceeds the particular date and which is representative of normal source operation. The Administrator shall allow the use of a different time period upon a determination that it is more representative of normal source operation. Actual emissions shall be calculated using the unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.

> The Administrator may presume that source specific allowable emissions for the unit are equivalent to the actual emissions of the unit.

> For any emissions unit which has not begun normal operations on the particular date, actual emissions shall equal the potential to emit of the unit on that date."

According to the application, the period 1979-1980 was found to be the most representative two-year period of normal operating conditions. However, the total actual emissions for this period were adjusted to "represent the effect of recent control techniques and an imposed particulate emission limit." According to the above definition, such modifications to actual data are not allowed. We request that the net emissions calculations be redone using either test data or other operational data for a two-year period after the control technique changes were made.

Another error in the net emissions calculations is that for PM emissions, maximum expected emissions were used instead of new allowable emissions. New allowable emissions are determined by using emissions limits specified in the application form. Specifically, PM emission limits indicated in the application forms for the proposed CFB boilers and KRB were not used in the net emissions calculations. According to the application form for the CFB boilers, PM emissions will be restricted to 0.03 lb of PM/mmBtu. Converting to a tons per year (TPY) limit indicates a potential to emit in the amount of 419 TPY:

$$\frac{0.03 \text{ lb PM}}{\text{mmBtu}} \times \frac{3189 \text{ mmBtu}}{\text{hr}} \times \frac{8760 \text{ hr}}{\text{year}} \times \frac{1 \text{ ton}}{2000 \text{ lb}} = 419 \text{ TPY}$$

8.

9.

RESPONSES

8. As was stated in the application, emissions for the 1979-1980 peri--- adjusted in order to best represent normal operating condition and current controls and regulatory constraints. The described a.. were made in order to arrive at the most representative emission values. The use of these adjustments was discussed with and approved by the DER. Because the adjustments reduced the emissions, they are also more conservative than the unadjusted values. That is, this procedure results in higher predicted net air quality impacts as a result of operation of the proposed project.

9. The emission rates given in Sections VI.A. of the Florida DER application forms are not intended to be maximum allowable emission rates. These values are given (as the form requests) as applicable new source performance standards (NSPS) for the respective sources. Because the net emissions increase in particulate matter is less than the "significant" criteria values for total particulate and PM_{10}, a BACT analysis was not required for particulate matter. Nevertheless, the applicant is proposing a permitted emission rate that is less than NSPS and more typical of current BACT determinations (0.02 lb PM/MBtu).

Similarly, the application form for the proposed KRB indicates a potential to emit PM in the amount of 488 TPY. This potential to emit was calculated by extrapolating the limit (equal to 355 TPY) indicated in Table 3.4-2 of the application to the 0.044 grains/dscf limit specified in the application form:

$$\frac{X}{0.044 \text{ gr/dscf}} = \frac{355 \text{ TPY}}{0.032 \text{ gr/dscf}} \qquad X = 488 \text{ TPY}$$

where X = maximum possible PM emissions

Table 3.4-2 should be adjusted to reflect each unit's potential to emit PM. According to our calculations, after converting PM emissions limits in the application forms to a TPY basis, the total PM emissions for all proposed sources will equal 965 TPY.

Air Quality Analysis (AQA)

The analysis for lead relied on using a 24-hour modeled value to show compliance with the quarterly standard. Instead of a short-term model, we request that a long-term model, such as the Industrial Source Complex Long Term (ISCLT) model, be used for this analysis. The ISCLT model should also be used for the AQA for the PSD permit.

Another comment regarding the AQA concerns the placement of the receptors during modeling. If the cogeneration project is under the same ownership as the kraft pulp mill, then a commonly defined plant boundary property line may be used. If the two facilities will have separate owners, then the air contained in the boundary of the kraft pulp mill is considered ambient air. Additionally, public access to the facility must be precluded by a fence or other physical barrier.

10.

11.

12.

10. The same response as that given for Comment 9 is again appropriate.

11. As discussed with FDER, a conservative estimate for lead impacts would be the 24-hour maximum concentration predicted from the Industrial Source Complex Short-Term (ISCST) dispersion model. This method is widely accepted to represent conservative quarterly estimates.

