Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

March 28, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Jeff Swain
AES/Cedar Bay Inc.
1001 North 19th Street
Arlington, Virginia 22209

Dear Mr. Swain:

Re: AES/Cedar Bay Inc.
Cogeneration Project, PSD-FL-137

Please find enclosed the above referenced permit. You have the right to petition for an administrative hearing pursuant to Section 120.57, Florida Statutes, within 14 days of receipt of this permit or file a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, within 30 days from the date this permit is filed with the Clerk of the Department. Further, you may request a public hearing. Such request must be submitted within 30 days of receipt of this permit.

If you have any questions, please call Barry Andrews at (904)488-1344 or write to me at the above address.

Sincerely,

Barry D. Andrews

for C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/kt

enclosure

cc: J. Harper, EPA
A. Kutyna, NE District
K. Kurts, BESD
T. Cole, Oertel & Hoffman

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of buisness on 3-29-91.

FILING AND ACKNOWLEDGEMENT FILED, on this date, pursuant to §120.52(9), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kyri Dober — Clerk

3-29-91 — Date

Final Determination

AES/Cedar Bay Inc.
Cogeneration Project
Duval County, Florida

Permit No: PSD-FL-137

Florida Department of Environmental Regulation
Division of Air Resources Management
Bureau of Air Regulation

March 28, 1991

Final Determination

AES/Cedar Bay, Inc.'s PSD permit application (part of the Power Plant Siting application), has been reviewed by the Division of Air Resources Management. Comments received from EPA Region IV dated March 27, 1991 (see attachment 2) are addressed below.

Public Notice

The EPA questioned why the notice was published on the same date that the Site Certification Hearing was scheduled to begin, thereby not providing a 30 day notice and comment period.

Notice was published originally on December 8, 1989, for a January 8, 1990 hearing. A copy of the proposed Notice was sent to Region IV on December 1, 1989 for review. No comments were received regarding the increment consumptions reflected in the Notice sent to EPA. The hearing was then postponed from January 8, 1990 to February 5, 1990. The hearing then had to be continued on February 20, 1990 for which the Notice was published on February 12, 1990. In addition, public access hearings were held on February 7, 1990 and February 21, 1990 for nonparty members of the public. The public always has the right to speak. Only if they intervene as a formal party do they need an attorney as required by Florida law.

BACT Analysis

The Department agrees with EPA that add-on NOx controls are technically feasible for the AES/Cedar Bay project. The decision to establish the NOx limitation at 0.29 lb/MMBtu was based on the overall benefits that would be obtained from the construction of the cogeneration facility (the additional cost of SNCR would cause the project to become financially unfeasible). The circulating fluidized bed (CFB) boilers will replace older boilers which have higher emissions per heat input. In addition, the 0.29 lb/MMBtu limitation was judged to be the most stringent limitation placed on a coal fired boiler which does not have add-on NOx controls.

For sulfur dioxide, the Department evaluated the cost of switching to a lower sulfur coal and determined that such a cost was prohibitive. It should be noted that the decision to limit the average annual sulfur content to 1.7 percent is well below the initial proposal of 3.3 percent by the applicant. With regard to the control efficiency, the Department believes that 90 percent efficiency is reasonable for the CFB design.

Florida Department of Environmental Regulation

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Lawton Chiles, Governor

Carol M. Browner, Secretary

PERMITTEE:
AES/Cedar Bay, Inc.
1001 North 19th Street
Arlington, VA 22209

Permit Number: PSD-FL-137
County: Duval
Latitude/Longitude: 30°25'21"N
81°36'23"W
Project: Cogeneration Project

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the installation of 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.

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 cogeneration facility will generate 225 MW of electricity for sale to Florida Power & Light as well as low pressure process steam for the Seminole Kraft Corporation.

Nitrogen oxides will be controlled by the good combustion characteristics which are an inherent part of the CFB technology. Sulfur dioxide will be controlled by limiting the average annual sulfur content to 1.7% and the inherent limestone scrubbing provided by the CFB technology. Particulates will be controlled with fabric filters.

Construction shall be in accordance with the permit application and additional information submitted except as otherwise noted in the Specific Conditions.

Attachments:

1. Power plant site certification package PA 88-24 and its associated attachments, dated January 19, 1990.
2. Letter from EPA dated March 27, 1991.
3. DER's Final Determination dated March 28, 1991.

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

GENERAL CONDITIONS:

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. a description of and cause of non-compliance; and

b. the period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance,

GENERAL CONDITIONS:

provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

(x) Determination of Best Available Control Technology (BACT)
(x) Determination of Prevention of Significant Deterioration (PSD)
(x) Compliance with New Source Performance Standards

14. The permittee shall comply with the following:

a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling or measurements;
- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

General Conditions:

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

1. The construction and operation of AESCB shall be in accordance with all applicable provisions of Chapters 17-2, F.A.C.. In addition to the foregoing, AESCB shall comply with the following conditions of certification as indicated.

A. Emission Limitations for AES Boilers

1. Fluidized Bed Coal Fired Boilers (CFB)

a. The maximum coal charging rate of each CFB shall neither exceed 104,000 lbs/hr, 39,000 tons per month (30 consecutive days), nor 390,000 tons per year (TPY). This reflects a combined total of 312,000 lbs/hr, 117,000 tons per month, and 1,170,000 TPY for all three CFBs.

b. The maximum wood waste (primarily bark) charging rate to the No. 1 and No. 2 CFBs each shall neither exceed 15,653 lbs/hr, nor 63,760 TPY. This reflects a combined total of 31,306 lbs/hr, and 127,521 TPY for the No. 1 and No. 2 CFBs. The No. 3 CFB will not utilize woodwaste, nor will it be equipped with wood waste handling and firing equipment.

c. The maximum heat input to each CFB shall not exceed 1063 MMBtu/hr. This reflects a combined total of 3189 MMBtu/hr for all three units.

d. The sulfur content of the coal shall not exceed 1.7% by weight on an annual basis. The sulfur content shall not exceed 3.3% by weight on a shipment (train load) basis.

e. Auxiliary fuel burners shall be fueled only with natural gas or No. 2 fuel oil with a maximum sulfur content of 0.3% by weight. The fuel oil or natural gas shall be used only for startups. The maximum annual oil usage shall not exceed 160,000 gals/year, nor shall the maximum annual natural gas usage exceed 22.4 MMCF per year. The maximum heat input from the fuel oil or gas shall not exceed 1120 MMBtu/hr for the CFBs.

f. The CFBs shall be fueled only with the fuels permitted in Conditions 1a, 1b, and 1e above. Other fuels or wastes shall not be burned without prior specific written approval of the Secretary of DER pursuant to condition XXI, Modification of Conditions.

g. The CFBs may operate continuously, i.e, 8760 hrs/yr.

2. Coal Fired Boiler Controls

The emissions from each CFB shall be controlled using the following systems:

a. Limestone injection, for control of sulfur dioxide.
b. Baghouse, for control of particulate.

3. Flue gas emissions from each CFB shall not exceed the following:

		Emission Limitations		
Pollutant	lbs/MMBtu	lbs/hr	TPY	TPY for 3 CFBs
CO	0.19	202	823	2468
NOx	0.29	308.3	1256	3767
SO_2	0.60 (3-hr avg.)	637.8	--	--
	0.31 (12 MRA)	329.5	1338	4015
VOC	0.015	16.0	65	195
PM	0.020	21.3	87	260
PM_{10}	0.020	21.3	86	257
H_2SO_4 mist	0.024	25.5	103	308
Fluorides	0.086	91.4	374	1122
Lead	0.007	7.4	30	91
Mercury	0.00026	0.276	1.13	3.4
Beryllium	0.00011	0.117	0.5	1.5

Note: TPY represents a 93% capacity factor. MRA refers to a twelve month rolling average.

4. Visible emissions (VE) shall not exceed 20% opacity (6 min. average), except for one 6 minute period per hour when VE shall not exceed 27% opacity.

5. Compliance with the emission limits shall be determined by EPA reference method tests included in the July 1, 1988 version of 40 CFR Parts 60 and 61 and listed in Condition No. 7 of this permit or by equivalent methods after prior DER approval.

6. The CFBs are subject to 40 CFR Part 60, Subpart Da; except that where requirements within this certification are more restrictive, the requirements of this certification shall apply.

7. Compliance Tests for each CFB

a. Initial compliance tests for PM/PM_{10}, SO_2, NOx, CO, VOC, lead, fluorides, mercury, beryllium and H_2SO_4 mist shall be conducted in accordance with 40 CFR 60.8 (a), (b), (d), (e), and (f).

b. Annual compliance tests shall be performed for PM, SO_2 and NOx, commencing no later than 12 months from the initial test.

c. Initial and annual visible emissions compliance tests shall be determined in accordance with 40 CFR 60.11(b) and (e).

d. The compliance tests shall be conducted between 90-100% of the maximum liscensed capacity and firing rate of each permitted fuel.

e. The following test methods and procedures of 40 CFR Parts 60 and 61 or other DER approved methods with prior DER approval shall be used for compliance testing:

(1) Method 1 for selection of sample site and sample traverses.
(2) Method 2 for determining stack gas flow rate.
(3) Method 3 or 3A for gas analysis for calculation of percent O_2 and CO_2.
(4) Method 4 for determining stack gas moisture content to convert the flow rate from actual standard cubic feet to dry standard cubic feet.
(5) Method 5 or Method 17 for particulate matter.
(6) Method 6, 6C, or 8 for SO_2.
(7) Method 7, 7A, 7B, 7C, 7D, or 7E for nitrogen oxides.
(8) Method 8 for sulfuric acid mist.
(9) Method 9 for visible emissions, in accordance with 40 CFR 60.11.
(10) Method 10 for CO.
(11) Method 12 for lead.
(12) Method 13B for fluorides.
(13) Method 25A for VOCs.
(14) Method 101A for mercury.
(15) Method 104 for beryllium.

8. Continuous Emission Monitoring for each CFB AESCB shall use Continuous Emission Monitors (CEMS) to determine compliance. CEMS for opacity, SO_2, NOx, CO, and O_2 or CO_2, shall be installed, calibrated, maintained and operated for each unit, in accordance with 40 CFR 60.47a and 40 CFR 60 Appendix F.

a. Each continuous emission monitoring system (CEMS) shall meet performance specifications of 40 CFR 60, Appendix B.

b. CEMS data shall be recorded and reported in accordance with Chapter 17-2, F.A.C., and 40 CFR 60. A record shall be kept for periods of startup, shutdown and malfunction.

c. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

d. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation and operation of all CEMS.

e. Opacity monitoring system data shall be reduced to 6-minute averages, based on 36 or more data points, and gaseous CEMS data shall be reduced to 1-hour averages, based on 4 or more data points, in accordance with 40 CFR 60.13(h).

f. For purposes of reports required under this certification, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Condition No. 10 herein, which exceeds the applicable emission limit in Condition No. 3.

9. Operations Monitoring for each CFB

a. Devices shall be installed to continuously monitor and record steam production, and flue gas temperature at the exit of the control equipment.

b. The furnace heat load shall be maintained between 70% and 100% of the design rated capacity during normal operations.

c. The coal, bark, natural gas and No. 2 fuel oil usage shall be recorded on a 24-hr (daily) basis for each CFB.

10. Reporting for each CFB

a. A minimum of thirty (30) days prior notification of compliance test shall be given to DER's N.E. District office and to the BESD (Bio-Enviro~~nmental Services~~ Division) office, in accordance with 40 CFR 60.

b. The results of compliance test shall be submitted to the BESD office within 45 days after completion of the test.

c. The owner or operator shall submit excess emission reports to BESD, in accordance with 40 CFR 60. The report shall include the following:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factors used, and the date and time of commencement and completion of each period of excess emissions (60.7(c)(1)).

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the furnace boiler system. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measured adopted (60.7(c)(2)).

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks, and the nature of the system repairs or adjustments (60.7(c)(3)).

(4) When no excess emissions have occured or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report (60.7(c)(4)).

(5) The owner or operator shall maintain a file of all measurements, including continuous monitoring systems performance evaluations; monitoring systems or monitoring device calibration; checks; adjustments and maintenance performed on these systems or devices; and all other information required by this permit recorded in a permanent form suitable for inspection (60.7(d)).

d. Annual and quarterly reports shall be submitted to BESD as per F.A.C. Rule 17-2.700(7).

11. Any change in the method of operation, fuels utilized, equipment, or operating hours or any other changes pursuant to F.A.C. Rule 17-2.100, defining modification, shall be submitted for approval to DER's Bureau of Air Regulation.

B. AES - Material Handling and Treatment

1. The material handling and treatment operations may be continuous, i.e. 8760 hrs/yr.

2. The material handling/usage rates shall not exceed the following:

Material	Handling/Usage Rate TPM	TPY
Coal	117,000	1,170,000
Limestone	27,000	320,000
Fly Ash	28,000	336,000
Bed Ash	8,000	88,000

Note: TPM is tons per month based on 30 consecutive days, TPY is tons per year.

3. The VOC emissions from the maximum No. 2 fuel oil utilization rate of 240 gals/hr, 2,100,000 gals/year for the limestone dryers; and 8000 gals/hr, 160,000 gals/year for the three boilers are not expected to be significant.

4. The maximum emissions from the material handling and treatment area, where baghouses are used as controls for specific sources, shall not exceed those listed below (based on AP-42 factors):

Source	Particulate Emissions lbs/hr	TPY
Coal Rail Unloading	neg	neg
Coal Belt Feeder	neg	neg
Coal Crusher	0.41	1.78
Coal Belt Transfer	neg	neg
Coal Silo	neg	neg
Limestone Crusher	0.06	0.28
Limestone Hopper	0.01	0.03
Fly Ash Bin	0.02	0.10
Bed Ash Hopper	0.06	0.25
Ash Silo	0.06	0.25
Common Feed Hopper	0.03	0.13
Ash Unloader	0.01	0.06

The emissions from the above listed sources and the limestone dryers are subject to the particulate emission limitation requirement of 0.03 gr/dscf. However, neither DER nor BESD will require particulate tests in accordance with EPA Method 5 unless the

VE limit of 5% opacity is exceeded for a given source, or unless DER or BESD, based on other information, has reason to believe the particulate emission limits are being violated.

5. Visible Emissions (VE) shall not exceed 5% opacity from any source in the material handling and treatment area, in accordance with F.A.C. Chapter 17-2.

6. The maximum emissions from each of the limestone dryers while using oil shall not exceed the following (based on AP-42 factors, Table 1, 3-1, Industrial Distillate, 10/86):

	Estimated Limitations		
Pollutant	lbs/hr	TPY	TPY for 2 dryers
PM/PM_{10}	0.25	1.1	2.2
SO_2	5.00	21.9	43.8
CO	0.60	2.6	5.2
NOx	2.40	10.5	21.0
VOC	0.05	0.2	0.4

Visible emissions from the dryers shall not exceed 5% opacity. If natural gas is used, emissions limits shall be determined by factors contained in AP-42 Table 1. 4-1, Industrial 10/86.

7. The maximum No. 2 fuel oil firing rate for each limestone dryer shall not exceed 120 gals/hr, or 1,050,000 gals/year. This reflects a combined total fuel oil firing rate of 240 gals/hr, and 2,100,000 gals/year, for the two dryers.
The maximimum natural gas firing rate for each limestone dryer shall not exceed 16,800 CF per hour, or 147 MMCF per year.

8. Initial and annual Visible Emission compliance tests for all the emission points in the material handling and treatment area, including but not limited to the sources specified in this permit, shall be conducted in accordance with the July 1, 1988 version of 40 CFR 60, using EPA Method 9.

9. Compliance test reports shall be submitted to BESD within 45 days of test completion in accordance with Chapter 17-2.700(7) of the F.A.C.

10. Any changes in the method of operation, raw materials processed, equipment, or operating hours or any other changes pursuant to F.A.C. Rule 17-2.100, defining modification, shall be submitted for approval to DER's Bureau of Air Regulation (BAR).

C. Requirements For the Permittees

1. Beginning one month after certification, AESCB shall submit to BESD and DER's BAR, a quarterly status report briefly outlining progress made on engineering design and purchase of major equipment, including copies of technical data pertaining to the selected emission control devices. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of any such device. Such disapproval shall be issued within 30 days of receipt of the technical data.

2. The permittees shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the BESD office.

3. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, regrassing or watering areas of disturbed soils, will be taken by the permittees.

4. Fuel shall not be burned in any unit unless the control devices are operating properly, pursuant to 40 CFR Part 60 Subpart Da.

5. The maximum sulfur content of the No. 2 fuel oil utilized in the CFBs and the two unit limestone dryers shall not exceed 0.3 percent by weight. Samples shall be taken of each fuel oil shipment received and shall be analyzed for sulfur content and heating value. Records of the analyses shall be kept a minimum of two years to be available for DER and BESD inspection.

6. Coal fired in the CFBs shall have a sulfur content not to exceed 3.3 percent by weight. Coal sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a.

7. AESCB shall maintain a daily log of the amounts and types of fuel used and copies of fuel analyses containing information on sulfur content and heating values.

8. The permittees shall provide stack sampling facilities as required by Rule 17-2.700(4) FAC.

9. Prior to commercial operation of each source, the permittees shall each submit to the BAR a standardized plan or procedure that will allow that permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

D. Contemporaneous Emission Reductions

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, that the following Seminole Kraft Corporation sources be permanently shut down and made incapable of operation, and shall turn in their operation permits to the Division of Air Resources Management's Bureau of Air Regulation, upon completion of the initial compliance tests on the AESCB boilers: the No. 1 PB (power boiler), the No. 2 PB, the No. 3 PB, the No. 1 BB (bark boiler), and the No. 2 BB. BESD shall be specifically informed in writing within thirty days after each individual shut down of the above referenced equipment. This requirement shall operate as a joint and individual requirement to assure common control for purpose of ensuring that all commitments relied on are in fact fulfilled.

Issued this 28th day
of March, 1991

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Carol M. Browner

Carol M. Browner, Secretary

ENVIRONMENTAL CONSULTING SERVICES, CO.

ROBERT G. HAINES, Ph.D.
President

P.O. Box 733
Orange Park, FL 32067-0733
(904) 282-7788

September 18, 1991

Dan Thompson, Esq.
Office of General Counsel
FL Dept. of Environmental Regulation
2000 Blair Stone Road
Tallahassee, FL 32399-2400

Re: AES - Cogeneration

Dear Dan:

Attached is a letter from the National Park Service Air Quality Division dated April 17, 1991 to Clair Fancy, DARM. Please supply: (1) the official response by FDER to this letter; (2) a full and complete reason why the Preliminary Determination document dated October 29, 1990 "arrived in the NPS office on March 15, 1991;" (3) who gave NPS assurance on March 20, 1991 that 30 days would be allowed for comment when the "final agency action" occurred on February 11, 1991; (4) a copy of the NPS comment letter that was belatedly filed; (5) was the public properly apprised of the permitting authority's response; (6) a complete explanation of why this procedure was not appropriately followed; (7) what was the response, if any, from Jellell Harper, EPA; (8) does the Power Plant Siting Act also preempt the involvement of the Federal Land Manager in PSD notification and permitting procedures; (9) a copy of <u>that</u> information that was supplied to NPS; (10) was the siting board informed on this obvious failure on part of the DER and if not, why not; (11) was the NPS and FLM notified of the existence of the 47,000 acre Timucuan Preserve established in 1988, of which Rep. Charles Bennett informed Gov. Martinez on 6/13/90, that is 3 km from the projected AES site and is a Class I area that has had no evaluation by the FLM or the Department; (12) what is the impact on the failure of DER to properly follow the procedures required by law on the validity of the "final agency action."

Your immediate response to these queries is important as the people in the Jacksonville Area are gravely concerned about this entire matter.

Sincerely,

Doc

R. G. Haines, Ph.D.
President

ejh
cc Steve Smallwood, DARM
David Maloney, Governor's Office
Congressman Charles Bennett
Diana Sawaya-Crane, Attorney General's Office
Mayor Ed Austin, Jacksonville

A Consulting Firm Dedicated To A Clean Environment.

RECEIVED
SEP 23 1991
Dept. of Environmental Reg.
Office of General Counsel

Mr. Campbell,
Enclosed is a copy of the document you requested. Please call me if you have questions.
Sandra Silva
(303) 969-2814

April 17, 1991

N3615(475)

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

Dear Mr. Fancy:

As you know, the National Park Service (NPS) Air Quality Division has been involved in the review of a number of Prevention of Significant Deterioration (PSD) permit applications submitted to the Florida Department of Environmental Regulation (FDER). For the most part, the FDER has been diligent in its efforts to inform us of projects with the potential to impact class I areas under the jurisdiction of the NPS and the U.S. Fish and Wildlife Service, and has been receptive to our comments on permit applications. We appreciate your continued cooperation in this regard. However, the process of Power Plant Site Certification (PPSC) appears to bypass Federal Land Manager (FLM) involvement in the permitting process. We understand that the PSD review is included as part of the PPSC process, and in these cases, the normal PSD notification and permitting procedures apparently are not followed. For example, in recent months, there have been two instances in which we did not receive a copy of your Technical Evaluation and Preliminary Determination (Preliminary Determination) document for a proposed project until long after the public comment period had ended.

The first case involves the Florida Power and Light Lauderdale Repowering Project. Although we received the original application in December of 1989, our office was not notified when the application was deemed complete by the FDER in May of 1990, nor were we notified when the public comment period began in August of 1990. On January 31, 1991, we received a copy of the Preliminary Determination document dated September 24, 1990. In this case, we were able to supply comments to the FDER in time for them to be considered.

The second case involves the AES/Cedar Bay Cogeneration Project. The Preliminary Determinatión document dated October 29, 1990, arrived in our office on March 15, 1991. We were assured by telephone on March 20 that we would have 30 days to comment; we later discovered that the final permit had been issued on March 28. In this instance, we were not able to supply comments in time for them to be considered by the FDER. We will forward a comment letter to you in the near future so that it may be included in the project file.

Generally, for projects with potential visibility impacts, the FLM is allowed a minimum of 60 days to review all information relevant to the permit application in order to evaluate potential impacts on a class I area and consult with the permitting authority on these potential impacts. If the FLM believes that the proposed facility may have an adverse impact on visibility, and so notifies the permitting authority within 30 days of receiving all relevant information (i.e., a complete application), then the public hearing notice must include certain information so that the public is fully apprised of the permitting authority's response to the FLM's information and can provide relevant comments at the hearing. For future applications that involve PPSC, we ask that you follow the same notification procedures that you use in other PSD projects, i.e., that you provide us with a copy of the application as soon as you receive it, and also notify our office when the application is deemed complete. We also ask that you forward copies of any supplemental information provided by the applicant, as well as your Preliminary Determination document. Additionally, we would like to be notified when the public comment period begins so that we can be assured of having ample time to provide comments to the FDER.

On a related matter, during a recent telephone conversation with FDER staff, we learned that members of your staff are in the process of reviewing a PPSC for Florida Power and Light's 1600 MW Martin Coal Gasification Project. We were told that we had not been notified of this project because the FDER was under the impression that we are only concerned about facilities proposed within a 100 km radius of a class I area. We wish to clarify that FLM notification should not be limited to this 100 km distance. Guidance provided by the Environmental Protection Agency (EPA) regarding FLM notification also recognizes the possible impacts of sources located more than 100 km from a class I area. In a March 19, 1979, policy memorandum, EPA states:

> ".....notice should be provided (to the FLM) for any facility which will be located within 100 km of a Class I area. Very large sources, however, may be expected to affect air quality related values at distances greater than 100 kilometers. The appropriate Federal Land Manager should be notified if such impacts are expected on a case-by-case basis".

Therefore, we suggest that you consult with us in the future on our need to review applications received on large projects located more than 100 km from a class I area. We are in the process of reviewing the Martin Coal Gasification Project application at this time and will submit our comments to the FDER shortly.

If you have any questions regarding these issues, please contact Tonnie Maniero in our office at (303) 969-2071.

Sincerely,

Erik R. Hauge for

Christine L. Shaver
Chief, Policy, Planning
and Permit Review Branch

cc:
Jellell Harper, Chief
Air Enforcement Branch
Air, Pesticides and Toxics
Management Division
U.S. EPA, Region 4
345 Courtland St., NE
Atlanta, Georgia 30365

bcc:
WASO: 475
SERO: AQC
EVER: Supt.
WOIS: Refuge Manager
CHAS: Refuge Manager
SAMA: Refuge Manager
OKEF: Refuge Manager
FWS-REG. 4: AQC
FWS-REG. 6: Ty Berry
AQD-DEN: Reading and Project Files, Bunyak, Notar, Shaver, Silva
AQD-DEN:TManiero:tm:4/11/91:x2071:Florida.ltr

PM
3-28-91
Atlanta, Ga.

File Copy

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

4APT-AEB

MAR 27 1991

RECEIVED
APR 1 1991
DER-BAQM

Mr. Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental
 Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Preliminary Determination for AES/Cedar Bay (PSD-FL-137)

Dear Mr. Fancy:

This is to acknowledge receipt of your preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility dated March 11, 1991. We have reviewed the package as requested and have the following comments.

Public Notice

The public notice submitted in the package was specifically for the Site Certification Process. The notice is dated February 5, 1990, with the Site Certification Hearing scheduled for February 5, 1990. This does not fulfil the 30 day notice and comment period requirement of Florida's PSD regulation which was approved pursuant to 40 CFR §51.162. Item 8 of the public notice requires that persons "wishing to intervene in these proceedings must be represented by an attorney or other person who can be determined to be qualified..." which is not consistent with the PSD regulation. Other notable items in the public notice are as follows:

1. The notice states that DER has been granted a delegation by EPA to carry out the PSD review process. As you know, Florida is a SIP approved state rather than a delegated state.

2. The increment consumption given in the notice of 0% for all pollutants and averaging times is misleading since it was based on the erroneous emissions netting between Seminole Kraft and AES/Cedar Bay. As detailed to you in our letter of November 14, 1989, and as acknowledged on page 33 of your preliminary determination, netting of emissions between Seminole Kraft and AESCB is not applicable. Thus, the increment consumption reported in the public notice is not correct.

BACT Analysis

The determination of BACT made by DER included combustion controls to limit NO_x emissions and a SO_2 removal efficiency of 90% resulting in emission limits of 0.29 lb NO_x/MMBTU and 0.31 lb SO_2/MMBTU. These limits are higher than what is currently being permitted even for pulverized coal boilers. We believe that NO_x add-on controls are technically feasible for this project and that SO_2 emissions could be reduced through the use of lower sulfur coal and through increasing the removal efficiency. However, due to the circumstances involved in this project, we will defer to the decision of DER for this project.

If you have any questions on these comments, please contact Mr. Gregg Worley of my staff at (404) 347-2904.

Sincerely yours,

Winston A. Smith

Winston A. Smith, Director
Air, Pesticides, and Toxics
Management Division

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

March 28, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Jeff Swain
AES/Cedar Bay Inc.
1001 North 19th Street
Arlington, Virginia 22209

Dear Mr. Swain:

Re: AES/Cedar Bay Inc.
Cogeneration Project, PSD-FL-137

Please find enclosed the above referenced permit. You have the right to petition for an administrative hearing pursuant to Section 120.57, Florida Statutes, within 14 days of receipt of this permit or file a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, within 30 days from the date this permit is filed with the Clerk of the Department. Further, you may request a public hearing. Such request must be submitted within 30 days of receipt of this permit.

If you have any questions, please call Barry Andrews at (904)488-1344 or write to me at the above address.

Sincerely,

Barry D. Andrews

for C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/kt

enclosure

cc: J. Harper, EPA
A. Kutyna, NE District
K. Kurts, BESD
T. Cole, Oertel & Hoffman

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of buisness on 3-29-91.

FILING AND ACKNOWLEDGEMENT FILED, on this date, pursuant to §120.52(9), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kim Dobos | 3-29-91
Clerk | Date

Final Determination

AES/Cedar Bay Inc.
Cogeneration Project
Duval County, Florida

Permit No: PSD-FL-137

Florida Department of Environmental Regulation
Division of Air Resources Management
Bureau of Air Regulation

March 28, 1991

Final Determination

AES/Cedar Bay, Inc.'s PSD permit application (part of the Power Plant Siting application), has been reviewed by the Division of Air Resources Management. Comments received from EPA Region IV dated March 27, 1991 (see attachment 2) are addressed below.

Public Notice

The EPA questioned why the notice was published on the same date that the Site Certification Hearing was scheduled to begin, thereby not providing a 30 day notice and comment period.

Notice was published originally on December 8, 1989, for a January 8, 1990 hearing. A copy of the proposed Notice was sent to Region IV on December 1, 1989 for review. No comments were received regarding the increment consumptions reflected in the Notice sent to EPA. The hearing was then postponed from January 8, 1990 to February 5, 1990. The hearing then had to be continued on February 20, 1990 for which the Notice was published on February 12, 1990. In addition, public access hearings were held on February 7, 1990 and February 21, 1990 for nonparty members of the public. The public always has the right to speak. Only if they intervene as a formal party do they need an attorney as required by Florida law.

BACT Analysis

The Department agrees with EPA that add-on NOx controls are technically feasible for the AES/Cedar Bay project. The decision to establish the NOx limitation at 0.29 lb/MMBtu was based on the overall benefits that would be obtained from the construction of the cogeneration facility (the additional cost of SNCR would cause the project to become financially unfeasible). The circulating fluidized bed (CFB) boilers will replace older boilers which have higher emissions per heat input. In addition, the 0.29 lb/MMBtu limitation was judged to be the most stringent limitation placed on a coal fired boiler which does not have add-on NOx controls.

For sulfur dioxide, the Department evaluated the cost of switching to a lower sulfur coal and determined that such a cost was prohibitive. It should be noted that the decision to limit the average annual sulfur content to 1.7 percent is well below the initial proposal of 3.3 percent by the applicant. With regard to the control efficiency, the Department believes that 90 percent efficiency is reasonable for the CFB design.

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor | Carol M. Browner, Secretary

PERMITTEE:
AES/Cedar Bay, Inc.
1001 North 19th Street
Arlington, VA 22209

Permit Number: PSD-FL-137
County: Duval
Latitude/Longitude: 30°25'21"N
81°36'23"W
Project: Cogeneration Project

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the installation of 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.

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 cogeneration facility will generate 225 MW of electricity for sale to Florida Power & Light as well as low pressure process steam for the Seminole Kraft Corporation.

Nitrogen oxides will be controlled by the good combustion characteristics which are an inherent part of the CFB technology. Sulfur dioxide will be controlled by limiting the average annual sulfur content to 1.7% and the inherent limestone scrubbing provided by the CFB technology. Particulates will be controlled with fabric filters.

Construction shall be in accordance with the permit application and additional information submitted except as otherwise noted in the Specific Conditions.

Attachments:

1. Power plant site certification package PA 88-24 and its associated attachments, dated January 19, 1990.
2. Letter from EPA dated March 27, 1991.
3. DER's Final Determination dated March 28, 1991.

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver of or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgement of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

GENERAL CONDITIONS:

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a. a description of and cause of non-compliance; and

b. the period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance,

GENERAL CONDITIONS:

provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

12. This permit or a copy thereof shall be kept at the work site of the permitted activity.

13. This permit also constitutes:

    (x) Determination of Best Available Control Technology (BACT)
    (x) Determination of Prevention of Significant Deterioration (PSD)
    (x) Compliance with New Source Performance Standards

14. The permittee shall comply with the following:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application for this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

    c. Records of monitoring information shall include:

        - the date, exact place, and time of sampling or measurements;
        - the person responsible for performing the sampling or measurements;
        - the dates analyses were performed;
        - the person responsible for performing the analyses;
        - the analytical techniques or methods used; and
        - the results of such analyses.

General Conditions:

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

1. The construction and operation of AESCB shall be in accordance with all applicable provisions of Chapters 17-2, F.A.C.. In addition to the foregoing, AESCB shall comply with the following conditions of certification as indicated.

A. Emission Limitations for AES Boilers

1. Fluidized Bed Coal Fired Boilers (CFB)

a. The maximum coal charging rate of each CFB shall neither exceed 104,000 lbs/hr, 39,000 tons per month (30 consecutive days), nor 390,000 tons per year (TPY). This reflects a combined total of 312,000 lbs/hr, 117,000 tons per month, and 1,170,000 TPY for all three CFBs.

b. The maximum wood waste (primarily bark) charging rate to the No. 1 and No. 2 CFBs each shall neither exceed 15,653 lbs/hr, nor 63,760 TPY. This reflects a combined total of 31,306 lbs/hr, and 127,521 TPY for the No. 1 and No. 2 CFBs. The No. 3 CFB will not utilize woodwaste, nor will it be equipped with wood waste handling and firing equipment.

c. The maximum heat input to each CFB shall not exceed 1063 MMBtu/hr. This reflects a combined total of 3189 MMBtu/hr for all three units.

d. The sulfur content of the coal shall not exceed 1.7% by weight on an annual basis. The sulfur content shall not exceed 3.3% by weight on a shipment (train load) basis.

e. Auxiliary fuel burners shall be fueled only with natural gas or No. 2 fuel oil with a maximum sulfur content of 0.3% by weight. The fuel oil or natural gas shall be used only for startups. The maximum annual oil usage shall not exceed 160,000 gals/year, nor shall the maximum annual natural gas usage exceed 22.4 MMCF per year. The maximum heat input from the fuel oil or gas shall not exceed 1120 MMBtu/hr for the CFBs.

PERMITTEE:
AES/Cedar Bay Inc.

Permit No. AC PSD-FL-137
County: Duval

f. The CFBs shall be fueled only with the fuels permitted in Conditions 1a, 1b, and 1e above. Other fuels or wastes shall not be burned without prior specific written approval of the Secretary of DER pursuant to condition XXI, Modification of Conditions.

g. The CFBs may operate continuously, i.e, 8760 hrs/yr.

2. Coal Fired Boiler Controls

The emissions from each CFB shall be controlled using the following systems:

a. Limestone injection, for control of sulfur dioxide.
b. Baghouse, for control of particulate.

3. Flue gas emissions from each CFB shall not exceed the following:

		Emission Limitations		
Pollutant	lbs/MMBtu	lbs/hr	TPY	TPY for 3 CFBs
CO	0.19	202	823	2468
NOx	0.29	308.3	1256	3767
SO_2	0.60 (3-hr avg.)	637.8	--	--
	0.31 (12 MRA)	329.5	1338	4015
VOC	0.015	16.0	65	195
PM	0.020	21.3	87	260
PM_{10}	0.020	21.3	86	257
H_2SO_4 mist	0.024	25.5	103	308
Fluorides	0.086	91.4	374	1122
Lead	0.007	7.4	30	91
Mercury	0.00026	0.276	1.13	3.4
Beryllium	0.00011	0.117	0.5	1.5

Note: TPY represents a 93% capacity factor. MRA refers to a twelve month rolling average.

4. Visible emissions (VE) shall not exceed 20% opacity (6 min. average), except for one 6 minute period per hour when VE shall not exceed 27% opacity.

5. Compliance with the emission limits shall be determined by EPA reference method tests included in the July 1, 1988 version of 40 CFR Parts 60 and 61 and listed in Condition No. 7 of this permit or by equivalent methods after prior DER approval.

6. The CFBs are subject to 40 CFR Part 60, Subpart Da; except that where requirements within this certification are more restrictive, the requirements of this certification shall apply.

7. Compliance Tests for each CFB

a. Initial compliance tests for PM/PM_{10}, SO_2, NOx, CO, VOC, lead, fluorides, mercury, beryllium and H_2SO_4 mist shall be conducted in accordance with 40 CFR 60.8 (a), (b), (d), (e), and (f).

b. Annual compliance tests shall be performed for PM, SO_2 and NOx, commencing no later than 12 months from the initial test.

c. Initial and annual visible emissions compliance tests shall be determined in accordance with 40 CFR 60.11(b) and (e).

d. The compliance tests shall be conducted between 90-100% of the maximum liscensed capacity and firing rate of each permitted fuel.

e. The following test methods and procedures of 40 CFR Parts 60 and 61 or other DER approved methods with prior DER approval shall be used for compliance testing:

(1) Method 1 for selection of sample site and sample traverses.
(2) Method 2 for determining stack gas flow rate.
(3) Method 3 or 3A for gas analysis for calculation of percent O_2 and CO_2.
(4) Method 4 for determining stack gas moisture content to convert the flow rate from actual standard cubic feet to dry standard cubic feet.
(5) Method 5 or Method 17 for particulate matter.
(6) Method 6, 6C, or 8 for SO_2.
(7) Method 7, 7A, 7B, 7C, 7D, or 7E for nitrogen oxides.
(8) Method 8 for sulfuric acid mist.
(9) Method 9 for visible emissions, in accordance with 40 CFR 60.11.
(10) Method 10 for CO.
(11) Method 12 for lead.
(12) Method 13B for fluorides.
(13) Method 25A for VOCs.
(14) Method 101A for mercury.
(15) Method 104 for beryllium.

8. Continuous Emission Monitoring for each CFB AESCB shall use Continuous Emission Monitors (CEMS) to determine compliance. CEMS for opacity, SO_2, NOx, CO, and O_2 or CO_2, shall be installed, calibrated, maintained and operated for each unit, in accordance with 40 CFR 60.47a and 40 CFR 60 Appendix F.

a. Each continuous emission monitoring system (CEMS) shall meet performance specifications of 40 CFR 60, Appendix B.

b. CEMS data shall be recorded and reported in accordance with Chapter 17-2, F.A.C., and 40 CFR 60. A record shall be kept for periods of startup, shutdown and malfunction.

c. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

d. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation and operation of all CEMS.

e. Opacity monitoring system data shall be reduced to 6-minute averages, based on 36 or more data points, and gaseous CEMS data shall be reduced to 1-hour averages, based on 4 or more data points, in accordance with 40 CFR 60.13(h).

f. For purposes of reports required under this certification, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Condition No. 10 herein, which exceeds the applicable emission limit in Condition No. 3.

9. Operations Monitoring for each CFB

a. Devices shall be installed to continuously monitor and record steam production, and flue gas temperature at the exit of the control equipment.

b. The furnace heat load shall be maintained between 70% and 100% of the design rated capacity during normal operations.

c. The coal, bark, natural gas and No. 2 fuel oil usage shall be recorded on a 24-hr (daily) basis for each CFB.

10. Reporting for each CFB

a. A minimum of thirty (30) days prior notification of compliance test shall be given to DER's N.E. District office and to the BESD (Bio-Environmental Services Division) office, in accordance with 40 CFR 60.

b. The results of compliance test shall be submitted to the BESD office within 45 days after completion of the test.

c. The owner or operator shall submit excess emission reports to BESD, in accordance with 40 CFR 60. The report shall include the following:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factors used, and the date and time of commencement and completion of each period of excess emissions (60.7(c)(1)).

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the furnace boiler system. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measured adopted (60.7(c)(2)).

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks, and the nature of the system repairs or adjustments (60.7(c)(3)).

(4) When no excess emissions have occured or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report (60.7(c)(4)).

(5) The owner or operator shall maintain a file of all measurements, including continuous monitoring systems performance evaluations; monitoring systems or monitoring device calibration; checks; adjustments and maintenance performed on these systems or devices; and all other information required by this permit recorded in a permanent form suitable for inspection (60.7(d)).

d. Annual and quarterly reports shall be submitted to BESD as per F.A.C. Rule 17-2.700(7).

11. Any change in the method of operation, fuels utilized, equipment, or operating hours or any other changes pursuant to F.A.C. Rule 17-2.100, defining modification, shall be submitted for approval to DER's Bureau of Air Regulation.

PERMITTEE:
AES/Cedar Bay Inc.

Permit No. AC PSD-FL-137
County: Duval

B. AES - Material Handling and Treatment

1. The material handling and treatment operations may be continuous, i.e. 8760 hrs/yr.

2. The material handling/usage rates shall not exceed the following:

Material	Handling/Usage Rate TPM	TPY
Coal	117,000	1,170,000
Limestone	27,000	320,000
Fly Ash	28,000	336,000
Bed Ash	8,000	88,000

Note: TPM is tons per month based on 30 consecutive days, TPY is tons per year.

3. The VOC emissions from the maximum No. 2 fuel oil utilization rate of 240 gals/hr, 2,100,000 gals/year for the limestone dryers; and 8000 gals/hr, 160,000 gals/year for the three boilers are not expected to be significant.

4. The maximum emissions from the material handling and treatment area, where baghouses are used as controls for specific sources, shall not exceed those listed below (based on AP-42 factors):

Source	Particulate Emissions lbs/hr	TPY
Coal Rail Unloading	neg	neg
Coal Belt Feeder	neg	neg
Coal Crusher	0.41	1.78
Coal Belt Transfer	neg	neg
Coal Silo	neg	neg
Limestone Crusher	0.06	0.28
Limestone Hopper	0.01	0.03
Fly Ash Bin	0.02	0.10
Bed Ash Hopper	0.06	0.25
Ash Silo	0.06	0.25
Common Feed Hopper	0.03	0.13
Ash Unloader	0.01	0.06

The emissions from the above listed sources and the limestone dryers are subject to the particulate emission limitation requirement of 0.03 gr/dscf. However, neither DER nor BESD will require particulate tests in accordance with EPA Method 5 unless the

C. Requirements For the Permittees

1. Beginning one month after certification, AESCB shall submit to BESD and DER's BAR, a quarterly status report briefly outlining progress made on engineering design and purchase of major equipment, including copies of technical data pertaining to the selected emission control devices. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of any such device. Such disapproval shall be issued within 30 days of receipt of the technical data.

2. The permittees shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the BESD office.

3. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, regrassing or watering areas of disturbed soils, will be taken by the permittees.

4. Fuel shall not be burned in any unit unless the control devices are operating properly, pursuant to 40 CFR Part 60 Subpart Da.

5. The maximum sulfur content of the No. 2 fuel oil utilized in the CFBs and the two unit limestone dryers shall not exceed 0.3 percent by weight. Samples shall be taken of each fuel oil shipment received and shall be analyzed for sulfur content and heating value. Records of the analyses shall be kept a minimum of two years to be available for DER and BESD inspection.

6. Coal fired in the CFBs shall have a sulfur content not to exceed 3.3 percent by weight. Coal sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a.

7. AESCB shall maintain a daily log of the amounts and types of fuel used and copies of fuel analyses containing information on sulfur content and heating values.

8. The permittees shall provide stack sampling facilities as required by Rule 17-2.700(4) FAC.

9. Prior to commercial operation of each source, the permittees shall each submit to the BAR a standardized plan or procedure that will allow that permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

VE limit of 5% opacity is exceeded for a given source, or unless DER or BESD, based on other information, has reason to believe the particulate emission limits are being violated.

5. Visible Emissions (VE) shall not exceed 5% opacity from any source in the material handling and treatment area, in accordance with F.A.C. Chapter 17-2.

6. The maximum emissions from each of the limestone dryers while using oil shall not exceed the following (based on AP-42 factors, Table 1, 3-1, Industrial Distillate, 10/86):

	Estimated Limitations		
Pollutant	lbs/hr	TPY	TPY for 2 dryers
PM/PM_{10}	0.25	1.1	2.2
SO_2	5.00	21.9	43.8
CO	0.60	2.6	5.2
NOx	2.40	10.5	21.0
VOC	0.05	0.2	0.4

Visible emissions from the dryers shall not exceed 5% opacity. If natural gas is used, emissions limits shall be determined by factors contained in AP-42 Table 1. 4-1, Industrial 10/86.

7. The maximum No. 2 fuel oil firing rate for each limestone dryer shall not exceed 120 gals/hr, or 1,050,000 gals/year. This reflects a combined total fuel oil firing rate of 240 gals/hr, and 2,100,000 gals/year, for the two dryers.
The maximimum natural gas firing rate for each limestone dryer shall not exceed 16,800 CF per hour, or 147 MMCF per year

8. Initial and annual Visible Emission compliance tests for all the emission points in the material handling and treatment area, including but not limited to the sources specified in this permit, shall be conducted in accordance with the July 1, 1988 version of 40 CFR 60, using EPA Method 9.

9. Compliance test reports shall be submitted to BESD within 45 days of test completion in accordance with Chapter 17-2.700(7) of the F.A.C.

10. Any changes in the method of operation, raw materials processed, equipment, or operating hours or any other changes pursuant to F.A.C. Rule 17-2.100, defining modification, shall be submitted for approval to DER's Bureau of Air Regulation (BAR).

D. Contemporaneous Emission Reductions

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, that the following Seminole Kraft Corporation sources be permanently shut down and made incapable of operation, and shall turn in their operation permits to the Division of Air Resources Management's Bureau of Air Regulation, upon completion of the initial compliance tests on the AESCB boilers: the No. 1 PB (power boiler), the No. 2 PB, the No. 3 PB, the No. 1 BB (bark boiler), and the No. 2 BB. BESD shall be specifically informed in writing within thirty days after each individual shut down of the above referenced equipment. This requirement shall operate as a joint and individual requirement to assure common control for purpose of ensuring that all commitments relied on are in fact fulfilled.

Issued this 28th day
of March, 1991

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Carol M. Browner

Carol M. Browner, Secretary

Attachment 1,2 and 3

Available Upon Request

SENDER: Complete items 1 and 2 when additional services are desired, and complete items 3 and 4.

Put your address in the "RETURN TO" Space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for additional service(s) requested.

1. ☐ Show to whom delivered, date, and addressee's address. *(Extra charge)*
2. ☐ Restricted Delivery *(Extra charge)*

3. Article Addressed to: Mr. Jeff Swain AES / Cedar Bay, Inc 1001 North 19th St. Arlington, VA 22209	4. Article Number P 407 852 653
	Type of Service: ☐ Registered ☐ Insured ☒ Certified ☐ COD ☐ Express Mail ☐ Return Receipt for Merchandise
	Always obtain signature of addressee or agent and DATE DELIVERED.
5. Signature — Addressee X	8. Addressee's Address *(ONLY if requested and fee paid)*
6. Signature — Agent X K. Downs	
7. Date of Delivery	

USPS APR 1 1991 VA

PS Form 3811, Apr. 1989 ★U.S.G.P.O. 1989-238-815 DOMESTIC RETURN RECEIPT

P 407 852 653

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED
NOT FOR INTERNATIONAL MAIL
(See Reverse)

Sent to Jeff Swain	
Street and No. AES / Cedar Bay	
P.O., State and ZIP Code Arlington, VA	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt showing to whom and Date Delivered	
Return Receipt showing to whom, Date, and Address of Delivery	
TOTAL Postage and Fees	$
Postmark or Date 3-29-91 Cogen. Proj. PSD-FL-137	

☆U.S.G.P.O. 1989-234-555

PS Form 3800, June 1985

BEST AVAILABLE COPY

● **SENDER:** Complete items 1 and 2 when additional services are desired, and complete items 3 and 4.
Put your address in the "RETURN TO" Space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for additional service(s) requested.
1. ☐ Show to whom delivered, date, and addressee's address. *(Extra charge)* 2. ☐ Restricted Delivery *(Extra charge)*

3. Article Addressed to:	4. Article Number
Ms. Jewell A. Harper, Chief Air Enforcement Branch U.S. EPA, Region IV 345 Courtland Street, N.E. Atlanta, Georgia 30365	P 407 853 180 Type of Service: ☐ Registered ☐ Insured XX Certified ☐ COD ☐ Express Mail ☐ Return Receipt for Merchandise Always obtain signature of addressee or agent and DATE DELIVERED.
5. Signature — Addressee X Darlene	8. Addressee's Address *(ONLY if requested and fee paid)*
6. Signature — Agent X 1991	
7. Date of Delivery	

PS Form **3811**, Apr. 1989 ★U.S.G.P.O. 1989-238-815 **DOMESTIC RETURN RECEIPT**

P 407 853 180

RECEIPT FOR CERTIFIED MAIL

NO INSURANCE COVERAGE PROVIDED
NOT FOR INTERNATIONAL MAIL
(See Reverse)

★U.S.G.P.O. 1989-234-555

Sent to Ms. Jewell A. Harper	
Street and No. EPA, Region IV	
P.O., State and ZIP Code	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt showing to whom and Date Delivered	
Return Receipt showing to whom, Date, and Address of Delivery	
TOTAL Postage and Fees	$
Postmark or Date Mailed: 3-12-91 Permit: PSD-FL-137	

PS Form 3800, June 1985

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

March 11, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Jewell A. Harper
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, NE
Atlanta, GA 30365

Dear Ms. Harper:

Re: Applied Energy Services (AES)/Seminole Kraft Corporation
Cedar Bay Cogeneration Project
Federal Number: PSD-FL-137

Enclosed for your review and comment is a copy of the Technical Evaluation and Preliminary Determination for the above referenced project. Please submit any comments or questions to Tom Rogers or Barry Andrews at the above address or call them at (904)488-1344 at your earliest convenience.

Sincerely,

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/CP

Enclosure

cc: A. Kutyna, NE Dist.
C. Kirts, BESD
C. Shaver, NPS

Technical Evaluation
and
Preliminary Determination

Applied Energy Services (AES)/Seminole Kraft Corporation
Cedar Bay Cogeneration Project
Duval County, Florida

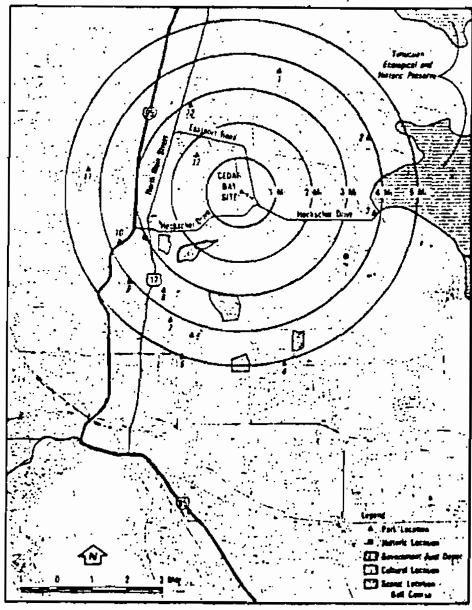
Permit No. PSD-FL-137

Department of Environmental Regulation
Division of Air Resources Management
Bureau of Air Regulation

October 29, 1990

NOTICE OF CERTIFICATION HEARING ON AN APPLICATION TO CONSTURCT AND OPERATE AN ELECTRICAL POWER PLANT TO BE LOCATED NEAR JACKSONVILLE, FLORIDA

1. Application number PA 88-24 for certification to authorize construction and operation of an electrical power plant near Jacksonville, Florida, and an associated transmission line from the Seminole Kraft Paper Mill site to Jacksonville Electric Authority's Eastport Substation is now pending before the Department of Environmental Regulation, pursuant to the Florida Electrical Power Plant Siting Act, Part II, Chapter 403, F.S. Certification of this power plant would allow construction and operation of a new source of air pollution which would consume an increment or air quality resources. The department review has resulted in an asessment of the prevention of significant deterioration impacts and a determination of Best Available Control Technology necessary to control the emission of air pollutants from this source.



