UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

RECEIVED

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DER - BAQM

January 5, 1989

Mr. Hamilton Oven
Siting Coordination Section
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32299-2400

Dear Mr. Oven:

Enclosed is a copy of the letter sent to Julie Blunden of AES concerning sufficiency of the Site Certification Application for the Cedar Bay Cogeneration facility in Jacksonville, Florida. Attached to the letter are comments from EPA (Region IV) review.

If you have any questions, please call me (404/347-7109).

Sincerely,

Marion Jones

Marion Jones
Project Monitor

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET
ATLANTA, GEORGIA 30365

January 5, 1989

Ms. Julie Blunden
Applied Energy Services, Inc.
1925 North Lynn Street
Arlington, VA 22209

Dear Julie:

We have reviewed AES Cedar Bay's Site Certification Application (SCA) for the Cedar Bay Cogeneration Project in Jacksonville, Florida and offer several comments. These comments represent EPA's requirements for information to perform our environmental review under NEPA.

The attached memorandums were received from various programs at EPA Region IV following review of the SCA. Please include these as an extension of the following comments.

1. The effect on aesthetic conditions at the site due to taller stacks and absence of screening material (trees, fences, hedges, etc.) should be addressed.

2. Groundwater consumption at the site will be increased from 19.5 million gallons per day (MGD) up to 26.5 MGD. The possibility of drawdown and salt water intrusion may exist. This possibility should be better evaluated. Any measures that are proposed to ensure that this will not occur should be described.

3. The method used in classifying the groundwater type at the proposed site needs clarification (see attachment A).

4. Coal will be delivered to the plant either by rail or by barge. Either method may potentially cause the destruction of some acreage of wetlands. More detailed information concerning the description of the potentially affected wetlands and available mitigative measures is requested (see attachment B).

5. The proposed construction area is presently used for storage of lime mud from the paper mill, fuel oil storage, and debris storage. The SCA states that "relocation of this sludge and debris . . . are required to make the area suitable for construction." The site for disposal of this material should be addressed. All environmental features and effects of the proposed disposal site must be evaluated.

6. A considerable amount of ash will be generated by the facility annually. The method of disposal of the ash should be decided and announced as soon as possible. The features of the disposal site and any environmental impacts should be described.

7. In the event of the construction of a rail spur for the delivery of coal, relocation of a species of special concern (the gopher tortoise) may be necessary. The feasibility and effects of this relocation should be evaluated through consultation with the US Fish and Wildlife Service.

8. Two areas relative to NPDES permitting require additional information and discussion: metal cleaning waste production, characteristics, and treatment, and development of an Erosion and Sediment Control Plan (see attachment C).

9. The demineralization regeneration wastewater produced by the plant may be considered a hazardous waste. A more detailed description of the neutralization basin is needed in order to make this determination (see attachment D).

10. In the event of the conveyor corridor construction, a small area of shallow water habitat may be impacted by dredging. More information is needed to assess these impacts (see attachment E).

Wayne Aronson, Chief of the Program Support Section in EPA's Air Programs Branch, has made several comments related to air quality and PSD Permitting. Please review and address his comments carefully (see attachment F).

If you have any questions concerning EPA's comments, please call me at 404/347-7109.

Sincerely,

Robert B. Howard

Robert B. Howard, Chief
NEPA Compliance Section

Attachments

cc Mr. Hamilton Oven

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

Date: DEC 14 1988

Subject: NEPA Review, Cedar Bay Cogeneration Project
Applied Energy Services, Jacksonville, Florida

From: David W. Hill, Regional Expert Engineer DWHill
Ground-Water Technology Unit

To: Robert B. Howard, Chief
NEPA Compliance Section

Thru: Gail M. Vanderhoogt, Chief GMV
Ground-Water Technology Unit

The following review comments are submitted on the Cedar Bay Cogeneration Project as you requested in your memorandum of November 28, 1988, to Stallings Howell. We understand that the three volumes labelled "Site Certification Application" will form the basis for an EIS to be prepared by EPA in conjunction with FDER.

SPECIFIC COMMENTS

Pages 2-62, 2-67, and 2-74 -- The ground-water classification discussed in this document is difficult to understand. Was it classified according to EPA's Final Draft Guidelines for Ground-Water Classification under the EPA Ground-Water Protection Strategy, dated December, 1986; or was it classified according to the Florida ground-water classification designations? The EPA classification designates "Class III" ground waters as non-potable, but the Florida classification uses the designation "G-III" for non-potable unconfined aquifers. In Florida only the Environmental Regulatory Commission, a lay-body appointed by the Governor, has the authority to classify ground water; yet, according to the second paragraph on Page 2-74, the "Class III" classification, "not a potential drinking water source," was made by the St. Johns Water Management District.