The quarterly concentration could not exceed the 24-hour concentration since the longer averaging time would "smooth" the data set, resulting in lower concentrations. Thus, the most conservative method was used to demonstrate compliance with the ambient air quality lead standard.

12. The SCA was submitted with Seminole Kraft Corporation and AES Cedar Bay, Inc. being co-applicants. Seminole Kraft Corporation will retain ownership of the proposed kraft recovery boilers (KRB), smelt dissolving tanks (SDT), and multiple-effect evaporators (MEE). The circulating fluidized bed (CFB) boilers will be owned and operated by AES Cedar Bay, Inc., on property leased from Seminole Kraft.

The existing kraft paper mill sources, that are being replaced by this project, have release points that are at heights which are below good engineering practice (GEP) stack heights. Pollutant dispersion from these short stacks can be heavily influenced by building downwash effects. That is, the turbulence can bring the pollutants quickly to the ground before sufficient dilution can occur. This situation can result in high pollutant concentrations near the source.

The proposed sources will utilize GEP stacks and will eliminate building downwash effects on pollutant dispersion. For the SCA, it was demonstrated that the modeled ambient air quality surrounding the facility will improve significantly. This improvement will be based on replacing the existing equipment with new, efficient, and well controlled boilers equipped with GEP stacks. Because of the significant improvement at all the modeled receptors, it is anticipated that there will be significant air quality improvement at any boundary location.

The paper mill is currently fenced to restrict public access. All buildings and coal handling equipment associated with the cogeneration facility will also be enclosed with a fence. The beginning and ending sections of the railroad will not be fenced.

BACT Determinations for the Cogeneration Boiler

1. SO$_2$ and Other Regulated Pollutant Emissions

The BACT analysis was performed in a "top-down" manner; however, we have concerns about the lack of justifications for not choosing the "top" level of control (wet limestone scrubber) as BACT and the lack of consideration of the amounts of other regulated and unregulated (air toxics) pollutants emissions that could be controlled if the "top" level of control was installed.

The applicant chose a limestone injection system (90% removal efficiency) as BACT. The main reason for not choosing the wet limestone scrubber (capable of reducing SO$_2$ emission by 94%) was cost. The applicant claimed the levelized annual cost for the wet limestone scrubber will be $43.6 million and the annual cost for the proposed limestone injection system will be $35.8 million. By using information in Table 10.8-3 of the application, the incremental annualized cost calculated is $636 per ton of SO$_2$ removed; however, this cost appears inflated because it was assumed that the boilers would only operate at 87 percent capacity. Actually, because the application form does not restrict capacity, it must be assumed that the facility will operate at 100 percent capacity; therefore, cost should be determined on that basis. Another error in the cost per ton value for each SO$_2$ removal alternative was that the applicant did not include, along with SO$_2$ emissions, the amounts of other pollutants, i.e., unregulated pollutants (including air toxics mentioned earlier) and other regulated pollutants, that could be reduced. According to Table 10.8-9 of the application, BACT analyses were also required for the following pollutants, all of which may be reduced by use of an SO$_2$ removal system:

lead	mercury	H$_2$SO$_4$ mist
fluorides	beryllium	

By using the annual costs tabulated in Table 10.8.8 of the application and the maximum control capability of each alternative (based on 100 percent capacity), we calculate an incremented cost of $553.45 per ton of SO$_2$ removed if the "top" level of control is chosen (see Table 1). When the estimated removal amounts of pollutants in Table 2 are included, the incremental cost for the wet limestone scrubber is $531.15 per ton of pollutants removed. The cost per ton value will be even lower once it is determined which unregulated pollutants would be controlled by the scrubber.

We feel that a cost of $531.15 per ton of pollutants removed for the "top" control is reasonable. Not only could SO$_2$ emissions be further reduced by 3353 TPY if the "top" alternative was chosen over the proposed SO$_2$ reduction control technology, but lead, other regulated non-criteria pollutants, and some unregulated pollutants could further be reduced by at least 1417 TPY (see Tables 2 and 3).

13.