Amendment 2
070789

SITE LOCATION – 5-MILE RADIUS WITH PARK, HISTORIC, GOVERNMENT, CULTURAL AND SCENIC LOCATIONS (JACKSONVILLE, FLORIDA)

Figure 2.2-1

2. The proposed 35 acre power plant site is located on the 425 acre Seminole Kraft Paper Mill site in northeastern Duval County. The site is aproximately seven and one-half miles northeast of downtown Jacksonville. The site will house three fluidized-bed, coal fired boilers, electrical generators, new chemical recovery boiler, multiple effect evaporators, smelt dissolving tanks, coal pile, cooling towers and related facilities. New turbines will be generating 42 MW of electricity for use in the paper mill and 225 MW for sale to Florida Power and Light Company. A short transmission line will connect the facility to an existing Jacksonville Electric Authority electrical substation.

3. The Department of Environmental Regulation has evaluated the application for the proposed power plant. Certification of the plan would allow its construction and operation. The application and the department's evaluation is available for public inspection at the addresses listed below:

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION
Northeast District Office
3426 Bills Road
Jacksonville, Florida 32207

CITY OF JACKSONVILLE
BIO-ENVIRONMENTAL SERVICES DIVISION
421 West Church Street
Jacksonville, Florida 32202-4111

ST. JOHNS RIVER WATER MANAGEMENT DISTRICT
P.O. Box 1429
Highway 100
Palatka, Florida 32077

4. Pursuant to Section 403.508, Florida Statutes, the certification hearing will be held by the Division of Administrative Hearings on February 5, 1990, at 10:00 a.m., in the First Coast Room of the Inn at Bay Meadows, 8050 Baymeadows Circle West Jacksonville, Florida, in order to take written and oral testimony on the effects of the proposed power plant or any other matter appropriate to the consideration of the site. There will be an opportunity for public testimony at 7:00 p.m. on February 7, 1990. Need for the facility has been predetermined by the Public Service Commission at a separate hearing. Written comments may be sent to Mr. Robert T. Benton (Hearing Officer) Division of Administrative Hearings, The Desoto Building, 1230 Apalachee Parkway, Tallahassee, Florida 32399-1550. This hearing will replace the hearing originally scheduled for January 8, 1990. During the period of February 6-9, the hearing will commence at 9:00 a.m. If the hearing is not completed by February 9, the Hearing will resume on February 19, 1990 at 10:00 a.m. at the Hospitality Inn, 7071 – 103rd. Street, Jacksonville, Florida.

4. Pursuant to 403.508(4), F.S.: "(a) Parties to the proceeding shall include: the applicant; the Public Service Commission; the Department of Community Affairs; the water management district as defined in Chapter 373, in whose jurisdiction the proposed electrical power plant is to be located; and the Department. (b) Upon the filing with the Department of a notice of intent to be a party at least 15 days prior to the date set for the land use hearing, the following shall also be parties to the proceeding:

1. Any county or municipality in whose jurisdiction the proposed electrical power plant is to be located.

2. Any state agency not listed in paragraph (a) as to matters within its jurisdiction.

3. Any domestic non-profit corporation or association formed in whole or in part to promote conservation or natural beauty; to protect the environment, personal health, or other biological values; to preserve historical sites; to promote consumer interests; to represent labor, commercial or industrial groups; or to promote orderly development of the area in which the proposed electrical power plant is to be located.

(c) Notwithstanding paragraph (4) (d), failure of an agency described in subparagraphs (4) (b) 1 and (4) (b) 2 to file a notice of intent to be a party within the time provided herein shall constitute a waiver of the right of the agency to participate as a party in the proceeding.

(d) Other parties may include any person, including those persons enumerated in paragraph (4) (b) who failed to timely file a notice of intent to be a party, whose substantiate interests are affected and being determined by the proceeding and who timely file a motion to intervene pursuant to Chapter 120, F.S., and applicable rules. Intervention pursuant to this paragraph may be granted at the discretion of the designated hearing officer and upon such conditions as he may prescribe any time prior to 15 days before the commencement of the certification hearing.

6. When appropriate, any person may be given an opportunity to present oral or written communications to the designated hearing officer. If the designated hearing officer proposes to consider such communication, then all parties shall be given an opportunity to cross-examine or challenge or rebut such communications.

7. Notices or petitions made prior to the hearing should be made in writing to:

Mr. Robert Benton
Division of Administrative Hearings
The Desoto Building
1230 Apalachee Parkway
Tallahassee, Florida 32399-1550

8. Those wishing to intervene in these proceedings must be represented by an attorney or other person who can be determined to be qualified to appear in administrative hearings pursuant to Chapter 120, F.S., or Chapter 17-1.21, FAC.

9. This Public notice is also provided in compliance with the federal Coastal Zone Management Act, as specified in 15 CFR Part 930, Subpart D. Public Comments on the applicant's federal consistency certification should be directed to the Federal Consistency Coordinator, Division of Environmental Permitting, Department of Environmental Regulation.

10. Pursuant to Section 403.511(2), F.S. AES/Cedar Bay seeks a variance from the water quality standards for aluminum, iron and phenol as contained in Chapter 17-3, F.A.C. for the purpose allowing construction dewatering discharge and for allowance of iron in cooling tower blowdown. The hearing officer will receive comments and testimony from the parties, the public and the affected agencies at the certification hearing.

11. On November 14, 1988, AES/Cedar Bay and Seminole Kraft Corporation applied to the DER, to construct the aforementioned cogeneration project. The application is also subject to U.S. Environmental Protection Agency (EPA) regulations for Prevention of Significant Deterioration of air quality (PSD), codified at 40 CFR 52.21, and Florida Administrative Code Chapter 17-2.500. These regulations require that, before construction on a source of air pollution subject to PSD may begin, a permit must be obtained from DER. Such permit can only be issued if the new construction has been determined by DER to comply with the requirements of the PSD regulations, which are described in 40 CFR 52.21 and 17.2.500, F.A.C. These requirements include a restriction on incremental increases in air quality due to the new source and application of best available control technology (BACT).

The DER has been granted a delegation by EPA to carry out the PSD review of this source. Acting under that delegation, the DER has prepared a draft permit which is included in the DER's staff analysis report. The DER has made a preliminary determination that the proposed construction will comply with all applicable PSD regulations. The degree of Class II increment consumption that will result from the construction is:

Pollutant	Annual Average	24-Hr. Average	3-Hr. Average
Particulate	0.0%	0%	
Sulfur Dioxide	0%	0%	0%

The source is located approximately 60 kilometers from the nearest Class I area the, Okefenokee Wilderness area.

The degree of Class I increment consumption that will result from the construction and operation of the source is:

Pollutant	Annual Average	24-Hr. Average	3-Hr. Average
Particulate	0%	0%	
Sulfur Dioxide	0%	0%	0%

Construction and operation of the source will not cause a violation of any ambient air quality standard nor will it cause an exceedance of any PSD increment.

Because of replacement of old, poorly controlled emission with new sources that have higher stacks and highly efficient air pollutant control equipment, this project will result in a decrease in current air quality concentrations.

TABLE OF CONTENTS

State of Florida Department of Environmental Regulation -
(Applied Energy Services/Seminole Kraft Corporation)
Cedar Bay Cogeneration Project
Electric Power Plant Site Certification Review Case No. PA 88-24

I. SUMMARY

Facilities Overview

Applied Energy Services (AES) in partnership with Seminole Kraft Corporation (SKC) proposes to certify a 256 megawatt (MW), coal and wood bark fired, fluidized bed, cogeneration project. A 42 MW generating unit associated with a chemical recovery boiler, multiple effect evaporators, and a smelt dissolving tank will also be constructed at the SKC paper mill site northeast of Jacksonville under separate DER permits.* The fluidized bed project is known as the Cedar Bay Cogeneration Project (CBCP). The 256 MW unit would be tied into the JEA and Florida Power and Light (FPL) power network via new transmission lines. One 138 KV line will be necessary to transmit the power from the plant to the JEA and FPL systems. Fuel delivery for three fluidized bed boilers would use the existing SCX rail lines or be derived from pulp mill wastes. The project will be known as the Cedar Bay Cogeneration Project.

Approximately 35 acres of land would be required for the operation of the CBCP. This would be due to in part to the need for holding/storage areas for the coal, the flush limestone, for the spent limestone, and for the bottom ash and fly ash disposal areas. AES plans to ship a pelletized ash/limestone mixtures back to the coal mine to minimize the waste storage problem. Fluidized bed boiler design and fabric filters will be used to limit air emissions. Fly ash will be collected and mixed with spent limestone and bottom ash then mixed with water and pelletized before shipment back to the coal mine.

AES proposes to utilize fresh water cooling towers with the blowdown into the existing Seminole Kraft cooling water discharge to the St. Johns River. Plant service water and cooling water would come from SKC wells into the Floridian Aquifer until such time as reclaimed water should become available. Wastewaters other than cooling waters would be pumped to wastewater treatment units with ultimate disposal via the SKC oxidation pond and discharge system. The cooling water and other waste streams would be disposed of via the SKC which empties into the St. Johns River.

Air Impacts

Based on the control technologies AES and SKC have proposed to utilize, it is expected that the Cedar Bay Project and associated facilities will emit much less than the minimum technology based standards that apply to these type of facilities. Analysis of the predicted effects of plant emission indicates that no significant air quality impacts should occur.

* SKC has recently decided to eliminate this project and convert the paper mill to another type.

Replacement of old units at the SKC mill will result in a net improvement compaterd to existing ambient air quality.

Consumptive Use of Water

AES will have an adequate supply of fresh water from the SKC wells for its cooling tower system. Because there is some concern about the adequacy of the fresh water supply in Duval County and potential salt water intrusion into the drinking water aquifer, the future use of reclaimed water from the Jacksonville sewage treatment system is under investigation.

Waste and Wastewater Impacts

The AES solid waste holding area will cover no more than two acres. The pelletized ash/limestone will be stored in a lined area. Coal pile runoff will be collected and treated. Leachate from the existing papermill lime mud piles which has contributed amounts of heavy metals to the groundwater on the site will be eliminated by removing the lime mud to a secure landfill and by construction dewatering.

Discharges from the AES wastewater treatment systems will be into the SKC treatment system/oxidation pond. Discharge of cooling tower blowdown, and construction dewatering discharge will go to the existing SKC discharge and may on occasion contribute to temporary violations of state water quality standards for certain parameters when the St. Johns River exceeds the standards.

Biological Impacts

The thermal effluent from the AES Units will combine with the SKC discharge. At the worst it could slightly raise the temperature of the combined wastewater discharge during winter months. At the best, the AES cooling tower blowdown could decrease the temperature of the SKC waste water discharge by 0.3°F. Adverse impacts on estuarine organisms should be minimal.

The use of the existing pulp mill site and the proposed rail spur off the existing rail line does not constitute an important loss of wildlife habitat. The area designated for the Cedar Bay Project does not contain valuable habitat. Impact on the surrounding areas from this project should be minimal due to existing industrial development.

Sociological/Economic Impacts

Because the SKC site already has a pulp and paper mill operating, the addition of a new co-generation plant on adjacent property is not expected to create significant sociological impacts other than induced traffic delays caused by coal trains. For the same reason, the economic impacts should primarily be felt in terms of financing rather than in areawide support service demands or other local costs.

of the previously mentioned species could be slightly affected by plant-related activities as food and habitat losses become more widespread.

A species is defined by the Florida Department of Environmental Regulation as "important" if: 1) it is commercially or recreationally valuable; 2) it is rare, endangered, threatened, or protected; or 3) it has unique ecological value.

Those species observed on the proposed site that were found to be commercially or recreationally valuable were the Whitetail deer, the Eastern gray squirrel, the marsh rabbit, raccoon, opossum, and bobwhite quail.

Besides the biota already discussed in previous paragraphs, other species which are considered endangered or threatened at the site include the American alligator, common dolphin, the gopher tortoise, Florida gopher frog, the eastern indigo snake, osprey, wood stork, red cockaded woodpecker, and bald eagle.

The Florida Gopher Tortoise a species of unique ecological value since Gopher Tortoise burrows provide a habitat for no less than 30 animal species, some of which can live nowhere else. Among these commensals inhabiting the dens are the Florida Gopher Frog (RARE), that emerges from these burrows only at night. Although it has been assumed that indigo snakes are uncommon in Duval County, no data is available on the number of these snakes living in gopher tortoise burrows at the SKC site.

VI. FACILITY SPECIFIC CONCERNS

A. Air quality

1. Selected Fuel

The units are planned for coal-fired operation; however, provisions are being made in the design to allow for burning of wood waste as well. Based on a study of availability of coal, east of the Mississippi River, there are practical sources of coal adequate to meet the plant's needs over the anticipated life of the project (approximately 1,105,000 tons per year). In addition, partial supplies could be obtained from several foreign sources.

The plant is designed to retain the flexibility to change its' coal supply (to insure against disruptions in supply, local market upsets and to maintain competitive prices) with minimum reduction in efficiency and without violating air quality standards. Analyses of potential coal supplies were therefore necessary so that the plant could be designed to accomodate coals with a variety of characteristics. Coals from the above sources were analyzed to determine the ranges of characteristics and chemical constituents.

The air quality control system is designed on a "worst case" basis assuming the maximum sulfur (4 percent) and ash (18 percent) in the coal and a minimum heating value (10,500

BTU/lb). This approach assumes the sulfur and ash contents of the coal are 3.8 lb/MMBtu (Million Btu) and 17.1 lb/MMBtu, respectively. The ash remaining after the coal is burned is assumed to be 80 percent fly ash and 20 percent bottom ash. The above values were used to develop collection equipment efficiencies, investment estimate and long and short-term ground level ambient air quality concentrations. This approach requires a more sophisticated, complex, efficient and costly air quality control system than would be required on the basis of average coal characteristics.

The coal handling system will provide for delivery of coal by rail delivery directly to the plant by unit train or in trainload lots. A bottom car dumper will be used to unload coal from the trains on the power plant site proper. The system will also include the yard area coal storage, transfer system, coal silos, and the tripper floor distribution system.

The emission of air pollutants from the Cedar Bay/Seminole Kraft site are limited by Chapter 17-2, FAC, and by the New Source Performance Standards as imposed by the U.S. Environmental Protection Agency. In order to comply with these regulations, Cedar Bay plans to utilize washed coal with a fluidized limestone bed to control emission of sulfur oxides. Particulate matter will be controlled by a fabric filter.

When all of the units are operating at 100% of rated capacity, the plant will consume 145 tons per hour of coal and will emit 1913 pounds per hour of SO_2, 64 pounds per hour of particulates, and 925 pounds per hour of nitrogen oxides.

The stack height of 425 feet will assist the control equipment in reducing ambient air quality impacts. Only during rare meteorological conditions will stack emissions reach the ground close to the plant. The stack height insures dispersion and dilution of air pollutants before the pollutants reach ground level at some distance from the site.

2. Air Quality Impact Analysis

A. Introduction

The proposed Cedar Bay Cogeneration facility (modifications to the Seminole Kraft plant), located in Jacksonville, will emit in PSD-significant amounts seven pollutants. These are the criteria pollutants carbon monoxide (CO), nitrogen oxides (NOx), and lead (Pb) and non-criteria pollutants beryllium (Be, mercury (Hg), flouride (Fl) and sulfuric acid mist.

The air quality impact analysis required by the PSD regulations for these pollutants includes:

- An analysis of existing air quality;
- An ambient Air Quality Standards (AAQS) analysis;
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality impacts; and
- A "Good Engineering Practice" (GEP) stack height determination.

An analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The PSD increment and AAQS analysis depend on air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the proposed sources at the cogeneration facility, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any PSD increment or ambient air quality standard. The CBCP will reduce the site's potential contribution to S^{O}_{2} exceedances. A discussion of the modeling methodology and required analyses follows.

B. Modeling Methodology

The EPA-approved screening level model PTPLU-2 and the EPA documents entitled Procedures for Evaluating Air Quality Impact of New Stationary Sources (Volume 10-revised) were used to determine the highest predicted ground level concentration for various plant operating conditions.

The operating conditions of the circulating fluidized bed (CFB) boilers were evaluated at 50 and 75 percent load capacity plus the maximum designed for the plant. The maximum CFB operation was determined to be the worst case operating condition and is the only operating level included in the refined air quality modeling. The proposed kraft recovery boiler (KRB) and smelt dissolving tank (SDT) are not expected to operate at varying conditions and thus were not evaluated with screening level modeling, nor are they included in this certification.

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used in the refined air quality impact analysis. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model incorporates estimates for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition and transformation. The ISCST model allows for the seperation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. These features were used in the refined modeling analyses.

The modeling primarily used polar receptors with the proposed CFB boiler stack at the center. Radials were spaced at 10° increments from 10° to 360°. The initial receptor distances modeled were 0.979, 1.273, 1.664, 2.252, 2.937, 3.818, 5.091, 6.657, and 8.811 km. Depending on the applicable averaging times and pollutants, additional receptor distances were included at 80-meter intervals from 0.220 km to 0.940 km. These distances represent locations near the plant boundary.

The meteorological data used in the ISCST model consisted of five years (1981-1985) of hourly surface data taken at Jacksonville, FL. Mixing heights used in the model were based on upper air data from Waycross, Georgia.

Table 1 lists the significant and net emission rates for the proposed modification. Table 2 lists the stack parameters and emission rates for the proposed facility, as well as, a combined configuration of the existing Seminole Kraft sources. Carbon monoxide and lead were modeled using the maximum emissions for the facility alone. The NO_2 modeling was based on the net emission change (proposed minus existing) using an emission rate of 0.36 lb/MBtu which is higher than the revised proposed emission rate of 0.29/MBtu.

C. Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all polutants subject to PSD review. In general, one year of quality assured data using an EPA reference, or the equivalent, monitor must be submitted. Sometimes less than one year of data, but no less than four months, may be accepted when Departmental approval is given.

An exemption to the monitoring requirement can be obtained if the maximum air quality impact, as determined by air quality modeling, is less than a pollutant-specific "de minimus" concentration. In addition, if current monitoring data already exist and these data are representative of the proposed source area, then at the discretion of the Department these data may be used.

The predicted maximum air quality impacts of the proposed facility for those pollutants subject to PSD review are listed in Table 3. Sulfuric acid mist is not listed because there is no de minimus level for this pollutant.

Based on the modeling results, no monitoring is required for CO, NOx, or Hg. Department lead monitoring results for 1986 through 1987 were used to determine existing lead levels. While the modeled impacts for Be and Fl are greater than their respective de minimus values, they are much below the Department guideline acceptable ambient concentrations of 0.0025 ug/m^3 (annual) and 11.90 ug/m^3 (24-hour), respectively. Therefore, monitoring for these pollutants is not necessary. Sulfuric acid mist was modeled and showed a maximum 24-hour concentration of 0.73 ug/m^3. This value is significantly less than the acceptable ambient concentration of 4.76 ug/m^3 (24-hour). Consequently, monitoring for this pollutant is not required.

D. AAQS Analysis

Given existing air quality in the area of the proposed facility, emissions from this facility are not expected to cause or contribute to a violation of an applicable AAQS. The results of the AAQS analysis are contained in Table 4.

Table 1. Significant and Net Emission Rates (Tons per Year)

Pollutant	Significant Emission Rates	Existing Emissions	Proposed Maximum Emissions*	Net Emissions	Applicable Pollutant
Carbon Monoxide	100	2933	4637	1704	YES
Nitrogen Dioxide	40	1522	6301	4779	YES
Sulfur Dioxide	40	5902	5525	-377	NO
Particulate Matter (PM)	25	875	812	-63	NO
Particulate Matter (PM_{10})	15	684	683	-1	NO
Ozone (VOC)	40	540	456	-84	NO
Lead	0.6	--	91	91	YES
Asbestos	0.007	--	<0.007	<0.007	NO
Beryllium	0.0004	--	1.5	1.5	YES
Mercury	0.1	--	3.4	3.4	YES
Vinyl Chloride	1.0	--	<1.0	<1.0	NO
Fluorides	3	--	1122	1122	YES
Sulfuric Acid Mist	7	--	322	322	YES
Total Reduced Sulfur	10	98	47	-51	NO

* Assumes a 100 percent capacity factor for the kraft recovery boiler, smelt dissolving tank, limestone dryers, and the multiple effects evaporator. Assumes a 93 percent capacity factor for the cogeneration plant.

Table 2. Stack Parameters and Emission Rates

Source	Stack Hgt. (m)	Exit Temp. (K)	Exit Vel. (m/s)	Stack Dia. (m)	Emission Rate (g/s)		
					NOx	CO	Pb
Proposed Sources							
Kraft Recovery Boiler	129.5	478	20.42	3.43	46.5	62.3	.006
CFB Boiler	129.5	403	33.22	4.27	145	76.4	2.8
Limestone dryer	9.1	355	21.34	1.04	0.6	0.1	--
Lime Kilns	22.9	339	10.36	1.13	--	--	--
Smelt Dissolving Tanks	73.1	344	14.32	1.5	--	--	--
Existing Composite Source Data							
Power Boilers	32.3	433	20.12	1.83	23.2	1.7	--
Bark Boilers	41.5	329	13.72	2.44	11.3	15.7	--
Kraft Boilers	38.4	344	16.76	2.74	9.2	66.9	--
Lime Kilns	22.9	339	10.36	1.13	--	--	--
Smelt Dissolving Tanks	37.8	344	4.27	1.22	--	--	--

Table 3. Maximum Air Quality Impacts for Comparison to the de minimus Ambient Levels

Pollutant and Averaging Time	Predicted Impact (ug/m^3)	De minimus Ambient Impact Level (ug/m^3)
CO (8-hour)	25.0	575
NO_2 (Annual)	<0	14
SO_2 (24-hour)	<0	13
Pb (3-month)	0.13 *	0.1
Be (24-hour)	0.0017	0.0005
Hg (24-hour)	0.004	0.25
Fl (24-hour)	1.375	0.25

* The Pb impact is based on a 24-hour modeling value and, therefore, the 3-month Pb average is expexted to be significantly less than this value.

Table 4. Comparison of Total Impacts with the AAQS

Pollutant and Averaging Time	Maximum Predicted Impact (ug/m^3)	Existing Background (ug/m^3)	Maximum Total Impact (ug/m^3)	Florida AAQS (ug/m^3)
CO (1-hour)	94.1	13	107.1	40000
CO (8-hour)	25.0	6	31.0	10000
NO_2 (Annual)	3.8	29	32.8	60
Pb (3-month)	0.13	0.3	0.43	1.5

Of the pollutants subject to review, only the criteria pollutants CO, NOx, and Pb have an AAQS. Dispersion modeling was performed as detailed earlier for the proposed facility. The results indicate that, except for Pb, the maximum impacts of these pollutants were less than the significant impact levels defined in Rule 17-2.100 (170), FAC. As such, no modeling of other sources was necessary for CO and NOx. For Pb, there is no significant impact defined in the rule. The maximum 24-hour Pb concentration was used as a conservative estimate of the quarterly concentration. When combined with the background concentration of 0.3 ug/m^3 (the highest quarterly average between 1986 and 1987 in Duval County), this results in a total concentration of 0.43 ug/m^3 which is well below the Pb AAQS. Therefore, no additional modeling for Pb was required.

The total impact on ambient air is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explictly modeled. These "background" concentrations were obtained from Department approved monitors near the Cedar Bay Site for 1986 (1985 for NOx).

E. Additional Impacts on Soils and Vegetation

1) Impacts on Soils and Vegetation

The maximum ground-level concentrations predicted to occur for the criteria pollutants as a result of the proposed project and a background concentration will be at or below all applicable AAQS including the national secondary standards developed to protect public welfare-related values. As such, these pollutants are not expected to have a harmful impact on soils and vegetation.

2) Impact on Visibility

To ensure the protection of visibility in the Okefenokee Wilderness area (PSD Class 1 area) area a Level 1 visibility analysis was done for the proposed facility. The results of this analysis indicate that the emissions from this facility will not significantly alter the visibility in this area.

3) Growth-Related Air Quality Impacts

The proposed facility is not expected to significantly change employment, population, housing or commercial/industrial development in the area to the extent that an air quality impact will result.

4) GEP Stack Height Determination

Good Engineering Practice (GEP) stack height means the greater of: 1) 65 meters or 2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less. The GEP stack height determination is dependent on the distance and orientation to the various buildings nearby the stack because the projected building width can change.

The applicant calculated the GEP heights for each proposed source based on the dimension of nearby buildings. The GEP height of 129.5m was used in the modelling for the circulating fluidized bed boiler.

3. Prevention of Significant Deterioration

Pursuant to Chapter 17-2, FAC, and 40 CFR 52.21, the Cedar Bay CFB units are subject to a review for the Prevention of Significant Deterioration (PSD) of air quality. The Clean Air Act Amendments of 1977 prescribe incremental limitations on the air quality impacts of a new source. The Department of Environmental Regulation has reviewed the PSD analysis submitted by AES and has found that the construction of the facility is not expected to violate state PSD regulations as contained in Section 17-204, FAC.

Additionally, the Preliminary Determination for Cedar Bay/Seminole Kraft was completed in December of 1989. Federal regulations on PSD (40 CFR 52.21) require the following air quality impacts to be addressed:

A. National Ambient Air Quality Standards
B. PSD increment impact
C. Visibility, soils and vegetation impacts
D. Impacts due to growth caused by the proposed source
E. Best Available Control Technology (BACT)
F. Class I area impacts

After their review, DER has made a preliminary determination that the construction can be approved provided certain conditions are met.

The predicted impact of the Cedar Bay Project on the Okefenokee Wilderness Area Class I area increments is presented in the following table:

TABLE 6

Increment	Pollutant Particulate	SO_2
Annual	20%	50%
24 Hour	10%	80%
3 Hour		72%

It appears that the Cedar Bay would not violate the Class I PSD increments in the Okefenokee.

The percent consumption of the applicable Class II PSD increments caused by the Cedar Bay Project and other new sources are present in the following table:

TABLE 7

Increment	Pollutant	
	Particulate	SO_2
Annual	12%	12%
24 Hour	46%	46%
3 Hour	N/A	65%

The plant emissions are not expected to violate the increments or cause significant deterioration of air quality in the Jacksonville area.

Nonattainment Areas

The extent of the contribution of the proposed plant to the formation of ozone and, therefore, its' impact on the Jacksonville ozone nonattainment areas cannot be estimated through modelling. However, because of the plant's low emission levels of NO_x and hydrocarbons (the primary precursors of ozone), it was assumed by AES that the impacts of the proposed plant on ozone concentrations in the Jacksonville area will not be significant.

The impact of the plant on the Jacksonville particulate nonattainment area was estimated through modelling and compared with the US EPA "significance levels" which are one ug/m^3 for an annual average and five ug/m^3 for a 24-hour average. The TSP nonattainment area basically covers the central downtown area and is at its' closest point six miles from the proposed plant.

The annual average impact was calculated using the total TSP emissions from the operation of the proposed plant including fugitive dust emissions from the coal handling, waste disposal and cooling towers. The results of the analysis indicate that the annual average TSP impact on the nonattainment area would be less than one ug/m^3, the EPA significance level. The maximum 24-hour TSP impact would be four ug/m^3, which is less than the five ug/m^3 EPA significance level.

It, therefore, appears that the proposed CBCP will not have a significant adverse effect on the downtown Jacksonville area.

Impacts on Visibility

The proposed power plant may have an impact on visibility in the area. Visibility is defined as the greatest distance at which it is just possible to see and identify with the unaided eye a prominent dark object against the sky at the horizon in the daytime or a known unfocused moderately intense light source at night. Visibility is diminished by four major processes: light scattering by gas molecules, light scattering by particles, light absorption by gases not naturally occurring in the atmosphere, and light absorption by particles.

Coal-fired power plants affect visibility through the three major combustion related pollutants: particulates, sulfur dioxide, and nitrogen dioxide. Visibility is decreased by particulates primarily through light scattering due to conversion of gaseous nitrogen 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 and 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 CBCP was 11.7 miles.

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

Impacts on Soils and Vegetation

Eighteen trace elements were selected for review on the basis of reported high concentrations in coal, capability for volatilization during combustion, potential for toxicity, and existence of regulatory guidelines. Since a coal source analysis has not been provided, trace element concentrations in coal were obtained from a report on trace elements in coal samples from the eastern United States.

The predicted deposition rates were determined on the basis of coal consumption, trace element concentration, and SO_2 emission rates. Elements considered to be volatile were assumed to exit the stack in an uncontrolled manner. Those trace elements typically occurring as particulates or absorbed on particulates were also assumed to exit in an uncontrolled state. These assumptions were utilized due to the lack of information on the behavior of trace elements passing through an FGD system. In addition, the use of these assumptions introduced a degree of conservatism to the assessment.

Studies of model power plants in most cases predicted increases in soil trace element levels of less than 10 percent of the total endogenous concentrations over the life of the model plant. It was concluded that uptake by vegetation would not increase dramatically unless the forms of deposited trace elements were considerably more available than the endogenous forms.

The estimated increases ranged from 0.6 x 10^{-5} to 4.8 x 10^{-3} percent, using average soil background concentrations. The estimated increases over the 40 year life of the plant, assuming that the elements remained concentrated in the top 25 cm of soil over this period ranged from 2.4 x 10^{-4} to 3.6 x 10^{-2} percent. The assessment of these increases was based on a number of worst case conditions. Under these conditions there should not be a perceptible increase on an annual basis. Over the 40 year plant life, those elements exhibiting a higher percent increase relative to the others studied included: arsenic, boron, cadmium, lead, mercury, and molybdenum.

The estimated soil concentration increase for arsenic would be 6 x 10^{-3} mg per kg of soil over the 40 year plant life. Naturally occuring arsenic levels in soils average about 6 ppm. Soil arsenic concentrations greater than 2 ppm, soluble form, have been shown to produce injury symptoms on alfalfa and barley and as such no effect could be expected under worst case conditions.

The estimated soil concentration increase for boron would be 1.02 x 10^{-2} mg per kg of soil over the 40 year plant life under worst case conditions. Naturally occuring boron concentrations range from 2-1000 ppm with the highest levels found in saline and alkaline soils. The average value is considered to be about 10 ppm. Using a toxicity level of 0.5-10 ppm for plants sensitive to boron as a means for comparison, no adverse effects to sensitive species such as citrus would be expected under worst case operating conditions.

The estimated soil concentration increase for cadmium would be 0.58 x 10^{-4} mg per kg of soil concentration over the average background level of 0.06 ppm, which is high in comparison with the other elements addressed. Toxicity to plants is reported to occur when cadmium concentration in plant tissues reaches about 3 ppm and it is unlikely that the estimated soil concentration will be high enough for the accumulation of 2 ppm in leaf tissue within the vicinity of the proposed plant.

The estimated soil increase for lead would be 1.43 x 10^{-2} mg per kg of soil over the 40 year plant life. Naturally occurring lead concentrations in soil averages about 10 ppm. Based on reported threshhold concentrations of 10 ppm lead in solution culture, the addition of 0.79 x 10^{-2} mg lead per kg of soil to soils containing as much as 5 ppm lead should not result in any adverse effects. It is thought that lead enters the plant primarily through the leaf surface. However, the effect of such accumulations cannot be predicted due to the lack of information concerning the concentration of lead in plants due to leaf deposition.

The estimated soil increase for mercury would be 0.48 x 10^{-4} mg per kg of soil. Naturally occurring mercury concentrations in soil average 0.1 ppm. Most higher vascular plants are resistant to toxicity from high mercury concentrations even though high concentrations are present in plant tissue. Concentrations of 0.5-50 ppm are found to inhibit the growth of cauliflower, lettuce, potato, and carrots. The addition of 0.48 x 10^{-4} mg per kg of soil is not considered to result in any adverse effect.

The estimated soil increase for molybdenum would be 1.12 x 10^{-3} mg per kg of soil over the 40 year life. Naturally occurring background concentrations average about 2 ppm. Molybdenum toxicity is rarely ovserved in the field since most plants seem to be able to tolerate high tissue concentration. A Mo concentration of 5 ppm in nutrient solution was found to be toxic to clover and lettuce. It would appear to be unlikely that the contribution of Mo from the proposed plant would result in adverse effects.

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. These units were recently permitted by the Department separately from the power plant siting proceeding.

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:

	Maximum Net Increase in Emissions (TPY)		PSD Signif. Emiss. Rate
Pollutant	AES Cedar Bay	Seminole Kraft	(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

Pollutant	AES Cedar Bay	Seminole Kraft	(TPY)
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 (Fluidized bed boilers)

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 (Kraft Recovery Boiler) *

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

* (deleted from power plant siting)

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:

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

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

o 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 fluidized 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.

BACT

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.

Sulfur Dioxide

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.

NOx - CBCP

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 0.29 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 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 3,645 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 $3,937. This is well above the NSPS guideline of $1,000 per ton, yet slightly less than one previous BACT determination in which post-combustion nitrogen oxides control was justified at a cost of approximately $4,200 per ton.

For SNCR, the applicant has indicated that an additional 2,430 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 $1,691 which is above the NSPS guideline but below the cost of some previous BACT determinations.

<u>Environmental Impact Analysis</u>

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 air quality impacts. This reduction in the impacts would result from the replacement of three old power boilers and three old recovery boilers which are now causing higher impacts than what is expected from the new cogeneration/recovery boiler complex.

BACT DETERMINATION BY DER

<u>Discussion</u>

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 heavy metals. In addition, the levels of control proposed for the coal handling facilities, and for products of incomplete combustion also represents 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 current 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.

The plant will be located in Duval County which is classified nonattainment for the pollutant ozone. It will be located in the area of influence of the Jacksonville particulate nonattainment area. However, the plant will not significantly impact the nonattainment area. The facility must comply with the provisions of 17-2.500 F.A.C. (Prevention of Significant Deterioration).

The proposed level of control for nitrogen oxides from the CFB cogeneration facility, under some circumstances would not be considered 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 does exceed the $1,000 guideline that is used for NSPS but is 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 concurrent 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.

EPA's recent BACT determinations for other facilities would tend to support incorporation of SNCR as BACT for nitrogen oxides control for the Cedar Bay facility. Another factor that would support higher than guideline treatment costs is the location of the proposed Cedar Bay/Seminole Kraft cogeneration venture. The site is located in an area which is designated as being nonattainment for ozone. Nitrogen oxides are known to be a precursor to ozone.

AES is locked into a fixed income source due to contracts approved by the Florida PSC. The additional costs of SNCR would cause the project to become financially unfeasible and result in stopping the project. Such an action would be detrimental since the project as proposed will result in overall reductions in air and water quality impacts.

Conclusion

Therefore, the department has concluded that in this particular case the levels of control proposed by the applicant are representative of BACT for this facility. With regard to nitrogen oxides emissions, the net benefits associated with the project as proposed do not justify additional control requirements which would serve to stop the project. The proposed emission level of 0.29 lbs/MMBtu is less than half the NOx level allowed by NSPS. In addition, a review indicates that this level will be the lowest NOx level established for a CFB without additional controls in the country.

Based on the information presented in the preceeding analysis, the emission limits for the Cedar Bay Cogeneration facility are established as follows:

AES Cedar Bay

Pollutant	Determination (lb/MM Btu)
TSP	0.020
PM10	0.020
SO_2	0.60 (3 hour average)
	0.31 (12 month rolling average)
NOx	0.29
CO	0.19
VOC	0.016
Pb	0.0070
Be	0.00011
Hg	0.00026
H_2SO_4	0.024
Fl	0.086

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 will be fitted with a water spray dust suppression system capable of 97 percent efficiency.

Coal will be unloaded at the plant site by a <u>bottom</u> 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 controlled by wetting agents for an efficiency of at least 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.

<u>Limestone Fugitive Dust Collection</u>

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 efficiency of at least 99.9 percent.

<u>Control and Collection of Fugitive Fly Ash Particulates</u>

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 efficiency.

<u>Cooling Tower Drift</u>

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

Rainfall acidity levels across Florida and other parts of the country have 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 man-made 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 5.0. It appears that after a certain amount of time, estimated to be on the order of 1-4 days, these gases interact with sunlight, water vapor, ammonia, and many other chemical compounds in the atmosphere, which converts them to sulfuric acid 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 generally agreed that the entire cause-effect-control relationship is very complex.

One feature that will mitigate some of the impact of the project is that stringent sulfur emission controls will be required prior to the plant going into operation. These units will thus have less impact than that of other units which do not employ those emission controls. The Cedar Bay units will utilize flue gas desulfurization via a fluidized bed of limestone sulfur emissions. Oxides of nitrogen will be controlled by boiler design. Such control will also help mitigate the rainfall acidification problem. In balancing the need for power with the environmental impacts from the operation of the plant, at this time, the required use of the fluidized bed and boiler controls seems to be the most relevant and effective way of addressing the unit's contribution to rainfall acidification.

Construction of new coal fired units may have a slightly positive effect on the acid rain problem in Florida. Data collected during the Florida Sulur Oxides Study indicated that the conversion of sulfur dioxide to sulfuric acid forms two to three times faster in the exhaust plume from an oil fired plant than from a coal fired plant. Oil fired power plants in Florida do not have emission controls for sulfur oxides or nitrogen oxides in most instances. As new coal fired power plants are built with pollution control devices, and as these new coal plants replace the oil plants that emit greater quantities of

SO_x and NO_x, then air pollution levels and acidic rainfall may decrease.

6. Coal Dust from Trains

The movement of coal supply trains to the proposed plant from coal mines outside the state will result in increased fugitive dust levels in areas near the railroad tracks. These increases in fugitive dust levels will be primarily the result of road bed dust emissions and coal dust blowing from the exposed coal contained within each hopper car. The only other quantifiable emissions associated with the coal trains result from the diesel locomotive emissions, which are relatively minor.

For an impact analysis of the coal trains as they move through Jacksonville, it was assumed that trains will travel 500 miles from the mines and that there will be a maximum of one train every three days with 90 cars per train, and a maximum of 106 tons of coal per car. An estimated one percent of coal by weight will be lost as fugitive dust over a journey of about 500 miles with an estimated 90 percent of the total losses escaping during the first few hours of train transit. This implies that only 0.1 percent of the original coal weight will be dispersed as fugitive dust during the rest of the trip, and only a small fraction of the 0.1 percent will be dispersed in the Jacksonville area.

The fugitive dust emissions from agitated road bed dust in the Jacksonville area were estimated using USEPA Publication AP-42 (1979), assuming that the road bed dust emissions are conservatively approximated by emissions from motor vehicles traveling on unpaved roads and that each train will travel at an average speed of ten miles per hour.

The 24-hour average TSP level in the Jacksonville area resulting from the operation of one coal train per day (a conservative estimate) was calculated to be 22 ug/m^3 at a distance of 100 meters downwind of the railroad tracks under light wind conditions. When added to the Jacksonville area background level of 50 ug/m^3, this total is relatively small compared to the National Ambient Air Quality secondary standard and Florida standard of 150 ug/m^3. It is noteworthy that the amount of the fugitive coal dust which was esimated to blow off the coal cars is about half of the expected emissions resulting from agitation of roadbed dust. This is primarily because of the very conservative method that was employed to estimate roadbed dust emissions.

B. Availability of Water

The primary source of water for the plant will be surface groundwater from the Floridan aquifer. Fresh groundwater or reclaimed water from Jacksonville sewage treatment plants will be used as makeup to the recirculating cooling water system. Groundwater will be used for plant potable water supply, fire protection system, plant service water system, and influent to the demineralized water system. Quantitative estimates for water requirements are expressed as annual average and/or maximum flows, whichever best describe system operation. In all

Appendix I. RECOMMENDED CONDITIONS OF CERTIFICATION

Appendix II-A. Public Service Commission Report
Appendix II-B. Department of Community Affairs Report
Appendix II-C. St. Johns River Water Management District Report
Appendix II-D. Jacksonville, Bio-Environmental Services Division Report

State of Florida Department of Environmental Regulation
AES Cedar Bay, Inc./Seminole Kraft Corp.
Cedar Bay Cogeneration Project
PA 88-25

CONDITIONS OF CERTIFICATION (Revised 1/8/91)

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Revised 01/08/91

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

AES CEDAR BAY, INC./SEMINOLE KRAFT CORP.
CEDAR BAY COGENERATION PROJECT
PA 88-24

CONDITIONS OF CERTIFICATION

When a condition is intended to refer to both AES Cedar Bay, Inc. and Seminole Kraft Corp., the term "Cedar Bay Cogeneration Project" or the abbreviation "CBCP" or the term "permittees" will be used. Where a condition applies only to AES Cedar Bay, Inc. the term "AES Cedar Bay, Inc." or the abbreviation "AESCB" or the term "permittee," where it is clear that AESCB is the intended responsible party, will be used. Similarly, where a condition applies only to Seminole Kraft Corp., the term "Seminole Kraft Corp." or the abbreviation "SK" or the term "permittee," where it is clear that SK is the intended responsible party, will be used. The Department of Environmental Regulation may be referred to as DER or the Department. BESD represents the City of Jacksonville, Bio-Environmental Services Division. SJRWMD represents the St. Johns River Water Management District.

I. GENERAL

The construction and operation of CBCP shall be in accordance with all applicable provisions of at least the following regulations of the Department: Chapters 17-2, 17-3, 17-4, 17-5, 17-6, 17-7, 17-12, 17-21, 17-22, 17-25 and 17-610, Florida Administrative Code (F.A.C.) or their sucessors as they are renumbered.

II. AIR

The construction and operation of AESCB shall be in accordance with all applicable provisions of Chapters 17-2, F.A.C. In addition to the foregoing, AESCB shall comply with the following conditions of certification as indicated.

A. Emission Limitations for AES Boilers

1. Fluidized Bed Coal Fired Boilers (CFB)

a. The maximum coal charging rate of each CFB shall neither exceed 104,000 lbs/hr, 39,000 tons per month (30 consecutive days), nor 390,000 tons per year (TPY). This reflects a combined total of 312,000 lbs/hr, 117,000 tons per month, and 1,170,000 TPY for all three CFBs.

b. The maximum wood waste (primarily bark) charging rate to the No. 1 and No. 2 CFBs each shall neither exceed 15,653 lbs/hr, nor 63,760 TPY. This reflects a combined total of 31,306 lbs/hr, and 127,521 TPY for the No. 1 and No. 2 CFBs. The No. 3 CFB will not utilize woodwaste, nor will it be equipped with wood waste handling and firing equipment.

c. The maximum heat input to each CFB shall not exceed 1063 MMBtu/hr. This reflects a combined total of 3189 MMBtu/hr for all three units.

d. The sulfur content of the coal shall not exceed 1.7% by weight on an annual basis. The sulfur content shall not exceed 3.3% by weight on a shipment (train load) basis.

e. Auxiliary fuel burners shall be fueled only with natural gas or No. 2 fuel oil with a maximum sulfur content of 0.3% by weight. The fuel oil or natural gas shall be used only for startups. The maximum annual oil usage shall not exceed 160,000 gals/year, nor shall the maximum annual natural gas usage exceed 22.4 MMCF per year. The maximum heat input from the fuel oil or gas shall not exceed 1120 MMBtu/hr for the CFBs.

f. The CFBs shall be fueled only with the fuels permitted in Conditions 1a, 1b, and 1e above. Other fuels or wastes shall not be burned without prior specific written approval of the Secretary of DER pursuant to condition XXI, Modification of Conditions.

g. The CFBs may operate continuously, i.e, 8760 hrs/yr.

2. Coal Fired Boiler Controls

The emissions from each CFB shall be controlled using the following systems:

a. Limestone injection, for control of sulfur dioxide.

b. Baghouse, for control of particulate.

3. Flue gas emissions from each CFB shall not exceed the following:

		Emission Limitations		
Pollutant	lbs/MMBtu	lbs/hr	TPY	TPY for 3 CFBs
CO	0.19	202	823	2468
NOx	0.29	308.3	1256	3767
SO_2	0.60 (3-hr avg.)	637.8	--	--
	0.31 (12 MRA)	329.5	1338	4015
VOC	0.015	16.0	65	195
PM	0.020	21.3	87	260
PM_{10}	0.020	21.3	86	257

H_2SO_4 mist	0.024	25.5	103	308
Fluorides	0.086	91.4	374	1122
Lead	0.007	7.4	30	91
Mercury	0.00026	0.276	1.13	3.4
Beryllium	0.00011	0.117	0.5	1.5

Note: TPY represents a 93% capacity factor. MRA refers to a twelve month rolling average.

4. Visible emissions (VE) shall not exceed 20% opacity (6 min. average), except for one 6 minute period per hour when VE shall not exceed 27% opacity.

5. Compliance with the emission limits shall be determined by EPA reference method tests included in the July 1, 1988 version of 40 CFR Parts 60 and 61 and listed in Condition No. 7 of this permit or by equivalent methods after prior DER approval.

6. The CFBs are subject to 40 CFR Part 60, Subpart Da; except that where requirements within this certification are more restrictive, the requirements of this certification shall apply.

7. Compliance Tests for each CFB

a. Initial compliance tests for PM/PM_{10}, SO_2, NOx, CO, VOC, lead, fluorides, mercury, beryllium and H_2SO_4 mist shall be conducted in accordance with 40 CFR 60.8 (a), (b), (d), (e), and (f).

b. Annual compliance tests shall be performed for PM, SO_2 and NOx, commencing no later than 12 months from the initial test.

c. Initial and annual visible emissions compliance tests shall be determined in accordance with 40 CFR 60.11(b) and (e).

d. The compliance tests shall be conducted between 90-100% of the maximum liscensed capacity and firing rate of each permitted fuel.

e. The following test methods and procedures of 40 CFR Parts 60 and 61 or other DER approved methods with prior DER approval shall be used for compliance testing:

(1) Method 1 for selection of sample site and sample traverses.

(2) Method 2 for determining stack gas flow rate.

(3) Method 3 or 3A for gas analysis for calculation of percent O_2 and CO_2.

(4) Method 4 for determining stack gas moisture content to convert the flow rate from actual standard cubic feet to dry standard cubic feet.

(5) Method 5 or Method 17 for particulate matter.

(6) Method 6, 6C, or 8 for SO_2.

(7) Method 7, 7A, 7B, 7C, 7D, or 7E for nitrogen oxides.

(8) Method 8 for sulfuric acid mist.

(9) Method 9 for visible emissions, in accordance with 40 CFR 60.11.

(10) Method 10 for CO.

(11) Method 12 for lead.

(12) Method 13B for fluorides.

(13) Method 25A for VOCs.

(14) Method 101A for mercury.

(15) Method 104 for beryllium.

8. Continuous Emission Monitoring for each CFB

AESCB shall use Continuous Emission Monitors (CEMS) to determine compliance. CEMS for opacity, SO_2, NOx, CO, and O_2 or CO_2, shall be installed, calibrated, maintained and operated for each unit, in accordance with 40 CFR 60.47a and 40 CFR 60 Appendix F.

a. Each continuous emission monitoring system (CEMS) shall meet performance specifications of 40 CFR 60, Appendix B.

b. CEMS data shall be recorded and reported in accordance with Chapter 17-2, F.A.C., and 40 CFR 60. A record shall be kept for periods of startup, shutdown and malfunction.

c. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

d. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation and operation of all CEMS.

e. Opacity monitoring system data shall be reduced to 6-minute averages, based on 36 or more data points, and gaseous CEMS data shall be reduced to 1-hour averages, based on 4 or more data points, in accordance with 40 CFR 60.13(h).

f. For purposes of reports required under this certification, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Condition No. 10 herein, which exceeds the applicable emission limit in Condition No. 3.

9. Operations Monitoring for each CFB

a. Devices shall be installed to continuously monitor and record steam production, and flue gas temperature at the exit of the control equipment.

b. The furnace heat load shall be maintained between 70% and 100% of the design rated capacity during normal operations.

c. The coal, bark, natural gas and No. 2 fuel oil usage shall be recorded on a 24-hr (daily) basis for each CFB.

10. Reporting for each CFB

a. A minimum of thirty (30) days prior notification of compliance test shall be given to DER's N.E. District office and to the BESD (Bio-Environmental Services Division) office, in accordance with 40 CFR 60.

b. The results of compliance test shall be submitted to the BESD office within 45 days after completion of the test.

c. The owner or operator shall submit excess emission reports to BESD, in accordance with 40 CFR 60. The report shall include the following:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factors used, and the date and time of commencement and completion of each period of excess emissions (60.7(c)(1)).

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the furnace boiler system. The nature and cause of any malfunction (if known) and the corrective action taken or preventive measured adopted (60.7(c)(2)).

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks, and the nature of the system repairs or adjustments (60.7(c)(3)).

(4) When no excess emissions have occured or the continuous monitoring system has not been inoperative, repaired, or adjusted, such information shall be stated in the report (60.7(c)(4)).

(5) The owner or operator shall maintain a file of all measurements, including continuous monitoring systems performance evaluations; monitoring systems or monitoring device calibration; checks; adjustments and maintenance performed on these systems or devices; and all other information required by this permit recorded in a permanent form suitable for inspection (60.7(d)).

d. Annual and quarterly reports shall be submitted to BESD as per F.A.C. Rule 17-2.700(7).