The first two complete sentences on Page 2-62 are incompatible. They state, "The surficial aquifer has been classified as Class III, not a drinking water source. It supplies water primarily for domestic and some industrial use."

If the "shallow rock aquifer" is considered part of the surficial aquifer, as stated in the text on Page 2-55, the third paragraph on Page 2-67 would clearly support a Class IIA, "current source of drinking water," classification for this aquifer according to the EPA guidelines. This paragraph on Page 2-67 states, "Most wells in the Jacksonville area producing water from the surficial aquifer system have been completed in the limestone unit or 'shallow rock zone' lying at approximately 40 to 100 feet in depth below land surface."

The EIS should clearly show the criteria, the reasoning, and the supporting data behind the ground-water classification cited in the current text.

The EIS should also include a ground-water classification according to EPA's Final Draft Guidelines for Ground-Water Classification under the EPA Ground-Water Protection Strategy, dated December 1986. According to these Guidelines, the ground water should be classified as Class IIA or IIB if, within a two mile radius of the site, the ground water aquifer in question is an actual or potential source of drinking water, respectively. Both Class IIA and Class IIB ground waters are subject to full protection under the laws administered by EPA.

Page 5-31 -- The parameters listed below should be added to the detailed listing on Table 5.3-1 for ground-water quality analysis. These minor additions will allow complete input into our several geochemical models, which could then be applied, if necessary, during the EIS preparation or review.

Chromium (Total) NOTE: This is in addition to the listed "Chromium (Hexavalent)" in order to allow the calculation of Chromium (Trivalent).

Carbonate

Dissolved Oxygen

Density

The ion balance, as defined below, should be calculated and reported with the chemical parameters. If the ion balance is not within five percent, parameters should be reanalyzed as needed until a calculation of less than five percent is achieved.

$$\text{Ion Balance (in percent)} = [(C - A)/(C + A)] \times 100$$

where, expressed in equivalents or milliequivalents,

C = sum of cations, and

A = sum of anions.

If you have any questions, or if you need ground-water modeling - either hydrologic or geochemical - in support of the EIS, please call us at x3866.

ATTACHMENT B

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

MEMORANDUM

DATE: DEC 15 1988

SUBJECT: Cedar Bay Cogeneration Project, Applied Energy Services (AES) Jacksonville, Florida

FROM: Frank M. Redmond, Chief
Wetlands and Coastal Programs Section

TO: Robert B. Howard, Chief
NEPA Compliance Section

Our Wetlands Section has reviewed the document you've enclosed and we make the following comments:

1. BioPhysical Environmental of the Coal Transport by Barge Corridor:

   It appears from our review of aerial infra-red photography of this site and figure 6.2-3 supplied by the applicant, the proposed barge corridor would impact a intertidal wetland area located along the conveyor route. We request additional information as to the approximate acreage of the wetland anticipated to be impacted and a mitigation plan if one has been prepared.

2. BioPhysical Environmental of the Coal Transport by rail corridor:

   Our wetlands concerns focus around the railway extension where it parallels the Broward River. The applicant indicates that this area is a low-tide, shallow mud flat, vegetated with black rush and cordgrass. We request additional information as to the size of this wetland area and the amount of impact.

Thank you for the opportunity to address our Section's wetland concerns.

ATTACHMENT C

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Region IV - 345 Courtland Street N.E. - Atlanta, GA 30365

DATE: December 16, 1988

SUBJECT: Site Certification Application
AES Cedar Bay Cogeneration Project
NPDES No. FL0041173

FROM: Charles H. Kaplan, P.E. (4WM-FP) CHK
National Expert, Steam Electric/Water

TO: Robert B. Howard, Chief
NEPA Compliance Section

Subject document has been reviewed relative to liquid waste discharges, treatment facilities, National Pollutant Discharge Elimination System (NPDES) permitting objectives, and associated environmental impacts. In general, the proposed project has been appropriately developed and discussed in the SCA. A high level of environmental control is proposed for the treatment of liquid waste effluents to assure compliance with new source performance standards (NSPS), 40 CFR §423.15. Cotreatment of Cedar Bay Cogeneration Plant and Seminole Kraft wastes will require that NPDES limitations for some pollutants in the AES wastes be imposed and monitored at internal locations (prior to discharge to the Seminole Kraft treatment facilities) to assure compliance with NSPS. NPDES permitting should proceed with minimal difficulty. Two primary areas, however, require additional information and discussion:

1. Metal cleaning waste production, characteristics, and treatment, and

2. Development of an Erosion and Sediment Control Plan.

Specific comments on these and other areas are attached.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV - ATLANTA, GEORGIA

MEMORANDUM

DATE: DEC 28 1988

SUBJECT: Comments on Cedar Bay Cogeneration Project
Jacksonville, Florida

FROM: Harry Desai, Acting Chief
Florida/Georgia Unit
Waste Engineering Section

TO: Robert B. Howard, Chief
NEPA Compliance Section

As per your request, the appropriate portions of the NPDES application/Site Certification for the Cedar Bay Cogeneration Project have been reviewed to determine the impact of this project with regard to Subtitle C of the Resource Conservation and Recovery Act (RCRA). Since fly ash and bottom ash wastes are excluded from the definition of hazardous waste (40 CFR §261.4(b)(4)), they would not be regulated under our program. The application briefly mentions that up to 6,000 cubic yards of fuel oil contaminated soils/material may need to be removed from the site and disposed (p. 4-13). This would not be regulated by Subtitle C of RCRA either; however, it is of concern and should be brought to the attention of the appropriate State program personnel to ensure proper excavation and disposal.

Based on past experience with energy generating facilities, the demineralization regeneration wastewater may be a hazardous waste due to its corrosive characteristics. According to the application, an average of 147,000 gpd of this wastewater will be routed to a neutralization basin for pH adjustment and then to the Seminole Kraft wastewater treatment facility (p. 3-40). The application also states that the basin would be exempt from RCRA regulation since it is considered an "elementary neutralization unit" (p. 3-43). If indeed the wastewater is a hazardous waste, the exemption under 40 CFR §264.1(g)(6) would need to be determined through the EPA's review of the design specifications for the basin. It is recommended that standard tank design specifications be used for construction of the basin if it is to meet the exemption requirements. The brief description of the basin (p. 3-41) is not adequate to make this determination.

Should you have any questions regarding these comments, please contact Robin Mitchell at x7603.

Detailed Comments
Site Certification Application
AES Cedar Bay Cogeneration Plant
NPDES No. FL0041173

1. Page 1-16, Table 1.3-1: The TVA pilot project appears to have been included twice, but the 200 MW demonstration project (Shawnee Unit 10) has not been included.

2. Page 1-35, et seq., Section 1.4.2: If the project is completed, how will it affect the Florida Power and Light Company schedules for modifications/additions at the Lauderdale and Martin County Sites?

3. Page 2-89, Table 2.3-14: Maximum temperature and maximum temperature rise criteria from Chapter 17-3.050 of the Florida Administrative Code (FAC) are applicable and should be included.

4. Page 3-6, Figure 3.2-3 (and possibly else where): Location of the Seminole Kraft treatment facilities should be shown.

5. Page 3-14, Section 3.3.5: Is a discharge from the spill containment dike expected?

6. Page 3-25, Section 3.4.3.1, first paragraph: It is noted that the Cedar Bay Cogeneration Plant (CBCP) will generate a maximum of 2.3 million lb/hr of steam. This converts to 10,222 lb/hr/MW (at 225 MW plant capacity) without reduction for the 640,000 lb/hr of steam to be sold to Seminole Kraft. However, 12,000 lb/hr was assumed to be necessary to produce one MW for Table 1.3-1 values (page 1-16). Clarification is requested.

7. Page 3-29, Figure 3.5-1 and the Mass Water Balance in the NPDES Application: Modification to show internal NPDES limitation/monitoring points for (1) boiler blowdown discharge to the cooling tower [total suspended solids (TSS) and oil and grease (O&G)], (2) metal cleaning wastes (total iron and total copper, and possibly O&G), (3) plant effluent prior to discharge to the Seminole Kraft treatment facilities (O&G and possibly pH, heavy metals, and other parameters), and/or (4) a final monitoring point prior to discharge (total residual chlorine, pH, and possibly other parameters).