13. Cost was not the only criterion used in the BACT analysis for rejecting a 94 percent SO$_2$ removal wet limestone scrubber FGD system as BACT for the Cedar Bay Cogeneration Plant. There is an environmental risk associated with use of a wet limestone scrubber. Wastes from a wet limestone scrubber consist primarily of calcium sulfate dihydrate and calcium sulfite hemihydrate. These compounds are difficult to dewater and fixate into materials of relatively low permeability. Lower permeabilities increase the potential for leachate from these wastes. The potential for leachate of trace metals and compounds into groundwater supplies represents a significant enviromental risk for wet limestone FGD process.

Alternatively, wastes from a CFB boiler FGD system consist primarily of calcium sulfate anhydrate (plaster of Paris) and unreacted quantities of lime. The controlled conditioning of this hygroscopic material with water results in a landfillable material with very low permeabilities. The cementatious properties of wastes from a CFB boiler minimizes the risk of leachate.

Wet limestone FGD systems are also energy intensive processes. Limestone must be crushed, slurried, and held in suspension in preparation for use. Contact of the slurry with the flue gas is accomplished by circulating large quantities of slurry in scrubber modules. Wastes from the scrubbing process contain large quantities of water which must be removed during thickener and vacuum filtration process steps. In addition, scrubber modules have large pressure drops requiring increased induced draft fan power. The analysis concluded that the wet limestone scrubber FGD system consumes almost three times the energy that a CFB boiler AQCS requires.

The incremental annualized cost calculated by the EPA of $636 per ton is in error. Annualized costs should be compared to the next level of control to determine the cost effectiveness of the more restrictive control alternative. Incremental costs calculated in this manner are the fundamental measure of cost effectiveness for varying levels of control. Therefore, the incremental cost of $2,700 per additional ton of SO$_2$ removed listed in the text is correct.

In addition, it is not correct that total levelized annual costs would remain unchanged for an increase in capacity factor from 87 percent to 100 percent. This assumption neglects to consider additional costs for limestone, energy, and waste disposal accrued for removing SO$_2$ during these additional hours of operation. Accounting for these considerations results in an incremental cost of $2,200 per incremental ton removed to go from 90 percent to 94 percent SO$_2$ removal at a 100 percent capacity factor.

The analysis conceded that a wet limestone scrubber FGD system designed for 94 percent SO$_2$ removal would be likely to remove larger quantities of regulated and unregulated non-criteria pollutants. However, the analysis concluded that this benefit did not outweigh aforementioned economic, environmental, and energy disadvantages associated with use of a 94 percent SO$_2$ removal wet limestone scrubber FGD system. Therefore, BACT regarding the control of SO$_2$ emissions from the Cedar Bay Cogeneration Plant is the use of circulating fluidized bed boilers with in-bed desulfurization.

Table 1. Sulfur Dioxide Emissions and Incremental Costs

Alternative	Uncontrolled Emissions (TPY)	SO₂ Removal Eff (%)	Annual Emissions (TPY)	Controlled Emissions (TPY)	*Annual Costs ($/year)	Incremental Cost($/ton)
Pulverized (PC)/Wet Limestone Scrubber	83,807	94.0	5028	78,779	43,600,000	553.45
CFB Boiler/ Fabric Filter	83,807	90.0	8380	75,426	35,850,000	475.30
PC Boiler/ Wet Limestone Scrubber	83,807	90.0	8380	75,426	41,290,000	547.42
PC Boiler/ Lime Spray Dryer	83,807	90.0	8380	75,426	46,640,000	618.35

*Obtained from Table 10.8-8 of the application

Table 2. Lead and Non-criteria Pollutant Emissions

Alternative	Compound	Uncontrolled Emissions (TPY)	Removal Eff. (%)	Estimated Emissions (TPY)	Estimated Removal (TPY)	PSD Significance (TPY)
Wet Limestone Scrubber	Lead	109.00	98.1	2.08	106.92	0.6
	Fluorides	2412.24	99.4	14.50	2397.74	3.0
	Mercury	4.06	10.0	3.65	0.41	0.1
	Beryllium	31.70	99.4	0.18	31.52	0.0004
	H₂SO₄ mist	1285.04	60.0	514.00	771.04	7.0
CFB Boiler/ Fabric Filter	Lead	109.00	10.0	98.10	10.90	0.6
	Fluorides	2412.24	50.0	1206.12	1206.12	3.0
	Mercury	4.06	10.0	3.65	0.41	0.1
	Beryllium	31.70	95.0	1.59	30.12	0.0004
	H₂SO₄ mist	1285.04	50.0	642.50	642.50	7.0