11. Any change in the method of operation, fuels utilized, equipment, or operating hours or any other changes pursuant to F.A.C. Rule 17-2.100, defining modification, shall be submitted for approval to DER's Bureau of Air Regulation.

B. AES - Material Handling and Treatment

1. The material handling and treatment operations may be continuous, i.e. 8760 hrs/yr.

2. The material handling/usage rates shall not exceed the following:

Material	Handling/Usage Rate TPM	TPY
Coal	117,000	1,170,000
Limestone	27,000	320,000
Fly Ash	28,000	336,000
Bed Ash	8,000	88,000

Note: TPM is tons per month based on 30 consecutive days, TPY is tons per year.

3. The VOC emissions from the maximum No. 2 fuel oil utilization rate of 240 gals/hr, 2,100,000 gals/year for the limestone dryers; and 8000 gals/hr, 160,000 gals/year for the three boilers are not expected to be significant.

4. The maximum emissions from the material handling and treatment area, where baghouses are used as controls for specific sources, shall not exceed those listed below (based on AP-42 factors):

Source	Particulate Emissions lbs/hr	TPY
Coal Rail Unloading	neg	neg
Coal Belt Feeder	neg	neg

Coal Crusher	0.41	1.78
Coal Belt Transfer	neg	neg
Coal Silo	neg	neg
Limestone Crusher	0.06	0.28
Limestone Hopper	0.01	0.03
Fly Ash Bin	0.02	0.10
Bed Ash Hopper	0.06	0.25
Ash Silo	0.06	0.25
Common Feed Hopper	0.03	0.13
Ash Unloader	0.01	0.06

The emissions from the above listed sources and the limestone dryers are subject to the particulate emission limitation requirement of 0.03 gr/dscf. However, neither DER nor BESD will require particulate tests in accordance with EPA Method 5 unless the VE limit of 5% opacity is exceeded for a given source, or unless DER or BESD, based on other information, has reason to believe the particulate emission limits are being violated.

5. Visible Emissions (VE) shall not exceed 5% opacity from any source in the material handling and treatment area, in accordance with F.A.C. Chapter 17-2.

6. The maximum emissions from each of the limestone dryers while using oil shall not exceed the following (based on AP-42 factors, Table 1, 3-1, Industrial Distillate, 10/86):

	Estimated Limitations		
Pollutant	lbs/hr	TPY	TPY for 2 dryers
PM/PM_{10}	0.25	1.1	2.2
SO_2	5.00	21.9	43.8
CO	0.60	2.6	5.2
NOx	2.40	10.5	21.0
VOC	0.05	0.2	0.4

Visible emissions from the dryers shall not exceed 5% opacity. If natural gas is used, emissions limits shall be determined by factors contained in AP-42 Table 1. 4-1, Industrial 10/86.

7. The maximum No. 2 fuel oil firing rate for each limestone dryer shall not exceed 120 gals/hr, or 1,050,000 gals/year. This reflects a combined total fuel oil firing rate of 240 gals/hr, and 2,100,000 gals/year, for the two dryers. The maximimum natural gas firing rate for each limestone dryer shall not exceed 16,800 CF per hour, or 147 MMCF per year

8. Initial and annual Visible Emission compliance tests for all the emission points in the material handling and treatment area, including but not limited to the sources specified in this permit, shall be conducted in accordance with the July 1, 1988 version of 40 CFR 60, using EPA Method 9.

9. Compliance test reports shall be submitted to BESD within 45 days of test completion in accordance with Chapter 17-2.700(7) of the F.A.C.

10. Any changes in the method of operation, raw materials processed, equipment, or operating hours or any other changes pursuant to F.A.C. Rule 17-2.100, defining modification, shall be submitted for approval to DER's Bureau of Air Regulation (BAR).

C. Requirements For the Permittees

1. Beginning one month after certification, AESCB shall submit to BESD and DER's BAR, a quarterly status report briefly outlining progress made on engineering design and purchase of major equipment, including copies of technical data pertaining to the selected emission control devices. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ratio and flow rate. The Department may, upon review of these data, disapprove the use of any such device. Such disapproval shall be issued within 30 days of receipt of the technical data.

2. The permittees shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the BESD office.

3. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, regrassing or watering areas of disturbed soils, will be taken by the permittees.

4. Fuel shall not be burned in any unit unless the control devices are operating properly, pursuant to 40 CFR Part 60 Subpart Da.

5. The maximum sulfur content of the No. 2 fuel oil utilized in the CFBs and the two unit limestone dryers shall not exceed 0.3 percent by weight. Samples shall be taken of each fuel oil shipment received and shall be analyzed for sulfur content and heating value. Records of the analyses shall be kept a minimum of two years to be available for DER and BESD inspection.

6. Coal fired in the CFBs shall have a sulfur content not to exceed 3.3 percent by weight. Coal sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a.

7. AESCB shall maintain a daily log of the amounts and types of fuel used and copies of fuel analyses containing information on sulfur content and heating values.

8. The permittees shall provide stack sampling facilities as required by Rule 17-2.700(4) FAC.

9. Prior to commercial operation of each source, the permittees shall each submit to the BAR a standardized plan or procedure that will allow that permittee to monitor emission control equipment efficiency and enable the permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

D. Contemporaneous Emission Reductions

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, that the following Seminole Kraft Corporation sources be permanently shut down and made incapable of operation, and shall turn in their operation permits to the Division of Air Resources Management's Bureau of Air Regulation, upon completion of the initial compliance tests on the AESCB boilers: the No. 1 PB (power boiler), the No. 2 PB, the No. 3 PB, the No. 1 BB (bark boiler),and the No. 2 BB. BESD shall be specifically informed in writing within thirty days after each individual shut down of the above referenced equipment. This requirement shall operate as a joint and individual requirement to assure common control for purpose of ensuring that all commitments relied on are in fact fulfilled.

III. WATER DISCHARGES

Any discharges into any waters of the State during construction and operation of AESCB shall be in accordance with all applicable provisions of Chapters 17-3, and 17-6, F.A.C., and 40 CFR, Part 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category, except as provided herein. Also, AESCB shall comply with the following conditions of certification:

A. Plant Effluents and Receiving Body of Water

For discharges made from the AESCB power plant the following conditions shall apply:

1. Receiving Body of Water (RBW) - The receiving body of water has been determined by the Department to be those waters of the St. John's River or Broward River and any other waters affected which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Discharge (POD) - The point of discharge has been determined by the Department to be where the effluent physically enters the waters of the State in the St. John's River via the SKC discharge outfall 001, which is the existing main outfall from the paper mill emergency overflow to the Broward River

3. Thermal Mixing Zones - The instantaneous zone of thermal mixing for the AESCB cooling system shall not exceed an area of 0.25 acres. The temperature at the point of discharge

State of Florida Department of Environmental Regulation
AES Cedar Bay, Inc./Seminole Kraft Corp.
Cedar Bay Cogeneration Project
PA88-5740
CONDITIONS OF CERTIFICATION

CONTENTS

CONTENTS (continued)

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

AES CEDAR BAY, INC./SEMINOLE KRAFT CORP.
CEDAR BAY COGENERATION PROJECT
PA 88-5740

CONDITIONS OF CERTIFICATION

When a condition is intended to refer to both AES Cedar Bay, Inc. and Seminole Kraft Corp., the term "Cedar Bay Cogeneration Project" or the abbreviation "CBCP" or the term "permittees" will be used. Where a condition applies only to AES Cedar Bay, Inc. the term "AES Cedar Bay, Inc." or the abbreviation "AESCB" or the term "permittee," where it is clear that AESCB is the intended responsible party, will be used. Similarly, where a condition applies only to Seminole Kraft Corp., the term "Seminole Kraft Corp." or the abbreviation "SK" or the term "permittee," where it is clear that SK is the intended responsible party, will be used.

I. AIR

The construction and operation of Cedar Bay Cogeneration Project shall be in accordance with all applicable provisions of Chapters 17-2, 17-4, 17-5, and 17-7, Florida Administrative Code. In addition to the foregoing, each permittee shall comply with the following conditions of certification as indicated.

A. Emission Limitations for AESCB Sources Units 1, 2 and 3.

1. Based on a combined maximum heat input of 3,189 million Btu per hour, stack emissions from the three circulating fluidized bed boilers shall not exceed the following when burning coal:

Base on each unit

   a. SO_2--0.6 lb per million Btu heat input, maximum three-hour average, 0.31 lb/MMBtu on a 12-month rolling average.

   b. NO_x--0.36 lb per million Btu heat input.

   c. Particulates--0.02 lb per million Btu heat input.

   d. Visible emissions--20 percent (six-minute average), except one six-minute period per hour of not more than 27 percent opacity.

test methods.

CPB Nos 1, 2 and 3

2. The height of the boiler ~~exhaust~~ stack for SJRPP ~~Unit 1~~ and 2 shall not be less than 425 ~~feet~~ above grade.
435 in application

3. Particulate emissions from the coal handling facilities:

    a. The permittee shall not cause to be discharged into the atmosphere from any coal processing or conveying equipment, coal storage system or coal transfer and loading ~~system~~ processing coal, visible emissions which exceed ~~10~~ percent opacity. Particulate emissions shall be controlled by use of control devices.

    b. The permittee must submit to the Department within thirty (30) days after it becomes available, copies of technical data pertaining to the selected particulate emissions control for the coal handling facility. These data should include, but not be limited to, guaranteed efficiency and emission rates, and major design parameters such as air/cloth ration and flow rate. The Department may, upon review of these data, disapprove the use of any such device if the Department determines the selected control device to be inadequate to meet the emission limits specified in 3(a) above. Such disapproval shall be issued within 30 days of receipt of the technical data.

PM/PM10

4. Particulate emissions from limestone and fly ash handling shall not exceed the following:

    a. Limestone silos--0.050 lb/h. 0.03 gr/dscf LAER

    b. Limestone hopper/transfer conveyors--0.65 lb/h.

    c. Fly ash handling system--0.2 lb/h.

Comprehensive?

FAC 17-2.650(2)(c)11b

VE 5%

5. Visible emissions from the following facilities shall be limited to 10 percent opacity: (a) limestone and fly ash handling system, (b) limestone day silos, and (c) fly ash silos.

6. Compliance with opacity limits of the facilities listed in Condition 5 will be determined by EPA reference Method 9 (Appendix A, 40 CFR 60). New ref.

7. Construction shall reasonably conform to the plans and schedule given in the application.

BESD

8. The permittee shall report any delays in construction and completion of the project which would delay commercial operation by more than 90 days to the Department's Northeast District office.

9. Reasonable precautions to prevent fugitive particulate emissions during construction, such as coating of roads and construction sites used by contractors, regrassing or watering areas of disturbed soils, will be taken by the permittee.

10. Coal shall not be burned in the units unless both baghouse and limestone injection are operating properly except as provided under 40 CFR Part 60 Subpart Da.

BACT PM=0.03 gr/dscf 5% VE or 98% control

11. The two unit limestone dryers shall fire No. 2 fuel oil with a maximum sulfur content of 0.3 percent by weight. Samples of all fuel oil fired in the boilers shall be taken and analyzed for sulfur content and heating value. Accordingly, samples shall be taken of each fuel oil shipment received. Records of the analyses shall be kept a minimum of two years to be available for FDER's inspection.

12. The same quality No. 2 fuel oil, used for the limestone dryers, shall be used for the CFB boilers during startup and low load operation.

13. (Deleted)

Need ash? ? 1.7 ton

14. Coal fired in the CFB boilers shall have an ash content not to exceed 18 percent and a sulfur content not to exceed 3.3 percent by weight. Coal sulfur content shall be determined and recorded in accordance with 40 CFR 60.47a.

15. (Deleted)

16. AESCB shall keep records of the frequency, duration, firing rate, and manner of operation of the limestone dryers.

B. Emission Limitations for SK Sources

(Later)

112889

C. Air Monitoring Program

1. AESCB shall install and operate continuously monitoring devices for each CFB boiler exhaust for sulfur dioxide, nitrogen oxide, carbon monoxide, carbon dioxide, and opacity. The monitoring devices shall meet the applicable requirements of Section 17-2.710, FAC, and 40 CFR 60.47a. The opacity monitor may be placed in the ductwork following the baghouses.

2. SK shall install and operate (to be completed later).

3. AESCB shall maintain a daily log of the amounts and types of fuel used and copies of fuel analyses containing information on sulfur content, ash content, and heating values.

4. The permittees shall provide stack sampling facilities as required by Rule 17-2.700(4) FAC.

5. (Deleted)

6. Prior to commercial operation of each source, the permittees shall each submit to the Department a standardized plan or procedure that will allow that permittee to monitor emission control equipment efficiency and enable that permittee to return malfunctioning equipment to proper operation as expeditiously as possible.

D. Stack Testing

1. Within 60 calendar days after achieving the maximum capacity at which each CFB unit will be operated, but no later than 180 ~~operating~~ calendar days after initial startup, AESCB shall conduct performance tests for particulates SO_2, NO_x, and visible emissions during normal operations near (\10 percent) maximum heat input and furnish the Department a written report of the results of such performance tests within 45 days of completion of the tests. The performance tests will be conducted in accordance with the provisions of 40 CFR 60.46a, 48a, and 49a.

2. Performance tests for the CFBs shall be conducted and data reduced in accordance with methods and procedures outlined in Section 17-2.700 FAC.

3. Performance tests for the CFBs shall be conducted under such conditions as the Department shall specify based on representative performance of the facility. AESCB shall make available to the Department such records as may be necessary to determine the conditions of the performance tests.

4. AESCB shall provide 30 days prior notice of the initial performance tests for the CFBs in order to afford the Department the opportunity to have an observer present.

5. CFB stack tests for particulates NO_x and SO_2 and visible emissions shall be performed annually in accordance with Conditions C.2, 3, and 4 above.

6. SK shall perform the following stack test: (Later).

BESD

E. Reporting

1. For the CFBs, AESCB shall report stack monitoring, fuel usage and fuel analysis data to the Department's Northeast District Office on a quarterly basis commencing with the start of commercial operation in accordance with 40 CFR, Part ~~60, Section~~ 60.7, and in accordance with Section 17-2.08, FAC.

2. (Deleted)

3. Beginning one month after certification, each permittee shall submit to the Department a quarterly status report briefly outlining progress made on engineering design and purchase of major pieces of air pollution control equipment on their respective sources. All reports and information required to be submitted under this condition shall be submitted to the Administrator of Power Plant Siting, Department of Environmental Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32301.

F. Contemporaneous Emission Reductions

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 ensuring that all contemporaneous emission reductions relied on are in fact made.

II. WATER DISCHARGES

Any discharges into any waters of the State during construction and operation of AESCB shall be in accordance with all applicable provisions of Chapter 17-3, Florida Administrative Code, and 40 CFR, Part 423, Effluent Guidelines and Standards for Steam Electric Power Generating Point Source Category, except as provided herein. Also, AESCB shall comply with the following conditions of certification.

A. Plant Effluents and Receiving Body of Water

For discharges made from the power plant the following conditions shall apply:

1. Receiving Body of Water (RBW)

The receiving body of water has been determined by the Department to be those waters of the St. John's River and any other waters affected which are considered to be waters of the State within the definition of Chapter 403, Florida Statutes.

2. Point of Discharge (POD)

The point of discharge has been determined by the Department to be where the effluent physically enters the waters of the State in the St. John's River or Broward River.

3. Thermal Mixing Zones

The instantaneous zone of thermal mixing for the cooling systems shall not exceed an area of __ acres. The temperature at the point of discharge into the St. John's River shall not be greater than ___ degrees F. The temperature of the water at the edge of the mixing zone shall not exceed the limitations of Paragraph 17-3.05(1)(d). Cooling tower blowdown shall not exceed __ degrees F as a 24-hour average.

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

JUL 02 1990

RECEIVED
JUL 5 1990
DER-BAQM

4APT-AE

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

RE: Ambient Air Quality Analysis Workplan
Applied Energy Services (AES)
Cedar Bay Cogeneration Project

Dear Mr. Fancy:

In a letter from Ms. Julie Blunden to Lewis Nagler of my staff dated June 8, 1990, we received a copy of the proposed air quality analysis workplan for the above referenced project. The proposed workplan appears acceptable to us (assuming that the emissions inventory to be used in the analysis is acceptable) with the following exceptions.

On page 3-5 of the workplan, AES states that ... "FDER has indicated that approximately 1,400 tpy of VOC are available as a new source allowance in Duval County." As you are aware, on May 26, 1988, EPA notified your Agency and the Governor that the Florida SIP was inadequate to achieve the ozone standard in six Florida counties, including Duval. Therefore, any growth allowances alotted by the SIP are no longer available. This policy has been clearly expressed in the March 10, 1986, memorandum from Darryl Tyler, Director, Control Programs Development Division (enclosed). It was also our understanding that any emissions offsets (VOC) or ambient offsets (SO_2) needed by AES would be obtained through various boiler shutdowns at the Seminole Kraft Corporation.

On pages 4-3 through 4-6, the workplan lists estimated particulate emission rates from various material handling and storage operations. Some of the control efficiencies referenced in this section suggest that precipitation will achieve a 100 percent control of fugitive emissions. This degree of control should be justified or corrected.

If you have any questions concerning this letter, please contact Mark Armentrout of my staff at (404) 347-2904.

Sincerely yours,

Brian L. Beals, Chief
Source Evaluation Unit
Air, Pesticides and Toxics
Management Division

Enclosure

cc: Julie Blunden
Development Manager
AES/Cedar Bay, Inc.
1001 North 19th Street
Arlington, VA 22209

B. Andrews
M. Linn
B. Owen
A. Kutyna, NE Dist.
R. Roberson, BESD
C. Shaver, NPS

JOINT PUBLIC NOTICE

U.S. Environmental Protection Agency
Region IV
Water Management Division - Facilities Performance Branch
345 Courtland Street, N.E.
Atlanta, Georgia 30365
404/347-3004

in conjunction with

Florida Department of Environmental Regulation
Twin Towers Office Building, 2600 Blair Stone Road
Tallahassee, Florida 32301
904/488-1344

Public Notice No. 90FL277 May 31, 1990

NOTICE OF PUBLIC INFORMATION HEARING

ON

NOTICE OF PROPOSED ISSUANCE OF NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM PERMIT, DRAFT ENVIRONMENTAL IMPACT STATEMENT, AND NOTICE OF CONSIDERATION FOR STATE CERTIFICATION OF THE NPDES PERMIT

The U.S. Environmental Protection Agency (EPA) proposes to issue a National Pollutant Discharge Elimination System (NPDES) permit to AES Cedar Bay, Inc.; 1001 North 19th Street, Suite 2000, Arlington, VA 22209; for its Cedar Bay Cogeneration Project; 9469 Eastport Road, Jacksonville, FL 32218. The application, NPDES No. FL0041173, describes two point source and eight internal discharges from construction and operation of the facility to the Broward (approximate latitude 30° 25', longitude 81° 37') and St. Johns Rivers (approximate latitude 30° 25', longitude 81° 36'). All wastes to the St. Johns River will be via the Seminole Kraft Corporation discharge diffuser system (NPDES No. FL0000400). These reaches of the Rivers are classified as Class III Waters - Recreation - Propagation and maintenance of a Healthy, Well-Balanced Population of Fish and Wildlife. The facility will generate and transmit electricity (SIC 4911).

A Draft Environmental Impact Statement (EIS) will be made available to the public on or about June 8, 1990, by the EPA.

In order to solicit further public participation on the proposed project, EPA will co-chair with FDER a public hearing on the Draft Environmental Impact Statement, the proposed issuance of the NPDES permit, and the Florida certification of the NPDES permit. The hearing will begin at 7:00 p.m. on July 12, 1990, at the Oceanway Community Center, 12216 West Sago Avenue, Jacksonville, FL. Individuals with handicaps requiring special assistance should contact Ms. Diane Barrett, Public Notice Coordinator, at 404/347-3004 by June 28, 1990, so that reasonable accommodations can be made.

Both oral and written comments will be accepted at the public hearing and a transcript of the proceedings will be made. For the accuracy of the record, written comments are encouraged. The Hearing Officer reserves the right to fix reasonable limits on the time allowed for oral statements.

The proposed NPDES permit contains limitations on the amounts of pollutants allowed to be discharged and was drafted in accordance with the provisions of the Clean Water Act (33 U.S.C. Section 1251 et seq.) and other lawful standards and regulations. The pollutant limitations and other permit conditions are tentative and open to comment from the public.

Persons wishing to comment upon or object to any aspects of permit issuance or the Draft Environmental Impact Statement are invited to submit same in writing, postmarked no later than July 23, 1990, to the Office of Public Affairs, Environmental Protection Agency, 345 Courtland Street, N.E., Atlanta, GA 30365, Attention: Ms. Diane Barrett. Pursuant to 40 CFR 124.13, any person who believes any condition of the permit is inappropriate must raise all reasonably ascertainable issues and submit all reasonably available arguments in full, supporting their position, by the close of the comment period. The public notice number and NPDES number should be included in the first page of comments.

A final EIS will be published after the close of the public comment period. Reviewers should be aware that EPA will not reprint the material contained in the Draft EIS for the Final EIS. The Final EIS will comprise a summary of the Draft EIS, the EPA decision on the preferred alternative, responses to comments received on the Draft EIS, the transcript of the public hearing (or a summary thereof), other relevant information or evaluations developed after publication of the Draft EIS, and a copy of the proposed NPDES permit.

After consideration of all written comments; all comments, statements and data presented at the public hearing; and of the requirements and policies in the Act and appropriate regulations, the EPA Regional Administrator will make a determination regarding the permit issuance. If the determination is substantially unchanged from that announced by this notice, the EPA Regional Administrator will so notify all persons submitting written comments and all persons participating in the hearing. If the determinations are substantially changed, the EPA Regional Administrator will issue a public notice indicating the revised determination. Request(s) for evidentiary hearing may be filed after the Regional Administrator makes the above-described determinations. No issues shall be raised by any party that were not submitted to the administrative record as part of the preparation of and comment on the draft permit, unless good cause for the failure to submit them in accordance with 40 CFR 124.76. Additional information regarding an evidentiary hearing is available in 40 CFR 124, Subpart E, or by contacting the Office of the Regional Counsel at the above EPA address or at telephone number 404/347-2335.

A fact sheet which outlines the applicant's proposed discharges and the EPA proposed pollutant limitations and conditions is available at no charge by writing the EPA address above. The administrative record, including (1) application, (2) the Draft Environmental Impact Statement (which includes items 3-5) (3) fact sheet, (4) draft permit, (5) a sketch showing the exact location of the discharges, (6) comments received, and (7) additional information on hearing procedures is available by writing the EPA address above, or for review and copying at 345 Courtland Street N.E., 3rd floor, Atlanta, Georgia, between the hours of 8:15 a.m. and 4:30 p.m., Monday through Friday. Copies will be provided at a minimal cost per page. Copies of the Draft EIS, fact sheet and other information will be available for review at reading rooms in the following locations in Jacksonville, Florida: (1) Public Library, Main Branch, 122 N. Ocean Street, 32202; (2) Highland Branch Public Library, 1826 Dunn Avenue; and (3) San Mateo Elementary School, 600

Baisden Road. A limited number of copies of the Draft EIS are available from Ms. Marion Hopkins, Federal Activities Branch, at the EPA address noted above (Telephone: 404/347-3776, FAX: 404/347-5056).

EPA has requested FDER to certify the discharge(s) in accordance with the provisions of Section 401 of the Clean Water Act (33 U.S.C. Section 1341). Comments on issuance of certification must be submitted to the FDER address above, Attn: Mr. H.S. Oven, Jr., Director, Siting Coordination Section, by July 23, 1990. As described above, the FDER will co-chair the hearing in order to receive comments relative to state certification.

Please bring the foregoing to the attention of persons who you know will be interested in this matter. If you would like to be added to our public notice mailing list, submit your name and mailing address to the Office of Public Affairs at the EPA address above.

###

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

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PRADEEP RAVAL, ENGINEER
FLORIDA DEPT. OF ENVR. REGULATION
BUREAU OF AIR QUALITY MGMT
2600 BLAIR STONE ROAD
TALLAHASSEE FL 32399

February 16, 1990

RECEIVED
FEB 23 1990
DER - BAQM

Hamilton S. Oven
Chief, Power Plant Siting
Department of Environmental Regulation
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Buck:

During a call with Pradeep Raval earlier this week, he requested that I submit a summary of our concerns related to air with the Cedar Bay Cogeneration Project's Conditions of Certification. Although the transcript of last week's hearing is unavailable, I believe all substantive concerns with the air conditions are addressed below. At this time, I believe that AES Cedar Bay and DER have agreed on all of the air conditions with the incorporation of the modifications provided by Steve Wolf to you in a letter dated February 16, 1990.

The points of concern and their resolutions are as follows:

- II.A.1.a and b - These conditions as stated could potentially limit AES Cedar Bay's power production by restricting the fuel feed rates while the facility remains well within the annual emission limits.
  Resolution - Change the fuel feed rates to reflect worst case coal quality as discussed in Steve Wolf's letter to you dated February 16, 1990.

- II.A.1.e - AES Cedar Bay wishes to remain flexible in the fuel used for the limestone dryers and during start-up. Therefore, we would like to have the option to use cleaner burning natural gas as an alternative to fuel oil.
  Resolution - DER agrees.

- II.A.3 - Limiting emissions on each boiler at a 93% capacity factor rather than on the three CFB's combined limits our flexibility to perform maintainence and to run a more reliable boiler more than 93% of the time while limiting power production on a less reliable boiler.
  Resolution - DER is unable to change this condition.

- II.A.9.b - In order to accomodate flexibility in our electric contract, AES Cedar Bay will maintain furnace heat load between 70% (rather than 80%) and 100% of design rated capacity during normal operations.
  Resolution - DER agrees.

- II.B.2 - Again, the material handling usage rates could limit power production because these figures are not based on worse case coal.
  Resolution - Incorporate worst case coal numbers provided in Steve Wolf's letter to you dated February 16, 1990.

AES/CedarBay Inc.

1001 North 19th Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier—(703) 528-4510

- II.B.4 - Calculation of the emission rates from the materials handling facility on a #/hr basis were of concern. To calculate hourly emissions by dividing the annual rates by the number of hours per year would be inaccurate as the materials handling facilities will not be operated on a continuous basis.
  Resolution - It is AES Cedar Bay's understanding that the AP 42 emission factors are based on design capacities for the belts which would be an accurate method of calculation.

- II.B.6 - The limestone dryer emissions presented a concern similar to that concerning the materials handling emissions.
  Resolution - It is AES Cedar Bay's understanding that the limestone dryer emissions are based on the oil firing rate which would be an accurate method of calculation.

- II.C.4 - 40 CFR 60 Subpart BB refers to kraft recovery boilers and should be deleted from the conditions of certification.
  Resolution - DER agrees.

Thank you and the air staff for your diligent help in resolving all of these issues. Please do not hesitate to give me a call if you have any questions.

Sincerely,

Julie

Julie Blunden
Development Manager

cc: Betsy Hewitt, DER
Clare Fancy, DER
Richard L. Maguire, City of Jacksonville
Kathryn Mennella, St. Johns River Water Management District
William Bostwick, Esq.
Terry Cole, Oertel, Hoffman, Fernandez & Cole

TELEFAX

DATE: 2/16

TO: Buck Oven

ORGANIZATION: DER

TELEFAX NUMBER: 904 487 4938

FROM: J Blunden

NUMBER OF PAGES TO FOLLOW: 4

MESSAGE: see you Monday evening or Tues.

THE AES CORPORATION
1001 NORTH 19TH STREET
ARLINGTON, VA 22209
PHONE: 703/522-1315
FAX: 703/528-4510

February 16, 1990

Hamilton S. Oven
Chief, Power Plant Siting
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Buck,

AES Cedar Bay representatives met with the DER staff Thursday, February 8, 1990 to discuss conditions of certification regarding the Cedar Bay Cogeneration Project. As a result of that meeting, AES-CB has agreed to provide this written request for changes to certain conditions in order that the conditions reflect actual operating parameters that were not identified in the application.

1. The maximum coal feed rates currently written into the conditions (Section II.A.1.a and II.B.2) do not reflect the "worse case" coal quality that can be expected. AES-CB has reviewed the coal specifications and determined that the worse case coal provided will have a heat content of 11,500 Btu/lb at 10% moisture. Additional moisture can be absorbed by the coal while being stored on-site. Assuming that a reasonable maximum moisture content in the coal pile is 20%, the resulting heat content will be 10,250 Btu/lb.

   The associated maximum coal feed rates follow. The maximum rates assume the worse case coal would exist 1 month each year.

   - 104,000 lbs/hour each CFB
   - 312,000 lbs/hour all three CFB's

   - 39,000 tons/month each CFB
   - 117,000 tons/month all three CFB's

   - 390,0000 tons/year each CFB
   - 1,170,000 tons/year all three CFB's

2. As discussed, the furnace heat load shall be maintained between 70% and 100% of design rated capacity during normal operations. (II.A.9.b)

3. As an alternate in conditions II.A.1.e and II.B.7, AES-CB would like the opportunity to add the following flow rates for natural gas should it become available as an economical alternative to fuel oil for firing the limestone dryer and startup burners.

AES/CedarBay Inc.

Auxilliary fuel burners:
22.4 million cubic feet per year

Limestone Dryers each:
16,800 cubic feet per hour
147 million cubic feet per year

Limestone Dryers total:
33,600 cubic feet per hour
294 million cubic feet per year

Thank you and the air staff for your cooperation in resolving the concerns of AES Cedar Bay with these air conditions.

Sincerely,

Steve Wolf / LB

Steve Wolf
Engineering Manager

February 16, 1990

Hamilton S. Oven
Chief, Power Plant Siting
Department of Environmental Regulation
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Buck:

During a call with Pradeep Raval earlier this week, he requested that I submit a summary of our concerns related to air with the Cedar Bay Cogeneration Project's Conditions of Certification. Although the transcript of last week's hearing is unavailable, I believe all substantive concerns with the air conditions are addressed below. At this time, I believe that AES Cedar Bay and DER have agreed on all of the air conditions with the incorporation of the modifications provided by Steve Wolf to you in a letter dated February 16, 1990.

The points of concern and their resolutions are as follows:

- II.A.1.a and b - These conditions as stated could potentially limit AES Cedar Bay's power production by restricting the fuel feed rates while the facility remains well within the annual emission limits.
  Resolution - Change the fuel feed rates to reflect worst case coal quality as discussed in Steve Wolf's letter to you dated February 16, 1990.

- II.A.1.e - AES Cedar Bay wishes to remain flexible in the fuel used for the limestone dryers and during start-up. Therefore, we would like to have the option to use cleaner burning natural gas as an alternative to fuel oil.
  Resolution - DER agrees.

- II.A.3 - Limiting emissions on each boiler at a 93% capacity factor rather than on the three CFB's combined limits our flexibility to perform maintainence and to run a more reliable boiler more than 93% of the time while limiting power production on a less reliable boiler.
  Resolution - DER is unable to change this condition.

- II.A.9.b - In order to accomodate flexibility in our electric contract, AES Cedar Bay will maintain furnace heat load between 70% (rather than 80%) and 100% of design rated capacity during normal operations.
  Resolution - DER agrees.

- II.B.2 - Again, the material handling usage rates could limit power production because these figures are not based on worse case coal.
  Resolution - Incorporate worst case coal numbers provided in Steve Wolf's letter to you dated February 16, 1990.

- II.B.4 - Calculation of the emission rates from the materials handling facility on a #/hr basis were of concern. To calculate hourly emissions by dividing the annual rates by the number of hours per year would be inaccurate as the materials handling facilities will not be operated on a continuous basis.
  Resolution - It is AES Cedar Bay's understanding that the AP 42 emission factors are based on design capacities for the belts which would be an accurate method of calculation.

- II.B.6 - The limestone dryer emissions presented a concern similar to that concerning the materials handling emissions.
  Resolution - It is AES Cedar Bay's understanding that the limestone dryer emissions are based on the oil firing rate which would be an accurate method of calculation.

- II.C.4 - 40 CFR 60 Subpart BB refers to kraft recovery boilers and should be deleted from the conditions of certification.
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Thank you and the air staff for your diligent help in resolving all of these issues. Please do not hesitate to give me a call if you have any questions.

Sincerely,

Julie

Julie Blunden
Development Manager

cc: Betsy Hewitt, DER
Clare Fancy, DER
Terry Cole, Oertel, Hoffman, Fernandez & Cole

PM
1-4-90
Arlington, Va.

File Copy

January 2, 1990

Mr. Steve Smallwood
Bureau Chief
Department of Environmental Regulation
Division of Air Resource Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED
JAN 8 1990
DER - BAQM

Dear Mr. Smallwood:

In Jeff Swain's letter to Barry Andrews dated December 12, 1989, he officially notified the Department of Environmental Regulation of AES Cedar Bay's ability to reduce the proposed maximum NO_X emission rate from their cogeneration plant to 0.29 lb/MBtu from 0.36 lb/MBtu. In light of this change, the DER should find that AES Cedar Bay's use of innovative fuel combustion technology - circulating fluidized bed (CFB) boilers - is the Best Available Control Technology (BACT) from a top-down approach.

In AES Cedar Bay's original BACT analysis, use of Selective Non-Catalytic Reduction (SNCR) systems was found to be an uneconomical alternative for the Cedar Bay Cogeneration Project. With the new proposal for a NO_X emission rate of 0.29 lb/MBtu, the cost effectiveness of SNCR is further diminished. The total annual cost to AES Cedar Bay for an SNCR system is estimated to be $4 million which is equivalent to about $1,700 per ton of NO_X emission reduced.

An additional cost of $4 million per year is not practicable for this project. AES Cedar Bay, as a qualifying facility regulated under PURPA, can not pass on additional costs to the ratepayer as a utility would. Independent power producers rely on long-term contracts with their customers and suppliers in order to finance their projects. AES Cedar Bay's electric contract, which will save Florida ratepayers $2.7 billion over the term of the contract, has already been approved by the Florida Public Service Commission (FPSC). When structuring its contract with Florida Power & Light (FPL), AES Cedar Bay took into account the cost of using an innovative fuel combustion technology. The CFB boilers will emit NO_X at a rate less than half of new source performance

AES/CedarBay Inc.
1001 North 19th Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier—(703) 528-4510

AES/CedarBay Inc.
1001 North 19th Street
Arlington, Virginia 22209

Barry Andrews
Clare Fancy
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attn: Bureau of Air Quality Management

standards and reduce ambient concentrations of NO_X in Jacksonville. However, an additional cost for NO_X emission reductions of more than $4 million per year was not anticipated. This additional cost would render the project unfinacable, and thus result in project cancellation.

The Environmental Protection Agency and Florida definitions of BACT state that it be 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 to be achievable though application of production processes and available methods, systems and techniques for control of each pollutant. These systems and techniques may include fuel cleaning or treatment, or innovative fuel combustion techniques such as CFB boilers. In this case there are energy, environmental, economic and other costs to the State of Florida should this project be halted due to a requirement for the use of SNCR.

A determination of need for his facility has been found by the FPSC. This need for additional electric capacity was dramatically reinforced by the rolling blackouts during the recent cold snap which found many families without electricity on Christmas morning. Without this facility, FPL's capacity margin will be further reduced in the near term, threatening electricity supply during peak loads. In the long term, FPL would replace this facility with another elsewhere in Florida. This hypothetical facility is less likely to offer the environmental benefits associated with the Cedar Bay Cogeneration Project.

AES Cedar Bay provides the Seminole Kraft Corporation with an opportunity to retire the paper mill's outdated power boilers. Without AES Cedar Bay, Jacksonville will not benefit from the ground level improvements in NO_X, nor the ambient VOC, SO_2 or particulate matter improvements offered by the project. Also, a FPL replacement plant will emit additional NO_X elsewhere in the State. If the cogeneration facility is replaced by a base-load pulverized coal unit, this facility would be very likely to demonstrate NO_X control to be unpracticable due to the very high costs of applying SNCR to a PC unit and the fact that this technology is not proven on PC units. Actually, the AES Cedar Bay facility will not only reduce ambient NO_X in Jacksonville, produce 225 MW of power for

Florida, and use innovative fuel combustion technology, but will have the lowest permitted NO_X emission rate of any coal-fired unit in the State.

In addition, there are also environmental concerns associated with the use of SNCR. Units equipped with this technology have had problems with high ammonia slip. It is also likely that use of SNCR technology will increase PM 10 emissions and possibly CO emissions. It is unclear that a requirement for the use of an SNCR technology on this project would result in a net environmental benefit.

Accordingly, AES Cedar Bay has proposed BACT for this project to be the use of CFB boilers to meet a NO_X emission limitation of 0.29 lb/MBtu. This project is important for the State of Florida from both energy security and environmental perspectives. A requirement for the use of SNCR on AES Cedar Bay risks losing the Cedar Bay Cogeneration Project and its benefits to Florida.

We look forward to discussing this matter further with your staff on Friday, January 5.

Sincerely,

J. Blunden

Julie Blunden
Development Manager

cc: Hamilton S. Oven
Clare Fancy
Barry Andrews ✓ cc rcd 1-8-90 RRW
Terry Cole
Steve Day
Pradeep Raval
Max Linn
A. Kutyna - NE Dist.
S. Pace - BESD
CHF / BT / SP
W. Aronson - EPA
C. Shaver - NPS
-9-90 RRW

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December 12, 1989

BY HAND DELIVERY

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:

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

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

- o 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.

<u>BACT Analysis</u>

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 x 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 CHF

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.

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- 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.

Precedent

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.

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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.)"

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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. Kettyrose, NE Dist.
B. Pace, BESD
CHF/BT

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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 MA 10/20 ARONSON WD 10/20 MILLER WA for BM 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.

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Wayne (mark)

Please prepare a response. Make sure that any response is coordinated & agreed to by Fla. from Bruce

KBN

October 2, 1989
89026

AIR PROGRAMS BRANCH
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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.

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 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.

KBN

Mr. Bruce Miller
October 2, 1989
Page Four

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

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.
1001 North 19th Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier—(703) 528-4510

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

Best Available Copy

Pradeep

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APR 18 1989

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

AES/Cedar Bay Inc.

1925 North Lynn Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier—(703) 528-4510

ATTACHMENT B

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

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

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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 D.W. Hill
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.

ATTACHMENT D

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

H. Desai

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

Best Available Copy

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.

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:

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

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^{o}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

BEST AVAILABLE COPY

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, JMB
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.

For Routing To Other Than The Addressee	
To: Pradeep	Location:
To:	Location:
To:	Location:
From:	Date:

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Air Resources Management Personnel

FROM: Buck Oven HSO

DATE: November 15, 1988

SUBJECT: AES-Cedar Bay Cogeneration Project, Power Plant Siting Application PA 88-24, Module 8184

Please review the attached power plant siting application for completeness. Please return your comments to me by November 23, 1988. There will be a meeting to discuss the completeness of the application on November 28, at 1:00 p.m. in Room 338D.

Several copies of the application are being provided to your staff for their review. Additional copies have been sent to the District Program Managers for their review and comment as well.

HSO

Attach:

cc: Barry Andrews, w/attach
Pradeep Ravel, w/attach
Max Linn, w/attach
Betsy Hewitt, w/attach

AES Meeting 3-3-88.

(1) PM_{10} & dates

(2) SO_2 problem.

Plans for 1992 startup.

Recovery Boiler can be permitted separately.
- If expansion is larger than 75 MW need PPS.

- Except for PPS if power consumed in house from recovery boiler.

- They need to send max building dimension to model downwash.

- PM_{10} monitoring probably will not be required if complete application is filed within 10 months from date the rule is effective (approx April 15??)

DER / AES MEETING
3/3/88

ATTENDEES

NAME	REPRESENTING	Ph
KERRY VARKONDA	AES-PROJ. DEV.	703 522 1315
Steven M. Day	Black & Veatch	913 339 2880
Max Linn	DER-BAQM	488-1344
JOHN BROWN	DER BAQM	488 1344
Tammy Collins	DER BAQM	488-1344
Barry Andrews	DER-BAQM	488-1344
Buck Oven	DER-PPS	487-2522
JOHN MILLICAN	AES (ENV. SERV.)	584-5137
PRADEEP RAVAL	DER, BAQM	488 1344
Terry Cole	Oertel + Hoffman	877 0099

Feb 2, 1988

DER Offices - Tallahassee FL

Steven M. Day	Black & Veatch	913-339-2880
Buck Oven	DER	904-487-2522
JOHN MILLICAN	AES/ENV. SERVICES	904-584-5137
JEFF SWAIN	AES	703-522-1315
Terry Cole	AES - Oertel + Hoffman	904 877 0099
Barry Andrews	DER/BAQM	904 488-1344
KERRY VARKONDA	AES	703-522-1315
Max Linn	BAQM	904 488 1344
Pradeep Raval	BAQM	904 488 1344
Sara Brumbaugh	Public Service Commission	904 488 8501
Paul Darst	DCA	904 488-4925

Best Available Copy

:T OF HEALTH, WELFARE
. . . :RONMENTAL SERVICES
›-Environmental Services Division

RECEIVED

DEC 2 : 1988

DER - BAQM

December 20, 1988

Mr. Hamilton S. Oven, P.E.
Chief, Power Plant Siting
Florida Department of Environmental Regulation
Twin Towers Building
2600 Blair Stone Road
Tallahassee, FL 32301

RE: THE CEDAR BAY COGENERATION PROJECT

Dear Mr. Oven:

Bio-Environmental Services Division (BESD) appreciates the opportunity to review the Cedar Bay Cogeneration Power Plant Siting Application, as filed by Applied Energy Systems (AES). In view of the significant environmental issues associated with such a project, BESD has, by separate correspondence, requested "Party" status for the plant and associated transmission lines (copy enclosed). Further BESD petitions by this correspondence to be specified in the final site certification as the local regulatory agency to enforce the air pollution, water pollution, water conservation, and noise pollution aspects of the final site certification.

The BESD, upon review of the Applied Energy Systems application feels that insufficient data has been submitted to provide for adequate project review, relative to compliance with a number of environmental issues.

The following discussion will address those areas where insufficiency exists and other concerns of BESD:

I. GENERAL COMMENTS

A. BESD strongly objects to the inclusion of the Kraft Recovery Boiler, the Smelt Dissolving Tank, the Multi-Effect Evaporator, and associated elements being included in the subject application. Such processes are not in concert with the intent or definition of Chapter 403, Florida Statutes (FS). Such processes should be addressed under typical DER permitting procedures, and not included in a Power Plant Siting application. Such elements are not included, or suggested in Sections 403.502, 403.503(4), or 403.503(7), FS and, therefore, it is inappropriate to attempt to include such non-related (per the statutes) processes within this application. 1.

:EA CODE 904 / 630 3666 / 421 WEST CHURCH STREET / JACKSONVILLE, FLORIDA 32202-4111

RESPONSES

1. Discussions were held with the Siting Coordination Section of DER early in the permitting phase of the project. The entire project is being developed concurrently with impacts resulting from each of the facilities. By including all of the related facilites in the SCA process, the DER believed that the total impacts would be better assessed and mitigated.

B. The applicant (AES) has included a request for approval of construction at night, as may be necessary, in order to comply with local Noise Pollution regulations. The applicant must make such application directly to the City of Jacksonville, and must be specific as to the times, dates, type of operations involved, projected noise impacts, specific on-site contact personnel with authority to cease operations as necessary, etc. The City will not issue a blanket relief from the Ordinance Code, hence specifics are required. 2.

C. The applicant has provided insufficient detail to evaluate whether the project shall comply with the City's Landscaping and Tree Protection requirements, as specified in Ordinance 88-668-397, enacted on July 29, 1988. 3.

D. The BESD has received a memorandum that the height of the stacks for this project affect the Federal Aviation Rules (FAR), relative to minimum operating altitude for the area. If a change (shortening) of the stack results from compliance with the FAR requirements, then the air quality modeling results will be adversely affected. Hence, until the FAR issue is resolved, insufficient data exists to evaluate air quality impacts. 4.

E. BESD poses the question of whether AES has considered the use of shredded tires as a supplemental fuel for the fluidized bed boilers, since the literature suggests such is within the capabilities of the technology. In today's problem of adequate space for disposal of waste tires in landfills, the utilization of waste tires as an energy source seems attractive, if the resulting emissions can be held within standards. 5.

F. Volume II, Page 4-2 - Statements in this section lead the agency to believe that the applicant will fill-in sections of the Broward River; BESD has previously understood that such fill projects were prohibited. 6.

muck

G. The applicant indicates that 42,000 cubic yards of lime mud, and 20,000 cubic yards of lime mulch will be disposed of, but does not specify where. Hence, insufficient data exists to evaluate this element. 7.

H. The applicant notes that two separate methods for ash handling, but is not clear as to which will actually be utilized. Some clarification is needed. 8.

RESPONSES

2. The SCA process preempts all state and local permit requirements except building permits. Nevertheless, all applicable federal, state, and local requirements must be met by the project. We will comply with these requirements including all applicable regulations and ordinances. Even though the Certification is a DER process, it does provide a means for other jurisdictions to become involved in the project's regulation and permitting. Therefore, the SCA process provides a framework for the approval of construction activities at night, should such activities become necessary. Provision of the required information by the applicant prior to initiating nighttime construction could be made a condition of the site certification.

3. The requirements of this ordinance will be complied with. A preliminary onsite survey did not identify any protected trees in the areas to be developed. However, thorough inspections in all developed areas will be made prior to any tree removal to ensure that protected trees are either not disturbed or that appropriate approvals are obtained for removal or relocation. A landscape plan will be submitted upon completion of detailed design of the project. The plan will conform to all tree and landscape material planting requirements. As in the previous response, these requirements could be made conditions of the site certification.

4. Discussion with the FAA, with regard to stack heights as indicated, is proceeding. A preliminary agreement involving the installation of a non-directional beacon has been reached between the applicant and the FAA and Jacksonville Port Authority. The FAA and other applicable agencies are currently reviewing the applicant's proposal to provide this equipment.

5. The use of shredded tires as a supplemental fuel for this project is not currently being considered. Although tires have been fired in grate type systems, their use in CFB boilers is an unproven technology. Additionally, the combustion of tires would contaminate the combustion wastes with zinc calcine which could make the ash environmentally unacceptable for use as a mine reclamation material.

6. No filling will be done within the established channel of the Broward River. A minimal amount of fill will be placed as necessary to raise the railroad subgrade above the existing grade to maintain the required top of rail elevation. No fill will be placed below mean high water elevation 2.0. The SCA notes that "Addition of fill should not increase flood elevations or flow velocities...."

7. The lime mud currently stored in the area of the new facilities will be relocated to the north end of the applicant's (Seminole Kraft) property for storage and potential reuse as a fluidized bed combustion boiler additive. In addition, new equipment being installed by Seminole Kraft may have the potential for reuse of the lime mud. It is intended that the material will be covered by an impervious liner to limit potential contamination of ground water by the relocated material.

8. At this time, no decision has been made on the final arrangement and method for ash disposal off site. Both methods should be considered viable when analyzing the Site Certification Application.

I. The applicant has not estimated or included in his air quality calculations the contribution from mobile sources, i.e., the high number of trucks that the applicant projects will be utilized (the truck traffic could add 0.8T/M of fugitive particulate to the atmosphere). 9.

J. The applicant denotes various types of demolition shall be effected during site preparation. The applicant has not noted that local permits, especially relative to asbestos, under NESHAP, will be obtained, or complied with. Hence, insufficient data exists to evaluate compliance with NESHAPs for asbestos. 10.

K. The applicant states that 6,000 cubic yards of fuel saturated soil will be disposed of, but fails to specify how or where.

BESD was unaware that a hazardous material/waste problem existed at this site, as such was not reported until review of the subject application. 11.

The information provided is insufficient to evaluate whether or not this hazardous waste will be properly handled.

L. Has the Department of Environmental Regulation promulgated Chapter 17-274, FAC, and if so, is the applicant in compliance with such requirements? 12.

II. NOISE POLLUTION COMMENTS

A. Volume II, Page 2-151 - It appears the applicant has misinterpreted the local noise regulations by speaking of impacts on adjoining property. The City regulates noise based upon noise impact at the reception property line, which may or may not be adjoining the source's property line. 13.

RESPONSES

9. In responding to this comment, AES requested additional information from BESD regarding their estimate of the fugitive dust emissions associated with truck traffic. BESD provided the supplemental information in a letter to Ms. Julie Blunden, of AES, dated February 2, 1989. In this letter, BESD corrected their original truck traffic fugitive dust estimate from 0.8 tons per month to only 0.18 tons per month. In a subsequent telephone call to BESD, it was determined that the "2 miles" mentioned in the February 2, 1989 letter should have been 7 miles. With this correction, the estimate of 0.18 tons per month can be verified from BESD's information.

Thus, the estimate of truck traffic fugitive emissions will be approximately 2.2 tons per year. This estimate conservatively assumes there will not be any precipitation during the entire year. However, Jacksonville has on the average 115 days per year with precipitation greater than 0.01 inches. If the mitigating effect of precipitation would be considered, the estimate could be reduced by approximately 32 percent.

The net particulate emissions for the project, considering the truck fugitive dust estimate, will result in a slight net particulate increase. However, increase will be well below EPA's significant emission rates of 25 tpy (TSP) and 15 tpy (PM_{10}).

10. Site preparation will involve the demolition and removal of a few existing structures. These structures include a fuel oil tank, minor maintenance structures, and railroad tracks. Some of these existing structures may contain asbestos materials. All demolition activities will be conducted in compliance with applicable requirements of the National Emissions Standards for Hazardous Air Pollutants (NESHAPS). In addition, required notification will be made to the Jacksonville Bio-Environmental Services Division prior to any demolition activities.

11. Because of the revision to the site arrangement that is described in Amendment 1 to the SCA, the area of the southern-most fuel oil tank and fuel oil contaminated soil is not part of the project site and will not be disturbed as part of this project. Therefore, disposal of the soil is not applicable to the project.