8. Page 3-33: Maximum expected cooling tower blowdown temperature is noted as approximately 93°F; however, the NPDES application (Form 2D, page 3 of 5, following page 10.1) indicates a daily maximum (24-hour) value of 95°F. Clarification is requested.

9. Page 3-39, Section 3.6.2: Use of hydrazine in the normal steam cycle is discussed; however, possible layup of the boiler (and possibly other equipment) during extended maintenance or repair could necessitate the use and discharge of much higher quantities of hydrazine. If not included in the NPDES application and permit, discharge would be unauthorized. Discussion is requested.

10. Page 3-40, Section 3.6.6: Discussion of metal cleaning wastes is incomplete. Three categories of metal cleaning wastes should be discussed, (1) preoperational metal cleaning (degreasing compounds with high phosphate concentrations and possibly acid and alkaline cleaning compounds, etc.), (2) operational chemical metal cleaning (acid and alkaline compounds, etc., but with much lower levels of phosphorus), and (3) nonchemical metal cleaning (water wash operations, generally without chemicals) of the fireside of the steam tubes, air

preheater (if one will be used), smoke stack, etc. The statement that neutralization will be provided by the cleaning contractor is inadequate to assure compliance with 40 CFR Part 423 requirements. Where acid cleaning and alkaline copper removal steps are practiced, the wastes generally must be treated separately since the chelated copper complex will not break down when mixed with the acid cleaning wastes. Two stage lime precipitation may be required to achieve adequate removal of heavy metals (and phosphorus) in preoperational metal cleaning and acid chemical cleaning wastes. If metal cleaning wastes are cotreated with other wastes, it is difficult to demonstrate compliance with quantity limitations on total iron and total copper (indicator parameters for all the heavy metal pollutants present) due to dilution. Revision to Figure 3.5-1, page 3-29 and the Water Mass Balance in the NPDES Application may require modification. See subsequent comments on this issue.

11. Page 3-43, Section 3.7.1: Possible outside storage of ash pellets should be reconsidered to assure that there is no discharge of pollutants from fly ash.

12. Page 3-43, Section 3.7.2: The statement that neutralization of acidic boiler cleaning wastes is inadequate as noted before.

13. Page 3-44, et seq., Section 3.8.1 and 3.8.2: It is suggested that a sand mound/perforated pipe discharge structure be incorporated in the ponds (see attached example). Both ponds should be designed to contain at least the volume of runoff that will result from a 10-year, 24-hour storm plus an allowance for solids that will be settled (approximately eight inches per 24 hours, rather than 0.5 inch as indicated for the Yard Area Runoff Pond. It is suggested that consideration be given to placing bright colored objects (frisby or similar discs) on top of impervious synthetic liners to assist in the location/protection of the liners during future cleaning operations.

14. Page 3-46, Section 3.8.3: Structures and facilities noted in this section should be located on a figure in the SCA.

15. Page 3-47, Section 3.9.1: Comments in item 13 are appropriate to any additional ponds which are to be provided.

16. Page 4-1, et seq., Chapter 4: An Erosion and Sediment Control Plan should be developed and submitted for review and approval, to include:

    a. Evaluation of site soil characteristics (by area, if necessary) as to particle size and characteristics, erodibility, and settlability,

    b. Discussions with topographic map(s) showing (1) specific areas and locations where control facilities (silt fences, hay bales, swales, ponds, etc.) will be used (2) all point source and nonpoint source discharges of runoff, and (3) structures and facilities referenced in the plan,

    c. Specific assessment of the handling and ultimate disposal of lime-mud piles and sediments,

    d. Specific assessment of the handling and disposal of oil contaminated soils,

    e. Consideration of additional sedimentation control facilities (sand filtration), and

f. Discussion of flood impacts, if any, on the above items.

It is anticipated that the NPDES permit will include a provision stating:

"Not later than the start of onsite constuction, the permittee shall implement the erosion and sediment control plan approved on (date). Erosion and sediment control practices and control of runoff from site construction shall be consistent with sound engineering practices, such as those found in "Guidelines for Erosion and Sediment Control Planning and Implementation," EPA-R2-72-015 (August 1972) and "Processes, Procedures and Methods to Control Pollution Resulting from Construction Activity," EPA-430/9-72-007 (October 1973). In addition to monitoring of point sources of runoff from construction as required in Part I of this permit, permittee shall submit a summary evaluation of monitoring frequency, results, adequacy, and environmental effects of runoff control practices on (date: six months after start of construction), (Date: 12 months after start of construction), and annually thereafter."