Table 3. Difference in Amount of Regulated
Pollutants Removed Between Alternatives (1) and (2)

Compound	Difference (TPY)
Lead	96.02
Fluorides	1192.62
Mercury	0.0
Beryllium	1.4
H₂SO₄ mist	128.54
Total	1417.60

2. NO$_x$ Emissions

The applicant chose a NO$_x$ emissions limit of 0.36 lb NO$_x$/mmBtu as BACT without adequately justifying why Thermal De-NO$_x$ controls were technically or economically infeasible for this project. The applicant gave two main reasons why Thermal De-NO$_x$ controls should not be considered as BACT, both of which are unsubstantiated. They are:

1. Test data is not available from three facilities in California that are using Thermal De-NO$_x$ controls on CFB boilers; and

2. The temperature for optimum SO$_2$ emissions control from the proposed CFB boilers is 1560°F. This temperature is not in the temperature range (1600°F - 1900°F) for optimum NO$_x$ emissions control by Thermal De-NO$_x$.

Because the burden of proof is on the applicant to prove that a "top" level of control is clearly technically or economically infeasible, unless better arguments are presented, Thermal De-NO$_x$ may be considered as BACT for this source. We recommend that data be submitted that reflects how SO$_2$ and NO$_x$ emissions will be effected if the SO$_2$ removal system and Thermal De-NO$_x$ were allowed to operate at temperatures slightly out of their optimum operational range, i.e., what will be SO$_2$ and NO$_x$ control trade-offs. We also recommend that the applicant evaluate the possibility of cooling the effluent stream leaving the Thermal De-NO$_x$ system. We feel that by cooling this stream to 1560°F, it would be technically feasible to operate both the Thermal De-NO$_x$ system and the limestone scrubber. The applicant should also evaluate the use of a urea injection process in the BACT analysis for this source. Information on a urea injection process named NO$_x$OUT, manufactured by Fuel Tech, Inc., is attached for the applicant's review.

The applicant also rejected Thermal De-NO$_x$ as BACT because of cost. The applicant claimed that the incremental costs to control NO$_x$ emissions with Thermal De-NO$_x$ controls on the proposed CFB boilers and on a pulverized coal (PC) boiler are $1500/ton and $1300/ton of NO$_x$ removed, respectively. However, by using the annual cost information contained in Table 10.8-12 of the application and assuming a maximum removal efficiency of 60 percent, we calculate that at 100 percent capacity the incremental costs associated with operating Thermal De-NO$_x$ on the CFB boilers and PC boiler are $1263 and $1137/ton of NO$_x$ removed, respectively (see Table 4). Additionally, by using Thermal De-NO$_x$ controls, NO$_x$ emissions will further be reduced by approximately 3,000 TPY for each type boiler. Based on the cost information presented in the application, we feel that Thermal De-NO$_x$ is a viable control option for this source.

Table 4. Nitrogen Oxides Emissions and Incremental Costs Associated with Thermal De-NO$_x$

Alternative	Uncontrolled Emissions (TPY)	NO$_x$ Removal Eff (%)	Annual Emissions (TPY)	Controlled Emissions (TPY)	Total Annual Costs ($/year)	Incremental Cost ($/ton)
CFB Boiler/ Thermal De-NO$_x$	5028.42	60.0	2011.37	3017	3,810,000	1263.00
PC Boiler/ Thermal De-NO$_x$	5587.13	60.0	2235.00	3352	3,810,000	1137.00

14. References made to Thermal DeNOx are somewhat generic in nature. The Thermal DeNOx system is licensed by Exxon is the most commercial proven selective non-catalytic NO$_x$ reduction (SNCR) system avai We recognize the commercial viability of the NOxOUT process. The NO$_x$OUT system is capable of approximately the same NO$_x$ reduction performance as the Thermal DeNOx system. System chemistries for the two systems are similar, except that Thermal DeNOx uses ammonia for additive whereas NOxOUT uses urea. Budget estimates obtained for both of these systems indicate that they are comparably priced. Therefore, costs listed in the BACT analysis with regard to a Thermal DeNOx system can be assumed to be analogous for a NOxOUT system.