12. The DER has not promulgated Chapter 17-274 FAC.

13. As was stated in the SCA, there are two separate local ordinances that apply to noise levels from the project site. The Jacksonville Land Use Regulation (S.656.323(a)(8)) is defined in terms of noise levels at "...a point where the district adjoins..." other districts. In addition, the Jacksonville Environmental Protection Board's Noise Pollution Control Rule (Rule No. 4) provides noise level restrictions for the City of Jacksonville. This rule defines the maximum sound pressure levels allowed within other land areas due to a noise source, depending on the land area's classification. Section 5.7 of the SCA includes assessments of maximum expected noise levels at nearby class B, C, and D land areas, whether or not these land areas adjoin the project property.

AIR POLLUTION COMMENTS

A. The monitoring methodology employed is acceptable. However, the use of 1979-1980 source data to determine existing emissions and whether there is a projected significant increase in emission is contrary to Section 17-2.500(2)(e)3, FAC, which states that "An increase or decrease in the actual emissions. . . is contemporaneous with a particular modification if it occurs within the period beginning five years 14
prior to the date on which the owner or operator of the facility submits a complete application for a permit. . .". This issue must be resolved in order to accurately project environmental impacts.

B. The applicant reflects in numerous sections of the report differing maximum percent sulfur content for the coal to be utilized. The sulfur content of the coal 15.
is a significant factor and the applicant should more clearly express what shall be used at the site.

C. BESD review did not locate the molar ratio of limestone to sulfur to be utilized as part of the sulfur dioxide control mechanism. This information is necessary to 16.
evaluate if the design is typical, as compared to historical installations.

IV. WATER POLLUTION COMMENTS

A. The discharge of potentially harmful levels of metals into receiving waters has not been adequately addressed in either the NPDES permit (Page 10-1) or the DER industrial waste permit (Page 10-18). In the NPDES permit, only iron and magnesium are included, this is an incomplete list of metals that may be discharged. 17.
The DER industrial waste permit table of wastewater characteristics (Page 54) refers to Table 5.2-8 of the SCA. This is a table of the quality of cooling tower blowdown, not wastewater effluent.

The topic of metals pollution is addressed in several tables, Page 5-12 - 5-20; however, this is also inadequate. There is only one table (Table 5.2-7) Page 5-20 which characterizes the total projected combined effluent, four metals are described here. This list should be expanded. The list (Table 5.2-7) is inadequate, 18.
in that it includes levels for copper and mercury as less than values. Both of these reported values exceed limits for Class III waters, better information must be provided. The aluminum value also exceeds Class III limits. Therefore, insufficient data exists to review this project for environmental compliance.

B. A mixing zone has been mentioned several places (Pages 5-15, 5-21, 5-28). Has a 19.
mixing zone been applied for or is there one already in effect? (BESD would recommend against a mixing zone if one is not in place now.)

C. A measurement program is described beginning on Page 5-28. Groundwater monitoring parameters and methods are given in great detail; however, no mention 20.
of surface water is made. Effluent monitoring should be described in a manner comparable to ground water.

RESPONSES

14. The use of 1979 and 1980 source data was discussed with and approved by DER for determining existing emissions. This use is consistent with FAC in that Section 17-2.500(2)(e)3 refers to "actual emissions" which are defined in 17-2.100(2)(a) to be "...representative of the normal operation of the source." This definition also states "The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the source."

15. A specific coal contract for the project has not been determined. To maintain flexibility in negotiating a coal contract, the maximum sulfur content for the various coals was used in establishing the worst case environmental impacts. Typically, sulfur content will be lower but the maximum percentage of 3.3 percent defines the expected upper limit for acceptable coals.

16. The design molar ratio of calcium to sulfur for the CFB boiler is 2.50. This value is included in Table 10.8-5 of the BACT analysis within the SCA.

17. The AES/Cedar Bay cooling tower blowdown and yard area runoff will be permitted separately from the Seminole Kraft facility discharge. The NPDES application requires data on all pollutants in Group A (Table 2D-2 of NPDES application guidance) and data on the pollutants in Group B which are expected to be present in the discharge. Iron and magnesium are the only constituents from Group B which are expected to be present in the AES/Cedar Bay discharge. This discharge will have essentially the same analysis as the cooling tower blowdown since the contribution from the yard area runoff is relatively small compared to the cooling tower blowdown.

18. Low volume drains, storage area runoff, and sanitary system effluent from the AES/Cedar Bay plant will be routed to the inlet of the Seminole Kraft wastewater treatment facility. Table 5.2-7 is provided to demonstrate that wastewater from the AES/Cedar Bay facility will not have a significant impact on the operation of the Seminole Kraft wastewater treatment system. Effluent from this treatment facility is included under the Seminole Kraft discharge permit.

19. A thermal mixing zone and a mixing zone for iron have been requested for the AES/Cedar Bay discharge. Section 5.1.1 has been revised (Amendment 1 to SCA) to include a discussion on a thermal mixing zone and Section 5.2.2 has also been revised to include a discussion on a mixing zone for iron. Subsequently, DER has indicated that only a variance for iron will be necessary and that a mixing zone will not be required. A variance request in the format specified by 17-103.100 FAC will be included in Amendment 2 to the SCA.

20. The discussion of monitoring on page 5-28 deals with groundwater monitoring only. There is currently no plan to monitor surface water during plant operation. The monitoring program for the individual wastewater streams is described in Subsection 5.2.3. By monitoring the individual wastewater streams, monitoring at the point of discharge in the St. Johns River is not required.

The two wastewater discharges from the AES/Cedar Bay plant will be cooling tower blowdown and effluent from the site runoff retention pond. Based on the estimated analyses of the two wastewater streams, only iron is expected to exceed the Class III standards. A variance is being requested for iron.

RESPONSES

The statement is made that when Class III limits are in violation outside the "mixing zones", mitigating measures will be taken. A more detailed description of "mitigating measures" is required. 21.

D. Impacts of the Coal Marine Terminal to water bodies begins on Page 6-10. Approximately 10,000 cubic yards will be dredged from a heavily industrialized area. The material to be removed is likely to be contaminated with numerous pollutants. Reentrainment of these sediments may pose serious risks to the aquatic biota of the river. The sediments should be thoroughly characterized, and disposed of accordingly, so as to pose as little threat to the aquatic environment as possible. Timing of the actual dredging operation should be timed in order to minimize impacts on aquatic life, colder winters months would be best. 22.

A small wetlands area will be crossed by the coal conveyor. Measures describing how this area will be protected or damage mitigated should be included. 23.

E. Affects of the railroad corridor on waters and wetlands are described on Page 6-16. It is noted that some wetland vegetation (black rush and cord grass) will be removed. This impact should be adequately restored and/or mitigated as soon as possible and not merely left to natural revegetation. 24.

21. Compliance with surface water quality criteria will be ensured through discharge monitoring as discussed in Section 5.2.3 of Amendment 1 to the SCA.

22. A thorough study of the sediments existing in the area of the proposed Coal Marine Terminal will be completed before any dredging operations commence. The results of the study will determine the appropriate methods of removal and disposal of these sediments. Construction procedures will be designed to minimize any potential impacts on aquatic life in the area. All applicable requirements of local, state, and federal government agencies will be addressed. It is anticipated that the dredging and construction operations will be scheduled for the winter.

23. Locations of the coal conveyor supports have not been finalized. The degree of impact upon the small tidal marsh will depend upon the proximity of the supports to the tidal marsh. Because the marsh is predominantly _Juncus_ - _Spartina_, any vegetation which is removed from the marsh during construction of the coal conveyor will be replaced in kind by _Juncus_ and _Spartina_ rhizomes. These rhizomes will be collected from the marsh before or during construction, then replanted upon completion of construction. _Juncus_ and _Spartina_ are extremely hardy plants, and the replanted rhizomes should revegetate the disturbed areas within a year of planting.

24. Construction of the proposed railroad corridor will not include filling in or otherwise disturbing the _Juncus_ - _Spartina_ marsh along the Broward River. The new siding construction will extend as far south as the southern end of the northern yard.

The only marsh area close enough to the construction corridor to be potentially impacted is a 170-foot stretch within 750 feet of the corridor's southern limit. This area will be protected from encroachment by construction soil by the construction of a retaining fence at the top of the Broward River bank.

Removal of wetland plants or alteration of their water regime will not occur in this area.

F. The application has information that indicates a reduction in the final wastewater effluent flow from a current 63.5 mgd to 20.8 mgd with the Cedar Bay Project. One of the current major sources of wastewater is the once-through cooling water which will be eliminated and replaced by cooling tower blowdown from Cedar Bay that will include only 2% of the existing flow-rate of the cooling water waste stream.

The other major waste stream flow, i.e., treated wastewater from the existing Seminole Kraft Wastewater Treatment Facility (WWTF) will remain relatively the same (20 mgd current versus approximately 19.4 mgd after Cedar Bay) except that 12,000 gpd of this waste will be from coal, limestone and ash pile runoff.

AES admits to probable problems meeting the iron water quality standard consistently in the final effluent. AES has discussed a mixing zone and variance for iron, but have not applied for either. Both mercury and aluminum have been singled out in the current Seminole Kraft State industrial permit review as poten-·ial exceedances of State water quality standards in the final effluent. These results were determined by Seminole Kraft prior to and without considering mixing with 43.5 mgd of once-through cooling water. AES has not proposed monitoring for any of these metals in their application nor has there been any specific dilution calculations or modeling to show compliance with the water quality standards at the point of discharge. The applicant has not provided sufficient data from which to evaluate this project. 25.

Further if approximately 42 mgd of dilution water (once-through cooling water) is eliminated and the current process wastewater stream flow is maintained, then the result is higher concentrations of pollutants in the final effluent to the St. Johns River. AES needs to re-evaluate what will be the concentration of heavy metals and other pollutants in the final effluent with the changes proposed by the Cedar Bay Project.

otal 5.2-2	Current	Proposed
	43.5 mgd Once-Through Cooling Water (SK)	1.4 mgd Cooling Tower Blowdown (CB)
	20 mgd Process Wastewater SK WWTF	19.4 mgd Process Wastewater SK & CB WWTF
	63.5 mg St. Johns River	20.8 mgd

G. AES needs to submit the calculations that were used to determine runoff flow from coal, limestone and ash storage areas. The wastewater characterization submitted for the coal and ash runoff ponds is based on "limited" analysis results. More specific data is required from current Florida operations on these wastewater sources. The type of coal and coal analysis should be matched with the wastewater analysis to be able to make the assumption that the wastewater analysis will be typical for all potential pollutant parameters from the Cedar Bay Project. 26.

RESPONSES

25. The discharge from the Seminole Kraft wastewater treatment facility is covered under existing NPDES permit FL0000400, which is currently under review for renewal. Any required demonstration of compliance, including the effects of elimination of the once-through cooling water, would be part of this permit renewal process. Monitoring and the compliance with water quality standards of this discharge is the responsibility of Seminole Kraft.

The SCA intends to demonstrate that wastewater from the AES/Cedar Bay facility will not have a significant impact on the operation of the Seminole Kraft wastewater treatment system and the overall Seminole Kraft discharge.

The need for a mixing zone for iron was identified in the original SCA submittal and a mixing zone request with more refined calculations has been included in Amendment 1 to the SCA. A variance for periods of high iron concentrations in the river was requested in Section 5.12 of the SCA. Subsequently, DER has indicated that only a variance for iron will be necessary. That is, a mixing zone for iron will not be required. A request for this variance in the form specified by 17-103.100 FAC will be included in Amendment 2 to the SCA. Monitoring for iron in the cooling tower blowdown was proposed in Section 5.2.3 of the SCA.

26. The analysis of the runoff from the coal, limestone, and ash storage areas will be affected by several factors such as source of coal, quantity of coal, and the duration and intensity of a rainfall event. Specific data from current operation is not possible since the source of coal has not been determined at this time. The analysis provided in Table 5.2-4 is based on literature values of operating data for Eastern Tennessee and Kentucky coal. See Attachment A.

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RESPONSE

H. Clarification of Table 5.2-7 is required. How was the analysis data obtained to determine the contribution of iron, aluminum, copper, mercury and silver from the Cedar Bay project to Seminole Kraft's WWTF? What calculations were performed to project the concentrations of the above metals in the industrial treatment plant effluent (process wastewater) and the combined effluent to the St. Johns River? Page 5-21 indicates that "Seminole Kraft Corporation recently performed a water quality analysis demonstrating that the existing discharge concentrations do not cause an exceedance of any water quality parameter in the St. Johns River". BESD presumes this analysis was performed for the State industrial permit application. The first question that AES needs to answer is what type of sample was collected and is it representative of the Seminole Kraft operation er a period of time that could be worst case conditions or includes a period f high production output. BESD and DER have determined in the State permit pplication review that the dilution assumptions from the calculations for at least aluminum and mercury were suspected to be in error. BESD has requested that Seminole Kraft perform mixing zone calculations for aluminum and mercury (see attached letter BESD to SK dated October 25, 1988) or reproduce the dilution calculations using the 43.5 mgd cooling water. The elimination of 43.5 mgd cooling water, however, will invalidate the dilution calculations again. 27

AES needs to address in more detail the Cedar Bay project wastewater system more in relation to the current Seminole Kraft system and the impacts on the water quality in the final effluent from elimination of the once-through cooling water. There is also a need for discussing the current SK Wastewater Treatment Facility and metal removal capabilities. A description of the major WWTF components, i.e., clarifier and aeration ponds, how the metals are removed and where they are ultimately disposed of is required. The chemical, biological and physical method of metal removal in the WWTF system needs to be addressed. For example, what oxidation of iron occurs in the aeration ponds and the removal efficiency from the water column.

I. The thermal impacts on receiving waters is sufficiently addressed by the DER (interoffice memorandum, Al Bishop to Richard Harvey, DER, dated November 29, 1988). 28

J. If mixing zones and/or variances are required, then application needs to be made by AES. 29

K. How is the water spray waste from pellet handling fugitive dust control (and other dust control) disposed of? 30

mud

...ill the lime mud and lime mulch be disposed of during removal and site ...a? The lime water ponds appear to remain intact under the Cedar Bay ...Will there be any changes in the causticizing area where the lime water waste is generated and are there any plans to eliminate the lime water ponds? If the lime water ponds are not eliminated, then where will the buildup of lime solids be disposed of? 31.

M. The application (Page 4-3) indicates that approximately 6,000 cubic yards of fuel-oil saturated soil will be removed and replaced with fill along with an existing fuel tank, paint shop, etc. What caused the fuel-oil to be there in the soil and has there been any preliminary contamination assessment performed? 32

27. Table 5.2-7 provides a simple mass balance based on the predicted quantities and qualities of the individual wastewater streams entering the Seminole Kraft wastewater treatment system. The projected quality of the industrial treatment plant effluent is based on the assumption that metals are not removed from the AES/Cedar Bay wastewater streams. This approach is considered conservative since partial removal of some metals will occur.

Table 5.2-7 is intended to demonstrate that the average overall effect of the AES/Cedar Bay wastewater on the Seminole Kraft wastewater treatment system will be insignificant. As previously indicated, the effluent from the Seminole Kraft wastewater treatment system will be permitted separately from the AES/Cedar Bay discharges and is the responsibility of Seminole Kraft.

28. Responses to the DER memorandum were provided by AES letter to DER of January 4, 1989. Follow-up DER comments and responses are being provided under separate cover.

29. A thermal mixing zone and a mixing zone and variance for iron have been requested in Amendment 1 to the SCA. Subsequently, DER has indicated that only a variance for iron will be necessary. That is, a mixing zone for iron will not be required. A request for this variance in the form specified by 17-103.100 FAC will be included in Amendment 2 to the SCA.

30. Spray water will be limited to the amount required for the control of fugitive dust. Runoff resulting from spray water will be minimal and will be routed to the Storage Area Runoff Pond. Quantities of this spray are so minimal that reuse is impractical.

31. Lime mud will be removed from the existing lime settling ponds and relocated to the north end of the applicant's property as discussed in the response to BESD comment I.G. (No. 7). Minor regrading of the lime settling pond area will be performed as necessary to prepare the ponds to serve as runoff ponds (the lined Storage Area Runoff Pond and the unlined Yard Area Runoff Pond). A new mud clarifier as shown on SCA Figure 3.2-1 (issued with Amendment 1) will be constructed to replace the lime settling ponds.

32. As we discussed in the response to Comment I.K. (No. 11) above, this area of Seminole Kraft property is not now intended to be part of this project. However, a preliminary Environmental Assessment was performed in the area and the second phase of this assessment is in progress. Seminole Kraft will follow-up by discussing the results of the subsequent assessment with applicable regulatory agencies.

RESPONSE

N. Sections 4.2.2 and 4.3.2 (Pages 4-5 and 4-6) seem to contradict each other with respect to measuring and monitoring during construction. AES needs to clarify these sections. Will there be any monitoring of the dewatering discharge (2,000 gpm) for 6 months from the shallow aquifer directly to the Broward River? 33.

O. Water mass balances for both proposed and the "current" Seminole Kraft operation is required to enable proper comparisons. 34.

P. What is the projected chloride concentration in the final effluent based on 4.6 cycles of concentration and mixing of process wastewater and yard area runoff? 35.

Q. The application (Page 5-15, Para 2) references a mixing zone and Page 5-21 references a mixing zone for iron. AES did <u>not</u> apply for a mixing zone in either the NPDES permit or the State permit so these statements require clarification. 36.

R. The application (Page 8-6) refers to chemical cleaning. To what extent will the chemical cleaning wastewater be treated by a contractor prior to discharging the waste into the Seminole Kraft WWTF? A wastewater characterization of the chemical cleaning waste is required with reasonable assurance that the current WWTF is capable of treating the waste. 37.

S. Is the current sanitary waste treatment system (Imhoff tank) capable of treating an increase of 4,000 gpd sewage. 38.

33. Section 4.2.2 should read:
During construction, water samples from the runoff collection pond discharge and from the Broward River will be collected and tested weekly and compared to the background data and water quality standards for Class III surface water. Should degradation of the Broward River water quality occur from construction water discharge, mitigating measures will be implemented at the runoff ponds.

Section 4.3.2 should read:
Background water quality was described in Subsection 2.3.2.1, Subsurface Hydrologic Data for the Site. New monitoring wells will be installed and ground water will be monitored as described in Subsection 5.3.5.

34. The Preface and Section 5.2 of the SCA describes the impacts of the overall water consumption and wastewater discharges. Internal streams in the Seminole Kraft plant have not been determined and, therefore, a water mass balance cannot be provided for the Seminole Kraft facility.

35. The chloride concentration of the AES/Cedar Bay cooling tower blowdown is estimated to average approximately 140 mg/l as Cl with a maximum of approximately 210 mg/l as Cl. The chloride concentration in the site runoff pond effluent will be negligible. Therefore, the overall chloride concentration in the AES/Cedar Bay wastewater discharge will be essentially the same as the cooling tower blowdown.

36. A thermal mixing zone and a mixing zone and variance for iron have been requested in Amendment 1 to the SCA. Subsequently, DER has indicated that only a variance is required for iron and that a mixing zone for iron is not necessary.

37. The chemical cleaning contractor will be required to properly dispose of the chemical cleaning wastewater offsite. Treatment and discharge onsite is no longer being considered as a disposal option at this time.

38. The current sanitary wastewater treatment system does have the additional capacity necessary to treat the expected increase.

T. Appendix C of the application includes what appears to be sample analysis results for two surface water sample locations (by ERM). AES needs to report the details of the sample, i.e., exact location, dates, sample type, purpose of samples, etc. 39.

V. GROUNDWATER COMMENTS

A. The data provided in Volume II, Pages 2-66 is insufficient for proper evaluation of the project. The applicant must provide for the wells into the Floridan Aquifer data that is current, or at least within the past few years. The applicant has provided data that is at least 10 years old. Also the applicant must submit one hydrograph, showing water level changes over time for at least one well in the well field. Also the applicant must submit water quality trends for the subject well. 40.

B. The data presented in Volume II, Page 2-66 is confusing. The data shown to Figure 2.3-18 is not the information that the text describes. 41.

C. A benchmark is required, but not provided, with the contours shown in Volume II, Page 2-69. This defect must be corrected. 42.

D. The applicant has failed to provide, but should provide a groundwater monitoring program for the Floridan Aquifer to verify that significant impacts upon the water levels of adjacent private wells will not occur. 43.

E. The applicant has not provided sufficient data or analysis to prove the applicant's conclusion (Volume II, Pages 5-28) that no water quality deterioration shall occur, over time, due to poorer quality waters in the lower zones migrating into the Floridan Aquifer wells. 44.

F. The applicant has not, but must provide a detailing of the rock wells in the area. This data is necessary to develop a complete understanding of the water usage of the area. 45.

G. The applicant in Volume II, Page 2-87 has omitted listing and details for J-3701 and D-262. Correction must be made. 46.

RESPONSE

39. The two surface water samples, SW-1 and SW-2, listed in Appendix C weretaken on July 9, 1988 from the Broward River and the lime ditch, respectively. The sample locations are shown on SCA Figure 2.3-24. Each sample was collected in a Teflon bottle and analyzed for EPA priority pollutant organics (EPA methods 624/625) and metals. The samples were also analyzed for total dissolved solids (TDS) and pH.

40. Additional ground water data has been requested from the Seminole Kraft Corporation, USGS, St. Johns River Water Management District, and the HRS Division. Data requested includes well depths and construction, aquifer penetrated, piezometric levels, water quality analysis results, and transmissivities for all wells within a 5-mile radius of the site. A hydrograph showing water level changes over time and water quality trends for at least one well is included at Attachment B.

41. Current SCA Figure 2.3-16 is to be omitted. All references to Figure 2.3-16 should be changed to Figure 2.3-17. All references to Figure 2.3-17 should changed to Figure 2.3-18. All references to Figure 2.3.18 should be changed to 2.3.18a. New Figure 2.3-18a is included as Attachment C.

42. The benchmark used for vertical control, SRD BM F-325, is a disk located in a concrete walk at the northeast corner of the Heckscher Drive bridge over the Broward River. The benchmark elevation is 14.39 ft msl.

43. A ground water monitoring program will be developed for the Floridan aquifer to verify that significant impacts upon the water levels of adjacent private wells will not occur. The applicant has attempted to obtain additional information on all wells located within a 5-mile radius of the Cedar Bay site. Minimal information resulted from this effort. A program is being developed to provide the necessary data to perform ground water modeling.

44. Refer to Response No. 49.

45. Data has been requested from the USGS regarding well depths and aquifers penetrated within a 5-mile radius of the site. A detailing of the rock wells will be made once this data is analyzed in conjunction with information obtained from the program referred to in Response No. 49.

46. Details for well J-3701 could not be located.

The entry for well D-262 should read as follows.

Owner	Use Type	Designation	Aquifer
Seminole Kraft Paper Co.	Industrial	D262	Floridan

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H. Some confusion exists in Volume II, Page 3-33, so the applicant should explain why a difference in make-up water exists between Figure 3.5-1, of 3,990,000 gpd, and the test of 4,147,200 gpd (a difference of 2,880 gpm). 47.

I. The applicant must provide greater details relative to the wastewater offsets (expressed in Volume II, Page 3-37), if a complete picture is to be achieved. 48.

J. The applicant must explain further why the groundwater impacts of this project are based upon only an analysis of one well (Well #7), and not some other well, or group of wells in the well field. Since normal operation of the well field includes rotating the load amongst the well, greater detail is necessary.

K. Insufficient data exists to explain why wells adjacent to Well #9, i.e., such as J-2094, will not be impacted by the increased withdrawal rates. Details must be projected based upon proposed operating schedules for the well field. (Volume II, Pages 5-25) 49.

L. In Volume III, the data supplied is 11 to 13 years old, more recent water quality data from the Floridan Aquifer wells is required.

BESD has expended a tremendous amount of resources in the review of the subject application. The comments and questions presented by BESD must be resolved prior to any further action on the subject application if BESD and DER are to have reasonable assurances of compliance by the applicant. At this time one cannot project that compliance can be or ... be achieved.

... committed to assisting in, and being a party to review, and ultimate regulation of this source. DER's continued cooperation in ensuring sufficient quality and quantity of information is obtained from the applicant is appreciated.

Very truly yours,

Robert S. Pace, P.E.
Assistant Division Chief

RSP/ns

cc: BESD Files
Khurshid K. Mehta, P.E.
... se
... swell, P.E.
... K. Flowe, P.E.

Disc 4/1

Enclosure

RESPONSE

47. The typical cooling tower makeup flow at 100 percent load will be 4,147,000 gpd (2,800 gpm) of which 3,990,000 gpd will be well water and 157,000 gpd will be boiler blowdown.

48. The offset in wastewater flows is described more fully in Section 5.2 of the SCA.

49. The currently available data are insufficient to perform detailed analyses. Additional data have been requested from Seminole Kraft Corporation, USGS, St. Johns River Water Management District, and the HRS Division. Data requested include well depths and construction, aquifer penetrated, piezometric levels, water quality analysis results, and transmissivities for all wells within a 5 mile radius of the site. Data received to date from Seminole Kraft and USGS are still insufficient to perform the requested detailed analyses. A program is being developed to provide the necessary data, including well testing at Seminole Kraft. The data will be used to model the groundwater at the site and the project's affect on the site wells and those in the surrounding area.

...MENT OF HEALTH, WELFARE
...O-ENVIRONMENTAL SERVICES
Environmental Services Division
...r and Water Pollution Control

October 25, 1988

...r. T. Frank Lee, General Manager
Seminole Kraft Corporation
9469 Eastport Road
P.O. Box 26998
Jacksonville, Florida 32218

Subject: Seminole Kraft, Jacksonville Facility, Application For Permit To Opera... An Industrial Wastewater Treatment Facility (WWTF), Application No. IO16-150596, Letter And Supplemental Information From T. Frank Lee, Kraft to Bio-Environmental Services Division (BESD) Dated August 30, 1988.

Dear Mr. Lee:

BESD acknowledges receipt of the subject letter and supplemental information. The application supplemental information has been reviewed by BESD and DER and the application is believed to be complete with the exception of the request item number (1), concerning water quality impact analysis. (see BESD letter to Seminole Kraft dated July 7, 1988).

BESD does not agree with the dilution calculations for aluminum, unionized ammonia and mercury and does not have reasonable assurance that there will not be any degradation to the water quality from these parameters. This determination is based on the criteria used to determine whether the discharge will "cause or contribute" to water quality degradation that includes a 2% maximum degradation factor and a minimum 1:100 dilution ratio.

In order to provide the necessary assurance for issuing an operation permit, BESD requests that Seminole Kraft perform the proper mixing zone calculations for the immediate area around the discharge diffusers for aluminum, unionized ammonia and mercury. If the calculations indicate that the discharge will not degrade water quality, then an operation permit can be issued with technology based effluent limits. If the calculations indicate that a mixing zone will be required, then Seminole Kraft must apply for same.

BESD and DER are open to meet to discuss the water quality impact analysis with Seminole Kraft if deemed necessary. The administrative clock under Chapter ... Florida Statutes (FS) has not been tolled so that BESD and DER must issue ...operation permit for the subject WWTF by November 27, 1988.

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..a mixing zone calculations requested here are not received by November
, 1988, then the Jacksonville Bio-Environmental Services Division and Florida
partment of Environmental Regulation will initiate proceedings to deny the
:mit per Chapter 403 Florida Statutes, Chapter 120 Florida Statutes, and
.pter 360 Ordinance Code.

:SD and DER would consider accepting a waiver of the 90 day clock if Seminole
:aft requires more time to complete and submit the mixing zone calculations.
:opy of waiver form attached).

Very truly yours,

Dennis R. Wylie

Dennis R. Wylie
Associate Engineer

:W/sdd

.ttachment

:: Mr. Bob Leetch, DER, Jax.
Mr. Bill Congdon, OGC, DER Tallahassee
Ms. Robyn Dean, OGC, Jax.
Ms. Kay Harris

Dept. of Community Affairs

RESPONSES

<u>Subparagraph 5.1.4.2. Salt Deposition.</u>--This subparagraph contains an estimate of the average and maximum salt deposition rates from the cooling tower. Please describe the effect on plant and animal life of these levels of salt deposition. 12.

12. Drift from cooling towers may effect nearby vegetation primarily as salt deposition upon plants and soils. Effects vary greatly from site to site, because salt levels result from the interaction of many changing conditions such as relative humidity, prevailing winds, amount and frequency of rainfall, and source of cooling tower water. These factors must then interact with biological variables such as type of vegetation, salt tolerance levels of nearby plants, type of soil, and developmental stage of the plants. Little research has been performed regarding salt deposition and the information that is available is site-specific and should not necessarily be interpreted as universally consistent. Therefore, only generalizations can be made regarding overall trends of salt deposition effects upon vegetation. The following statements are generalizations regarding potential impacts upon nearby vegetation due to drift from AES Cedar Bay's ground water mechanical draft cooling towers:

1. It is assumed that wintertime icing of vegetation due to salt-induced fogging will not occur at the Cedar Bay facility, because the climate is too warm for ice to form.

2. It is likely that most of the native vegetation growing in the project area already has some tolerance to sodium chloride because of the area's proximity to brackish and salt water sources. Plants growing in the area are already adapted to salt from sea spray and mist from the brackish water of the St. Johns and Broward rivers.

3. It is likely that the sandy composition of native soils combined with high annual precipitation ratios will allow rapid leaching of salts from the soil, rather than accumulation.

4. As shown in Figure 5.1-1 of the AES Cedar Bay SCA Amendment 1, the heaviest salt deposition will occur onsite and over the Broward River, in a 5/8 mile radius around the cooling towers. There is also a leeward corridor extending an additional 3/4 mile eastward. The maximum offsite deposition rate - 1.5 kg/km^2/month - is low. A generalized deposition rate of 400 kg/km^2/month has been calculated as the threshold salt deposition rate above which visible damage to vegetation begins to occur. While this number is an approximation based upon existing research and should be used only as a general rule of thumb, it is much higher than the offsite deposition rates predicted for the proposed project. This suggests that, if project area vegetation respond to salt deposition in a manner comparable to existing data, effects of salt deposition upon vegetation near the proposed project will be minimal.

ATTACHMENT K

TABLE 1 COMPARISON OF COOLING TOWER ALTERNATIVES

Parameter	Type of Cooling Tower: Dry	Wet-Dry	Natural Draft	Mechanical Draft
Capital Cost, $1000[a]	19,000	16,925	4,200	2,500
Annual Operating Cost[b]	20	9.6	Base	0.12
Height, feet	50	55	350	32
Water Use, 1000 gpd[c]	324[d]	971	3,236	3,236
Blowdown Volume, 1000 gpd[c] (Flow)	91[d]	273	911	911
Make-up Volume, 1000 gpd[c] (Flow)	415[d]	1,244	4,147	4,147

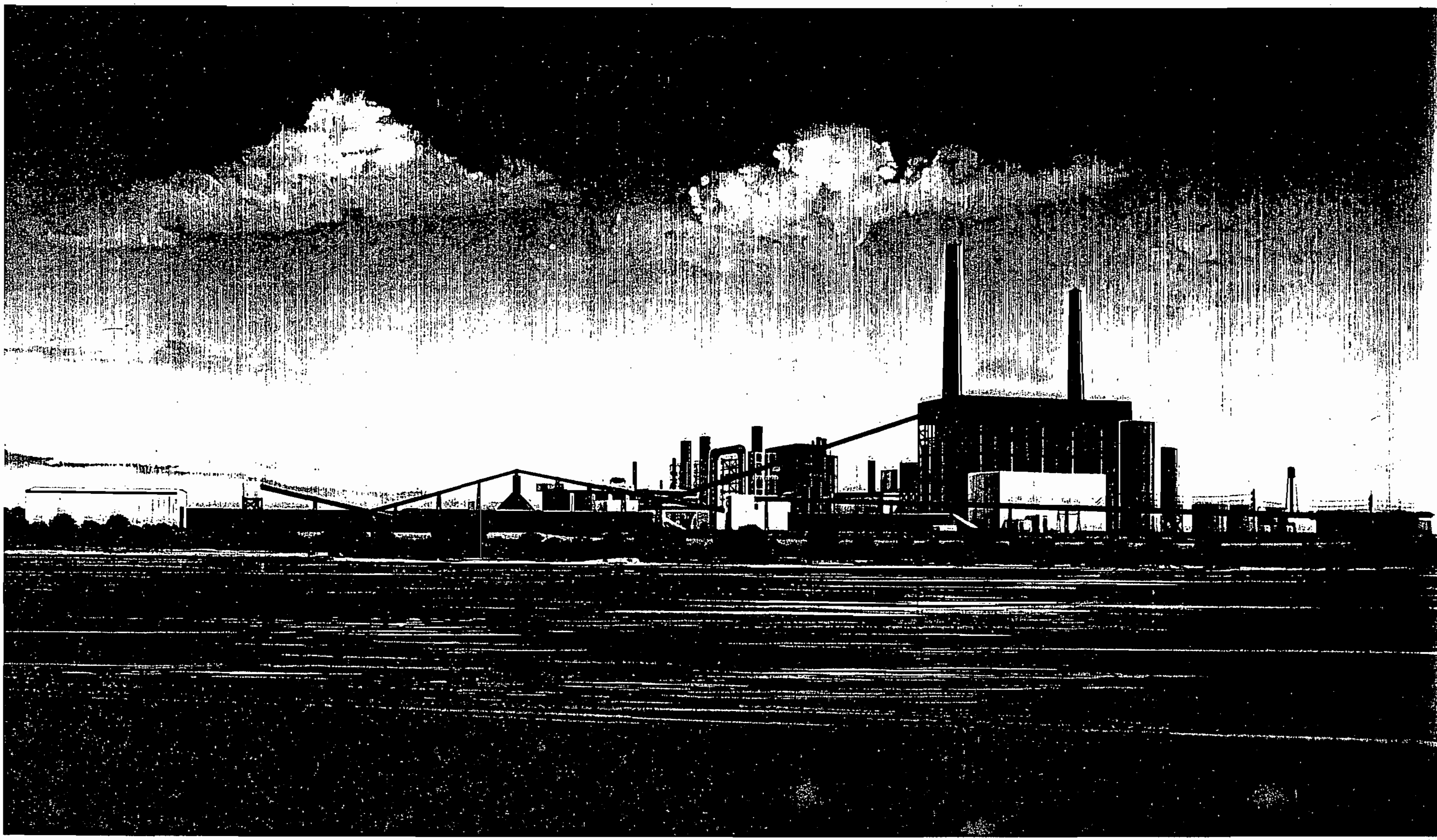
[a]Includes all Balance of Plant costs as well as Cooling Tower Costs.
[b]Differential Net Power Requirements, MW.
[c]Based on 100 percent load.
[d]Water use attributable to separate wet cooling tower required for auxiliary cooling requirements.

SITE CERTIFICATION APPLICATION

THE CEDAR BAY COGENERATION PROJECT

VOLUME 1

Submitted by AES/Cedar Bay Inc.



CEDAR BAY COGENERATION PROJECT

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CONTENTS (Continued)

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CONTENTS (Continued)

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PREFACE

PURPOSE

This Site Certification Application (SCA) is being submitted by AES Cedar Bay, Inc. (AES-CB), and Seminole Kraft Corporation for the Cedar Bay Cogeneration Project.

This SCA is intended to serve the following purposes.

- Site Certification Application for the Cedar Bay Cogeneration Project including all state and local permits for the construction and operation of the facilities; Section 401 water quality certification; and certification of compliance with the Florida Coastal Zone Management Program. 3
- Application to the US Environmental Protection Agency for a permit to discharge under the Clean Water Act National Pollutant Discharge Elimination System (NPDES) Program. This SCA also serves as the applicants' Environmental Information Document (EID) in compliance with the requirements of the National Environmental Policy Act (NEPA).

Summary of the major section headings:

1. Need for Power.
2. Site and Vicinity Characterization.
3. Plant and Directly Associated Facilities.
4. Effects of Site Preparation, and Plant and Associated Facility Construction.
5. Effects of Plant Operation.
6. Transmission Lines and Other Linear Facilities.
7. Economic and Social Effects of Plant Construction and Operation.
8. Site and Design Alternatives.
9. Coordination.

10. Appendices.

The pertinent applicant information follows the Preface.

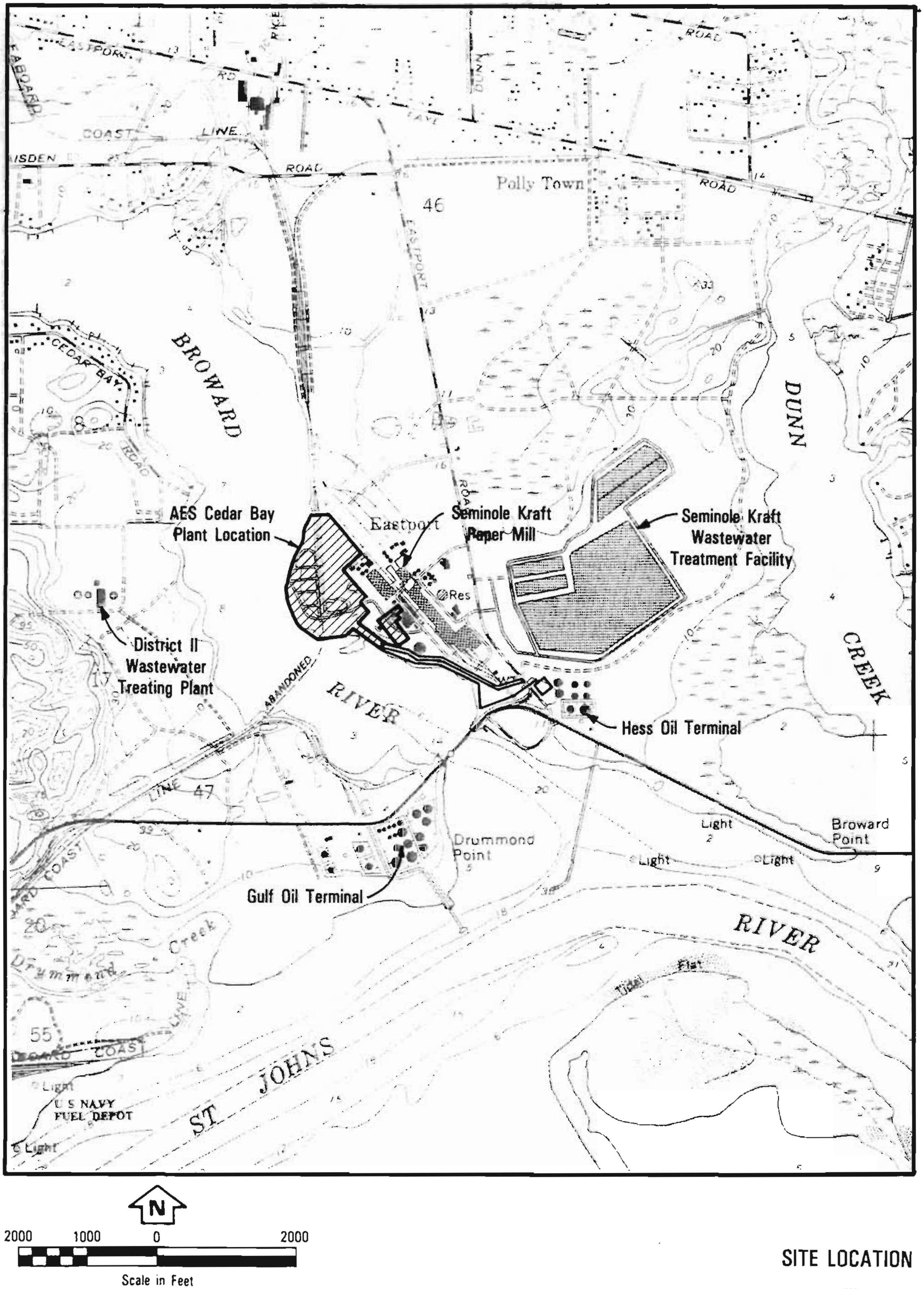
PROJECT INFORMATION

The AES Cedar Bay Cogeneration Project is an integrated power complex to be built on an existing industrial site in Jacksonville, Florida (Figure A). The cogeneration plant will produce 225 MW of electricity for sale to Florida Power and Light Company (FP&L) as well as process steam for sale to the adjacent Seminole Kraft Corporation paper mill. The project also includes installation of a new kraft recovery boiler system required to modernize the paper mill (Figure B).

The proposed cogeneration plant will burn fuel made up of approximately 96 percent coal and 4 percent bark in three circulating fluidized bed (CFB) boilers. These technically advanced boilers produce steam at 1,800 pounds per square inch gauge (psig) for a new double automatic extraction condensing turbine generator. This process will generate 225 MW as well as 640,000 lb/h of 175 psig and 75 psig process steam for the mill. These boilers will be owned and operated by AES-CB (Figure C).

The new kraft black liquor recovery boiler (KRB) system, owned and operated by Seminole Kraft, will burn black liquor solids, and produce 1,250 psig steam, replacing the three existing recovery boilers. A new automatic extraction condensing turbine generator will generate 42 MW of electric power for internal mill consumption as well as 600 psig and 175 psig steam for the kraft mill processes. The existing multiple effect evaporators and smelt dissolving tanks will also be replaced as a part of this project.

Offsets from the elimination and replacement of old equipment with higher pollution levels at the mill will minimize the project's environmental impacts. Eight existing boilers at the mill will be shut down; three oil-fired and two bark-fired power boilers and three kraft recovery boilers. The new CFB boilers will replace the power boilers process steam generation and the old kraft recovery boilers will be replaced with a modern low-odor unit.



SITE LOCATION

Figure A

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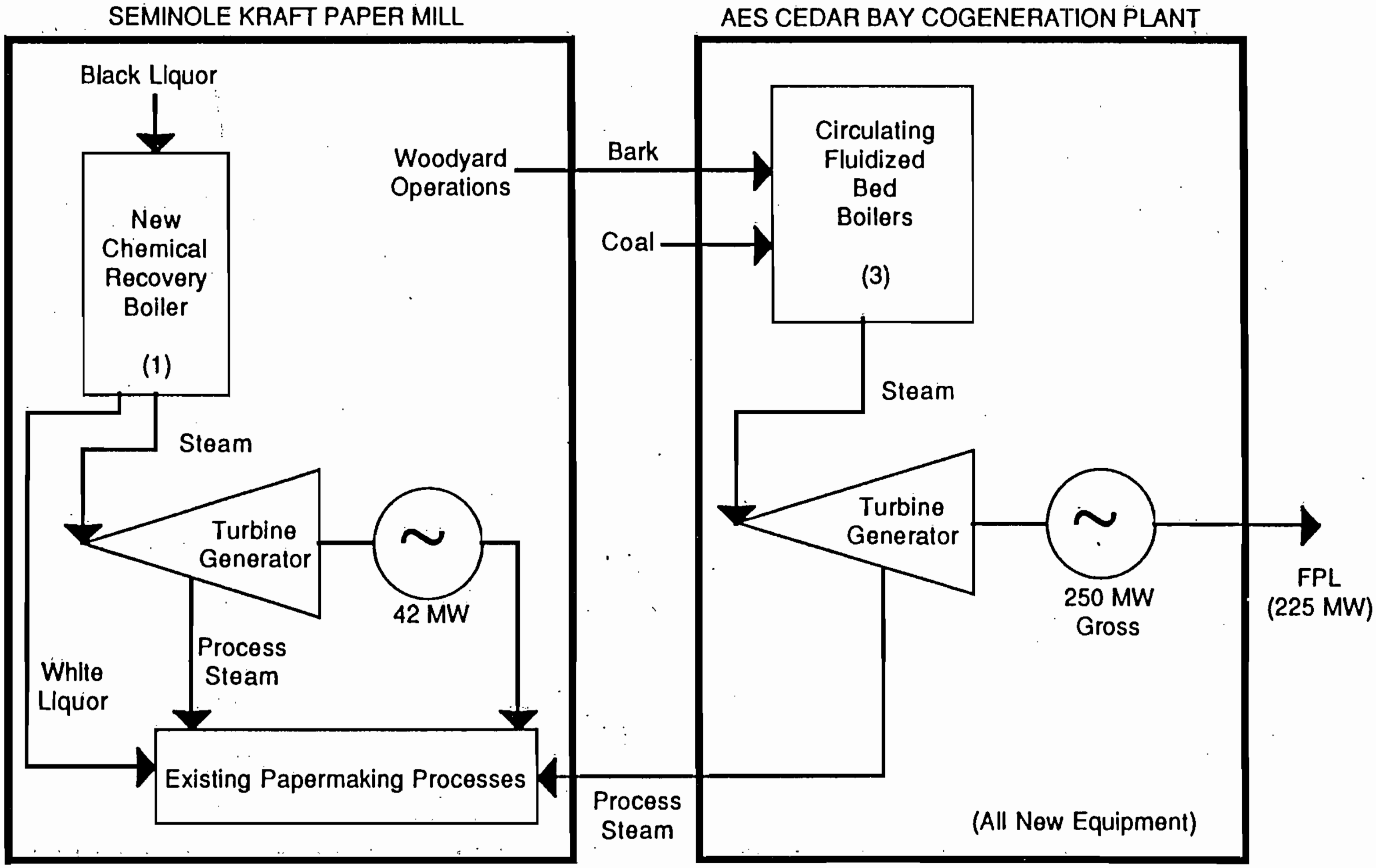
Figure B

AES Cedar Bay Cogeneration Project, Jacksonville, Florida



Note : Seminole Kraft does not currently sell any of their electricity, and has no plans to do so in the future.
Approximately 10% of AES Cedar Bay's gross generation will be consumed internally to run the plant equipment.

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Typical Flow Chart for a Circulating Fluidized Bed Boiler System

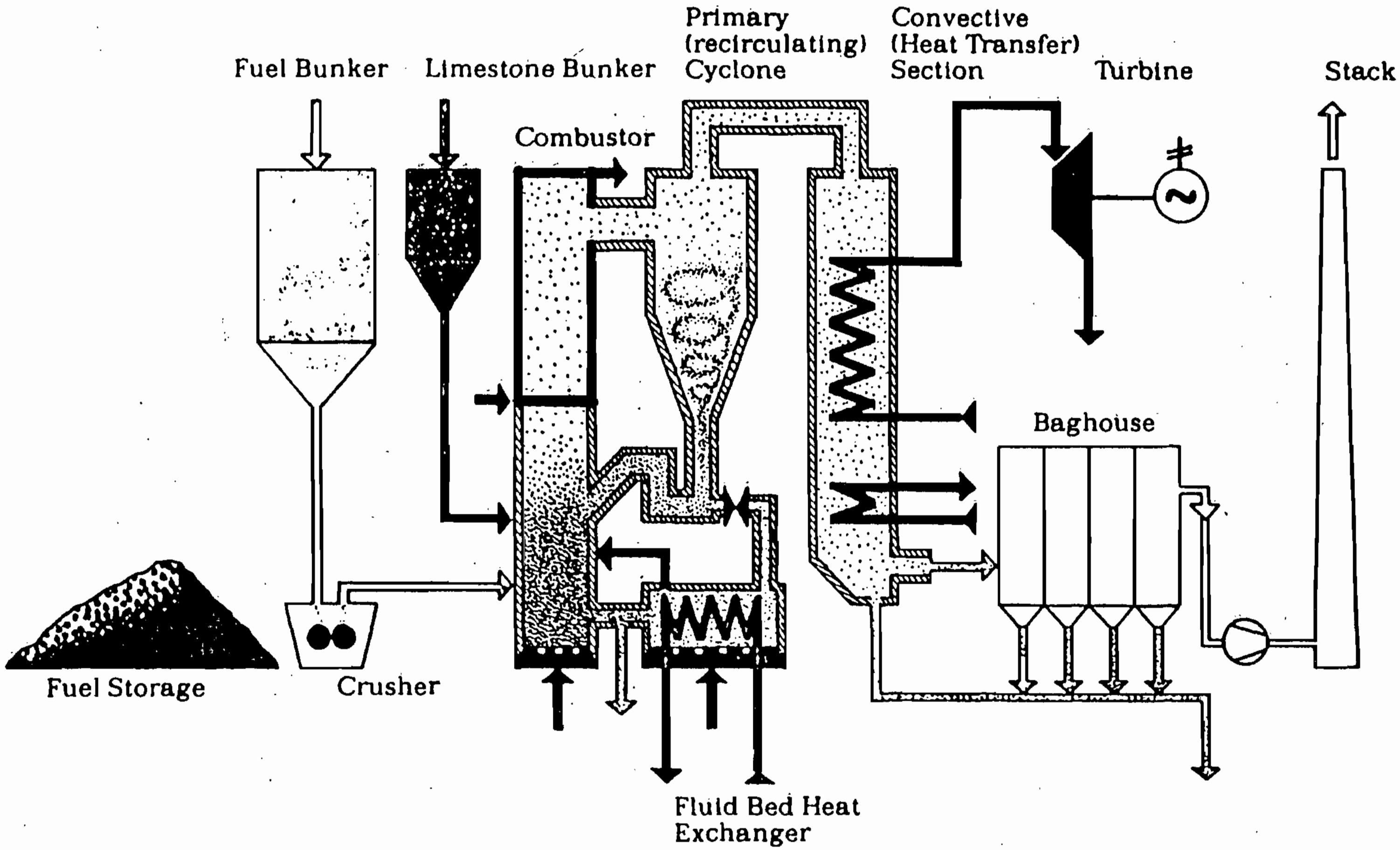


Figure C

PROJECT IMPACTS

Air

By shutting down old equipment at the paper mill, utilization of modern technology, and installation of stacks consistent with good engineering practices, the project will result in numerous benefits to the environment. Improvements will be observed in both the net annual emissions (the total amount of emissions from the project in one year), and in ambient impacts (the effects of the emissions on air quality). These improvements include reductions in the ambient concentration of sulfur dioxide (SO_2), particulate matter, volatile organic compounds (VOC), and total reduced sulfur (TRS), an odor-producing sulfur compound. Specific impacts include the following.