Note: More recent references may be included.

17. Page 5-6, et seq., Section 5.2.1: A discussion and tables of of waste characteristics and impacts on discharges of all three categories of metal cleaning wastes, should be included. Although these wastes are produced and discharged infrequently, they contain high concentrations of heavy metals and other pollutants. Although NSPS for nonchemical metal cleaning wastes [40 CFR §423.15(e)], it is anticipated that effluent limitations equivalent to those for best practicable control technology currently available (BPT) for metal cleaning wastes [§423.12(c)(5)] will be included in the NPDES permit (O&G, total copper, and total iron). Additionally, it is anticipated that a phosphorus limitation of 2.0 mg/l will be included for preoperational metal cleaning waste and subsequent operational wastes if a high phosphate containing chemical is used. See previous comments on this subject.

18. Page 5-8, Table 5.2-1: Although nonchemical metal cleaning waste limitations have been reserved, reference should be included in the table.

19. Page 5-12 through -14, 5-16 and -17, and 5-22 and -23, Tables 5.2-3, -4, -5 and -8, respectively: Constituant (pollutant) names should be provided rather than abbreviations and symbols.

20. Page 5-18, Table 5.2-6: Temperature criteria should be included.

21. Page 5-21, Section 5.2.2: A mixing zone for temperature may also be required.

22. Page 5-24, Section 5.2.4: Are characterics of coal proposed for the site similar to those evaluated in the referenced document? What source(s) of information were used to estimate the characteristics of the other plant wastes?

ATTACHMENT E

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

ENVIRONMENTAL SERVICES DIVISION
ATHENS, GEORGIA 30613

MEMORANDUM

DATE: DEC [illegible]

SUBJECT: Site Certification Application, Cedar Bay Cogeneration Project

FROM: Delbert B. Hicks, Chief
Ecological Support Branch

TO: Robert Howard

Per your request, I reviewed the subject site application. My comments are limited to the potential project impacts to aquatic life.

1. The proposed use of closed cycle cooling via mechanical draft towers relieves concern regarding intake and discharge impact on aquatic life.

2. The only question of concern relates to the proposed conveyor corridor. To accommodate this corridor, the dredging of approximately 3 to 3.5 acres of shallow water habitat (depths less than 4 feet) will be required for construction needs, i.e. pile driving barges and possibly long term maintenance needs of the conveyor system. The document inadequately describes the biological community types associated with the shallow water habitat to be impacted by the dredging. Authors of the document diminish the importance of this relatively small area (3 to 3.5 acres) on the basis that it is nonsignificant when considering the total area of the two rivers. This rationale may not be appropriate if the subject 3 to 3.5 acres is a sensitive aquatic vegetation (SAV) community.

3. In the absence of a critical habitat such as an SAV community, the proposed dredges for the conveyor corridor appear justifiable as indicated in the document.

ATTACHMENT F

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 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

Wayne J. Aronson

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

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 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:

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

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.

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_2SO_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).

Table 1. Sulfur Dioxide Emissions and Incremental Costs

Alternative	Uncontrolled Emissions (TPY)	SO_2 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
	H_2SO_4 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
	H_2SO_4 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
H_2SO_4 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_xOUT, 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

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

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

MEMORANDUM

DATE: DEC 22 1988

TO: Robert B. Howard
NEPA Compliance Section

FROM: Jim Bloom, JW
Water Quality Standards and Monitoring Section
Water Quality Management Branch

SUBJECT: Cedar Bay Cogeneration Project, Applied Energy Services
Jacksonville, Florida

Per your request, we have reviewed the site certification application for the above project with regards to potential adverse surface water impacts.

One issue of concern is an anticipated iron concentration in the expected wastewater discharge which may exceed the Class III Florida water quality criteria of 0.3 mg/l. Since the receiving water, the St. Johns River, at times exceeds 0.3 mg/l a variance will be needed to allow an effluent iron concentration above 0.3 mg/l. Iron is not a priority pollutant. The federal criterion for freshwater aquatic life is 1.0 mg/l and there currently is no federal criterion for marine aquatic life. Consequently, a minor increase in iron in the St. Johns if allowed by Florida would not exceed federal criteria and should not adversely affect aquatic life or human health.

In summary, our review did not indicate that this project would have any serious adverse affects on aquatic life or, through aquatic organism ingestion, on human health.

Please telephone me (x 2126) if you have any questions or comments.