Subsequent communications with parties involved with the two oper fluidized boilers with selective non-catalytic NO$_x$ reduction sys have provided additional information regarding these installatio. The Corn Products project located in Stockton, California has passed compliance tests. However, ammonia slip emissions have exceeded the targeted value of 20 ppm when maintaining compliance with NO$_x$ emission requirements. The Cogeneration National project also located in Stockton, has not been able to meet NO$_x$ emission requirements while maintaining compliance with CO and SO$_2$ emission requirements. The plant is continuing with adjustments targeted at achieving coincidental compliance with all air permit requirements.

Operation of the CFB boiler at 1560 F already occurs outside the optimum temperature range for SNCR applications of 1600 to 1900 F. A temperature of 1560 F is optimal for SO$_2$ removal. Increasing combustion temperatures to better fit within the optimum SNCR temperature window will increase NO$_x$ emissions from the boiler (increased thermal NO$_x$ from combustion air) and decrease the efficiency of the SO$_2$ removal process (due to sintering of limestone particles). The more typical approach would be if a problem exists with SNCR system efficiency at the 1560 F temperature, then hydrogen would be injected with the ammonia to raise localized gas temperatures into the optimum range. Use of hydrogen onsite would pose a safety risk to the project.

Total levelized annual costs would not remain unchanged for an increase in capacity factor from 87 percent to 100 percent. This assumption neglects to consider additional costs for ammonia and energy accrued during additional hours of operation. Accounting for these considerations results in an incremental cost of $1,400 and $1,200 per incremental NO$_x$ ton reduced at a 100 percent capacity factor using a SNCR system on CFB and pulverized coal boilers, respectively.

Lack of SNCR operational data and operational temperature concerns are not the only reasons given for rejecting SNCR systems as BACT. The consideration of environmental factors also supports the selection of combustion controls as BACT. SNCR systems emit various amine compounds formed by unreacted ammonia exiting these systems. This represents a potential adverse human health effect, since many amine compounds are known or suspected carcinogens. Although ammonia emissions are not regulated nationally, at least one district in California recently set a limit of 10 ppm. Unreacted ammonia emissions from an SNCR system could be as high 30 ppm.

Therefore, based on economic, environmental, and energy considerations BACT for NO$_x$ emissions from the Cedar Bay Cogeneration Plant is a CFB boiler with combustion controls for minimizing NO$_x$ emissions.

BACT Determinations for SO_2 Emissions from the KRB

According to the BACT/LAER Clearinghouse, there are two KRBs operating
that have SO_2 emission limits lower than the SO_2 emission limit of 180
ppm for the proposed KRB. One KRB located in Kentucky is limited to an
SO_2 emissions limit of 100 ppm and a KRB in Wisconsin is limited to an
SO_2 emissions limit of 158 ppm. The applicant claims that the boiler in
Kentucky is having problems with meeting its SO_2 limit and that no
operational data is available on the boiler in Wisconsin. We feel that
these are not sound reasons for rejecting the SO_2 emission limits for
these facilities as BACT. Without additional information regarding
operational or design differences between the boilers in Kentucky and
Wisconsin and the proposed boiler, an SO_2 emissions limit in the range
of 100-158 ppm may be required as BACT for the proposed source.

Thank you for allowing us to provide our input. If you have any questions
or comments regarding our comments, please feel free to contact me or
Karrie-Jo Shell of my staff at extension 2864.

Attachment

15.

15. As indicated in Section 10.9 of the BACT analysis, the lowest SO_2 emission
requirement found in BACT/LAER Clearinghouse documents is 100 ppmvd for a
KRB in Kentucky. The plant is still having trouble meeting this low
emission limit. Accordingly, the plant is applying to the state to
increase their SO_2 emission limit to 200 ppm.

The second lowest SO_2 emission limit for a KRB is 158 ppmvd for a facility
being built in Wisconsin. Performance tests for this facility will be
performed in the next six to nine months.

No other KRB facilities listed in the BACT/LAER Clearinghouse documents
have SO_2 emission limits less that 180 ppmvd. Based on this information
and the objective of maintaining maximum flexibility regarding KRB
manufacturer selection, it is still felt that KRB combustion controls
designed to meet a 180 ppmvd SO_2 emission limit represents BACT for the
Cedar Bay KRB.

EMISSION COMPLIANCE TEST METHODS

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