- SO_2--Maximum potential annual emissions will be lower than representative emissions from existing mill sources. In addition, maximum ambient impacts will be dramatically reduced as a result of this project. 3
- TRS--Odor causing emissions will be reduced by more than 70 percent from the current KRB's permitted emissions.
- Total Suspended Particulates (TSP)--Emissions will be significantly lower. Ambient impacts will also be significantly reduced. 3
- Particulate Matter Less Than 10 um (PM-10)--Emissions and ambient impacts will be reduced.
- VOC--Emissions will be reduced. Ambient impacts will be significantly reduced.
- NO_x--Emissions will increase, but will be well within the New Source Performance Standards. Ambient impacts will be significantly below applicable air quality standards.
- CO--Emissions will increase, but net ambient impacts will be significantly below applicable air quality standards.

Air emission control features on the new equipment will include the following.

- Circulating Fluidized Bed Boilers.
  - Limestone injection for SO_2 reduction.

- -- Baghouses for particulate reduction.
  - -- Low combustion temperature control for NO_x reduction.
- Kraft Recovery Boiler.
  - -- Electrostatic precipitators for particulate control.
  - -- Noncontact black liquor evaporators for TRS control.
- Smelt Dissolving Tanks.
  - -- Liquid contact scrubber for particulate and TRS control.

Water Use

As a result of the installation of a cooling tower, the Cedar Bay project will eliminate the use of Broward River water. The existing mill requires approximately 30,000 gallons per minute (gpm) of Broward River water in a once-through turbine condenser cooling system.

Ground water consumption at the site will be increased from the current average mill consumption of 19.5 million gallons per day (mgd) up to 26.5 mgd. The increase is required for the cooling tower, power cycle, and other miscellaneous plant uses. Ground water quality will be unaffected by this increase.

The project's total water use will be about 58 percent lower than that 1
of Seminole Kraft at present.

Land

The project site has been used for industrial purposes since the 1950s, before the paper mill was built. As a result of industrial activity
and fill, the land has already been extensively disturbed. The site is 3
zoned heavy industrial (IH) and is designated for continued IH use in the
Jacksonville Planning Department's 2010 North District Plan. 3

A biophysical assessment of the site concluded that the proposed plant site is not inhabited by any endangered species. However, a gopher tortoise habitat appears to exist on land adjacent to the CSX railyard, north of the site. The gopher tortoise has been categorized as a species of special concern by the Florida Committee of Rare and Endangered Plants and

Animals. In the event that additional rail spurs need to be constructed, affected tortoises could be relocated to the large adjacent habitat without adverse impacts to the tortoises moved or to the remainder of the population.

There are no archaeological, historic, or cultural sites present on the proposed project site or in the immediate vicinity that are expected to be impacted by the project's construction or operation.

Fuel

Coal will be delivered by rail, by essentially the same railroad access presently serving the papermill. The existing railroad track system will be extended to accommodate coal delivery to the cogeneration site. This expansion is discussed in Section 6.3. 3

Environmental impacts from fuel handling will be minimized. Conveyors will be designed to minimize spillage. Transfer points will be enclosed and dust will be controlled by fabric filter type dust collectors. Coal and limestone pile and site runoff will be collected and treated before use or discharge to the St. Johns River to ensure compliance with water quality standards.

Wastewater and Solid Waste

Due to the elimination of once-through cooling water at the site, thermal loading of the St. Johns River is expected to be reduced by 90 percent or more. Cooling tower blowdown contributes 633 gpm to the discharge. Total wastewater discharge from the site will be reduced by 70 percent. Discharge will be through the mill's existing discharge structure.

The volume of wastewater generated from sources other than cooling tower blowdown will remain essentially equal to that of the current operation. Wastewater will be treated in the existing Seminole Kraft treatment system and will meet all applicable standards. No impacts are expected from the wastewater since the loading to the existing treatment system will not be increased.

Ash from the combustion process will be pelletized by AES-CB and disposed out of state by the coal supplier. This material is also potentially marketable in the engineering materials industry. This ash is not a hazardous material, and impacts on the environment are expected to be minimal.

Trash and other solid waste will be disposed of at an approved facility. A licensed contractor will be responsible for treatment and disposal of boiler cleaning wastes.

<u>Socioeconomic</u>

During the peak year of construction, an average of over 630 jobs will be created by the project. The net direct employment effect will be the creation of 58 full-time positions for the operating life of the plant. A consent decree between Seminole Kraft, the Florida Department of Environmental Regulation, and the Jacksonville Bio-Environmental Services Division exists requiring compliance by the mill with the TRS New Source Performance Standards by November of 1992. The Cedar Bay Cogeneration Project will provide the new KRB, allowing Seminole Kraft to continue operation in compliance with these standards. In effect, the project significantly contributes to the continued viability of the paper mill.

<u>Need for Power</u>

Electricity demand in Florida is growing rapidly. In April 1987, the Florida Public Service Commission (FPSC) stated that needs for additional generating capacity of 220 MW, 740 MW, and 815 MW exists in years 1993, 1994, and 1995, respectively. FPSC staff has indicated that recent data show that capacity above this amount will be needed.

The FPSC has designated a coal-fired plant as the state-wide avoided unit and strongly supports reductions in Florida's dependence on oil and gas in the electric industry. Ratepayers will also benefit because the price of electricity sold to FP&L is below the state-wide avoided unit cost. In addition, construction of the plant will be privately funded, eliminating ratepayer investment risk.

Preliminary meetings with the FPSC staff indicate support for the AES Cedar Bay Project, due to its use of advanced clean coal technology, the environmental benefits, and the attractive price of the electricity generated.

SCHEDULE

The Cedar Bay Cogeneration Project major milestones follow.

• Power Purchase Agreement		
-- Signed	May 1988	
-- FPSC Approval	April 1989	
• Permit Applications Submitted	November 1988	
• Permitting Complete	November 1989	
• Financing Complete	December 1989	2
• Construction Begins	January 1990	
• Construction Complete		
-- Recovery Boiler	June 1992	
-- Power Boilers	July 1992	

Applied Energy Services, Inc.

AES Cedar Bay, Inc. is a wholly owned subsidiary of Applied Energy Services, Inc., a privately held corporation that builds, owns, and operates cogeneration facilities that sell steam and electricity to industrial and utility customers. AES currently operates three facilities--in Texas, Pennsylvania, and California--with a combined capacity of 350 MW. Two more plants, representing an additional 500 MW of capacity, are under construction in Oklahoma and Connecticut. Several other projects are in advanced stages of development. To date, AES has raised over $1.2 billion from private sources to finance its projects.

AES' objective is to be a long-term, low cost, reliable supplier of energy. The company concentrates on innovative coal-burning technology and superior plant operations.

Seminole Kraft Corporation

Seminole Kraft Corporation is a privately held corporation which owns and operates the Seminole Kraft paper mill. The mill produces unbleached linerboard and kraft paper and has been in operation under Seminole Kraft since April 1987. Stone Container Corporation owns 60 percent of Seminole Kraft's common stock, has management responsibility for the mill and buys all of the mill's output. After a 33-year operating record, the mill ceased operation in October 1985 and was purchased by Seminole Kraft in October 1986. Substantial expenditures were made to rehabilitate and modernize the mill prior to startup in April 1987. The mill currently employs over 350 people. 3

APPLICANT INFORMATION

Applicants' Official Names	
AES Cedar Bay, Inc.	Seminole Kraft Corporation
Address	
1925 North Lynn Street Arlington, Virginia 22209	9469 Eastport Road Jacksonville, Florida 32218-0998
Address of Official Headquarters	
Same as address	Same as address
Business Entity (corporation, partnership, cooperative)	
Corporation	Corporation
Names, Owners, etc.	
Applied Energy Services, Inc.	Seminole Kraft Corporation
Name and Title of Chief Executive Officer	
Roger Sant--Chief Executive Officer	Roger Stone--President and Chairman
Name, Address, and Telephone Number of Official Representative Responsible for Obtaining Certification	
Jeffrey V. Swain 1001 North 19th Street Suite 2000 Arlington, Virginia 22209 (703) 522-0073	Larry A. Stanley 2 9469 Eastport Road 3 Jacksonville, Florida 32218-0998 (904) 751-6400

Site Location (County)

Duval County

Nearest Incorporated City

Jacksonville

Latitude and Longitude

30 degrees, 25 minutes, 21 seconds north latitude 3

81 degrees, 36 minutes, 23 seconds west longitude

UTMs

Section, Township, and Range

Section 46, Township 1S, Range 27E

Location of any Directly Associated Transmission Facilities (Counties)

Duval

Nameplate Generating Capacity

256 MW Fluidized Bed Boiler Plant 43 MW Kraft Recovery Boiler

Capacity of Proposed Additions and Ultimate Site Capacity (where applicable)

Total of 299 MW nameplate additions; no ultimate site capacity request.

Remarks: (Additional information that will help identify the applicant)

AES Cedar Bay, Inc., is a wholly owned subsidiary of Applied Energy Services, Inc., of Arlington, Virginia.

Seminole Kraft Corporation is a privately held corporation. Stone Container Corporation of Chicago, Illinois, owns 49 percent interest in Seminole Kraft Corporation.

ACRONYMS AND ABBREVIATIONS

AAQS	Ambient Air Quality Standards
AES-CB	AES Cedar Bay, Inc.
AFBC	Atmospheric fluidized bed combustion
AQCS	Air Quality Control System
AREA	American Railroad Engineering Association
BACT	Best Available Control Technology
BB	Bark boiler
BOD	Biochemical oxygen demand
BTU	British thermal unit
Btu/h	British thermal units per hour
CFB	Circulating fluidized bed
cfs	Cubic feet per second
CO	Carbon monoxide
COD	Chemical oxygen demand
dBA	Decibels (A-weighted)
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERM	Environmental Resources Management - South, Inc.
F	Degrees Fahrenheit
FAC	Florida Administrative Code
FCG	Florida Electric Power Coordinating Group
FCREPA	Florida Committee on Rare & Endangered Plants & Animals
FDA	Florida Department of Agriculture
FDER	Florida Department of Environmental Regulation
FGD	Flue gas desulfurization
FGFWFC	Florida Game and Fresh Water Fish Commission
FNAI	Florida Natural Areas Inventory
FPL	Florida Power & Light
FPSC	Florida Public Service Commission
F.S.	Florida Statutes
GEP	Good Engineering Practice
gpd	Gallons per day

gpm	Gallons per minute
gr/dscf	Grains per dry standard cubic foot
GWH	Gigawatt hours
HgA	Mercury, absolute
HRSG	Heat recovery steam generator
IGCC	Integrated gas combined cycle
IH	Heavy Industrial District
ISCST	Industrial Source Complex Short-Term
IW	Waterfront Industrial District
JEA	Jacksonville Electric Authority
kg	Kilograms
km	Kilometers
KRB	Kraft recovery boiler
LAER	Lowest achievable emission rate
lb/h	Pounds per hour
lb/MBtu	Pounds per million British thermal units
LETCO	Law Engineering and Testing Company
LOLP	Loss of load probability
LTRS	Long term reserve shutdown
m	Meters
MBtu/h	Million British thermal units per hour
MEE	Multiple effect evaporators
mgd	Million gallons per day
mg/l	Milligrams per liter
mg/m^3	Milligrams per cubic meter
mm	Millimeters
msl	Mean sea level
m/s	Meters per second
m/sec	Meters per second
MW	Megawatts
MWh	Megawatt hour
NEMA	National Electrical Manufacturers Association
NML	Noise monitoring location

NO_x	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NWS	National Weather Service
OR	Open Rural District
PB	Power boiler
PC	Pulverized coal
pCi/l	Picocuries per liter
PM_{10}	Particulate matter less than 10 microns
ppm	Parts per million
ppmvd	Parts per million by volume dry
PSC	Florida Public Service Commission
PSD	Prevention of Significant Deterioration
psig	Pounds per square inch, gauge
PTPLU-2	Screening level point source dispersion model
SACTI	Seasonal/annual cooling tower impact
SCA	Site Certification Application
scfm	Standard cubic feet per minute
SCR	Selective catalytic reduction
SCS	Soil Conservation Service
SDT	Smelt dissolving tank
SIP	State Implementation Plan
SJRPP	St. John's River Power Park
SK	Seminole-Kraft
SO_2	Sulfur dioxide
STP	Sewage treatment plant
TDS	Total dissolved solids
TECO	Tampa Electric Company
TOC	Total organic carbon
tpy	Tons per year
TRS	Total reduced sulfur
TSP	Total suspended particulate
TSS	Total suspended solids

ug/m^3	Micrograms per cubic meter
UNAMAP	User's Network for the Applied Modeling of Air Pollution
UPS	Unit Power Sales
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UTM	Universal Transverse Mercator
VOC	Volatile organic compounds

SITE CERTIFICATION
APPLICATION

THE CEDAR BAY COGENERATION PROJECT

VOLUME 2

Submitted by AES/Cedar Bay Inc.

2.0 SITE AND VICINITY CHARACTERIZATION

2.1 SITE AND ASSOCIATED FACILITIES DELINEATION

This section provides information concerning the geographic location of the proposed site. This section also provides maps showing the area, communities in the vicinity, adjacent properties, and existing and proposed uses of the site.

2.1.1 Site Location

The Cedar Bay Cogeneration Project site is located in Duval County, Florida. The geographic coordinates of the cogeneration plant chimney are approximately 30 degrees 25 minutes 21 seconds north latitude and 81 degrees 36 minutes 24 seconds west longitude. The geographic coordinates of the kraft recovery complex chimney are approximately 30 degrees 25 minutes 24 seconds north latitude and 81 degrees 36 minutes 25 seconds west longitude. The site is located in Section 46, Range 27 East, Township 1 South. This section is shown on the USGS 7-1/2 minute series, Eastport, Florida, Quadrangle. The site location relative to the Jacksonville, Florida, area is shown on Figures 2.1-1 and 2.1-2. The cross-hatched area on Figure 2.1-2 indicates the existing Seminole Kraft paper mill property boundaries. The owners of property abutting or adjacent to the Seminole Kraft Mill are Zion Jacksonville Limited Partnership, Champion International Corp., and Amerada Hess Corporation.

2.1.2 Site Modification

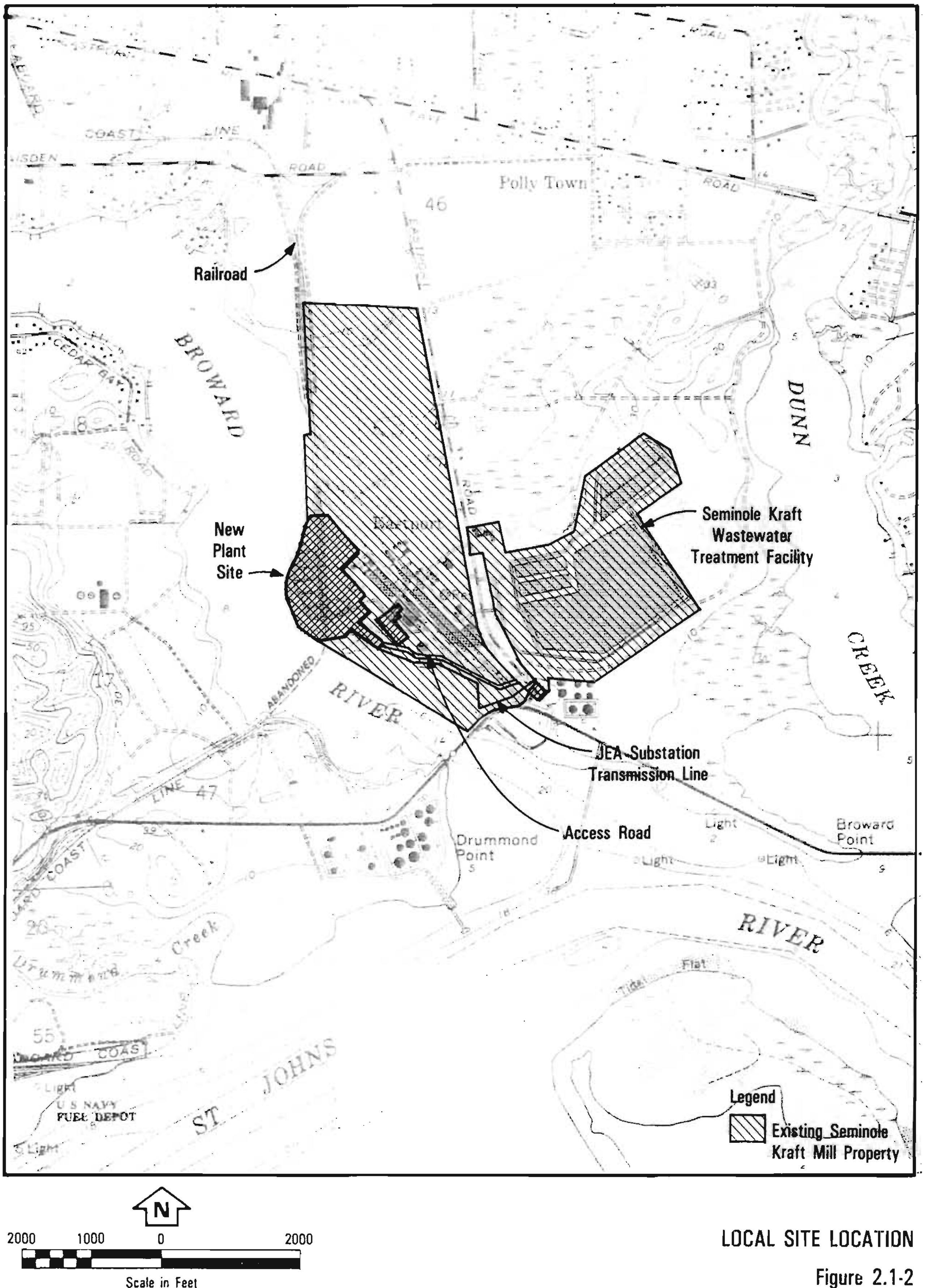
The total existing mill site consists of 425 acres. The new facilities will occupy approximately 28 of these acres. The location of the new facilities on the site relative to adjacent properties and the existing mill is shown on Figure 2.1-3. All property adjacent to the cogeneration plant is owned by Seminole Kraft.

2.1.3 Existing and Proposed Uses

Presently, most of the overall site is occupied by the Seminole Kraft paper mill. The eastern portion of the overall site is occupied by the wastewater treatment facilities for the paper mill. The western portion is

REGIONAL SITE LOCATION

Figure 2.1-1



LOCAL SITE LOCATION

Figure 2.1-2

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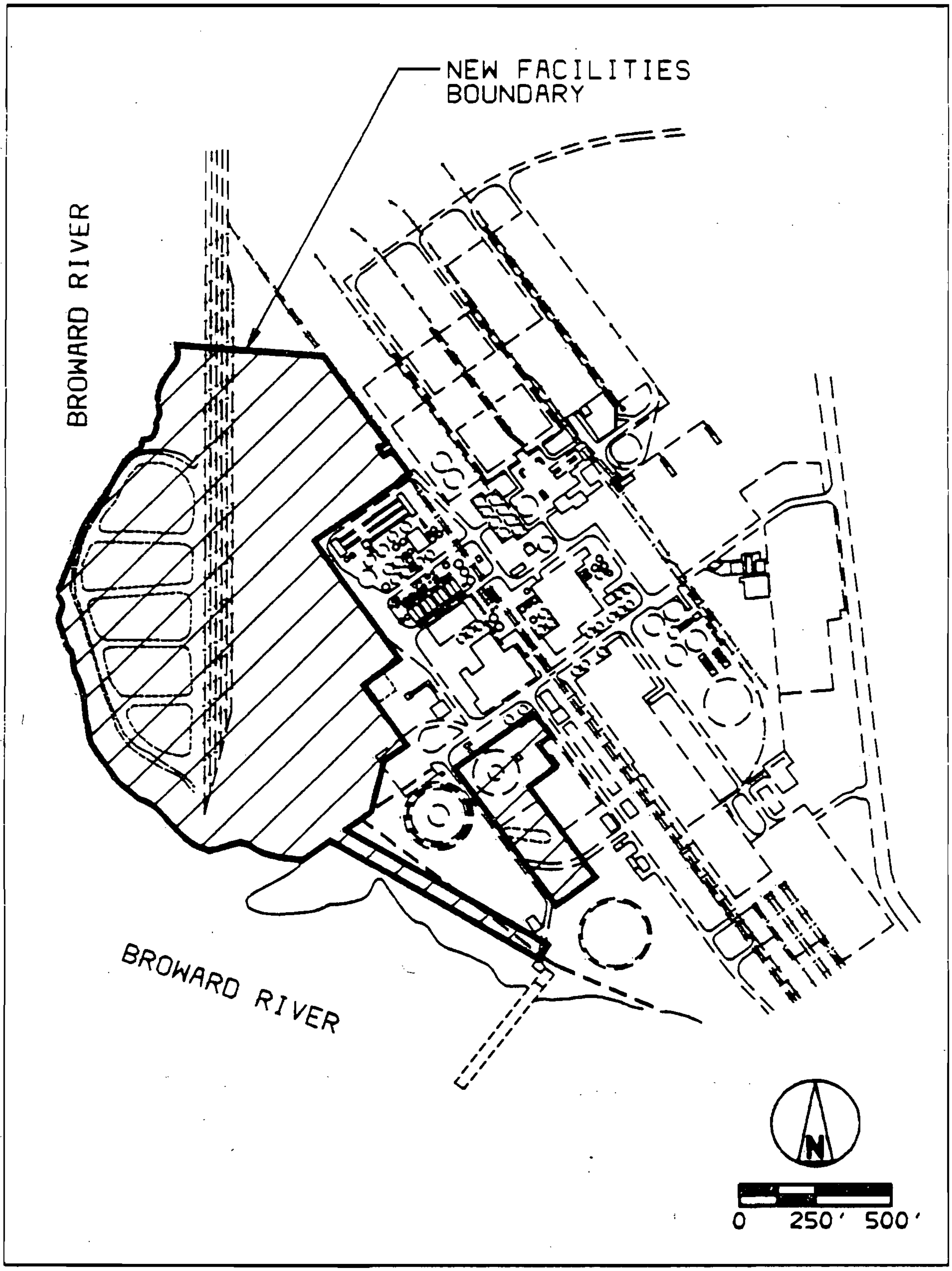

NEW FACILITIES LOCATION

Figure 2.1-3

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occupied by the mill facilities, wood storage yard, and lime mud settling ponds and storage areas. The new cogeneration project will be located west 2
of the existing mill power plant and east of the Broward River. The area to be occupied by the cogeneration plant is currently used for storage of lime mud from the mill and construction debris. An oil tank is located in the vicinity of the proposed kraft recovery boiler facilities. A rail yard 2
is located on the west side of the site. No other proposed uses for the site are known. Site preparation is described in Subsection 4.1.4.

2.1.4 <u>100-Year Flood Zone</u>

A 1.5-acre area in the southwestern portion of the site is within the 100-year flood zone, as shown on Figure 2.1-4. A portion of the railroad 2
for the new cogeneration plant will be located in the 1.5-acre area currently in the 100-year base flood plain. The base flood elevation is 7 feet national geodetic vertical datum. Proposed flood protection measures are described in Subsection 4.1.3.

2.2 SOCIO-POLITICAL ENVIRONMENT

2.2.1 <u>Governmental Jurisdictions</u>

The proposed cogeneration facility site and the area within a 5-mile radius of the site are within the city limits of Jacksonville, Florida, which encompasses most of Duval County.

Figure 2.2-1 shows the 1-, 2-, 3-, 4-, and 5-mile radii centered on the cogeneration facility chimney. As shown on the map, the proposed site property adjoins the Broward River to the west, is less than 1 mile from the St. Johns River to the south, and is a little more than 1 mile from Dunn Creek to the east.

Two historic sites are shown on Figure 2.2-1 within the 5-mile radius of the site. Approximately 3-1/2 miles to the southeast of the site is the Yellow Bluff Fort on New Berlin Road. Approximately 3 miles southwest of the site is the Napoleon Bonaparte Broward home. A government area, the US Navy Fuel Depot, is just over 2 miles southwest of the facility site. A

3.0 THE PLANT AND DIRECTLY ASSOCIATED FACILITIES

3.1 BACKGROUND

The proposed Cedar Bay Cogeneration Plant and paper mill kraft recovery boiler complex, together with their supporting equipment and facilities, are shown on Figure 3.1-1.

The cogeneration plant consists of a single steam turbine-driven electrical generator with steam supplied by three circulating fluidized bed boilers. A large quantity of steam is extracted from the turbine and transported to Seminole Kraft for use as process steam. Three boilers are proposed for the following reasons.

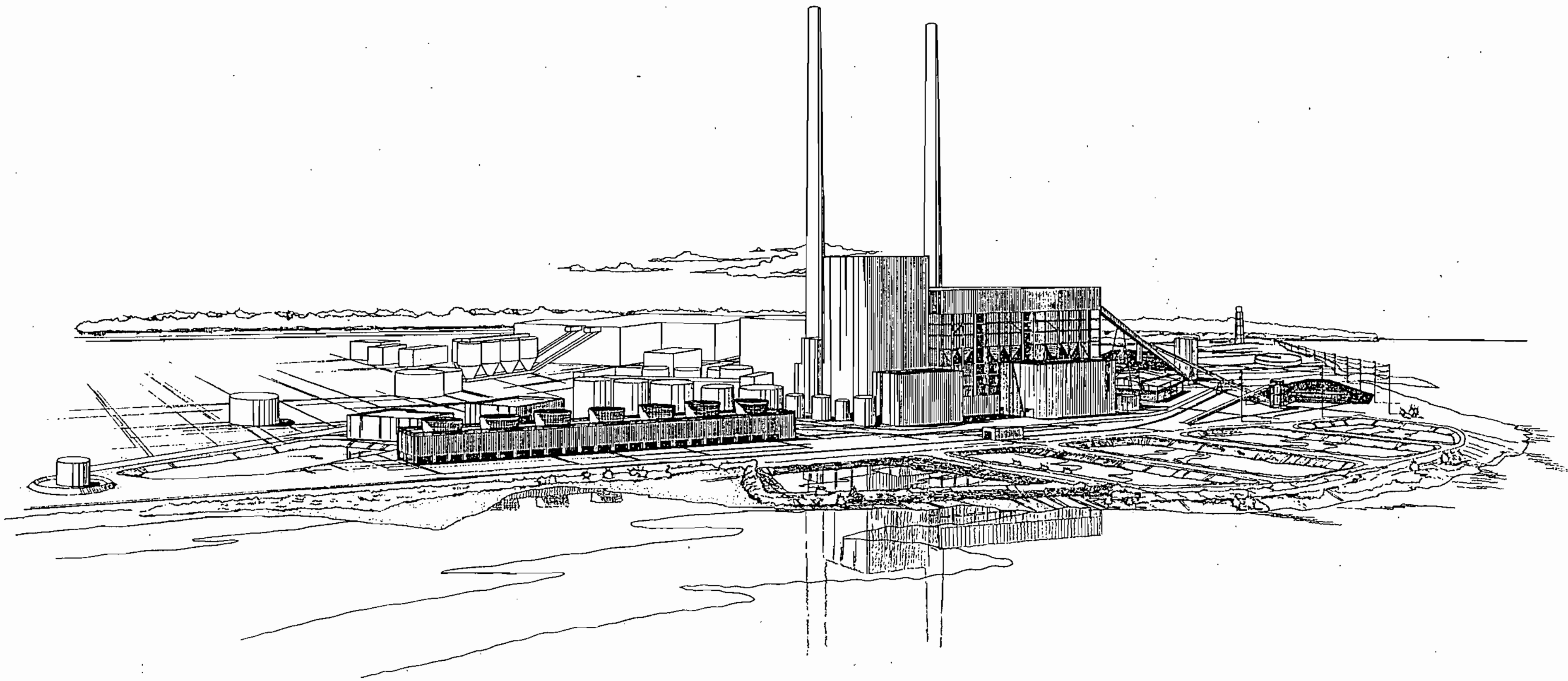
- Boilers with the capacity of the one-third capacity size have been designed and successfully operated. Boilers of the half-capacity or full capacity size would require design extrapolation and would be more subject to development problems.
- Three boilers will enhance availability of the plant. The loss of one boiler will reduce plant capacity by less than one third.

Flue gas desulfurization will be accomplished in the fluidized bed boilers. Separate fabric filters will be provided for each boiler to 3
remove particulates from the flue gas stream. The selection of fabric filters is discussed in Section 3.4.

Cycle heat rejection is planned to be accomplished with rectangular, wooden, mechanical draft cooling towers as discussed in Subsection 8.2.1. The cogeneration cooling towers will be sized to also reject the heat from the kraft recovery boiler complex turbine exhaust and evaporator/concentrator condenser. Well water will be used for cooling tower makeup, as discussed in Subsection 3.5.1.

The steam cycle equipment (condenser, condensate pumps, boiler feed pumps, deaerator, feedwater heaters, and piping and valves) will be typical of central electric generating stations.

The kraft recovery boiler complex includes a kraft recovery boiler sized to recover the chemicals from the black liquor produced in the



PROPOSED CEOAR BAY COGENERATION
PLANT AND PAPER MILL KRAFT
RECOVERY BOILER COMPLEX

Figure 3.1-1

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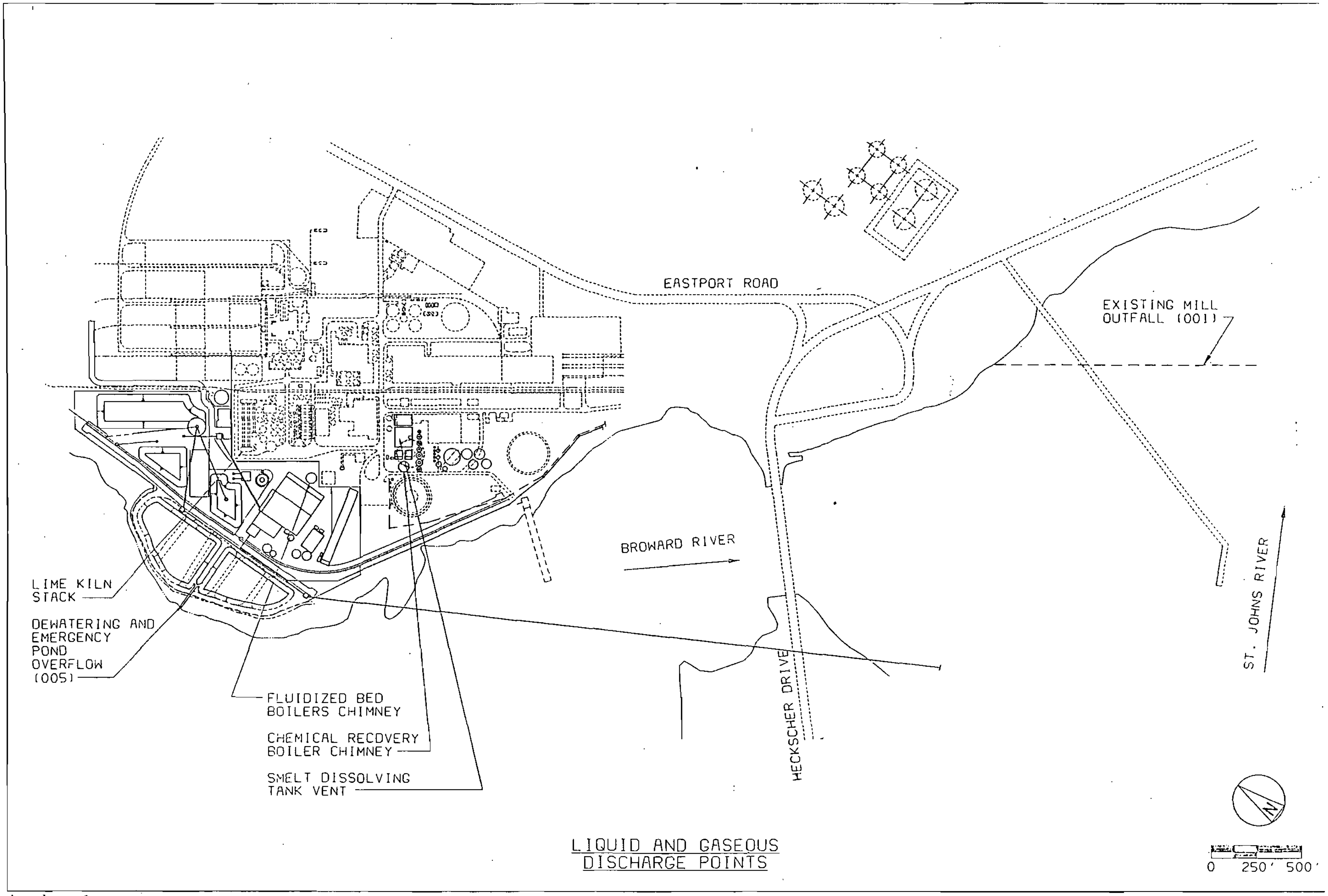

LIQUID AND GASEOUS DISCHARGE POINTS

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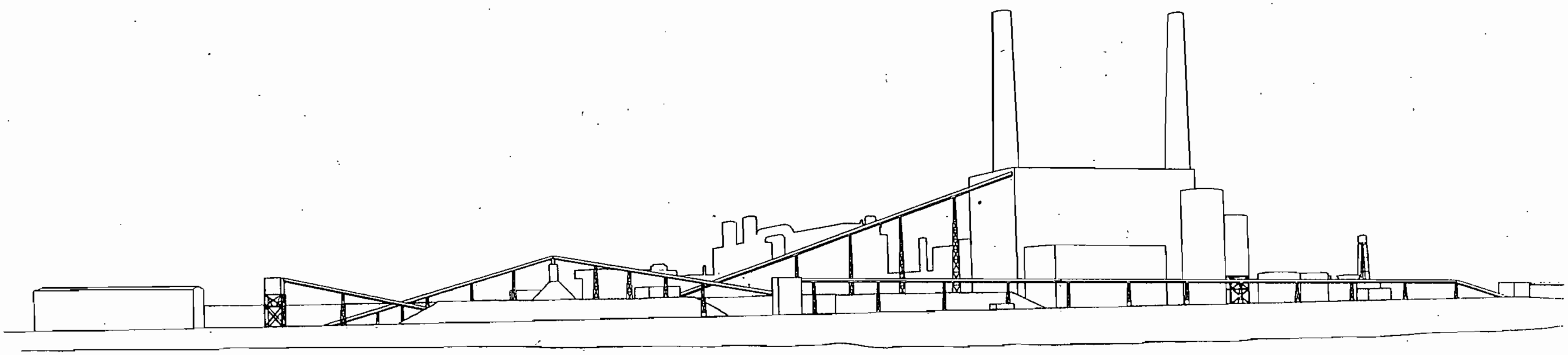

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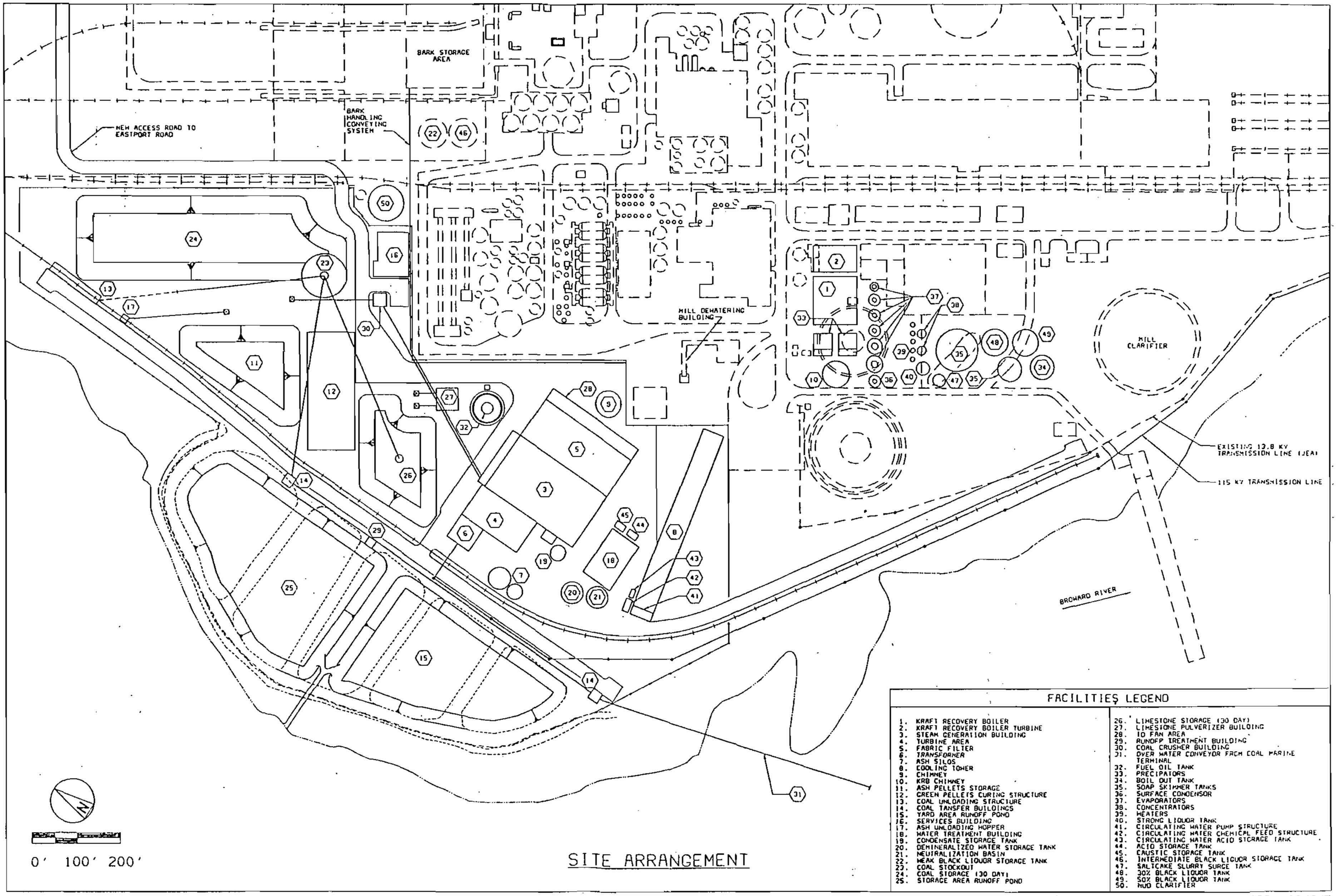
GENERAL PLANT PROFI
LOOKING EAST SOUTHEA
Figure 3.2



SITE ARRANGEMENT

FACILITIES LEGEND

1. KRAFT RECOVERY BOILER
2. KRAFT RECOVERY BOILER TURBINE
3. STEAM GENERATION BUILDING
4. TURBINE AREA
5. FABRIC FILTER
6. TRANSFORMER
7. ASH SILOS
8. COOLING TOWER
9. CHIMNEY
10. KRB CHIMNEY
11. ASH PELLETS STORAGE
12. GREEN PELLETS CURING STRUCTURE
13. COAL UNLOADING STRUCTURE
14. COAL TANSFER BUILDINGS
15. YARD AREA RUNOFF POND
16. SERVICES BUILDING
17. ASH UNLOADING HOPPER
18. WATER TREATMENT BUILDING
19. CONDENSATE STORAGE TANK
20. DEMINERALIZED WATER STORAGE TANK
21. NEUTRALIZATION BASIN
22. WEAK BLACK LIQUOR STORAGE TANK
23. COAL STOCKOUT
24. COAL STORAGE (30 DAY)
25. STORAGE AREA RUNOFF POND
26. LIMESTONE STORAGE (30 DAY)
27. LIMESTONE PULVERIZER BUILDING
28. ID FAN AREA
29. RUNOFF TREATMENT BUILDING
30. COAL CRUSHER BUILDING
31. OVER WATER CONVEYOR FROM COAL MARINE TERMINAL
32. FUEL OIL TANK
33. PRECIPATORS
34. BOIL OUT TANK
35. SOAP SKIMMER TANKS
36. SURFACE CONDENSOR
37. EVAPORATORS
38. CONCENTRATORS
39. HEATERS
40. STRONG LIQUOR TANK
41. CIRCULATING WATER PUMP STRUCTURE
42. CIRCULATING WATER CHEMICAL FEED STRUCTURE
43. CIRCULATING WATER ACID STORAGE TANK
44. ACID STORAGE TANK
45. CAUSTIC STORAGE TANK
46. INTERMEDIATE BLACK LIQUOR STORAGE TANK
47. SALTCAKE SLURRY SURGE TANK
48. 30% BLACK LIQUOR TANK
49. 50% BLACK LIQUOR TANK
50. MUD CLARIFIER

SITE ARRANGEMENT

Figure 3.2-1

pulping operation of the Seminole Kraft paper mill. The complex also includes a steam turbine-driven generator sized to generate electric power requirements for the paper mill. Wet bottom electrostatic precipitators are provided for the kraft recovery boiler as discussed in Section 3.4.

3.2 SITE LAYOUT

Figure 3.2-1 shows the proposed layout for the cogeneration project, chemical recovery boiler, and associated facilities. The new facilities will occupy all of the 28-acre portion of the site between the mill, lime settling ponds, and the Broward River.

A general plant profile of the new facilities is shown on Figure 3.2-2. This profile is based on the elevations of the various facilities as viewed from the west looking east. The elevations and dimensions shown on Figure 3.2-2 are preliminary and may change as detailed engineering design proceeds.

Figure 3.2-3 shows the existing and proposed new release points for liquid and gaseous wastes. Wastewaters will be treated and discharged using the existing outfall into the St. Johns River, as discussed in Sections 3.5 and 3.6. Surface runoff from the fuel, limestone, and ash storage areas will be collected in the Fuel Area Runoff Pond as discussed in Section 3.8. The water will be treated as required and discharged via the existing Seminole Kraft treatment system. The surface runoff from other areas will be collected in the Yard Area Runoff Pond, detained, and released via the existing outfall as discussed in Section 3.8.

The primary new gaseous waste discharge points are the two chimneys for the fluidized bed boilers and the chemical recovery boiler, and the vent from the smelt dissolving tank. The amount of gaseous waste and impacts are discussed in Sections 3.4 and 5.6.

3.3 FUEL

3.3.1 <u>Fuel Types and Qualities</u>

The primary fuel for the Cedar Bay Cogeneration Plant will be coal. Although the coal supply contract for the plant has not been finalized, it is anticipated that bituminous coal will be used. It is also anticipated that the coal supply may change in the future with the renegotiation of coal supply contracts. To provide the necessary design flexibility to accommodate the use of coals with a wide range of properties, a generalized design-basis coal has been selected for use with the steam generators and particulate removal system. Designing these major components to handle this coal will provide the overall system design flexibility to burn other coals with similar properties. Properties of the design-basis coal are shown in Table 3.3-1.

The three steam generators will also be designed to burn wood waste, consisting primarily of bark, in conjunction with the primary fuel. Wood waste will be provided from the adjacent Seminole Kraft pulp and paper mill. Transport, storage, and firing equipment for wood waste combustion, however, will be provided for only two of the three steam generators. Each steam generator will be capable of firing wood waste at a rate equivalent to 10 percent of the total heat input to the steam generator at maximum continuous rating. Within the control range of the steam generator, the wood waste feed rate will be constant, with the load fluctuations handled by adjusting the primary fuel feed rate. Typical properties of wood waste are shown in Table 3.3-2.

The steam generators will be started with No. 2 fuel oil. During periods of low load operation, No. 2 fuel oil will also be used for stabilization. The emergency fire pump, mobile coal handling equipment, and other vehicles will use gasoline or diesel fuel.

3.3.2 Fuel Quantities

Based on the design coal in Table 3.3-1, the coal consumption rate will be 145 tons per hour. At the design capacity factor of 87 percent, the annual coal consumption for the cogeneration plant would be 1,105,000 tons per year.

Based on operation with a combination of design-basis coal and wood waste, the wood waste consumption rate for each steam generator will be approximately 8 tons per hour. The annual wood waste consumption, assuming

TABLE 3.3-1. COAL PROPERTIES

Proximate Analysis	Design-Basis Coal
Moisture, percent (maximum)	15
Ash, percent (maximum)	15
Volatile Matter, percent (minimum)	25
Fixed Carbon, percent (minimum)	45
Higher Heating Value, Btu/lb (minimum)	11,000
Sulfur, percent (maximum)	3.3

TABLE 3.3-2. WOOD WASTE PROPERTIES

Fuel Analysis	Typical
Heating Value, Btu/lb	6,791
Carbon, percent (dry basis)	50.11
Hydrogen, percent (dry basis)	6.08
Nitrogen, percent (dry basis)	0.26
Sulfur, percent (dry basis)	0.012
Chloride, percent (dry basis)	0.061
Oxygen, percent (dry basis)	41.67
Ash, percent (dry basis)	1.804
Moisture (as received)	34.89

the availability of sufficient fuel, would be approximately 66,000 tons per year for each steam generator.

It is estimated that each of the three steam generators will experience 5 cold and 12 hot startups per year during each year of operation. This will require 160,000 gallons of No. 2 fuel oil per year.

3.3.3 Fuel Transportation

The plant is being designed for coal to be delivered to the plant site by unit train railcars, as described in Section 6.3. For 90-car unit 3
trains, 120 trains per year or one train every three days will be required to supply the plant.

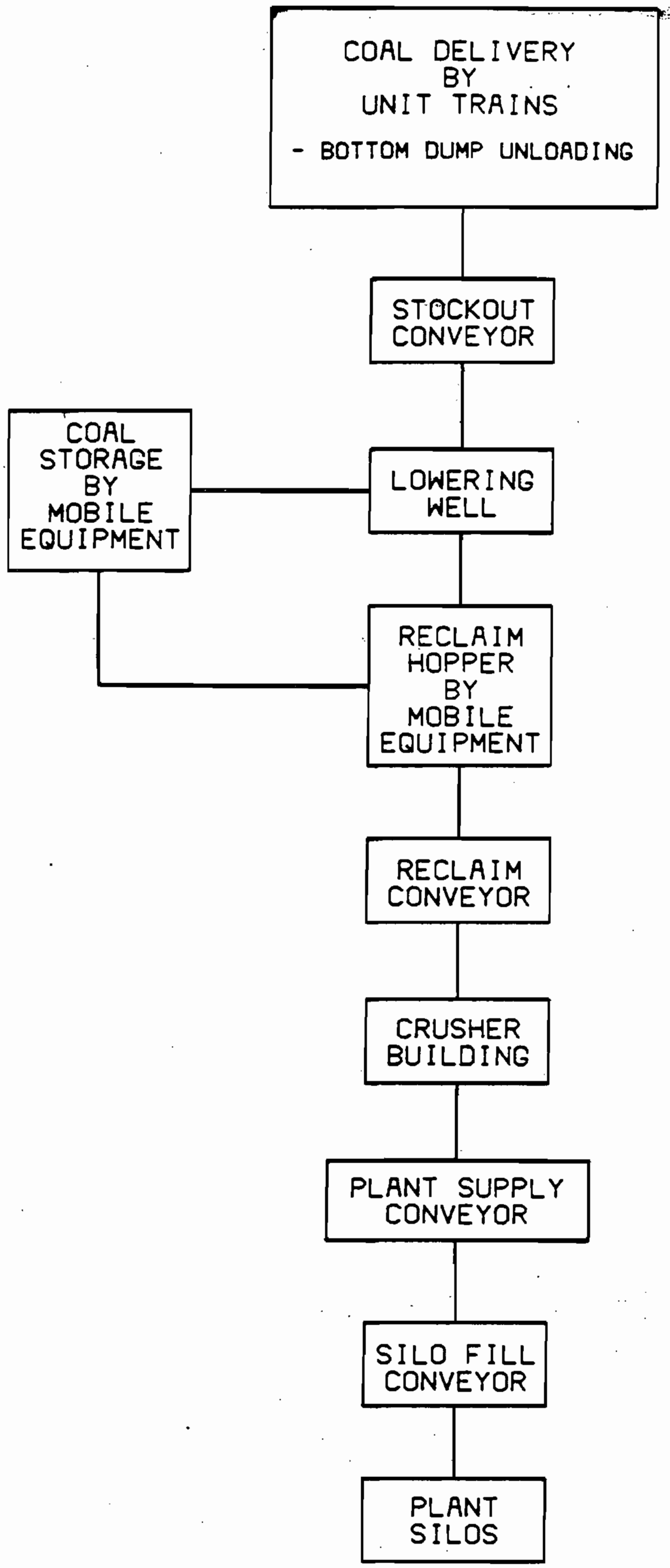
Fuel oil will be shipped to the plant by truck or rail, depending on the supplier.

3.3.4 Coal Handling and Storage

The coal handling system will consist of unloading, stocking, reclaiming, and storing. Figure 3.3-1 shows a schematic of the coal handling process and Figure 3.3-2 shows the layout of the coal handling facilities.

The railcar coal unloading system will employ an enclosed bottom dumping type facility designed for bottom dump railcars. 3

Bottom dump unloading will be accomplished by positioning the bottom dump railcars over the receiving hopper and opening the railcar hopper doors to unload the coal. Cars will be unloaded at a rate of 6 to 15 cars per hour. 3



COAL HANDLING PROCESS DIAGRAM

Figure 3.3-1

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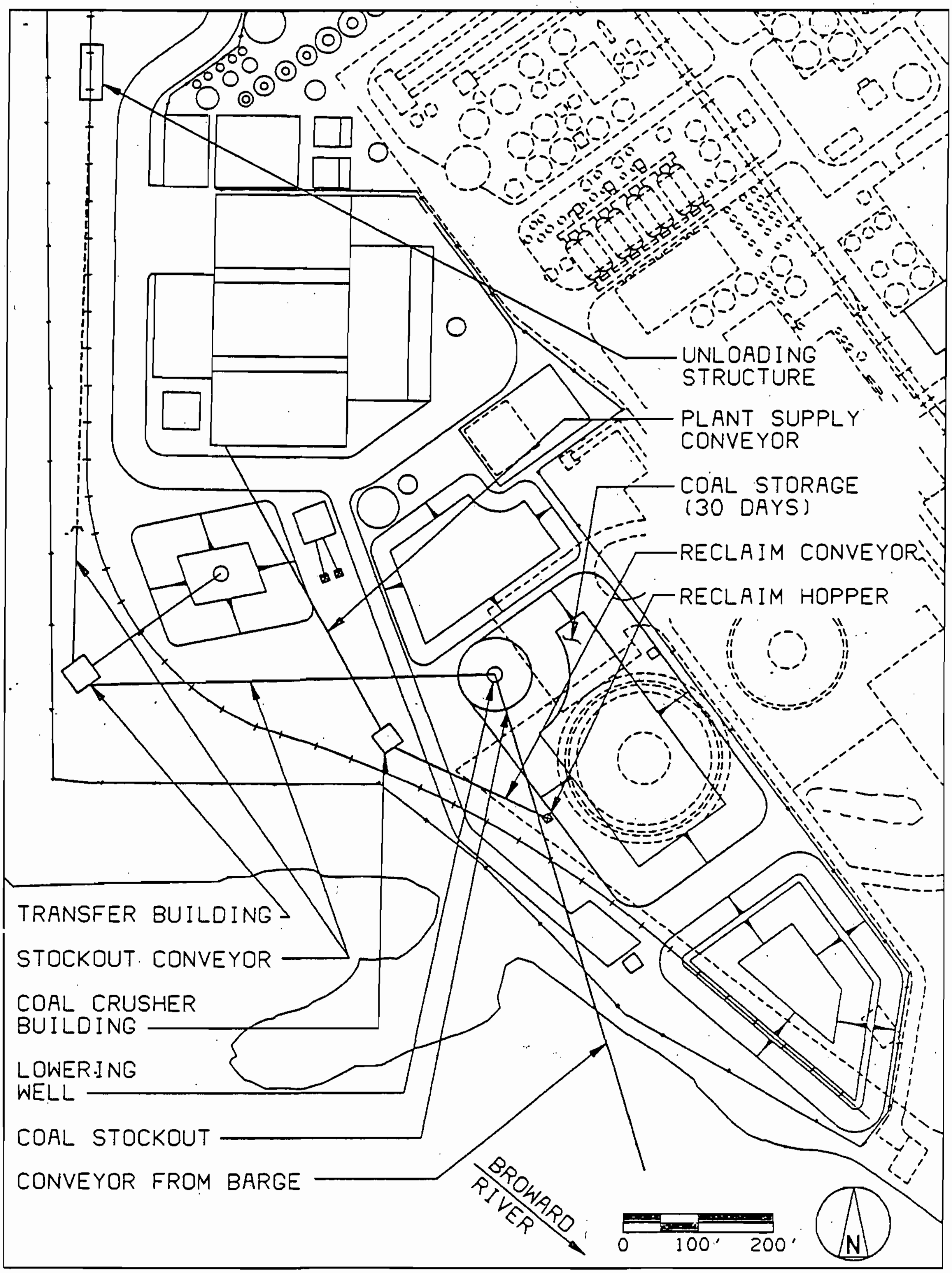

COAL HANDLING SITE PLAN

Figure 3.3-2

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Associated rail facilities and car marshalling are described in Section 6.3. 3

The coal stockout system for railcar unloading will consist of a conveyor loaded automatically from the receiving hopper. Coal will be conveyed to the coal storage lowering well which will allow for the discharging of coal through openings in the walls of the concrete structure. Mobile equipment will be used to transfer coal from the lowering well to the coal storage pile or the reclaim system.

The coal and ash storage areas will be lined with a synthetic material 2 placed over a prepared subgrade to minimize seepage of leachate into the ground water.

The coal storage area will consist of approximately 105,000 tons of coal and will be located north of the Steam Generation Building. The coal 2 storage will provide approximately 30 days of coal at the maximum burn rate of the power plant.

The coal reclaim system will consist of either mobile equipment to reclaim and load coal into an above grade hopper or an automatic reclaim system. The reclaim system will supply coal to a conveyor to the Coal Crusher Building. The discharge end of the conveyor will have a magnetic separator to remove tramp iron from the coal stream. The conveyor will also be equipped with a scale to provide inventory control of the coal storage system.

The coal crushing and silo fill system will crush the coal to an acceptable size and transport it by conveyor to the coal silos located in the Steam Generation Building. An as-fired coal sample will be taken prior to distribution of coal to the silos.

Fugitive dust associated with handling of coal will be controlled with enclosures, water sprays, compaction, and bag filter dust collection. Coal conveyors not underground or within enclosed buildings will have covers.

Conveyors will have loading skirts and head pulley enclosures with deck plate. Dust pickup hoods will be located at each material and conveyor transfer point to reduce fugitive dust.

The receiving structure will be provided with an enclosed superstructure. A dust collector will collect dust from the car discharge area inside the enclosure and from the conveying equipment beneath the track hopper.

The stockout lowering well will be a cylinderical concrete structure with rectangular openings staggered around the perimeter. Each opening will be equipped with a flop gate. When the coal reaches the level of an opening, the flop gate will open, allowing the coal to discharge to the pile with a short length of coal free fall. A top cover for the tower will minimize dust emission during coal stockout.

Water sprays will be used as required to reduce fugitive dust from the coal pile and mobile equipment operations. The coal pile will be compacted to reduce fugitive dust.

3.3.5 Fuel Oil Storage and Handling

The fuel oil, as received, will be unloaded and pumped to a storage tank. No. 2 fuel oil will be stored in a 60,000-gallon tank, located north of the main generating facilities. A spill-containment dike will be provided around the tank. Pumps located at the storage tank facility will supply fuel oil to the steam generator igniters in the main plant building.

3.3.6 Alternate Fuel Types

Design provisions have been included to allow the burning of wood waste in conjunction with coal up to a maximum of 10 percent wood on a Btu basis. Wood waste will be pneumatically conveyed from the bark storage area to two live bottom storage bins located at the Steam Generator Building. A drag chain conveyor will distribute the wood waste to the steam generator bark feed chutes.

3.4 AIR EMISSIONS AND CONTROL

3.4.1 Air Emission Types and Sources

The cogeneration project is subject to the permitting requirements of the Prevention of Significant Deterioration (PSD) program. PSD permit requirements apply because the net emissions increase of at least one regulated pollutant exceeds the "significant" levels defined by EPA and FDER. The air quality assessment for all applicable pollutants must meet PSD permit requirements including a Best Available Control Technology (BACT) determination.

Net pollutant emissions are determined by comparing emission rates of the proposed facility against those of the existing Seminole Kraft sources to be replaced. The replaced sources will be three power boilers (PB), two bark boilers (BB), three kraft recovery boilers (KRB), and three smelt dissolving tanks (SDT). An emissions inventory of these sources was compiled for the years 1978 through 1987. Although below the maximum capacity of the mill, the period 1983-1984 was found to be the most representative back-to-back years of normal operataing conditions. The 1979-1980 operating period was originally selected as the most representative operating period in the AES Power Plant Site Certification Application. However, additional examination of the mill's records determined that sharp increases in fuel costs during 1980-1981 had caused the plant to adjust fuel usage to minimize oil consumption and, as a result, reduced pulp production in 1982. 3
Therefore, a period after 1982 is more representative of current operations.

Limited plant operating hours in 1985 and 1987, and a plant shutdown in 1986 preclude the 1985-1987 data from further consideration. The operating conditions in 1983-1984 best represent normal plant operations as evidenced by pulp production rates and fuel oil usage rates. Thus, the 1983-1984 data will be used as representative of the normal operating condition at the existing pulp mill. These rates are shown in Table 3.4-1.

The 1983-1984 emissions are shown in Table 3.4-1a. The total actual emissions of the existing sources have been adjusted to represent the effect of recent control techniques and an imposed particulate emission limit. Specifically, the SDT emissions are adjusted to reflect a reduction

TABLE 3.4-1. PUMP PRODUCTION RATES AT SEMINOLE KRAFT (1979-1988)

Year	Pulp Production tons ADUP	Fuel Oil Burned 10^6 gallons
1979	464,198	36.5
1980	478,134	34.4
1981	441,520	34.5
1982	345,698	25.7
1983	410,238	25.5
1984	436,032	23.6
1985	273,614*	14.6
1986	Mill Shutdown	Mill Shutdown
1987	281,352*	24.9
1988	415,904	28.8

3

*Operational 9 months in year.

TABLE 3.4-1a. REPRESENTATIVE (1983-1984) EXISTING SEMINOLE KRAFT EMISSIONS (TONS PER YEAR)

Pollutant	PB	BB	KRB	SDT	Total
TSP	180.8	144.2	427.2	122.6	874.8
PM_{10}	128.4	125.5	320.5	109.7	684.1
SO_2	4,294	118.4	1,481	8.6	5,902
NO_x	807.3	393.4	321.1	—	1,522
CO	60.3	545.8	2,327	—	2,933
VOC	9.2	190.8	340.2	—	540.2
TRS	—	—	89.3	8.9	98.2

Legend: PB = Power boilers (3 total)
BB = Bark boilers (2 total)
KRB = Kraft recovery boilers (3 total) 3
SDT = Smelt dissolving tanks (3 total)
TSP = Total suspended particulate
PM_{10} = Particulate under 10 microns
SO_2 = Sulfur dioxide
NO_x = Nitrogen oxides
CO = Carbon monoxide
VOC = Volatile organic compounds
TRS = Total reduced sulfur
-- = Negligible amount

NOTES:

1. Totals may vary because of rounding.
2. Emissions reflect current operational configuration with adjustments made to actual data as discussed in Subsection 3.4.1.

in total reduced sulfur (TRS) due to the recent replacement of the vent filters in 1988. Also, the TSP emissions were adjusted to reflect the current particulate emission limit for the power boilers (See the Consent Order, Section 10.4.). The limiting standard for particulate emissions was 0.2 lb/MBtu during 1983 and 1984. The current limiting standard is 0.1 lb/MBtu. Since the operation of the mill's power boilers during 1983 3
and 1984 would not reflect operation in compliance with today's standard, the TSP emissions were adjusted. The adjusted emissions were computed by assuming the boilers emitted 0.1 lb/MBtu of TSP for the fuel use rates and operating hours in 1983 and 1984. The formula for calculation is as fol- 3
lows.

$$\text{TSP (tpy)} = \frac{\text{ABHI (MBtu/yr)} \times 0.1 \text{ (lb TSP/MBtu)}}{2{,}000 \text{ (lb/ton)}}$$

where

ABHI = actual boiler heat input for the year (1979 or 1980) based on fuel usage.

For particulates less than 10 microns in diameter (PM_{10}), the emissions are determined according to the percentage of total suspended particulate (TSP) given in EPA's Compilation of Emissions Factors (AP-42).

Short-term air quality modeling is based on the maximum allowable emission rates for the existing Seminole Kraft sources. These emission rates are determined from the available information included in operating permits. For any pollutant not included in the operating permit, the maximum allowable emission rate is calculated using maximum operating conditions (as specified in the permit) and AP-42 emission factors.

Table 3.4-2 summarizes the maximum expected emissions for the proposed facility. The Cedar Bay facility will consist of a cogeneration plant with three coal fired circulating fluidized bed boilers, a kraft recovery boiler, a smelt dissolving tank, a multiple effect evaporator, two limestone dryers, and various material handling operations. Emission estimates for the kraft 3
recovery boiler, smelt dissolving tank, multiple effect evaporator, and limestone dryers are based on the Cedar Bay facility operating at maximum

TABLE 3.4-2. MAXIMUM EXPECTED EMISSIONS FOR THE CEDAR BAY COGENERATION FACILITY (TONS PER YEAR)*

Pollutant	Cogen-eration Plant	Kraft Recovery Boiler	Smelt Dissolving Tank	Limestone Dryers	Multiple Effect Evaporator	Material Handling	Total**
Carbon Monoxide	2,468	2,167	--	1.63	—	—	4,637
Nitrogen Dioxide	4,676	1,618	--	6.54	—	—	6,301
Sulfur Dioxide	4,015	1,486	10	13.8	—	—	5,525
Particulate Matter	260	469	74.9	—	—	8	812
Particulate Matter (PM_{10})	257	351	67	—	—	8	683
Ozone (VOC)	208	248	--	0.06	—	—	456
Lead	91	0.21	--	0.0003	—	—	91.2
Arsenic	154	—	—	0.0002	—	—	154
Asbestos	—	—	--	—	—	—	—
Beryllium	1.5	0.016	--	0.03	—	—	1.5
Mercury	3.4	--	—	—	—	—	3.4
Vinyl Chloride	—	—	—	--	—	—	--
Fluorides	1,122	—	--	0.003	—	—	1,122
Radionuclides	***	—	—	—	—	—	**
Sulfuric Acid Mist	308	13.3	—	0.26	—	—	322
Total Reduced Sulfur	—	32.9	12	--	2	—	47
Polycyclic Organic Matter	30	6.7	--	—	—	—	36.7
Chlorine	0	14.3	1.2	0.022	—	—	607
Barium	1.5	—	--	0.0003	—	—	1.5
Zinc	35	—	—	0.0009	—	—	35
Vanadium	4.5	—	—	0.91	—	—	5.4
Cadmium	1.6	—	—	0.09	—	—	1.7
Nickel	49	—	--	0.13	—	—	49
Cobalt	18	—	--	0.0009	—	—	18
Chromium	33	1.0	0.01	0.0003	—	—	34
Copper	2.6	—	—	0.0009	—	—	2.6
Manganese	397	—	—	0.0009	—	—	397
Hydrogen Sulfide	—	25.1	9.7	—	—	—	34.8
Methyl Mercaptan	—	6.3	3.6	—	—	—	9.9
Hydrogen Chloride	591	0.7	0.06	0.022	—	—	591.8
Phosphorus	1,772	—	—	—	—	—	1,772
Phenol	30	—	—	—	—	—	30
Pyridine	30	—	—	—	—	—	30
Acetaldehyde	30	—	—	—	—	—	30
Acetic Acid	30	—	—	—	—	—	30
Formaldehyde	2.9	—	—	—	—	—	2.9

*Assumes 93 percent capacity factor for the Cogeneration Plant; 100 percent for all other sources.

**Totals may vary because of rounding.

***It is estimated that radionuclide emissions will be approximately 0.15 Ci/year.

— = Negligible amount.

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load for the entire year. The emission estimates for the fluidized bed boilers are based on a capacity factor of 93 percent. 3

Annual emissions listed in Table 3.4-2 are based on the following emission rates.

- Cogeneration plant.
  - -- Sulfur dioxide = 0.31 lb/MBtu (at least 90 percent removal). 3
  - -- Nitrogen oxides = 0.36 lb/MBtu.
  - -- Carbon monoxide = 0.19 lb/MBtu.
  - -- Particulate = 0.02 lb/MBtu.
  - -- VOC = 0.016 lb/MBtu.
- Kraft recovery boiler.
  - -- Sulfur dioxide = 120 ppmvd corrected to 8 percent oxygen. 3
  - -- Nitrogen oxides = 180 ppmvd corrected to 8 percent oxygen.
  - -- Carbon monoxide = 400 ppmvd corrected to 8 percent oxygen.
  - -- Particulate = 0.044 gr/dscf corrected to 8 percent oxygen. 3
  - -- TRS = 5 ppmvd corrected to 8 percent oxygen.
  - -- VOC = 80 ppmvd corrected to 8 percent oxygen.
- Smelt dissolving tank.
  - -- TRS = 0.032 lb/ton black liquor solids. 3
  - -- Particulate = 0.20 lb/ton black liquor solids.

Applicable new source performance standards (NSPS) and Best Available Control Technology (BACT) emissions are given in Table 3.4-2a for comparison. Estimated maximum annual emissions resulting from use of fuel oil (startup, shutdown, flame stabilization) are presented in Table 3.4-2b. 2

The material handling emissions are estimated using AP-42 fugitive dust emission factors and conservative assumptions. The fugitive dust emissions from this project are minimized by numerous dust control methods. These methods vary from wet suppression of the active storage piles (50 percent control) to full enclosure and dust collectors (99 percent control). To conservatively estimate the potential controlled emissions, minimum control efficiencies are assumed for each control method. For example, conveyor covers are reported to control 70 to 90 percent of the fugitive dust generated. Also, dust collectors are generally considered 99 to 99.9 percent efficient. For this project, the lower range control efficiencies, 70 and 99 percent, are assumed for conveyor covers and dust collectors. Table 3.4-3 shows the material consumption during worst-case conditions and typical material characteristics that are assumed.

Table 3.4-5 identifies the fugitive dust sources and their associated emissions at the Cedar Bay facility. This table shows that the dust con- 3
trol methods limit the fugitive dust emissions to approximately 8.0 tons per year or 1.8 pounds per hour. The major fugitive dust sources at the plant are the active coal storage pile (about 2.5 tons per year) and the coal crusher (about 1.8 tons per year). The fugitive dust from the active coal storage pile will be controlled by wet suppression to the pile. Controls for the coal crusher include enclosures and dust collection to a fabric filter baghouse.

TABLE 3.4-2a. EMISSION LIMITS FOR THE CEDAR BAY COGENERATION FACILITY

Pollutant	Circulating Fluidized Bed Boiler NSPS lb/MBtu	Circulating Fluidized Bed Boiler BACT lb/MBtu	Kraft Recovery Boiler NSPS lb/MBtu	Kraft Recovery Boiler BACT lb/MBtu	Smelt Dissolving Tank NSPS lb/MBtu	Smelt Dissolving Tank BACT lb/MBtu	Multiple Effects Evaporator NSPS lb/MBtu	Multiple Effects Evaporator BACT lb/MBtu
Carbon Monoxide	NA	0.19	NA	400 ppmvd @ 8% O_2	NA	NA	NA	NA
Nitrogen Dioxide	0.60	0.36	0.4	180 ppmvd @ 8% O_2	NA	NA	NA	NA
Sulfur Dioxide	0.60 70-90% Removal	*	NA	*	NA	NA	NA	NA
Particulate Matter	0.03	*	0.044 gr/dscf	*	0.2 lb/ ton BLS	NA	NA	NA
Particulate Matter (PM_{10})	0.03	*	0.044 gr/dscf	NA	0.2 lb/ ton BLS	NA	NA	NA
Ozone (VOC)	NA	*	NA	NA	NA	NA	NA	NA
Total Reduced Sulfur	NA	NA	5 ppmvd @ 8% O_2	*	0.033** lb/ton BLS	*	5 ppmvd @ 10% O_2	*

*No BACT required because of emission netting. (Not So)

**EPA limit; FDER limit is 0.032 lb/ton BLS (0.048 lb/3,000 lb BLS).

NA = Not Applicable.

ppmvd = parts per million dry volume.

dscf = dry standard cubic foot.

BLS = Black Liquor Solids.

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TABLE 3.4-3. FUGITIVE DUST EMISSION ASSUMPTIONS

Operational Parameters*		
Limestone Consumption (22.5 tph)	197,000 tpy	3
Coal Consumption (145 tph)	1,270,000 tpy	
Total Combustion Waste (41.3 tph)	361,800 tpy	3
Bed Ash	72,400 tpy	
Fly Ash	289,400 tpy	
Transfer points drop height, H	varies	
Material Characteristics		
Coal Silt Content, s (AP-42 mean)	6.2 percent	
Coal Surface Moisture, M (AP-42 mean)	6.9 percent	
Limestone Silt Content, s (AP-42 mean)	1.6 percent	
Limestone Moisture Content, M (AP-42 mean)	0.7 percent	
Combustion Waste Silt Content, s (AP-42 mean)	70 percent	
Combustion Waste Moisture Content, M (AP-42 mean)	2.0 percent	
Meteorological Parameters		
Wind Speed, U (mean)	9 mph	
Number of Days With Precipitation >0.01 in., p (mean)	116 days	
Percentage of Time Wind Speed >12 mph, f (mean)	18 percent	

*Assumes 100 percent capacity factor.

TABLE 3.4-4

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TABLE 3.4-5. MATERIALS HANDLING DUST EMISSIONS BASED ON RAIL CAR UNLOADING

No.	Source	Activity	Emission Equation	H	U	s	M	Y	Emission Factor	Use Rate	Uncontrolled Emissions	Control Method	Control Efficiency	Total Controlled Emissions	Point Source Emissions	Area Source Emissions
1	Rail Car Unloading	Bottom Drop (coal)	Batch Drop	10	9	6.2	6.9	148	0.0002 lb/t	1,270,000 ton/yr	0.11 ton/yr	Enclosure & Baghouse	99%	0.00 ton/yr		0.00 lb/hr
2	Belt Feeder	Coal Unloading	Continuous Drop	3	9	6.2	6.9		0.0001 lb/t	1,270,000 ton/yr	0.05 ton/yr	Enclosure & Baghouse	99%	0.00 ton/yr	0.00 lb/hr	
3	Conveyor 1	Coal Conveying	Conveying						0.0034 lb/t	1,270,000 ton/yr	2.16 ton/yr	Partial Underground and Covers	85%	0.32 ton/yr		0.07 lb/hr
4	Active Coal Pile	Coal Stockout (drop tower)	Continuous Drop	40	9	6.2	6.9		0.0010 lb/t	1,270,000 ton/yr	0.66 ton/yr	Drop Tower	75%	0.17 ton/yr		0.04 lb/hr
		Coal Reclaim	Batch Drop	5	9	6.2	6.9	10	0.0002 lb/t	1,270,000 ton/yr	0.13 ton/yr	None	0%	0.13 ton/yr		0.03 lb/hr
		Wind Erosion	Wind Erosion			6.2			8.9343 lb/ac/day	3 acres	4.89 ton/yr	Wet Suppression	50%	2.45 ton/yr		0.56 lb/hr
5	Limestone Pile	Limestone Stockout (truck)	Batch Drop	5	9	1.6	0.7	30	0.0036 lb/t	197,000 ton/yr	0.36 ton/yr	None	0%	0.36 ton/yr		0.08 lb/hr
		Limestone Reclaim	Batch Drop	5	9	1.6	0.7	7	0.0059 lb/t	197,000 ton/yr	0.58 ton/yr	None	0%	0.58 ton/yr		0.13 lb/hr
		Wind Erosion	Wind Erosion			1.6			2.3056 lb/ac/day	0.75 acres	0.32 ton/yr	Wet Suppression	50%	0.16 ton/yr		0.04 lb/hr
6	Coal Crusher Dust Collector	Coal Crushing	Stone Crushing						0.28 lb/t	1,270,000 ton/yr	177.80 ton/yr	Enclosure & Baghouse	99%	1.78 ton/yr	0.41 lb/hr	
7	Pulverizer Vent Dust Collector	Limestone Crushing	Stone Crushing						0.28 lb/t	197,000 ton/yr	27.58 ton/yr	Enclosure & Baghouse	99%	0.28 ton/yr	0.06 lb/hr	
8	Conveyor 2	Coal Conveying	Conveying						0.0034 lb/t	1,270,000 ton/yr	2.16 ton/yr	Covers	70%	0.65 ton/yr		0.15 lb/hr
9	Belt Transfer Structure #1	Coal Belt Transfer	Continuous Drop	3	9	6.2	6.9		0.0001 lb/t	1,270,000 ton/yr	0.05 ton/yr	Enclosure & Baghouse	99%	0.00 ton/yr	0.00 lb/hr	
10	Generation Building	Plant Coal Silo	Continuous Drop	40	9	6.2	6.9		0.0010 lb/ton	1,270,000 ton/yr	0.66 ton/yr	Enclosure & Baghouse	99%	0.01 ton/yr	0.00 lb/hr	
		Plant Limestone Hopper	Continuous Drop	40	9	1.6	0.7		0.0261 lb/ton	197,000 ton/yr	2.57 ton/yr	Enclosure & Baghouse	99%	0.03 ton/yr	0.01 lb/hr	
11	Fly Ash Reinjection Surge Bin	Fly Ash Surge Bin Fill	Continuous Drop	20	9	70	2		0.0699 lb/ton	289,400 ton/yr	10.11 ton/yr	Enclosure & Baghouse	99%	0.10 ton/yr	0.02 lb/hr	
12	Bed Ash Hopper	Bed Ash Hopper Fill	Continuous Drop	20	9	70	2		0.0699 lb/ton	72,400 ton/yr	2.53 ton/yr	Displacement Air Filter	90%	0.25 ton/yr	0.06 lb/hr	
13	Ash Silo Filters	Fly and Bed Ash Silo Fill	Continuous Drop	40	9	70	2		0.1397 lb/ton	361,800 ton/yr	25.27 ton/yr	Enclosure & Baghouse	99%	0.25 ton/yr	0.06 lb/hr	
14	Common Feed Hopper	Common Feed Hopper Fill	Continuous Drop	20	9	70	2		0.0699 lb/ton	361,800 ton/yr	12.64 ton/yr	Enclosure & Baghouse	99%	0.13 ton/yr	0.03 lb/hr	
15	Ash Conditioning Unloader	Combustion Waste Unloading	Continuous Drop	10	9	70	2		0.0349 lb/ton	361,800 ton/yr	6.32 ton/yr	Enclosure & Baghouse	99%	0.06 ton/yr		0.01 lb/hr
													TOTAL	7.69 ton/yr	0.64 lb/hr 0.08 g/sec	1.11 lb/hr 0.14 g/sec

Parameters
- H = material drop height, ft
- M = material moisture content, percent
- s = material silt content, percent
- U = mean wind speed, mph
- Y = material silt content, percent

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Table 3.4-6 compares the existing pollutant emissions with the proposed facility's emissions and establishes the net emissions (existing minus proposed). EPA's significant emission rate criteria are also included in Table 3.4-6 to determine pollutant applicability with regards to PSD permitting requirements. The finalization of a long-term coal contract has led to the proposed use of coal with a sulfur content reduced from that presented in the initial SCA. This lower percentage of sulfur will 3
actually reduce the existing facility-wide SO_2 emissions by 377 tons per year. Table 3.4-6 indicates that sulfur dioxide (SO_2), total suspended particulate (TSP), total reduced sulfur (TRS), PM_{10}, and volatile organic compounds (VOC) will "net out" and, therefore, will not be subject to the requirements of the PSD program (including BACT) or nonattainment review for TSP and VOC. The other criteria pollutants, carbon monoxide (CO), lead 3
(Pb), and nitrogen oxides (NO_x) will not net out and, therefore, exceed the applicable pollutant significance levels. These pollutants will require a BACT determination (Subsection 3.4.3) and an appropriate air quality impact assessment. The air quality impact assessment is described in Section 5.6.

3.4.2 Air Emission Controls

A circulating fluidized bed boiler (CFB) with limestone injection and appropriate combustion controls, followed by a fabric filter, will be used to control NO_x and remove SO_2 and particulate to levels well below New 3
Source Performance Standards. Other criteria and noncriteria pollutants will be controlled consistent with flue gas desulfurization (FGD) and particulate removal systems.

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.

TABLE 3.4-6. SIGNIFICANT AND NET EMISSION RATES (TONS PER YEAR)

Pollutant	Significant Emission Rates	Existing Emissions	Proposed Maximum Emissions*	Net Emissions	Applicable Pollutant	
Carbon Monoxide	100	2,933	4,637	1,704	Yes	
Nitrogen Oxide	40	1,522	6,301	4,779	Yes	
Sulfur Dioxide	40	5,902	5,525	-377	No	
Particulate Matter	25	875	812	-63	No	3
Particulate Matter (PM_{10})	15	684	683	-1	No	
Ozone (Volatile Organic Compounds)	40	540	456	-84	No	
Lead	0.6	--	91	91	Yes	
Asbestos	0.007	--	<0.007	<0.007	No	
Beryllium	0.0004	--	1.5	1.5	Yes	3
Mercury	0.1	--	3.4	3.4	Yes	
Vinyl Chloride	1.0	--	<1.0	<1.0	No	
Fluorides	3	--	1,122	1,122	Yes	
Sulfuric Acid Mist	7	--	322	322	Yes	
Total Reduced Sulfur	10	98	47	-51	No	3

*Assumes 100 percent capacity factor for Kraft recovery boiler, smelt dissolving tank, limestone dryers, and multiple effects evaporator. Assumes 93 percent capacity factor for cogeneration plant.

3.4.3 Best Available Control Technology Analysis Summary

The following is a summary of results from the BACT analysis. The complete analyses for the cogeneration plant and the Kraft recovery boiler are contained in Sections 10.8 and 10.9.

- The pollutant applicability analysis contained in Subsection 3.4.1 concluded that the criteria pollutants--NO_x, CO, and 3 lead--require a BACT analysis. The noncriteria pollutants--beryllium, mercury, fluoride, and sulfuric acid mist--also re- 3 quire 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.

3.4.3.1 Cogeneration Plant.

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- CFB boilers have lower NO_x emission levels (0.36 lb/MBtu) as compared to pulverized coal fueled boilers. 3 A CFB boiler should be capable of meeting a CO emission rate of 0.19 lb/MBtu while meeting a NO_x emission limit of 0.36 lb/MBtu. 3
- Selective catalytic reduction (SCR), and selective noncatalytic reduction (SNCR) NO_x emission control technologies are the only 3 technologies adequately demonstrated to be considered for installation. Problems presented by the use of these systems include 3 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. 3 Despite limited experience and technical problems, a technical and economic analysis was performed for thoroughness of analysis.
- Installation of a 90 percent efficient SCR system on a CFB boiler would result in an incremental NO_x reduction cost of $6,800 per ton. 2 3 Installation of a 60 percent efficient SNCR system would result in an incremental NO_x reduction cost of $1,400 per ton. 2 3

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- Consideration of environmental factors also supports the selection of combustion controls as BACT for NO_x. Use of a SCR or a 3 SNCR 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.
- BACT regarding applicable noncriteria pollutants is accomplished as a result of flue gas desulfurization and particulate removal 3 operations.

3.4.3.2 <u>Kraft Recovery Boiler</u>. 3

- Low combustion temperatures and staged combustion inhibit the formation of NO_x in KRB. Manufacturers indicate that current KRB designs can consistently meet a NO_x emission requirement of 180 ppmvd corrected to 8 percent oxygen (approximately 0.34 lb/ MBtu) when burning black liquor solids.

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- 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. 2
- 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.

3.4.4 Design Data for Control Equipment

Control equipment design data are included as part of the detailed BACT analyses contained in Sections 10.8 and 10.9.

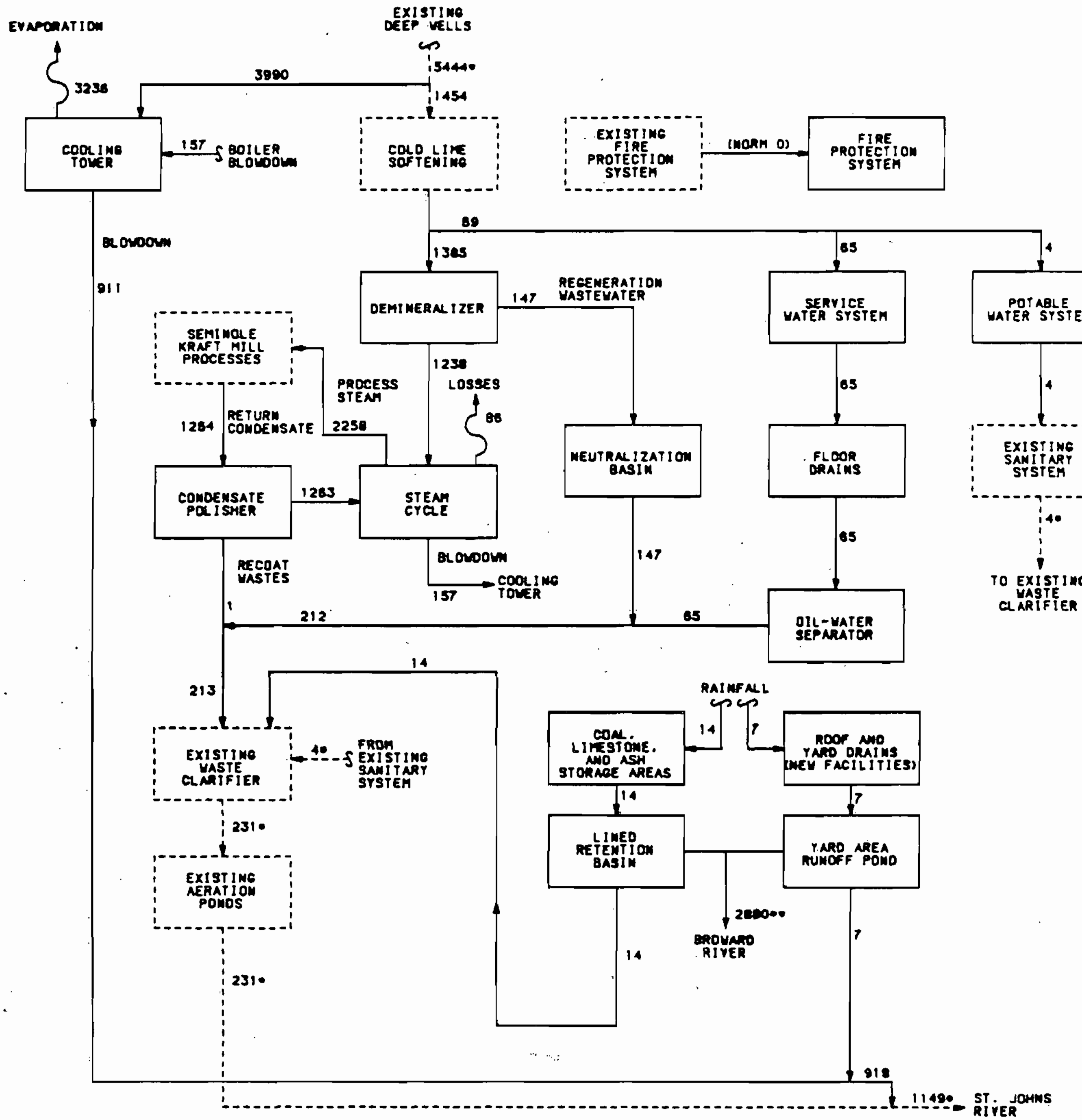
3.4.5 Design Philosophy

In general, air quality control system designs are determined based on conservative design parameters. Parameters are developed to ensure adequate performance to equal or better emission requirements. Where necessary, adequate spares are provided to ensure the operating reliability of the plant. Specific details of the design philosophy can be found in the detailed BACT analyses contained in Sections 10.8 and 10.9.

3.5 PLANT WATER USE

The primary source of water for the Cedar Bay Cogeneration Plant will be ground water from the Floridan aquifer. Most of the water will be used as makeup to the cooling towers. The remainder will be used for potable water, general plant uses, fire water, and makeup to the steam cycle. A water mass balance for average flows based on full load operation is shown on Figure 3.5-1.

The well water will be obtained from the existing Seminole Kraft Cororation well field. Makeup to the cooling towers will be untreated.



NOTES:

1. FLOWS ARE ESTIMATED ANNUAL AVERAGES EXPRESSED IN 1000 GALLONS PER DAY FOR 100 PERCENT LOAD.
2. SOLID LINES REPRESENT NEW EQUIPMENT OR PIPELINES.
3. DASHED LINES REPRESENT EXISTING EQUIPMENT OR PIPELINES.

* AMOUNT OF FLOW ATTRIBUTABLE TO CEDAR BAY COGENERATION PROJECT

** CONSTRUCTION DEWATERING. FLOW WILL OCCUR ONLY DURING CONSTRUCTION.

WATER MASS BALANCE
WELL WATER C. T. MAKEUP

Figure 3.5-1 | 1

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Water for all other plant uses will be treated by lime softening and filtration in the existing Seminole Kraft Corporation pretreatment system. The anticipated qualities of the raw and treated well water are shown in Table 3.5-1.

When the Cedar Bay Cogeneration Plant goes into service, the existing Seminole Kraft Corporation power boilers, bark boilers, and kraft recovery boilers will be taken out of service. As a result, the existing once-through cooling system will no longer discharge 30,000 gallons per minute of heated water to the St. Johns River.

3.5.1 <u>Heat Dissipation System (Cooling Tower)</u>

The major use of water by the proposed project will be for heat dissipation. Plant waste heat will be rejected to the atmosphere in a circulating water system using mechanical draft cooling towers. The rejection of waste heat from the steam cycle requires the evaporation of large amounts of water which must be replaced by makeup. To maintain the cooling tower water quality, blowdown is required to remove dissolved solids. Makeup is also required to replace blowdown losses. The majority of the makeup will be well water. Boiler blowdown will be routed to the cooling tower to supply a small portion of the makeup.

3.5.1.1 <u>System Design</u>. The circulating water system consists of a power cycle condenser, kraft recovery cycle condenser, evaporator condenser, cooling towers, circulating water pumps, and supply and return circulating water piping.

The condensers will be single pressure, single shell, surface condensers. The condensers will be designed to operate under maximum conditions under the parameters listed in Table 3.5-2.

In addition to the surface condenser, an auxiliary cooling system for equipment cooling will be located in the Generation Building. This system consists of two water-to-water heat exchangers and receives cooling water from the circulating water system at the rate of approximately 12,500 gpm.

The cooling towers will be rectangular, mechanical draft, counterflow cooling towers. The following are preliminary design conditions for the cooling towers.

TABLE 3.5-1. ANTICIPATED RAW WELL WATER AND TREATED WATER ANALYSES

Constituent	Raw Well Water	Treated Well Water*
Calcium, mg/l as $CaCO_3$	160	35
Magnesium, mg/l as $CaCO_3$	110	99
Sodium, mg/l as $CaCO_3$	42	42
Potassium, mg/l as $CaCO_3$	1	1
M-Alk, mg/l as $CaCO_3$	173	37
Sulfate, mg/l as $CaCO_3$	100	100
Chloride, mg/l as $CaCO_3$	39	39
Nitrate, mg/l as $CaCO_3$	1	1
SiO_2, mg/l as SiO_2	33	33
Iron, mg/l as Fe	0.06	0

*Treatment by cold lime softening.

TABLE 3.5-2. CONDENSER DESIGN PARAMETERS

	Power	Recovery	Evaporator
Condenser Surface Area, sq ft	140,000	35,000	70,000
Circulating Water Flow, gpm	122,500	27,500	28,200
Tube Material	304 SS	304 SS	304 SS
Tubesheet Material	Carbon	Carbon Steel	Carbon Steel Steel
Circulating Water Inlet Temperature, F	93	93	93
Maximum Heat Rejection, Btu/h	950×10^6	195×10^6	280×10^6

- Circulating water flow--200,000 gpm.
- Tower approach--11 F.
- Tower range--16 F.
- Wet-bulb temperature--82 F.
- Relative humidity--76 percent.
- Maximum heat rejection--1,520 by 10^6 Btu/h.

The expected cooling tower evaporation rate at 100 percent load conditions will be approximately 2,250 gpm. The estimated maximum makeup rate for the cooling system at 100 percent load is 2,880 gpm.

The predicted makeup water quality should allow the cooling tower to operate at 4.6 cycles of concentration. The estimated quality of the circulating water is shown in Table 3.5-3. Based on the 4.6 cycles of concentration, maximum blowdown will be approximately 633 gpm. Blowdown will be from the cold side of the cooling tower with a maximum expected temperature of approximately 95 F. Cooling tower blowdown will be discharged via the 1
existing Seminole Kraft discharge pipeline to the St. Johns River. 3

3.5.1.2 Source of Cooling Water. The water for use in the heat dissipation system will be primarily ground water from the Floridan aquifer. The well water will not be treated before use as cooling tower makeup. The expected makeup water quality is shown in Table 3.5-3. Existing Seminole Kraft water supply wells will be used to supply the well water needs of the new facilities. The wells are approximately 1,400 feet deep, and are located on the site as shown on Figure 2.3-23.

A small portion of the makeup will be obtained by routing blowdown water from the boilers to the cooling towers.

3.5.1.3 Dilution System. The circulating water system at the Cedar Bay Cogeneration Plant will not use a dilution system.

3.5.1.4 Blowdown, Screened Organisms, and Trash Disposal. An existing outfall structure located in the St. Johns River is currently used to discharge effluent from the Seminole Kraft mill. Cooling tower blowdown will be discharged to the St. Johns River via this outfall. The location of the outfall structure is shown on Figure 3.2-3.

TABLE 3.5-3. ANTICIPATED RAW WELL WATER AND CIRCULATING WATER ANALYSES

Constituent	Raw Well Water	Circulating Cooling Water*
Calcium, mg/l as $CaCO_3$	160	728
Magnesium, mg/l as $CaCO_3$	110	500
Sodium, mg/l as $CaCO_3$	42	150
Potassium, mg/l as $CaCO_3$	1	5
M-Alk, mg/l as $CaCO_3$	173	100
Sulfate, mg/l as $CaCO_3$	100	1,142
Chloride, mg/l as $CaCO_3$	39	191
SiO_2, mg/l as SiO_2	33	150
Iron, mg/l as Fe	0.06	0.3

*Assumes pH controlled to approximately 7.0 to 7.5 through the addition of sulfuric acid and organic phosphate feed as a scale inhibitor.

Since the Cedar Bay Cogeneration Plant will use only well water as its raw water source, there will be no screened organisms or trash for disposal.

3.5.1.5 Injection Wells. Injection wells will not be used at the Cedar Bay Cogeneration Plant.

3.5.2 Domestic/Sanitary Wastewater

Domestic/sanitary wastewater flow is assumed equivalent to the potable water usage described in Subsection 3.5.3. This wastewater will be treated in the existing Seminole Kraft sanitary system.

3.5.3 Potable Water Systems

Potable water uses at the cogeneration plant will include sanitary water for drinking, washing, and for toilets. Potable water for the plant will be well water treated by the existing Seminole Kraft pretreatment system and then chlorinated prior to use. The annual average expected potable water usage is 4,100 gpd (3 gpm) based on an average plant staff of 75 people and an average potable water requirement of 55 gallons per capita per day.

3.5.4 Process Water Systems

3.5.4.1 Makeup Demineralizer System. Other than cooling water, the major use for water in the new facility will be for demineralized water makeup to the boiler/turbine/condenser cycles. These cycles will produce steam for power generation and Seminole Kraft uses, and will replace the existing Seminole Kraft boilers.

Demineralized makeup water is required to replace water lost to Seminole Kraft process steam uses, boiler blowdown, and miscellaneous steam losses. Blowdown is necessary to maintain a low dissolved solids content in the boilers. Well water, softened and filtered in the Seminole Kraft pretreatment system, will be demineralized in three ion exchange demineralizer trains. Each train will consist of four exchangers: a primary cation exchanger, a primary anion exchanger, a secondary cation exchanger, and a secondary anion exchanger. The demineralizer ion exchange vessels will be regenerated with dilute solutions of sulfuric acid and sodium hydroxide. The resulting regenerant waste streams will be routed to the neutralization basin for pH adjustment and then to the existing Seminole Kraft waste clarifier as described in Subsections 3.6.4 and 3.7.2. The regenerant wastewater is not suitable for reuse because of its high dissolved solids content.

3.5.4.2 Condensate Polishing. A portion of the steam produced for Seminole Kraft uses will be returned as condensate. This condensate will be polished using a powdered resin type condensate polishing system for removal of dissolved and suspended solids before it is returned to storage for use in the steam cycles. The condensate polisher recoat wastewater will consist of condensate quality water containing the spent powdered resin. This wastewater contains high suspended solids, is not suitable for reuse, and will be directed to the existing Seminole Kraft waste clarifier for treatment.

3.5.4.3 Service Water. General water requirements including water seals, cleaning, and flushing will be provided by the service water system. Service water requirements are expected to average 45 gpm and will be supplied from the existing Seminole Kraft pretreatment system.

3.5.4.4 Fire Water. The fire water system will be an extension of the existing Seminole Kraft fire water system.

3.5.4.5 Ash Pelletizing. A maximum of approximately 150 to 160 gpm of water during an eight-hour period each day will be required to pelletize the combustion ash before disposal. This results in an average requirement 3
of approximately 75,000 gpd. Project makeup water from the well system will be used for this purpose.

3.5.4.6 Plant Drains. Separate collection systems will be used to collect chemical wastewater and miscellaneous plant wastewater. Chemical wastewater piping will be constructed of chemical resistant materials and will be routed to the neutralization basin. Miscellaneous floor drains will be directed to an oil separator and then routed to the existing Seminole Kraft waste clarifier.

3.5.4.7 Coal, Limestone, and Ash Area Runoff. Surface runoff from the coal, limestone, and ash storage areas will be collected in the fuel storage area runoff pond as discussed in Section 3.8. The combined runoff will then be routed to the existing Seminole Kraft waste clarifier as described in Subsection 3.6.9.

3.5.4.8 Existing Wastewater Treatment Facility. The Cedar Bay Cogeneration Plant will utilize the Seminole Kraft Corporation's existing wastewater treatment facility for treatment of demineralizer regeneration wastewater, condensate polisher regeneration wastewater, miscellaneous plant drains wastewater, and coal, limestone, and ash area runoff. The existing equipment consists of a clarifier followed by aeration ponds. The facility has a daily average discharge limitation of 7,840 lb/day of BOD_5 and 15,860 lb/day of suspended solids. The discharge pH is limited to between 6.0 and 9.0. Wastewater from the Cedar Bay Cogeneration Plant routed to the wastewater treatment facility is expected to average 231,000 gallons per day of flow, 75 lb/day of suspended solids, and 20 lb/day of BOD_5. The peak flow, which will occur during heavy rainfall periods, is expected to be 624,000 gallons per day. Since existing less efficient demineralizers and boilers are being retired, the average Cedar Bay Cogeneration Plant wastewater flow is expected to be offset by a decrease in wastewater from existing facilities.

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3.5.5 Water Use Variations

All water requirements discussed in the preceding sections are based on full load operation of the plant. When the plant operates at less than full load, the evaporation rate from the cooling towers, and hence the cooling tower makeup and blowdown rates, decreases proportionately. Since the major use of water for the plant is for cooling tower makeup, a decrease in plant operating capacity would mean a substantial decrease in overall plant water use. Demineralized water makeup requirements will decrease somewhat at less than full operating load, but not to the same degree as the cooling tower needs because a large portion of the makeup is for replacement of steam lost to Seminole Kraft process uses. The balance of plant water uses will be essentially independent of plant operating load.

In the case of prolonged plant shutdown, the cooling system will also be shut down and no makeup will be required. The other water requirements (demineralizer, equipment cleaning, etc.) may increase somewhat.

3.6 CHEMICAL AND BIOCIDE WASTE

The principal uses of chemicals and biocides at the proposed project will be for cooling tower circulating water quality control, steam cycle water quality control, sanitary wastewater treatment, makeup water demineralization, return condensate polishing, chemical cleaning of the boiler and preboiler cycle piping systems, and miscellaneous chemical drains.

3.6.1 Cooling Tower Circulating Water Treatment

The circulating water will be treated with chemicals to protect the system and to prevent excessive scaling and corrosion. Sulfuric acid will be added at the cooling tower basin to reduce alkalinity and to control the scaling tendency of the circulating water system. The estimated maximum use of sulfuric acid will be 5,112 pounds per day based on maximum load conditions and expected water quality. Control of sulfuric acid feed will be in proportion to the makeup water flow with a pH bias. Sulfuric acid reacts with alkalinity present in the well water to produce a circulating water in the desired pH range (7.0 to 8.0). To further inhibit scale deposition, an organic phosphate type scale inhibitor will be automatically fed at the cooling tower basin as a sequestering agent. The estimated maximum use of scale inhibitor based on maximum load conditions is 152 pounds per day as product. Scale inhibitor will be fed automatically on the basis of blowdown flow. The sulfuric acid and organic phosphate will be stored in tanks located in a curbed area beside the cooling towers. The curbed areas will be routed to the neutralization basin.

To prevent biofouling of the circulating water system, intermittent shock chlorination will be used. A chlorine solution will be fed into the circulating pump basin through diffusers. The estimated average usage of chlorine will be 493 pounds per day based on a feed rate of 5 mg/l for a total period of one hour per day.

Dechlorination of the cooling tower blowdown will be practiced to preclude discharge of residual chlorine in excess of discharge limits to the St. Johns River. Sulfur dioxide or sodium sulfite will be fed to the blowdown for dechlorination. The estimated use of sodium sulfite is approximately 2.3 pounds per day. If sulfur dioxide is used, the estimated usage will be approximately 1.1 pounds per day.

3.6.2 Steam Cycle Water Treatment

The steam cycle water will be treated with an oxygen scavenger, such as hydrazine, for dissolved oxygen control and with an amine, such as ammonia, for pH control. Sodium phosphate may also be fed to the cycle. Residual phosphate will react with calcium hardness in the boiler to form a nonadherent precipitate. The oxygen scavenger, amine, and sodium phosphate will be stored in the Generation Building. Estimated maximum usages are 8.6 pounds per day of hydrazine and 17.2 pounds per day of ammonia, based on maximum load conditions. The estimated sodium phosphate usage will be approximately 3.9 pounds per day. Boiler blowdown will be reused by routing to the cooling towers for use as makeup.

3.6.3 Sanitary Wastewater Treatment

The sanitary wastewater produced by the plant will be routed to the existing sanitary facilities at the Seminole Kraft Corporation. The annual average expected flow of sanitary wastewater is 4,100 gpd (3 gpm) based on an average plant staff of 75 people and an average requirement of 55 gallons per capita per day. The average expected biological loading is 5.6 pounds of BOD_5 per day, based on 0.075 pound of BOD_5 per capita per day.

3.6.4 Makeup Water Demineralization

As discussed in Section 3.5.4, the makeup water to the steam cycle will be demineralized using three ion exchanger type demineralizer trains. The demineralizer system will use sulfuric acid for cation resin regeneration and sodium hydroxide for anion resin regeneration. The sulfuric acid and sodium hydroxide will be stored in tanks located in or adjacent to the Water Treatment Building. The use of these chemicals will be on an intermittent basis dependent on demineralizer operation. Based on the maximum plant capacity and makeup requirements, the estimated usage rate for 66 degree Baumé sulfuric acid will be 5,660 pounds per day, and the rate of 100 percent sodium hydroxide will be 4,717 pounds per day. The wastes from this system will be regenerant water containing unreacted sulfuric acid and caustic plus sodium and sulfate salts of the ions removed from the ion exchange resins during regeneration. The estimated regenerant waste flow will average 147,000 gpd based on maximum load conditions. These wastes will be routed to the neutralization basin for pH adjustment and then to the existing Seminole Kraft waste clarifier.

3.6.5 Return Condensate Polishing

A powdered resin type condensate polishing system will be used to remove both suspended and dissolved solids from the process condensate being returned from the Seminole Kraft mill. The wastes from this system will consist of condensate quality water containing the spent powdered resin. The production of these wastes will be on an intermittent basis and will depend on the quality and quantity of the condensate being returned. The estimated wastewater flow will average 730 gpd. This wastewater, which contains high suspended solids, is not suitable for reuse within the water system and will be routed to the existing Seminole Kraft waste clarifier.

3.6.6 Metal Cleaning 2

The steam generator and preboiler cycle piping will be chemically cleaned initially during commissioning and also periodically during the life of the plant. The chemicals used will not be stored onsite and will be administered by means of a temporary system. The chemical cleaning solutions to be used for acid and alkaline cleaning of the boiler will be somewhat dependent on the boiler manufacturer selected. The actual cleaning solutions used must be consistent with the boiler manufacturer's recommendations. Chemicals typically used in boiler and preboiler cleaning include the following.

- Inhibited hydrochloric acid.
- Ammonia bifluoride.

- Hydroxyacetic acid.
- Formic acid.
- Disodium phosphate.
- Trisodium phosphate.
- Soda ash.
- Nonfoaming wetting agents.
- Foam inhibitors.

Wastewaters will consist of the cleaning solutions and material re-
moved during the cleaning process. Since cleaning the metal piping is an 2
infrequent maintenance operation, it does not contribute to the liquid
wastes produced by the normal operation of the plant. The preoperational
chemical cleaning wastes are estimated to be approximately 180,000 gallons,
with subsequent acid cleaning resulting in an estimated additional 105,000
gallons for each cleaning operation. The chemical cleaning contractor will
be required to haul offsite and properly dispose of the wastes resulting
from chemical cleaning which have metal concentrations in excess of the
requirements of 40 CFR Part 423 for new sources. Chemical cleaning wastes
that meet the requirements of 40 CFR Part 423 for new sources will be
routed to the Seminole Kraft wastewater treatment facility.

Nonchemical metal cleaning wastes will result from periodic washing of
the boiler firesides and air preheaters. The frequency of these cleaning
operations will be a function of the cleanliness of the equipment and will
be determined once the plant is in operation. The air preheater wash water 2
and the boiler fireside wash water will contain dissolved and suspended
solids. It is anticipated that both fireside wash water and air preheater
wash water will tend to be basic because of the injection of limestone into
the fluidized bed boiler and the resulting reaction of sulfur with the
limestone to form calcium sulfate. Because the wash waters will not be
acidic, the metal content of the wash waters will be minimal. Nonchemical
cleaning wastes will be routed to a neutralization basin for pH adjustment
and then to the Seminole Kraft wastewater treatment facility.

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3.6.7 Miscellaneous Chemical Drains

Chemical wastewater can result from draining a chemical storage tank, overflowing a chemical tank during a filling operation, or from maintenance operations such as hosing down chemical storage areas. These wastes will be routed to the neutralization basin via the chemical drains system. Flows from the miscellaneous chemical drains will be intermittent and will not normally contribute to the wastewater flows.

3.6.8 Neutralization Basin

A neutralization basin of approximately 150,000 gallons capacity will be provided for treatment of chemical wastes prior to their ultimate disposal. A basin of this capacity will be sufficient to accommodate the wastewaters produced during regeneration of the makeup demineralizer. The neutralization basin will be a reinforced concrete basin lined with chemical resistant membrane, brick, and mortar. A chemical waste mixer, mounted on a walkway spanning the basin, will be provided to hasten pH adjustment of the chemical wastes. Sulfuric acid and sodium hydroxide, as required for neutralization, will be available from the makeup demineralizer regeneration equipment. The pH adjusted chemical wastewaters will be transported to the existing Seminole Kraft waste clarifier.

3.6.9 Coal, Limestone, and Ash Storage Areas Runoff Treatment

The runoff water from the coal pile, limestone pile, and ash pelletizer areas will be collected in a lined retention basin as discussed in Section 3.8. The retention basin will allow for settling of suspended solids and flow equalization. Runoff water will then be pumped to the existing Seminole Kraft waste clarifier.

3.7 SOLID AND HAZARDOUS WASTE

3.7.1 Solid Waste

The combustion byproducts generated by the Cedar Bay Cogeneration Project will consist of fly ash and bed ash. This material will be disposed of by the coal supplier at an approved disposal location outside of the state of Florida or sold within the building materials industry. The quantities of waste produced will depend on the properties of the coal and limestone used in the combustion process. The following quantities are based on the typical properties of the design-basis coal.

The fly ash will be collected by a fabric filter. The estimated production of fly ash is 336,000 tons per year. The fly ash will be conveyed by an enclosed vacuum transport system from the fabric filter hoppers to the fly ash storage silo. Bag filters will be employed to control fugitive dust emissions from the ash silo and vacuum system.

Fly ash collected in the air heater hoppers will be conveyed to the fly ash silo by a branch of the fly ash vacuum transport system. Estimated production of air heater hopper ash is 18,000 tons per year.

The bed ash will be conveyed from the boiler ash coolers to the bed ash storage hopper by mechanical ash conveyors. Bed ash from the bed ash storage hopper will be conveyed by vacuum to a bed ash silo. The bed ash production is estimated at 88,000 tons per year.

Two alternatives for ash handling are being considered. The first alternative would consist of discharging dry ash from the silos directly into enclosed haul trucks or railcars. Fugitive dust, potentially generated during the loading process, would be controlled by dust collection systems and water sprays.

Under the second alternative, ash would be conditioned into pellets suitable for outdoor storage. The ash pellets are made by combining and mixing bed ash, fly ash, and water in the proper proportions in ash conditioning and pelletizing machine. The pellets would be conveyed from the pelletizer to a covered "green" pellet storage area where the pellets would be allowed to cure. After curing, the pellets would be moved to the cured pellet storage area for temporary storage before disposal offsite by truck or railcar. Fugitive dust from the pelletizing process would be collected and returned to the silos by a dust collection system.

3.7.2 Hazardous Waste

There will be no hazardous waste generated by the Cedar Bay Cogeneration Project. Demineralizer wastes, which can contain up to 10 percent sulfuric acid (H_2SO_4) or up to 5 percent sodium hydroxide (NaOH), will be routed to the neutralization basin for pH adjustment. The neutralization basin serves as an "elementary neutralization unit" allowing the cogeneration plant an exemption from permitting as a hazardous waste facility. Furthermore, because the demineralizer wastes are not stored prior to pH adjustment, they are not counted as generated hazardous waste, and the plant is therefore not subject to regulation as a hazardous waste generator. Disposal of acidic boiler cleaning wastes will be accomplished by the chemical cleaning contractor as discussed in Subsection 3.6.6. 2 1

3.8 ONSITE DRAINAGE SYSTEM

Site drainage facilities will be designed in accordance with the requirements of the St. Johns River Water Management District. Channels and piping systems will be sized to carry the flow resulting from a 50-year, 24-hour rainfall. Site runoff facilities will provide storage to satisfy criteria for maintenance of water quality and control of discharge rates.

Runoff from areas of the site not disturbed by construction activities or plant operations will be directed to the natural drainage systems within the area. Runoff from areas of the site disturbed by construction activities or plant operations will be collected in a ditch system and/or catch basin and underground piping system and directed to ponds as described in the following subsections. Drainage systems will be designed for gravity flow wherever site conditions allow. A site arrangement for the new facilities is shown on Figure 3.2-1.

Generally, the drainage in the area of the new facility will be directed away from the structures and routed to either of the two onsite storage ponds as described below. The drainage along the entrance road for the new facilities will follow the existing drainage pattern, to the south and west. Where required, culverts will be placed under the road to allow for these drainage patterns.

The 100-year base flood elevation is approximately 7 feet msl, as determined by the local Flood Insurance Rate Map (see Figure 2.1-4). The southwestern portion of the site is within the 100-year flood plain as shown on Figure 2.1-4. Compacted fill material will be placed within the plant site so that all major plant facilities are located above the 100-year base flood elevation. The grade in the area of the new facilities will vary from approximately Elevation 11 to Elevation 8 (msl). The onsite drainage system will be designed to carry the surface runoff away from the structures and direct the flow into the onsite ponds as described in the following subsections.

3.8.1 Storage Area Runoff Pond

Surface runoff from the coal, limestone, and ash storage areas will be collected and directed into the Storage Area Runoff Pond which is located on the southern portion of the site. The coal storage pile, limestone storage pile, and the ash storage pile will occupy approximately 3 acres, 1 acre, and 1 acre, respectively. The associated facilities for these bulk storage piles will occupy an additional 5 acres. The coal and ash handling areas will be underlain by an impervious synthetic liner. The pond liner will consist of 60 mil (minimum) synthetic liner placed on a prepared subgrade layer creating a stable, highly impermeable liner.

In accordance with National Pollution Discharge Elimination System permit requirements, the Storage Area Runoff Pond will be designed to contain the runoff resulting from a 10-year, 24-hour rainfall event for the entire storage and associated facilities areas, and the direct precipitation on the pond area. Runoff from precipitation exceeding the 10-year, 24-hour event will be detained and directed to the existing outfall to be discharged at a rate which will not exceed the peak rate of discharge from the undeveloped site resulting from a 25-year, 24-hour storm. Flows which exceed that resulting from the 25-year, 24-hour storm event will be piped directly to the existing outfall structure.

Runoff and direct precipitation retained within the Storage Area Runoff Pond will be directed to the Seminole Kraft treatment facilities as described in Subsection 3.6.9. Controlled drawdown of the runoff pond to its normally empty condition will be accomplished through a buried pressure pipeline routed to the runoff treatment facilities.

The Storage Area Runoff Pond will be built early during construction to serve as a construction runoff retention pond. A system of temporary construction ditches and piping will direct the flow to the pond. The construction period will last for approximately 2 years. Yard runoff will be directed to the Yard Area Runoff Pond as soon as it is operational (approximately halfway through the construction period). This sequencing will allow time for the Storage Area Runoff Pond to be cleaned out and the synthetic liner installed prior to the initial delivery of coal. Once the liner is in place, runoff from storage areas will be collected and treated as discussed above.

3.8.2 Yard Area Runoff Pond

Surface runoff from the main plant complex area and yard areas not affected by bulk materials handling will be collected and directed to the Yard Area Runoff Pond. This pond will be located in the northern portion of the new facilities area. The pond will be designed to retain, without direct discharge, the volume of stormwater associated with 0.5 inch of runoff from tributary site areas. The Yard Area Runoff Pond will also be sized to detain the runoff volume resulting from the 25-year, 24-hour storm. This volume will be discharged at a rate not to exceed the maximum rate of discharge from the undeveloped site for the 25-year, 24-hour storm. This controlled drainage will be accomplished through a buried pressure pipe system routed to the existing discharge outfall. Figure 3.2-3 shows the location of the existing outfall. Any flows in excess of the 25-year, 24-hour storm runoff will be piped directly to the existing outfall structure.

3.8.3 Existing Drainage Patterns

Surface runoff from site areas north of the mill dewatering building currently drains to the lime settling ponds located west of the rail spurs. The supernatent from the lowest (northernmost) of these ponds is pumped into the mill sewage collection system. After being routed through the existing clarifier and receiving biological treatment, the runoff is eventually discharged at the outfall structure located in the St. Johns River south of the site.

The site area between the dewatering building and the clarifier would naturally drain to the Broward River, but Seminole Kraft has constructed berms along the river to provide containment for potential oil spills. Therefore, rainfall which lands on this area collects in localized depressions and eventually percolates to the ground water table.

Offsite runoff will not be collected in the onsite drainage system. Swales will be provided to direct runoff which originates in offsite, upgradient areas around the site perimeter and into existing drainage patterns. These swales will be designed to preserve the existing drainage conditions and water quality to the maximum extent possible.

3.9 MATERIALS HANDLING

This section discusses the transportation of construction materials and equipment, limestone, and ash. Roads, railroads, and conveyors will be included. Pollution control measures for storage and laydown areas will be described. Fuel transportation, storage, and handling are discussed in Sections 3.3, 6.2, and 6.3.

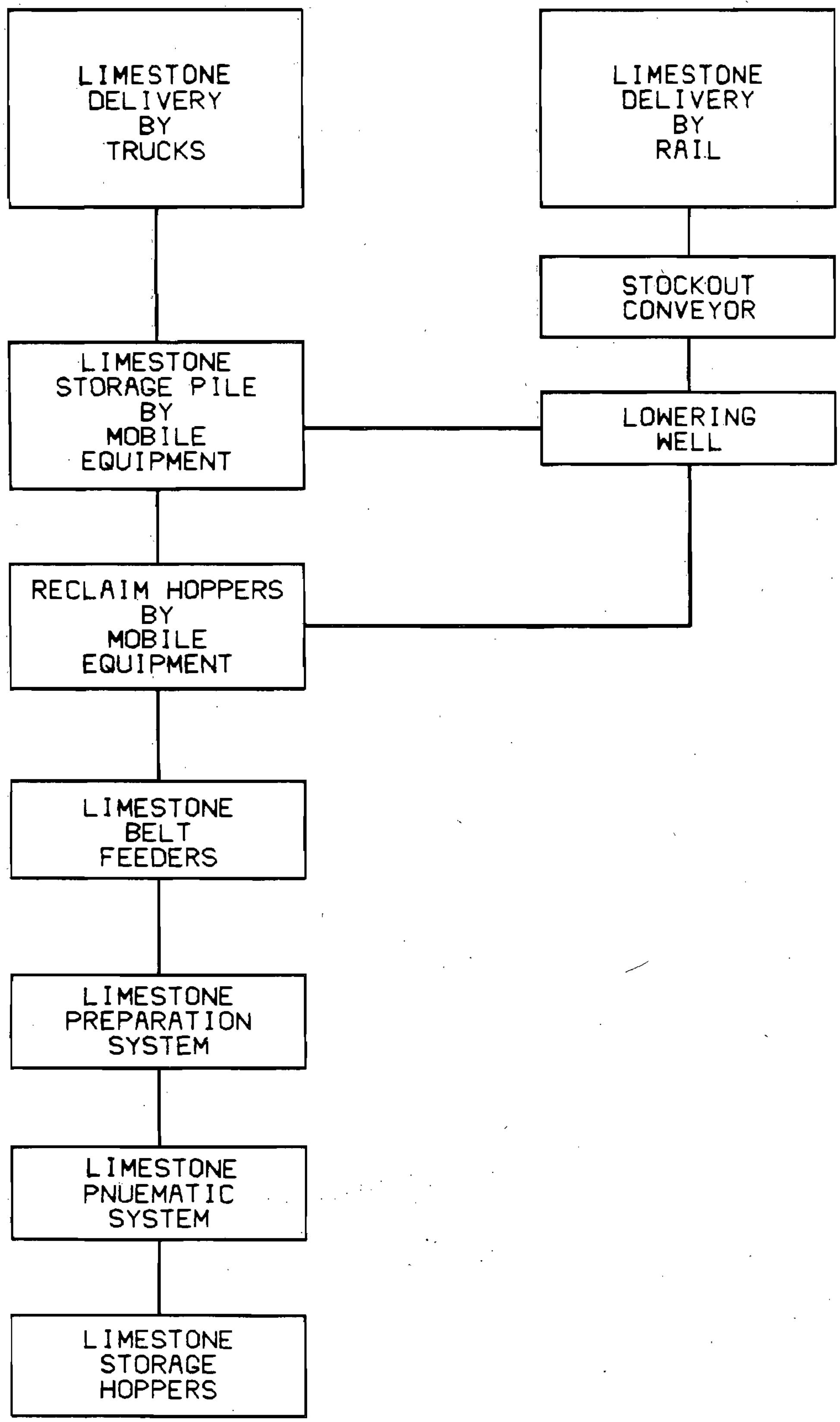
3.9.1 Construction Materials and Equipment

Construction materials and equipment will be delivered to the site by existing roads and railroads. No barge or ship delivery to the site is planned. The paper mill currently uses both modes of transportation for delivery of logs and wood chips and shipment of finished products. No off-site upgrading of road or rail facilities is anticipated for delivery of construction equipment and materials. As shown on Figure 3.2-1, a new access road will be constructed on the mill site to provide access to the construction areas from Eastport Road. Figure 3.2-1 also shows the onsite rail layout for the project.

Construction material laydown areas will be located north of the paper mill wood yard in areas currently used to store lime mud, logs, and debris. The area will be prepared as described in Subsection 4.1.4. Materials will be unloaded, and moved around the site using portable cranes and trucks. Some of the heaviest items such as the generator stator and transformer will require rail delivery and special rigging for onsite handling. Pollution control measures for the laydown areas will include runoff detention ponds to hold precipitation runoff so that suspended sediment can settle out prior to release to natural drainage. Main roads in the laydown areas will be gravel surfaced and treated with dust palliative to reduce dust. Water sprays will also be used, as required, to control dust due to traffic.

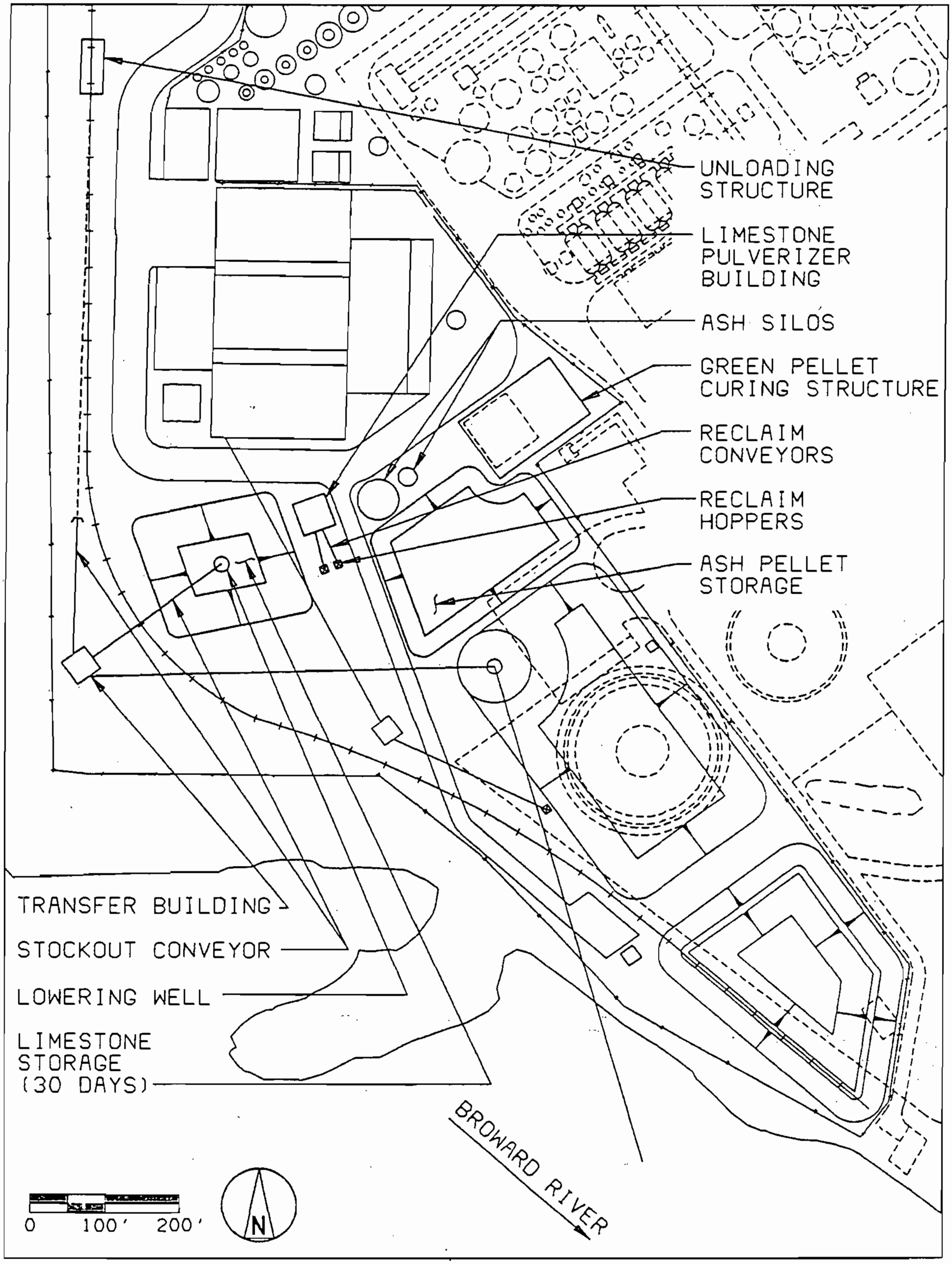
3.9.2 Limestone Handling

The limestone handling system will consist of unloading, stockout, reclaiming, preparation, and limestone storage. Figure 3.9-1 shows a schematic of the limestone handling process. Figure 3.9-2 shows the arrangement of the limestone handling equipment on the site. Based on a maximum short-term coal sulfur content of 3.3 percent, the maximum consumption rate will be 34 tons per hour. Based on the project's long-term average percent 3
sulfur of 1.70 and an annual capacity factor of 87 percent, the maximum annual limestone consumption will be 171,000 tons.



LIMESTONE HANDLING PROCESS DIAGRAM

Figure 3.9-1



LIMESTONE AND ASH HANDLING
SITE PLAN

Figure 3.9-2

Limestone will be delivered to the plant site by either trucks or
rail. Truck delivered limestone will be unloaded on the ground adjacent to
the limestone storage pile. Approximately 5,700 30-ton truckloads per year 3
or 110 loads per week would be required. Rail delivered limestone will be
unloaded in the fuel receiving structure described in Section 3.3. The
limestone will then be transported by conveyors to the limestone stockout
pile. About 1,710 railcar loads of limestone will be required per year or 3
33 cars per week.

Limestone will be reclaimed by mobile equipment and loaded into above
grade hoppers. Limestone will be reclaimed from the hopper by belt feeders
and transported to the limestone pulverizers and preparation system. The
limestone preparation system will reduce the limestone to the required
particle size and transport it pneumatically to the limestone storage hop-
pers located in the Steam Generation Building.

The limestone storage area will consist of a maximum of 25,000 tons of 3
limestone and will be located north of the Steam Generation Building. The 2
limestone storage will provide approximately 30 days of limestone at the
maximum usage rate of the steam generators.

Fugitive dust control from the handling of limestone will be accomplished by fabric filter dust collectors. The limestone belt conveyors and feeders will have covers over the belt to control fugitive dust. If limestone is delivered by rail, then a lowering well as described in Section 3.3 will be used for limestone stockout. Water sprays will be used as required to control dust from mobile equipment operations. Precipitation runoff from the limestone storage area will be collected as described in Section 3.8.

3.9.3 Ash Handling

Figure 3.9-2 shows the arrangement of the ash handling equipment on
the site. Ash production and handling are described in Section 3.7. Up to
seven days of ash pellet production may be stored onsite. This will amount
to a maximum of about 9,400 tons. The storage area will be lined with a 3
synthetic liner to minimize ground water impacts. The liner will be

protected with a soil cover. Precipitation runoff will be directed to the Storage Area Runoff Pond as described in Section 3.8.

Ash will be removed from the site by either truck or rail. If removed by rail, approximately 3,150 100-ton car loads will be required per year. The weekly rate would be 61 car loads. If removed by 30-ton trucks, up to 10,500 truckloads would be required per year. The maximum weekly rate would be 202 truckloads. 3

Ash will be loaded directly into closed trucks or railcars from the storage silos or ash pellets will be loaded by mobile equipment. A covered conveyor with dust collectors will be used if pellets are loaded into railcars. Water sprays will be used as required to reduce fugitive dust from pellet handling. If ash is loaded out in a dry form, then fabric filter type dust collectors will be used for dust control.

3.9.4 Roads

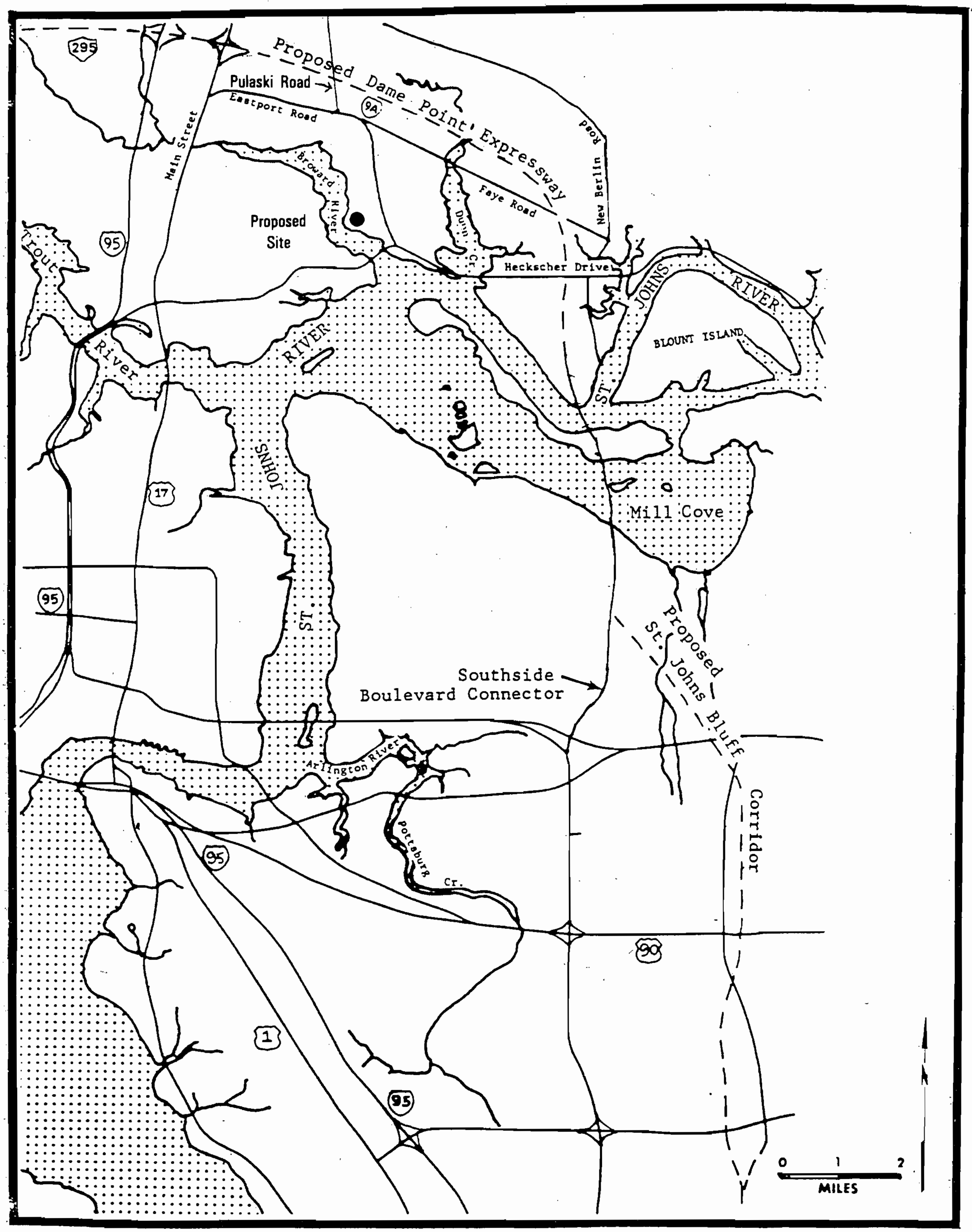
Heavily loaded construction trucks will travel to the site from Interstates 95 and 295 or the Dames Point Bridge to Highway 9A, as shown on Figure 3.9-3. Traffic will then exit to Pulaski Road south to Eastport Road. Heavy construction traffic will avoid Heckscher Drive due to bridge load limits. The state of Florida is currently studying the possibility of upgrading Heckscher Drive. This improvement is not expected to be completed until after construction of the cogeneration project.

Heavily loaded trucks that may be required to haul ash and limestone should be able to use Heckscher Drive after it is upgraded. Trucks could travel east to the Dame Point Bridge or west to Highway 17. These trucks could also use Eastport Road to the north.

The impacts of construction traffic are discussed in Section 4.6. The impacts of ash disposal are discussed in Section 5.4.

3.9.5 Railroads

The CSX Railroad currently serves the mill site. The line that the mill spur branches from is currently used for unit train coal delivery to



MAJOR ROADS IN THE VICINITY OF THE PROJECT SITE

Figure 3.9-3

the JEA St. Johns Power Park a few miles east of the mill site. Therefore, it should not be necessary to upgrade this line. Section 6.3 discusses modifications to the mill spur that will be required for the cogeneration plant. 3

ATTACHMENT E

8/9/88

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. 1.

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): 2.

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

RESPONSES

1. The FDER application form (Section III Part E - Fuels) for the CFB boilers 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.

RESPONSES

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). 3.

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. 4.

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. 5.

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. 6.

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. 7.

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

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. 8.

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: 9.

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

RESPONSES

8. As was stated in the application, emissions for the 1979-1980 period [illegible] adjusted in order to best represent normal operating condition and current controls and regulatory constraints. The described [illegible] 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. 10.

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. 11.

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. 12.

RESPONSES

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_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).

13.

RESPONSES

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)	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. 14.

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

RESPONSES

14. References made to Thermal DeNOx are somewhat generic in nature. The Thermal DeNOx system as 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_xOUT 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 opera fluidized boilers with selective non-catalytic NO_x reduction sys have provided additional information regarding these installatior 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. 15.

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. 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.

ATTACHMENT B

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

Best Available Copy

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COUNTY OF SACRAMENTO

ENVIRONMENTAL MANAGEMENT DEPARTMENT

NORMAN D. COVELL, DIRECTOR

TC

AIR POLLUTION CONTROL DISTRICT
Richard G. Johnson, Chief

August 9, 1988

Pat Frost
SMUD
PO Box 15830 MS30
Sacramento, CA 95852-1830

Don Becker
Senior Purchasing Agent
Campbell Soup Company
6200 Franklin Blvd
Sacramento, CA 95824

Gentlemen:

Please refer to your applications to construct the following equipment located at 6200 Franklin Blvd, Sacramento:

APPLICATION NOS. 8577 - 8586:

1. Four steam boilers, rated at a total of 400 MM Btu/hr heat input, flue gas recirculation, low NOx burner.

2. One gas turbine, rated at 600 MM Btu/hr heat input, steam injection.

AUTHORITY TO CONSTRUCT

Authorization to construct is hereby granted with the following conditions:

1. The boilers and turbine shall be fired on natural gas only.
   a. In the event of an interruption of natural gas supply or for the routine testing of the emergency fuel system, the boilers and turbine may be fired on No.2 diesel fuel or No.5 fuel oil subject to the limitations in Condition 2.
   b. SMUD/Campbell Soup Company shall submit a written report to the District within 10 days of the start of any period of liquid fuel usage (excluding routine testing) detailing the circumstance of the natural gas service interruption.

2. The use of No.2 diesel fuel or No.5 fuel oil in the turbine and boilers shall not cause SO_2 emissions to exceed 250 pounds per day. SMUD/Campbell Soup Company shall submit a plan to the District specifying how this limit will be achieved and obtain approval prior to using liquid fuels

3. The emission of oxides of nitrogen (NOx) from each boiler shall not exceed:
   a. 40 ppmvd at 3% O_2 when firing natural gas.
   b. The lowest concentration established by source testing when firing No.2 diesel fuel or No.5 fuel oil.

4. The emission of oxides of nitrogen (NOx) from the turbine shall not exceed:
   a. 25 ppmvd at 15% O_2 when firing natural gas.
   b. The lowest concentration established by source testing when firing No.2 diesel fuel or No.5 fuel oil.

5. The majority of the usable thermal exhaust from the gas turbine shall not be diverted to the heat recovery steam generator, for generation of process steam, more than 1500 hours per year. A plan for such recordkeeping shall be submitted to the District for approval prior to operating the turbine.

6. The combined emissions from the boilers and turbine when using natural gas fuel shall not exceed:

	pounds	pounds	tons	tons/calendar quarter			
Pollutant	hour	day	year	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	77	1734	144	34	33	44	33
SO_2	0.5	11	0.9				
CO	36	840	75				
ROC	5	103	9				
Particulate	10	217	18				

7. A continuous Emissions Tracking System to calculate the hourly, daily, quarterly and yearly emissions from the boilers and turbine shall be installed and operated to insure the limits in Condition 6 are not exceeded. SMUD/Campbell Soup shall submit a description of such an Emissions Tracking System that will accomplish this requirement to the APCO within 180 days of issuance of the Authority to Construct. SMUD/Campbell Soup must receive approval of the Emission Tracking System from the APCO before operation of the boilers and turbine begins.

8. A continuous system to monitor and record the fuel consumption and the ratio of steam or water injected to fuel fired in the turbine shall be installed in accordance with Rule 805 Section 501.

9. Approved monitors for NOx and O_2 shall be properly installed, maintained, operated and calibrated at all times for each boiler and the turbine (see Attachment 2).
   a. Specifications of the NOx and O_2 monitors chosen for installation shall be submitted to the Air Pollution Control Officer for approval.
   b. A Quality Assurance Plan for the maintenance, operation and calibration of the monitors shall be submitted to the Air Pollution Control Officer for approval.

10. An oxides of nitrogen (NOx) and carbon monoxide (CO) source test of each boiler and the turbine shall be performed and the test results submitted to the Air Pollution Control Officer within 60 days of the initial start-up of the process.
    a. Submit a test plan to the Air Pollution Control Officer for approval at least 30 days before the source test is to be performed.
    b. Notify the Air Pollution Control Officer at least a week prior to the actual source test date.

11. An emission test for NOx shall be conducted each year during the period May 1 through May 31.
    a. Submit a test plan to the Air Pollution Control Officer for approval at least 30 days before the source test is to be performed.
    b. Notify the Air Pollution Control Officer at least a week prior to the actual source test date.

12. Sample ports and test platforms, as necessary, shall be constructed per applicable EPA and OSHA requirements (see Attachment 1).

13. Within 180 days following the issuance of the Authority to Construct SMUD/Campbell Soup Company shall contact the District regarding:
    a. Requirements for the source test specified in Condition 10.
    b. Sampling ports specified in Condition 12.
    c. Continuous monitors specified in Condition 8 and 9.

14. Access, facilities, utilities and any necessary safety equipment for source testing and inspections shall be provided upon request of the Air Pollution Control Officer.

15. A written report of excess emissions shall be submitted to the Air Pollution Control Officer for every calendar quarter. Excess emissions are defined as:
    1) any one hour period during which the average emissions of NOx exceeds the limits of Conditions 3 or 4 or,
    2) any one hour period during which the steam-to-fuel ratio falls below the level that demonstrates compliance or,
    3) any daily period during which the sulfur content of the fuel exceeds 0.5% by weight.

    The report shall include the following:
    a. The magnitude of excess emissions in units of ppmvd and pounds per hour and the date and time of commencement and completion of each time period of excess emissions.
    b. Specific identification of each period of excess emissions that occurs during start-ups, shutdowns and malfunctions (if known), the corrective action taken or preventative measures adopted.
    c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of the system repairs or adjustments.
    d. When no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired or adjusted, such information shall be stated in the report.

16. Records shall be maintained (i.e. fuel usage rates, boiler load levels, hours of operation, etc.) to verify compliance with all permit conditions. Such records shall be maintained for the most recent two year period and shall be made available to the Air Pollution Control Officer on request.

17. The following are excess emission offsets resulting from the removal of the existing boilers and after offsets have been used for the proposed project.

	tons/calendar quarter			
Pollutant	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	9	2	37	11

a. The excess emission offsets shall be available for use as offsets either onsite or offsite subject to the following:
   1. The excess emission offsets shall be subject to the rules in effect at the time they are proposed to be used.
   2. The calculation method of Section 413.2 of Rule 202-New Source Review will not be applicable to these emissions in the future. The actual operating conditions averaged over the last three years were used to quantify the emissions from the existing boilers at the time of permit application. In the future, calculating the emissions by using actual operating conditions over the last three years will not apply.
   3. The District does not consider the replacement of the boilers to be a "source shutdown" as used in Section 413.6 of Rule 202 - New Source Review. The Campbell Soup Company will still exist after the boiler replacement and there will still be a requirement for steam. The new controlled emission boilers are considered to be the same as if an air pollution control system was installed on the old uncontrolled emission boilers. Therefore the restriction to onsite use of the emission offsets will not be applicable to the use of these emissions offsets in the future.

18. Permits to Operate for the existing boilers shall be cancelled when the new boilers and turbine are in normal operation.

Commencing work under this authority to construct shall be deemed acceptance of all the conditions specified.

This, however, does not constitute a permit to operate nor does it guarantee that the proposed equipment will comply with air pollution control regulations.

You are requested to notify this office when construction has been completed. A final inspection will then be made to determine whether the equipment has been constructed according to the plans approved by this District. At that time, operation will be observed and permission to operate will be granted upon compliance with the rules and regulations of the Sacramento County Air Pollution Control District.

Sincerely,

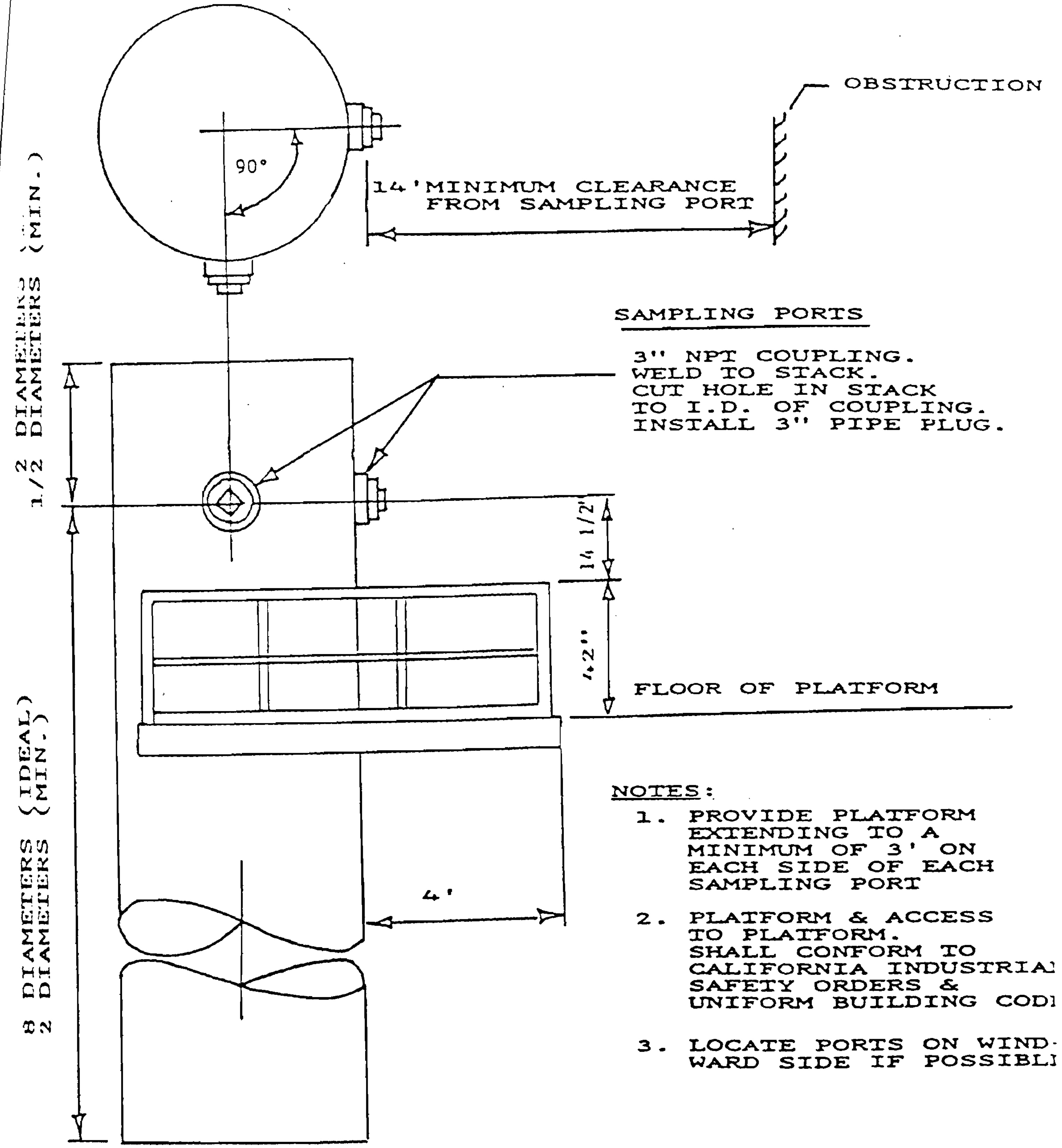
Bruce Nixon

Bruce Nixon
Air Pollution Control Engineer

AC8577

ATTACHMENT I

PLATFORM AND PORT SPECIFICATION SHEET



NOTES:

1. PROVIDE PLATFORM EXTENDING TO A MINIMUM OF 3' ON EACH SIDE OF EACH SAMPLING PORT
2. PLATFORM & ACCESS TO PLATFORM. SHALL CONFORM TO CALIFORNIA INDUSTRIAL SAFETY ORDERS & UNIFORM BUILDING CODE
3. LOCATE PORTS ON WIND-WARD SIDE IF POSSIBLE

IF THE STACK DIAMETER IS TOO LARGE TO TRAVERSE FROM ONE PORT, 4 SAMPLING PORTS AT 90° APART MAY BE USED TO TRAVERSE THE STACK. THIS AVOIDS USING A LONGER PROBE WHICH MAY CAUSE SAGGING (NONPERPENDICULAR ARRANGEMENT).

ATTACHMENT 2

Continuous Emission Monitors

PERFORMANCE SPECIFICATIONS

NOx and SO_2

:uracy	≤ 20 pct of the mean value of the reference method test data
nt Accuracy	≤ 10 pct
.ion Error	≤ 5 pct of (50 pct, 90 pct) calibration gas mixture value
·ift (2h)	2 pct of span
rift (24h)	2 pct of span
·ation drift (2h)	2 pct of span
ration drift (24h)	2.5 pct of span
nse time	15 min maximum

O_2 and CO_2

drift (2h)	≤ 0.4 pct O_2 or CO_2
drift (24h)	≤ 0.5 pct O_2 or CO_2
ration drift (2h)	≤ 0.4 pct O_2 or CO_2
acy	≤ 10 pct
nse time	10 min
ration	≤ 5 pct of calibration gas value

SACRAMENTO COUNTY AIR POLLUTION CONTROL DISTRICT
8475 Jackson Road
Sacramento, Ca 95826

AUTHORITY TO CONSTRUCT ENGINEERING EVALUATION

SMUD/CAMPBELL SOUP COMPANY

BOILER AND TURBINE PROJECT

PERMIT APPLICATIONS A/C 8577 - 8586

August 9, 1988

Authority to Construct Engineering Evaluation
SMUD/Campbell Soup Company
Boiler and Turbine Project
August 5, 1988

I. INTRODUCTION

A. Background

The Sacramento Municipal Utility District (SMUD) and Campbell Soup Company have submitted a joint application for Authority to Construct for four boilers and a gas turbine on Campbell Soup's property. The project will remove the five existing uncontrolled emissions boilers at Campbell Soup and install four new controlled emissions boilers. The new boilers will have emission controls for nitrogen oxides. The new turbine emissions will be offset by the excess emission reductions from the boilers changing from uncontrolled emissions to controlled emissions.

B. Process Description

1. Process Equipment

The proposed project will consist of four controlled emission steam boilers with a combined output of 300,000 pounds of steam per hour. They will replace five uncontrolled emission boilers that have a combined steam output of 280,000 pounds of steam per hour.

A 49.5 MW cogeneration gas turbine will also be installed to provide electrical peaking power for SMUD and process steam for Campbell Soup Company. The turbine is proposed to run no more than 3499 hours per year, which is approximately 40% of the 8760 hours in a year.

2. Air Pollution Control Equipment

The proposed equipment requires Best Available Control Technology (BACT).

Air pollution control equipment includes:

a. Nitrogen Oxides Controls

BACT for NOx for the boilers is 40 ppmvd at 3% O_2 in the exhaust gas. This will be met by designing the boilers with low NOx burners and flue gas recirculation.

BACT for NOx for the turbine is 25 ppmvd at 15% O_2 in the exhaust gas. This will be met by designing the turbine with steam injection in the combustion zone.

b. Carbon Monoxide Controls

BACT for carbon monoxide from the boilers and the gas turbine is good combustion control to minimize the carbon monoxide emissions.

c. Reactive Organic Compounds Control

BACT for reactive organic compounds from the boilers and gas turbine is good combustion control to minimize the reactive organic compound emissions.

d. Sulfur Dioxide Controls

BACT for sulfur dioxide is the use of natural gas for the primary fuel and the use of low sulfur oil for standby fuel. The standby fuel will be less than 0.5% sulfur by weight.

e. Particulate Controls

BACT for particulate is the use of natural gas for the primary fuel.

C. REGULATORY SUMMARY

The most significant air quality requirements related to the permitting of this project are: 1) Best Available Control Technology and 2) Emission Offsets.

1. Best Available Control Technology

District regulations require the use of Best Available Control Technology to reduce emissions of each pollutant that exceeds a specified emission level. The proposed project will use emission control equipment and techniques considered to be BACT for all applicable pollutants as described above.

2) Emission Offsets

District regulations require that an applicant for a proposed project with emissions in excess of specified levels provide emission reductions to offset the project's emission increases. In this case the applicant will offset the emission increases from the turbine with emission decreases from the boilers.

II PROJECT EMISSIONS

Detailed calculations of emissions are presented in Appendix A, "Emission Estimates for New Boilers and Turbine" and Appendix B, "Emission Estimates for Boilers to be Used as Offsets". The emissions are summarized for the proposed project in the following table.

TABLE 1

WORST CASE EMISSIONS SUMMARY

The worst case hourly, daily and yearly emissions are presented below for the new equipment. These emission rates are based on the maximum emitting capacity of the equipment operating within the limitations imposed as permit conditions. SMUD/Campbell Soup will accept permit conditions limiting the hourly, daily, quarterly and annual emissions from the boilers and turbine.

WORST CASE EMISSIONS

Based on the following operating conditions:	Hourly	Daily	Yearly
Turbine	60 min/hr	22 hrs/day	3499 hrs/yr
Boilers (Half Load)	60 min/hr	22 hrs/day	3362 hrs/yr
Boilers (Full Load)	0 min/hr	2 hrs/day	1040 hrs/yr

		Worst Case pounds/hour	Worst Case pounds/day	Worst Case tons/year
NOx				
	Boilers	10	260	27
	Turbine	67	1474	117
	Total	77	1734	144
SO_2				
	Boilers	0.1	3	0.3
	Turbine	0.4	8	0.6
	Total	0.5	11	0.9
CO				
	Boilers	12	312	33
	Turbine	24	528	42
	Total	36	840	75
ROC				
	Boilers	1	15	2
	Turbine	4	88	7
	Total	5	103	9
Particulate				
	Boilers	1	27	3
	Turbine	9	190	15
	Total	10	217	18

TABLE 2

EMISSION INCREASES, DECREASES AND SUMMARY

The emission increases due to the new controlled emission boilers and the new turbine will be offset by the emission decreases from the removal of the existing uncontrolled emission boilers. The table below indicates that a portion of the excess emission reductions from the controlled emission boilers replacing the uncontrolled emission boilers will be applied to this project.

Pollutant	Emission Increase Due to New Boilers tons/yr	Emission Increase Due to Turbine tons/yr	Emission Offset Due to Old Boilers tons/yr	Net Emission Increase tons/yr	Net Emission Increase lb/day
NOx	27	117	<117>	27	148
SO_2	0.3	0.6	<0.4>	0.5	3
CO	33	42	<13>	62	340
ROC	2	7	<2>	7	38
Particulate	3	15	<3>	15	82

III. COMPLIANCE WITH APPLICABLE REGULATIONS

In this section the District rules that apply to the proposed project are identified and compliance with the requirements is determined.

A. RULE 202 NEW SOURCE REVIEW

The most significant rule affecting the permitting of the proposed project is the District's Rule 202 New Source Review. The requirements of the rule include: 1) Best Available Control Technology and 2) Emission Offsets.

1. Determination of Best Available Control Technology (BACT)

The requirement for BACT is applicable when the emissions of a given pollutant exceed a specified level as designated in Rule 202.

For the proposed project the worst case emissions given in Table 1 are used to determine if BACT is required for each pollutant. According to Rule 202 BACT is required for NOx when emissions exceed 150 pounds per day and for CO when emissions exceed 550 pounds per day.

a. **NOx BACT for Boilers**
SMUD/Campbell Soup are proposing to meet an emission limit of 40 ppmvd NOx at 3% O_2 through the use of low-NOx burners and flue

gas recirculation. This emission limitation has been determined to be BACT by the APCO for three A/C's issued for similar size boilers within the District.

b. **NOx BACT for Gas Turbine**
SMUD/Campbell Soup are proposing to meet an emission limit of 25 ppmvd NOx at 15% O_2 through the use of steam or water injection in the turbines combustion zone. BACT in some California APCD's has been determined to be 9 ppmvd NOx for gas turbines that operate enough hours per year to justify the expense of the NOx control system. The APCO has determined that the cost to achieve 9 ppmvd NOx is excessive for the turbine because it will operate in combined cycle mode only a portion of its total operating time. The following table shows the historical steam usage at Campbell Soup:

Average Steam Usage (pounds per hour)	Annual Hours
275,000	786
(210,000 Design output of turbine)	-
190,000	384
150,000	1416
100,000	2784
60,000	1320
21,000	1128
None	960

The turbine will run in simple cycle or partial combined cycle most of its operating time, not fully using the exhaust gas to produce steam to be used for food processing. The temperature reduction needed in the exhaust gas to be compatible with a catalyst type control to achieve 9 ppmvd would not be possible in the simple cycle or partial combined cycle mode.

c. **SO_2 BACT for Boilers and Turbine**
SMUD/Campbell Soup will use natural gas as the primary fuel to the boilers and turbine to minimize the emission of SO_2. Emergency fuel oil will contain less than 0.5% by weight sulfur to also minimize SO_2 emissions.

d. **CO and ROC BACT for Boilers and Turbine**
SMUD/Campbell Soup will use good combustion control to minimize the emission of CO and ROC from the boilers and turbine.

e. **Particulate BACT for Boilers and Turbine**
SMUD/Campbell Soup will use natural gas as the primary fuel to the boilers and turbine to minimize the emission of particulate matter.

2. **Determination of Emission Offsets**

The requirement to offset emissions is applicable if the net emission increase from the proposed project exceeds:

Particulate	150 lb/day
NOx, SO_2, ROC	250 lb/day
CO	550 lb/day

The requirement for offsets is applicable to each individual source of emission that exceeds the above limits because of the way "stationary source" is defined in Rule 202. Internal source emission reductions can not be applied to net out of offsets if a piece of emitting equipment by itself exceeds the limits. In this application the turbine, by itself, exceeds the limits therefore the entire turbine emission must be offset.

For the new boilers and turbine as a total project, SMUD/Campbell Soup proposes to apply internal offsets from the replacement of the existing boilers to keep the net emission increase below the levels specified above. Table 2 indicates the amount of each pollutant from the existing boilers that will be applied to the proposed project. The offset emissions will be provided from the same stationary source so the offset ratio will be 1.0 to 1.0.

B. RULE 401 VISIBLE EMISSIONS

Proper control of combustion parameters on boilers and turbines fired on natural gas and fuel oil results in an exhaust plume that is essentially nonvisible.

C. RULE 406 SPECIFIC CONTAMINANTS

1. The use of emergency fuel oil with a sulfur content less than 0.5% by weight will result in a SO_2 concentration in the exhaust gas less than 0.2% by volume.

2. The concentration of particulate matter in the exhaust gas will be less than 0.1 grains/dscf at 12% CO_2.

D. RULE 420 SULFUR CONTENT OF FUELS

The emergency fuel oil will have a sulfur content less than 0.5% by weight.

E. RULE 805 NEW SOURCE PERFORMANCE STANDARDS - GAS TURBINES

The NSPS requirements for new gas turbines are substantially less stringent than those resulting from BACT requirements of the District's New Source Review Rule. The 75 ppmvd NOx requirement of Section 301.2 will be met by the proposed turbine.
The steam or water injection and fuel monitoring requirements of Section 500 are included as permit conditions.

IV BANKING OF EXCESS OFFSET EMISSIONS

The proposed project will only use a portion of the emission offsets from the replacement of the existing boilers. SMUD/Campbell Soup would like to identify the excess emission reductions so that they can be used for future projects either onsite or offsite. The District regulations do not contain an Emission Banking rule specifying how excess emissions can be quantified and secured for future use. Such a rule has not been adopted because there has not been a need for such a rule in the past and it is expected that there will be minimal need in the future. Instead of diverting limited District resources to the development and adoption of an Emissions Banking rule that may only be applicable to this single project, conditions will be added to the Permit to Operate to accomplish the same purpose. The conditions will specify:

1. The quantity of each pollutant that will be available to be used as emission offsets in the future.

2. The calculation method of Section 413.2 of Rule 202-New Source Review will be applied only once to determine the excess emission offsets. The actual operating conditions averaged over the last three years have been used to quantify the emissions from the existing boilers at the time of permit application. In the future, available offsets will be the amount calculated in this analysis.

3. Excess emission offsets will be governed by the District rules in effect at the time they are proposed to be used.

The excess emission offsets, after removing that portion used to offset the proposed project emissions, are:

NOx 59 tons/yr

The District considers that the excess emission offsets have been obtained from voluntary control of existing emission sources. The replacement of the existing uncontrolled emission boilers with new controlled emission boilers is not considered by the District to be a "shutdown". After the new boilers are installed, the Campbell Soup Company will continue to operate, require steam and produce food products as they have in the past.

V PERMIT CONDITIONS

This section contains a list of permit conditions which the proposed equipment must meet in order to comply with District regulations. The conditions impose control over the operation of the proposed process equipment (such as the type and amount of fuel that can be used) and the air pollution control equipment (such as the minimum allowable steam or water to fuel ratio). The conditions also set emission limitations for applicable pollutants and specify monitoring and source test requirements to assure that these emission limits are not exceeded.

1. The boilers and turbine shall be fired on natural gas only.
   a. In the event of an interruption of natural gas supply or for the routine testing of the emergency fuel system, the boilers and turbine may be fired on No.2 diesel fuel or No.5 fuel oil subject to the limitations in Condition 2.
   b. SMUD/Campbell Soup Company shall submit a written report to the District within 10 days of the start of any period of liquid fuel usage (excluding routine testing) detailing the circumstance of the natural gas service interruption.

2. The use of No.2 diesel fuel or No.5 fuel oil in the turbine and boilers shall not cause SO_2 emissions to exceed 250 pounds per day. SMUD/Campbell Soup Company shall submit a plan to the District specifying how this limit will be achieved and obtain approval prior to using liquid fuels

3. The emission of oxides of nitrogen (NOx) from each boiler shall not exceed:
   a. 40 ppmvd at 3% O_2 when firing natural gas.
   b. The lowest concentration established by source testing when firing No.2 diesel fuel or No.5 fuel oil.

4. The emission of oxides of nitrogen (NOx) from the turbine shall not exceed:
   a. 25 ppmvd at 15% O_2 when firing natural gas.
   b. The lowest concentration established by source testing when firing No.2 diesel fuel or No.5 fuel oil.

5. The majority of the usable thermal exhaust from the gas turbine shall not be diverted to the heat recovery steam generator, for generation of process steam, more than 1500 hours per year. A plan for such recordkeeping shall be submitted to the District for approval prior to operating the turbine.

6. The combined emissions from the boilers and turbine when using natural gas fuel shall not exceed:

	pounds	pounds	tons	tons/calendar quarter			
Pollutant	hour	day	year	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	77	1734	144	34	33	44	33
SO_2	0.5	11	0.9				
CO	36	840	75				
ROC	5	103	9				
Particulate	10	217	18				

7. A continuous Emissions Tracking System to calculate the hourly, daily, quarterly and yearly emissions from the boilers and turbine shall be installed and operated to insure the limits in Condition 6 are not exceeded. SMUD/Campbell Soup shall submit a description of such an Emissions Tracking System that will accomplish this requirement to the APCO within 180 days of issuance of the Authority to Construct. SMUD/Campbell Soup must receive approval of the Emission Tracking System from the APCO before operation of the boilers and turbine begins.

8. A continuous system to monitor and record the fuel consumption and the ratio of steam or water injected to fuel fired in the turbine shall be installed in accordance with Rule 805 Section 501.

9. Approved monitors for NOx and O_2 shall be properly installed, maintained, operated and calibrated at all times for each boiler and the turbine (see Attachment 2).
   a. Specifications of the NOx and O_2 monitors chosen for installation shall be submitted to the Air Pollution Control Officer for approval.
   b. A Quality Assurance Plan for the maintenance, operation and calibration of the monitors shall be submitted to the Air Pollution Control Officer for approval.

10. An oxides of nitrogen (NOx) and carbon monoxide (CO) source test of each boiler and *the turbine shall* be performed and the test results submitted to the Air Pollution Control Officer within 60 days of the initial start-up of the process.
    a. Submit a test plan to the Air Pollution Control Officer for approval at least 30 days before the source test is to be performed.
    b. Notify the Air Pollution Control Officer at least a week prior to the actual source test date.

11. An emission test for NOx shall be conducted each year during the period May 1 through May 31.
    a. Submit a test plan to the Air Pollution Control Officer for approval at least 30 days before the source test is to be performed.
    b. Notify the Air Pollution Control Officer at least a week prior to the actual source test date.

12. Sample ports and test platforms, as necessary, shall be constructed per applicable EPA and OSHA requirements (see Attachment 1).

13. Within 180 days following the issuance of the Authority to Construct SMUD/Campbell Soup Company shall contact the District regarding:
    a. Requirements for the source test specified in Condition 10.
    b. Sampling ports specified in Condition 12.
    c. Continuous monitors specified in Condition 8 and 9.

14. Access, facilities, utilities and any necessary safety equipment for source testing and inspections shall be provided upon request of the Air Pollution Control Officer.

15. A written report of excess emissions shall be submitted to the Air Pollution Control Officer for every calendar quarter. Excess emissions are defined as:
    1) any one hour period during which the average emissions of NOx exceeds the limits of Conditions 3 or 4 or,
    2) any one hour period during which the steam-to-fuel ratio falls below the level that demonstrates compliance or,
    3) any daily period during which the sulfur content of the fuel exceeds 0.5% by weight.

    The report shall include the following:

a. The magnitude of excess emissions in units of ppmvd and pounds per hour and the date and time of commencement and completion of each time period of excess emissions.
b. Specific identification of each period of excess emissions that occurs during start-ups, shutdowns and malfunctions (if known), the corrective action taken or preventative measures adopted.
c. The date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of the system repairs or adjustments.
d. When no excess emissions have occurred or the continuous monitoring system has not been inoperative, repaired or adjusted, such information shall be stated in the report.

16. Records shall be maintained (i.e. fuel usage rates, boiler load levels, hours of operation, etc.) to verify compliance with all permit conditions. Such records shall be maintained for the most recent two year period and shall be made available to the Air Pollution Control Officer on request.

17. The following are excess emission offsets resulting from the removal of the existing boilers and after offsets have been used for the proposed project.

	tons/calendar quarter			
Pollutant	Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	9	2	37	11

a. The excess emission offsets shall be available for use as offsets either onsite or offsite subject to the following:
   1. The excess emission offsets shall be subject to the rules in effect at the time they are proposed to be used.
   2. The calculation method of Section 413.2 of Rule 202-New Source Review will not be applicable to these emissions in the future. The actual operating conditions averaged over the last three years were used to quantify the emissions from the existing boilers at the time of permit application. In the future, calculating the emissions by using actual operating conditions over the last three years will not apply.
   3. The District does not consider the replacement of the boilers to be a "source shutdown" as used in Section 413.6 of Rule 202 - New Source Review. The Campbell Soup Company will still exist after the boiler replacement and there will still be a requirement for steam. The new controlled emission boilers are considered to be the same as if an air pollution control system was installed on the old uncontrolled emission boilers. Therefore the restriction to onsite use of the emission offsets will not be applicable to the use of these emissions offsets in the future.

18. Permits to Operate for the existing boilers shall be cancelled when the new boilers and turbine are in normal operation.

VI RECOMMENDATION

The conclusion of this review is that all applicable permit requirements have been met by SMUD/Campbell Soup Company and the Air Pollution Control Officer, therefore, has made the decision to issue an Authority to Construct for the following equipment with the conditions discussed:

1. Four steam boilers, rated at a total of 400 MM Btu/hr heat input, flue gas recirculation, low NOx burner.

2. One gas turbine, rated at 600 MM Btu/hr heat input, steam or water injection.

APPENDIX A

EMISSION ESTIMATES FOR NEW BOILERS AND TURBINE

A. EMISSION FACTORS

The following emission factors are used to calculate the emissions from the proposed new boilers and turbine.

Pollutant	Emission Factor	Source of Emission Factor
NOx		
Boilers (Half Load)	10 lb/hour	Manufacturer's Data and 40 ppmvd
Boilers (Full Load)	20 lb/hour	Manufacturer's Data and 40 ppmvd
Turbine	67 lb/hour	Manufacturer's Data and 25 ppmvd
SO_2		
Boilers	0.6 $lb/10^6$ ft^3 fuel	AP-42, Section 1.4 (10/86)
Turbine	0.6 $lb/10^6$ ft^3 fuel	AP-42, Section 1.4 (10/86)
CO		
Boilers (Half Load)	12 lb/hour	Manufacturer's Data
Boilers (Full Load)	24 lb/hour	Manufacturer's Data
Turbine	24 lb/hour	Manufacturer's Data
ROC (Reactive organic compounds)		
Boilers	2.8 $lb/10^6$ ft3 fuel	AP-42, Section 1.4 (10/86)
Turbine	4 lb/hour	Manufacturer's Data
Particulate		
Boilers	5 $lb/10^6$ ft^3 fuel	AP-42, Section 1.4 (10/86)
Turbine	14 $lb/10^6$ ft^3 fuel	AP-42, Section 3.1 (12/77)

B. WORST CASE OPERATING CONDITIONS

The following maximum fuel use rates and worst case operating hours are used with the above emission factors to calculate emissions.

Boilers	
Maximum firing rate	400 MM Btu/hr
Maximum fuel use rate	.412 10^6 ft^3 natural gas/hr
Maximum daily hours	22 hours half load and 2 hours full load
Maximum yearly hours	
Half load	3362 hours
Full load	1040 hours
Turbine	
Maximum firing rate	600 MM Btu/hr
Maximum fuel usage rate	.618 10^6 ft^3 natural gas/hr
Maximum daily hours	22 hours
Maximum yearly hours	3499 hours

APPENDIX B

EMISSION ESTIMATES FOR BOILERS TO BE USED AS OFFSETS

A. EMISSION FACTORS

The following tables list:

1. The average monthly natural gas consumption for the each of the five existing boilers at Campbell Soup Company for the period May 1983 through April 1986.

2. The emission factor used for each pollutant for each month of the year.
    a. NOx
       The factors are from a source test performed in April 1985. The factor varies for each boiler. The factor also varies for each month because the boilers are operated at a higher firing rate during the summer canning season.
    b. SO_2
       From AP-42, Section 1.4 (10/86)
    c. CO
       The factors are from a source test performed in April 1985. The factor varies for each boiler.
    d. ROC (Reactive organic compounds)
       From AP-42, Section 1.4 (10/86)
    e. Particulate
       From AP-42, Section 1.4 (10/86)

3. The average monthly pollutant emission for each of the five existing boilers.

B. TOTAL EMISSIONS FROM EXISTING BOILERS

Pollutant	tons/year	tons/calendar quarter			
		Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
NOx	180	39	31	70	40
SO_2	0.4				
CO	13				
ROC	2				
Particulate	3				

NOx EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
SEP	37.8	33.5	21.1	71.3	24.5	188.2
OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE NOx EMISSION FACTOR (lbs NOx/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	510	380	110	120	120
JUN	510	380	110	120	120
JUL	558	385	110	123	120
AUG	572	395	110	120	120
SEP	559	387	110	121	120
OCT	510	380	110	120	120
NOV	510	380	110	120	120
DEC	510	380	110	120	120
JAN	510	380	110	120	120
FEB	510	380	110	120	120
MAR	510	380	110	120	120
APR	510	380	110	120	120

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE NOx EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL	
MAY	13515	5814	671	3972	0	23972	
JUN	10608	6612	583	1596	96	19495	
JUL	16517	11550	2013	5806	972	36857	
AUG	24138	15050	2717	10224	3492	55621	
SEP	21130	12965	2321	8627	2940	47983	
OCT	14382	7714	1221	4476	24	27817	
NOV	13719	8398	1133	3540	12	26802	
DEC	16983	2926	1628	4116	0	25653	
JAN	18819	7372	1199	4500	0	31890	
FEB	15096	2584	792	3864	0	22336	
MAR	14484	3496	429	4344	0	22753	
APR	13260	1710	561	3792	12	19335	
TOTAL	192651	86190	15268	58857	7548	360514	lbs per year
	96	43	8	29	4	180	tons per year

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SO2 EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
SEP	37.8	33.5	21.1	71.3	24.5	188.2
OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE CO EMISSION FACTOR (lbs SO2/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	0.6	0.6	0.6	0.6	0.6
JUN	0.6	0.6	0.6	0.6	0.6
JUL	0.6	0.6	0.6	0.6	0.6
AUG	0.6	0.6	0.6	0.6	0.6
SEP	0.6	0.6	0.6	0.6	0.6
OCT	0.6	0.6	0.6	0.6	0.6
NOV	0.6	0.6	0.6	0.6	0.6
DEC	0.6	0.6	0.6	0.6	0.6
JAN	0.6	0.6	0.6	0.6	0.6
FEB	0.6	0.6	0.6	0.6	0.6
MAR	0.6	0.6	0.6	0.6	0.6
APR	0.6	0.6	0.6	0.6	0.6

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE SO2 EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	16	9	4	20	0	49
JUN	12	10	3	8	0	35
JUL	18	18	11	28	5	80
AUG	25	23	15	51	17	132
SEP	23	20	13	43	15	113
OCT	17	12	7	22	0	58
NOV	16	13	6	18	0	53
DEC	20	5	9	21	0	54
JAN	22	12	7	23	0	63
FEB	18	4	4	19	0	45
MAR	17	6	2	22	0	47
APR	16	3	3	19	0	40
TOTAL	220	135	83	293	38	769 lbs per year
	0.1	0.1	0.0	0.1	0.0	0.4 tons per year

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CO EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
SEP	37.8	33.5	21.1	71.3	24.5	188.2
OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE CO EMISSION FACTOR (lbs CO/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	12	11	4	37	12
JUN	12	11	4	37	12
JUL	12	11	4	37	12
AUG	12	11	4	37	12
SEP	12	11	4	37	12
OCT	12	11	4	37	12
NOV	12	11	4	37	12
DEC	12	11	4	37	12
JAN	12	11	4	37	12
FEB	12	11	4	37	12
MAR	12	11	4	37	12
APR	12	11	4	37	12

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE CO EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL	
MAY	318	168	24	1225	0	1735	
JUN	250	191	21	492	10	964	
JUL	355	330	73	1746	97	2602	
AUG	506	419	99	3152	349	4526	
SEP	454	369	84	2638	294	3839	
OCT	338	223	44	1380	2	1989	
NOV	323	243	41	1092	1	1700	
DEC	400	85	59	1269	0	1813	
JAN	443	213	44	1388	0	2087	
FEB	355	75	29	1191	0	1650	
MAR	341	101	16	1339	0	1797	
APR	312	50	20	1169	1	1552	
TOTAL	4394	2467	555	18082	755	26254	lbs per year
	2	1	0	9	0	13	tons per year

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ROC EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
SEP	37.8	33.5	21.1	71.3	24.5	188.2
OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE POC EMISSION FACTOR (lbs POC/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	2.8	2.8	2.8	2.8	2.8
JUN	2.8	2.8	2.8	2.8	2.8
JUL	2.8	2.8	2.8	2.8	2.8
AUG	2.8	2.8	2.8	2.8	2.8
SEP	2.8	2.8	2.8	2.8	2.8
OCT	2.8	2.8	2.8	2.8	2.8
NOV	2.8	2.8	2.8	2.8	2.8
DEC	2.8	2.8	2.8	2.8	2.8
JAN	2.8	2.8	2.8	2.8	2.8
FEB	2.8	2.8	2.8	2.8	2.8
MAR	2.8	2.8	2.8	2.8	2.8
APR	2.8	2.8	2.8	2.8	2.8

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE POC EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	74	43	17	93	0	227
JUN	58	49	15	37	2	161
JUL	83	84	51	132	23	373
AUG	118	107	69	239	81	614
SEP	106	94	59	200	69	527
OCT	79	57	31	104	1	272
NOV	75	62	29	83	0	249
DEC	93	22	41	96	0	252
JAN	103	54	31	105	0	293
FEB	83	19	20	90	0	212
MAR	80	26	11	101	0	218
APR	73	13	14	88	0	188
TOTAL	1025	628	389	1368	176	3587 lbs per year
	1	0	0	1	0	2 tons per year

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PM EMISSIONS FROM OLD BOILERS

TABLE 1

CAMPBELL SOUP MONTHLY AVERAGE FUEL CONSUMPTION (MM cubic feet/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	26.5	15.3	6.1	33.1	0.0	81.0
JUN	20.8	17.4	5.3	13.3	0.8	57.6
JUL	29.6	30.0	18.3	47.2	8.1	133.2
AUG	42.2	38.1	24.7	85.2	29.1	219.3
SEP	37.8	33.5	21.1	71.3	24.5	188.2
OCT	28.2	20.3	11.1	37.3	0.2	97.1
NOV	26.9	22.1	10.3	29.5	0.1	88.9
DEC	33.3	7.7	14.8	34.3	0.0	90.1
JAN	36.9	19.4	10.9	37.5	0.0	104.7
FEB	29.6	6.8	7.2	32.2	0.0	75.8
MAR	28.4	9.2	3.9	36.2	0.0	77.7
APR	26.0	4.5	5.1	31.6	0.1	67.3
TOTAL	366	224	139	489	63	1,281

TABLE 2

CAMPBELL SOUP MONTHLY AVERAGE PM EMISSION FACTOR (lbs PM/MM cubic feet)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5
MAY	5	5	5	5	5
JUN	5	5	5	5	5
JUL	5	5	5	5	5
AUG	5	5	5	5	5
SEP	5	5	5	5	5
OCT	5	5	5	5	5
NOV	5	5	5	5	5
DEC	5	5	5	5	5
JAN	5	5	5	5	5
FEB	5	5	5	5	5
MAR	5	5	5	5	5
APR	5	5	5	5	5

TABLE 3

CAMPBELL SOUP MONTHLY AVERAGE PM EMISSION (lbs/month)
MAY 1983 TO APRIL 1986

	BOILER 1	2	3	4	5	TOTAL
MAY	133	77	31	166	0	405
JUN	104	87	27	67	4	288
JUL	148	150	92	236	41	666
AUG	211	191	124	426	146	1097
SEP	189	168	106	357	123	941
OCT	141	102	56	187	1	486
NOV	135	111	52	148	1	445
DEC	167	39	74	172	0	451
JAN	185	97	55	188	0	524
FEB	148	34	36	161	0	379
MAR	142	46	20	181	0	389
APR	130	23	26	158	1	337
TOTAL	1831	1122	694	2444	315	6405 lbs per year
	1	1	0	1	0	3 tons per year

smud5.wk1

APPENDIX C

ALLOWABLE QUARTERLY EMISSIONS FOR BOILERS AND TURBINE

The following is the methodology used to:

1. Calculate the maximum allowable quarterly emissions from the combination of the boilers and the turbine. The purpose of the calculations is to ensure that the new project emissions are offset by emissions that have historically occurred in the same timeframe. It would not be to the benefit of air quality to offset a new source that emits ozone precursors in the summertime with ozone precursor emission reduction credits that historically occurred in the wintertime.

2. Calculate the emission reduction credits remaining after the emissions from the turbine have been fully offset and the net emission increase from the project is less than 250 pounds of NOx per day.

   (The following data is based on NOx only because it is the primary pollutant of concern from the new equipment.)

TABLE C-1

Quarter	(1) Emission Reduction Credits Available (tons)	(2) Emission Reduction Credits Used for Project (tons)	(3) Remaining Emission Reduction Credits (tons)	(4) New Turbine Emissions (tons)	(5) New Boiler Emissions (tons)	(6) Total Project Emissions (tons)	(7) Net Emission Increase (tons)
Jan-Mar	39	30	9	30	4	34	4
Apr-Jun	31	29	2	29	4	33	4
Jul-Sep	70	33	37	29	15	44	11
Oct-Dec	40	29	11	29	4	33	4
Total Annual	180	121	59	117	27	144	23

(1) See Appendix B

(2) Emission reduction credit used for each quarter to fully offset the emissions from the turbine. The third quarter also has 4 tons of additional emission reduction credits to offset the boiler usage so that the net emission increase from the project is less than 250 pounds per day during the quarter.

(3) Column (1) - Column (2)

(4) Emission from the turbine based on 875 hours of operation each quarter.

(5) This is the emission from the boilers based on 829 hours at half load for each of the first, second and fourth quarters. The third quarter is based on 875 hours at half load and 1040 hours at full load.

(6) Column (4) + Column (5)

(7) Column (6) - Column (2)

AES Fax

6-30-88

- SO_2 quality settlement, Max.
- Type of models to be used, Tom.

- Max's comments -

- TSP Nonattainment designation
- PM_{10} stds are in effect
- Irregular operations 81/82

Ask Bill on Policy

Call Terry Varkonda

Called Terry on 7-7-88 with DER/EPA Comments.

BACT, Barry + CAER (voc)

- Scrubbers on Boilers + RB + Smelt tank
- Include non regulated pollutants + toxics
- Duval Co nonattainment for ozone. VOC → CAER

- Duval O_3 increment available?
- Amount of VOC over 100 TPY without net out.

DER / AES 6/30/88

		DER
Buck Oven	488-1344	Siting Coord
Pradeep Raval	"	BAQM
Terry Cole	877 0099	AES
JEFF SWAIN	703-522-1315	AES
KERRY VARKONDA	"	"
Curt Barton	~~Stone Container~~ 404 621 6707	Stone Container/
JOHN MILLICAN	584-5137	Seminole Kraft ENVI. SERVICE
Larry Alfred	913-339-2325	Black & Veatch
Barry Andrews	488-1344	BAQM
Max Linn	488-1344	BAQM

RECEIVED
JUN 23 1988
DER - BAQM

June 21, 1988

Mr. Max A. Linn
Meteorologist
Bureau of Air Quality Management
State of Florida
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301

Dear Max:

Attached for your review are three (3) copies of the Air Quality Analysis Work Plan (AQAWP) for our AES-Cedar Bay cogeneration plant to be built in Jacksonville. Please provide a copy to Buck Oven and Barry Andrews. I spoke to Buck concerning a time to meet with you to discuss this plan in more detail, and we have tentatively scheduled this meeting for Thursday, June 30th at 1:00 p.m. in Tallahassee.

As far as the agenda goes, I propose we step through the plan page by page, addressing areas needing further discussion as we come to them.

In addition to issues specifically addressed in the AQAWP, there are several other issues we would like to get clarification on during this meeting:

- What are the implications of the ozone non-attainment status of Duval County?
  - -- What growth allowance exists and what amount will be available for the project ?
- What analysis will be required for trace metals emissions?

AES/Cedar Bay Inc.

1925 North Lynn Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier—(703) 528-4510

June 21, 1988

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Bureau of Air Quality Management
State of Florida
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AES/Cedar Bay Inc.

1925 North Lynn Street • Arlington, Virginia 22209 • (703) 522-1315 • Telecopier—(703) 528-4510

- Although already addressed in the plan, we want to be sure we are clear on how to deal with the modeled SO_2 exceedence issue. I think our approach effectively addresses DER and BES concerns, but am very interested in hearing feedback from you and others.

I look forward to meeting with you on the 30th.

Sincerely,

Kerry

Kerry Varkonda
Project Development Specialist

cc: James Manning, Division Chief, BESD - Jacksonville

KV/clr
Attachment

bcc: Mr. Jeff Swain, AES
Mr. Tom Tribone, AES
Mr. Terry Cole, Oertel & Hoffman
Mr. John Millican, Envir. Services
Mr. Curt Barton, Stone Container
Mr. Michael Riddle, Seminole Kraft Corp.
Mr. Steve Day, B&V
Mr. Larry Alfred, B&V

DEPARTMENT OF ENVIRONMENTAL REGULATION

ROUTING AND TRANSMITTAL SLIP

ACTION NO

ACTION DUE DATE

1. TO: (NAME, OFFICE, LOCATION)	
~~Clair~~	Initial Date
2. ~~Larry~~ YS	Initial Date
3. Bill	Initial Date
4.	Initial Date

REMARKS:

FYI - Copies of attachment given to Max, Barry + Buck

INFORMATION

- [ ] Review & Return
- [ ] Review & File
- [ ] Initial & Forward

DISPOSITION

- [ ] Review & Respond
- [ ] Prepare Response
- [ ] For My Signature
- [ ] For Your Signature
- [ ] Let's Discuss
- [ ] Set Up Meeting
- [ ] Investigate & Report
- [ ] Initial & Forward
- [ ] Distribute
- [ ] Concurrence
- [ ] For Processing
- [ ] Initial & Return

FROM: Patty

DATE 6-24

PHONE

AES CEDAR BAY, INC.
CEDAR BAY COGENERATION PROJECT
B&V PROJECT 14573
B&V FILE 32.0203

AIR QUALITY ANALYSIS WORK PLAN

CONTENTS

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(Continued)

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LIST OF FIGURES

1.0 INTRODUCTION

AES Cedar Bay, Inc. (AES-CB) proposes to construct the AES Cedar Bay Cogeneration Project to be located in Jacksonville, Florida. The project will incorporate three fluidized bed boilers burning coal and bark (the cogeneration plant) and one chemical recovery boiler burning the black liquor by-product of the adjacent Seminole Kraft paper mill. The cogeneration plant will sell electric power to Florida Power and Light and provide process steam to the kraft paper mill. The chemical recovery boiler will provide steam and electricity for internal consumption at Seminole Kraft. Eight existing boilers fueled by oil, bark, and black liquor will be removed from service as a result of the installation of the proposed sources. The existing smelt dissolving tanks and multiple effect evaporators will also be replaced by new units. Commercial operation of the proposed facility is scheduled to begin in 1992.

The project will replace older, less environmentally efficient equipment with advanced chemical recovery boiler and clean coal technology, resulting in numerous environmental benefits. Major reductions are anticipated in ambient impacts of sulfur dioxide (SO_2), total suspended particular matter (TSP), and particulate matter with aerodynamic diameter less than 10 microns (PM_{10}). In addition, the maximum total reduced sulfur (TRS) emission rate from the new recovery boiler is expected to drop to less than one-third of that from the existing recovery boilers, significantly reducing ambient impacts and thereby odor.

This air quality analysis work plan describes the proposed methodology for obtaining the required air permits for the installation and operation of the proposed emission sources of the AES Cedar Bay Cogeneration Project.

2.0 PROJECT DESCRIPTION

The AES Cedar Bay Cogeneration Project is a cogeneration facility to be located in Jacksonville, Florida. The proposed project site is shown on Figure 2-1. The site is located at the existing industrial site of the Seminole Kraft paper mill on the east bank of the Broward River. The proposed facility will be built between the existing mill and the river.

The AES Cedar Bay Cogeneration Project will generate process steam which will be sold to the adjacent Seminole Kraft Corporation mill and will generate approximately 225 MW of electricity for sale to Florida Power and Light Company (FP&L). The facility will be located at the existing Seminole Kraft pulp and paper mill site where oil, bark, and kraft black liquor are currently burned to produce steam and electric power.

The proposed cogeneration plant will fire bark and coal in three circulating fluidized bed (CFB) boilers which will produce steam at 1,800 psig for a new double automatic extraction condensing turbine generator. This will produce the 225 MW for sale and also 175 psig and 75 psig process steam for the mill. These boilers will be operated by AES-CB and will replace the existing three oil fired boilers and the two bark boilers at the mill.

A new kraft black liquor recovery boiler, which will be operated by Seminole Kraft, will replace the three existing recovery boilers and will produce 1,250 psig steam. A new double automatic extraction condensing turbine generator will produce 42 MW of electric power for internal mill consumption as well as 600 psig and 175 psig process steam for the kraft mill processes. Due to improvements in technology, the new boiler will utilize a noncontact black liquor evaporation system versus the direct contact evaporation system currently in service. As discussed earlier, this will result in a significant reduction in TRS emissions from the recovery boiler. The existing multiple effect evaporators (MEEs) and smelt dissolving tanks (SDTs) will also be replaced as part of this project. A basic process flow diagram for the pulping and chemical recovery equipment is given on Figure 2-2. Noncondensable gases from the new MEE are directed

PROPOSED SITE LOCATION

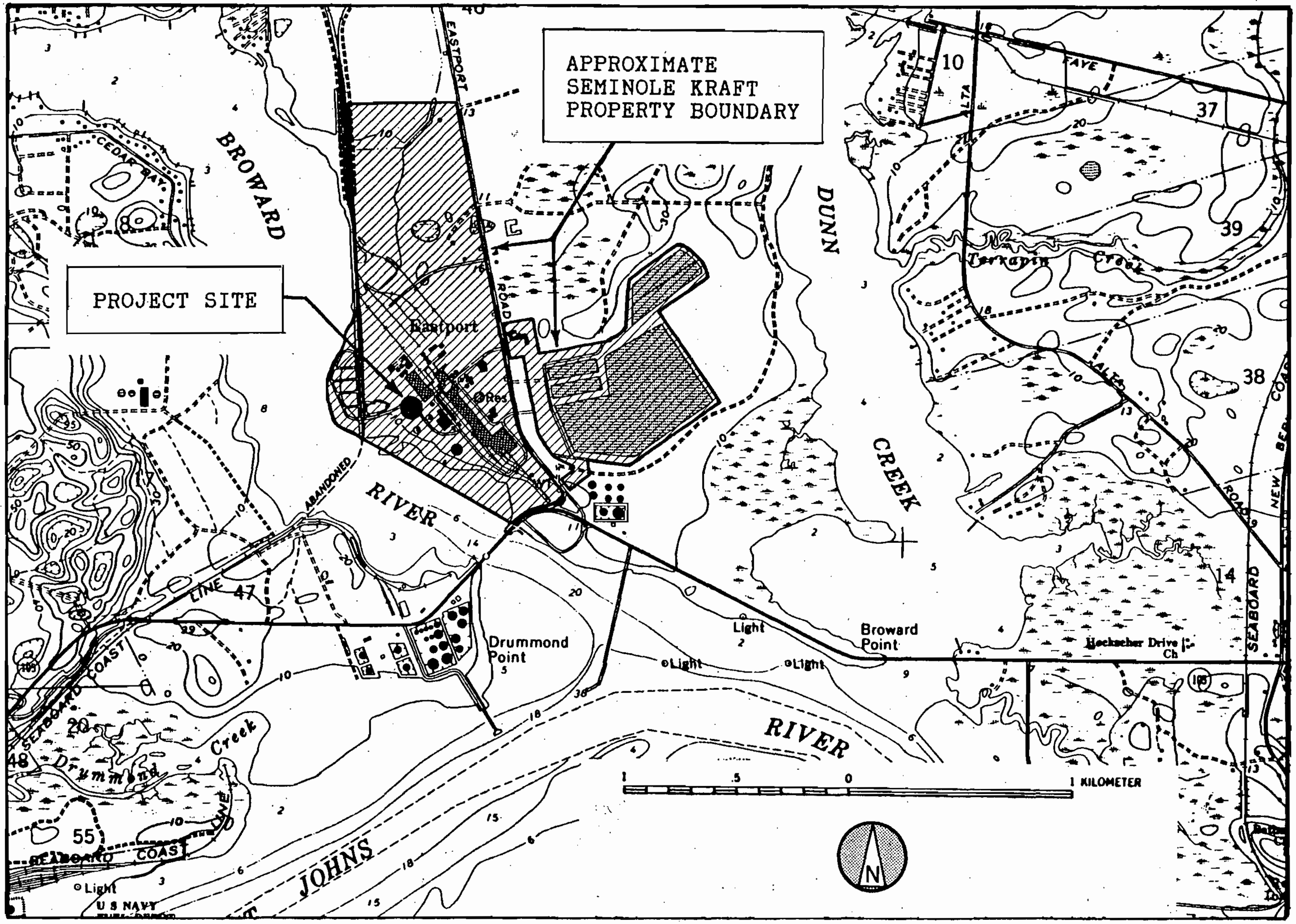

FIGURE 2-1

062288
AIRQUAL

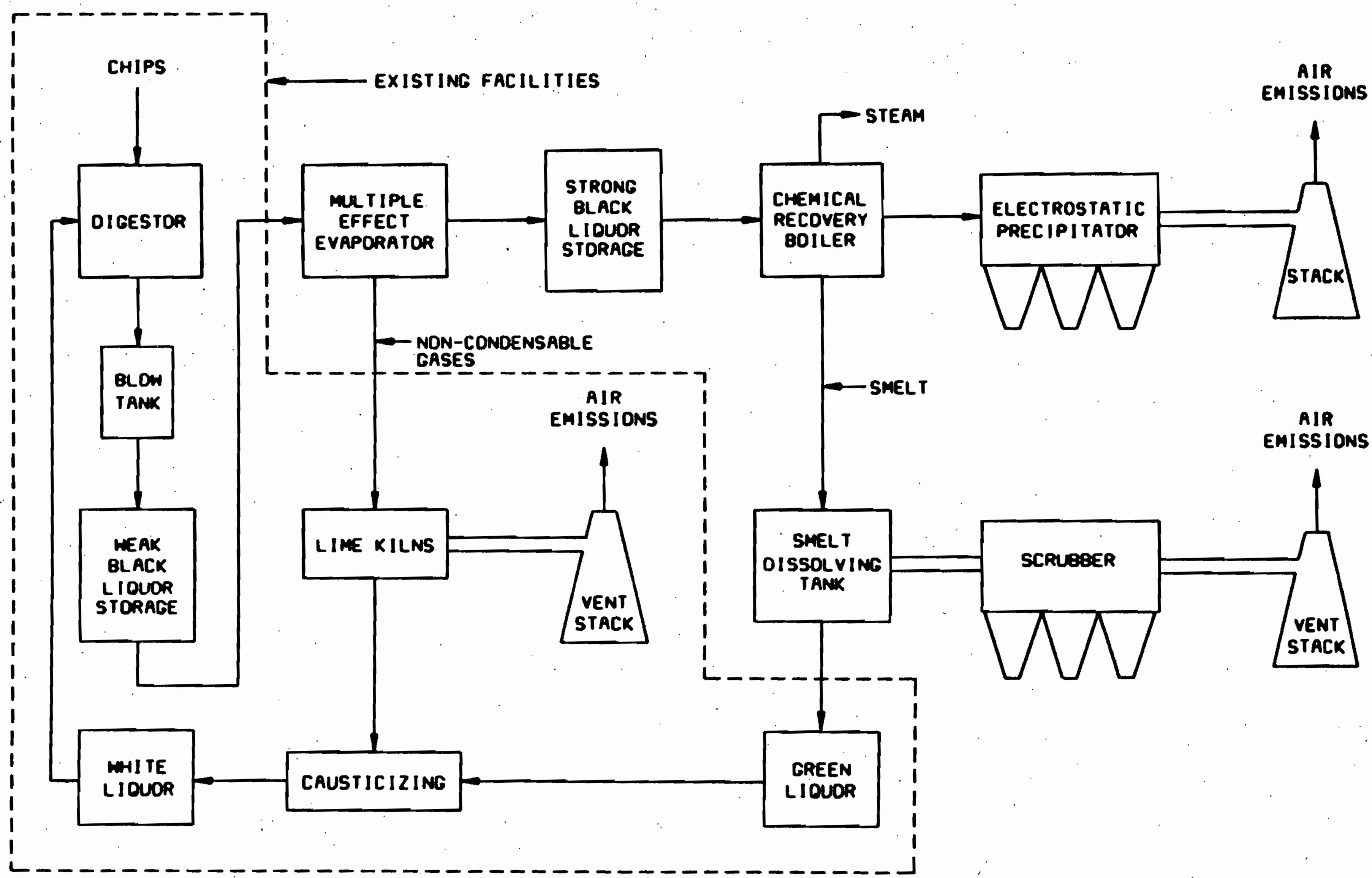

FIGURE 2.2
BASIC PROCESS FLOW
FOR PULPING AND
CHEMICAL RECOVERY

to the existing lime kilns for incineration. The net air emission changes due to the equipment replacement are discussed in Section 3 of this work plan.

The CFB boilers will burn approximately 3,200 MBtu/h. Of this, approximately 96 percent will be coal and the remainder bark. The recovery boiler will burn approximately 1,100 MBtu/h black liquor solids.

Emissions control for the CFB boilers is expected to include:

- o Limestone injection for SO_2 reduction.
- o Baghouses for particulate reduction.
- o Low combustion temperature control for NO_x reduction.

Emissions control features for the recovery boilers are expected to include:

- o Electrostatic precipitators for particulate control.
- o Non-contact black liquor evaporators for total reduced sulfur control.

Emission control for the smelt dissolving tank is expected to include a liquid contact scrubber for particulate and TRS control.

The proposed facility will receive coal by rail or barge according to economic attractiveness.

The coal combustion byproduct (ash) will be stored in silos or on impervious pads for removal from the site. This material may be sent to mines, landfilled, or potentially marketed in the engineering materials industry.

3.0 POLLUTANT APPLICABILITY

The proposed project site area is currently designated attainment for all "criteria" pollutants except ozone. A portion of Jacksonville was formerly designated nonattainment for total suspended particulate matter but was recently designated as unclassifiable with respect to new fine particulate (PM_{10}) standards.

The cogeneration project will be subject to the permitting requirements of the Prevention of Significant Deterioration (PSD) program because the net emissions increase of at least one regulated pollutant is expected to exceed 100 tons per year. Specific regulated pollutants which have net emissions increases at levels that exceed "significant" levels defined by EPA and FDER must be included in the permit application (including a Best Available Control Technology assessment).

Table 3-1 lists the estimated net increases in annual emissions for the cogeneration project. Each net emissions increase is the difference between estimated emissions from the four new boilers and SDT vent and the actual emissions from the eight boilers and SDT vents to be replaced.

Actual emissions are proposed to be based on the average of the last five mill operating years. During this period of time, mill operations were not typical, relative to the mill's capacity or historical operations. Mill ownership changed in 1983 and again in 1985 before being shut down in late 1985. Equipment reliability was poor during these years, as were mill product market conditions. The mill was purchased by Stone Container Corporation in 1986 and restarted in early 1987.

Due to the irregular nature of operations from 1982 through 1987, the proposed method of calculating representative emissions for each source in each year is as follows:

$$\text{Representative Emissions} = \text{Actual Emissions} \times \frac{\text{8400 Hours}}{\text{Actual Hours}}$$

The 8400 hour figure represents 350 operating days per year. The remaining 15 days are assumed as typical downtime needed for equipment maintenance. This is consistent with historical plant operations.

TABLE 3-1. SIGNIFICANT AND NET EMISSION RATES FOR PROPOSED FACILITY

Pollutant	Significant Emission Rates t/yr	Actual Emissions[a] t/yr	Estimated Maximum Emissions[b] t/yr	Net Increase t/yr	Applicable Pollutant Yes/No
Carbon monoxide	100	c	4,765	d	d
Nitrogen oxide	40	c	6,360	d	d
Sulfur dioxide	40	c	10,775	d	d
Particulate matter	25	c	648	d	d
Particulate matter (PM_{10})	15	c	648	d	d
Ozone (volatile organic compounds)	40	c	539	d	d
Lead	0.6	e	e	d	d
Asbestos	0.007	e	e	d	d
Beryllium	0.0004	e	e	d	d
Mercury	0.1	e	e	d	d
Vinyl chloride	1.0	e	e	d	d
Fluorides	3	e	e	d	d
Sulfuric acid mist	7	e	e	d	d
Total reduced sulfur	10	c	44	d	d

[a]Based upon average of sum of 1982, 1983, 1984, 1985, and 1987 actual emissions prorated to represent full years of operation (see Section 3.0).
[b]Based upon proposed design criteria of all proposed sources (detailed in Table 5-4).
[c]Currently in preparation.
[d]Will be included with permit application submittal.
[e]Will be estimated from fuel analysis data or applicable literature information.

The above equation would be used to estimate representative emissions from each source for years 1982 through 1985 and 1987. 1986 would be excluded since the mill did not operate during that year.

Emission figures which were not included as part of the annual mill emission reports will be estimated based on AP-42 factors.

The emission estimates for the proposed new sources assume that all new boilers will be operated at maximum load for the entire year (8,760 hours). These estimates also assume the three CFB boilers to be operated totally on coal, producing higher expected emissions than when burning bark. The "significant" levels for the regulated pollutants are included in the table for comparison.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

A BACT document will be prepared separately for the AES Cedar Bay Cogeneration Project. The BACT analysis will include those pollutants shown to be applicable because of expected significant emissions.

Under the federal Clean Air Act, BACT represents the maximum degree of pollutant reduction determined on a case-by-case basis after consideration of environmental, energy, and economic factors. However, BACT cannot be less stringent than the emission limits imposed through any applicable new source performance standard (NSPS).

The BACT analysis will follow the so-called "top down" approach as presented the December 1, 1987, memorandum from J. Craig Potter to the EPA Regional Administrators. For each pollutant or group of pollutants, the most stringent control available for a similar source or source category will be addressed first. If it can be shown that this level of control is technically or economically infeasible for the source, than the next most stringent level of control will be determined and similarly evaluated until the proposed BACT level is reached.

The proposed BACT control methods will not be finalized until after completion of the BACT analysis, but is expected to include fabric filter control for particulates, a circulating fluidized bed (CFB) boiler with limestone injection and fabric filter control for sulfur dioxide, and a CFB boiler without supplemental control for nitrogen dioxide and carbon monoxide. Because of the nonattainment status of the site and with regard to ozone, the CFB boilers will be analyzed for VOC emissions from the standpoint of Lowest Achievable Emission Rate (LAER). Expected BACT controls for the chemical recovery boiler include an electrostatic precipitator for particulate control and low-odor boiler technology for control of total reduced sulfur (TRS). The BACT control for the MEE system is expected to be incineration in the lime kilns. The BACT control for the smelt dissolving tank is expected to be a liquid contact scrubber for reducing particulate and TRS emissions.

5.0 AIR QUALITY ASSESSMENT METHODOLOGY

An analysis of flue gas emissions will be conducted to facilitate the assessment of the impacts of airborne pollutants on ground level ambient air quality levels, visibility, soils, and vegetation in the project vicinity. This section describes the overall air quality assessment methodology proposed for this study including the various modeling data requirements. The assessment methodology is based on EPA's Guideline on Air Quality Models (Revised) July 1986 (including Supplement A, July 1987) and the UNAMAP 6 dispersion models.

Copies of pertinent air quality modeling runs will be included as a separate appendix to the actual air permit application.

5.1 APPLICABLE AIR QUALITY DISPERSION MODELS

For most air quality modeling assessments it is desirable to use both screening level and refined dispersion modeling techniques. For this project, EPA's screening level model PTPLU-2 and the EPA document entitled Procedures for Evaluating Air Quality Impact of New Stationary Sources (Volume 10--Revised) will be used to determine the highest predicted ground level concentration for various plant operating conditions. The operating conditions of the circulating fluidized bed (CFB) boilers will be evaluated at 50 and 75 percent capacity plus the maximum design for the plant. The worst case operating conditions then will be further evaluated using refined dispersion modeling techniques.

The terrain is level in the vicinity of the proposed Cedar Bay Cogeneration Project. Following the recommended EPA modeling guidance for refined models, the ISCST (Industrial Source Complex Short-term) dispersion model will be used with five years of hourly meteorological data. Concentrations will be predicted for 1-, 3-, 8-, and 24-hour plus annual averaging periods.

The proposed modeling site will be considered rural for modeling purposes based on the land use within a 3-kilometer radius. Standard EPA default modeling options will be used for this analysis.

Building downwash will be used in the modeling assessment as appropriate to consider the effects of nearby buildings. The proposed new sources will utilize good engineering practice (GEP) stack heights. The PSD permit application will include a plot plan and building dimensions to support GEP determinations.

5.2 METEOROLOGICAL DATA

Preprocessed meteorological data obtained from the Florida DER for Jacksonville, Florida, for the five-year period 1981 to 1985 will be used for the dispersion modeling.

5.3 SOURCE DATA

The proposed emissions associated with this project can be classified as fugitive and combustion gas emissions. Combustion gas emissions will be evaluated for operation of the existing sources as well as proposed new sources.

5.3.1 Fugitive Dust Emissions

The generation of particulate emissions from the handling and storage of coal, wood waste, limestone, and combustion waste will be minimized. An estimated fugitive dust emissions inventory will be developed and submitted as part of the permit application. Modeling of ambient air quality impacts will be performed using the recommended ISCST dispersion model. The modeling will include both point and area sources within the plant, as appropriate. Receptors will be positioned at locations on the plant boundary and 100 meters beyond the boundary. The results of the modeling will demonstrate compliance with all particulate air quality standards.

Emission factors and typical dust control efficiencies will be obtained from EPA's Compilation of Air Pollutant Emission Factors (AP-42). The emission inventory will be based on annual material throughput for facility operation.

5.3.2 Combustion Gas Emissions

Combustion gas emissions will be evaluated for operation of the existing sources and for the new sources proposed for this project. The purpose of evaluating both existing and proposed sources is to determine the effects on the ambient air quality of replacing existing equipment with new, efficient, and well controlled boilers equipped with GEP stacks. It is anticipated that the replacement of the existing power and recovery boilers and their respective short stacks with three fluidized bed and one recovery boiler equipped with GEP height stacks will show a net ambient air quality improvement.

5.3.2.1 Existing Source Data. Table 5-1 summarizes the existing Seminole Kraft paper mill source information, including sulfur dioxide emissions in accordance with FDER's emissions inventory. A modeling study was previously performed by the FDER of major sources in the Jacksonville area to assess potential sulfur dioxide levels. For convenience, the FDER study combined similar Seminole Kraft sources into "composite" sources for modeling. The source parameters for the composite sources were developed from the combined worst-case source parameters for the sources included in each composite.

EPA's Guide for Compiling a Comprehensive Emission Inventory (March 1973) is a more refined method of "lumping" similar sources together. The procedure calculates a plume buoyancy term (K) for each individual stack using stack height (H), flow volume (V), exhaust gas temperature (T), and Emission Rates (a) in the following equation.

$$K = (H)(V)(T)/(a)$$

When combining sources, the stack with the lowest K value is selected and its stack parameters are used to represent the composite source. Emissions from all sources are added and used for the composite source. This method simplifies the dispersion modeling effort. Table 5-2 shows the simplified source configuration for the existing Seminole Kraft SO_2 sources. The stack heights for the five combined sources represent less than GEP heights and require modeling of downwash effects induced by buildings in the immediate area of the stacks.

TABLE 5-1. EXISTING SEMINOLE KRAFT SOURCE DATA

Source	SO_2 Emission Rate[a] g/sec	(x.132) lb/h	Stack Height m	Stack Exit Temperature K	Stack Exit Velocity m/sec	Stack Diameter m
P. Boiler #1	54.6	7.2	32.3	433	20.12	1.83
P. Boiler #2	72.7	9.6	32.3	450	21.34	2.13
P. Boiler #3	72.7	9.6	32.3	450	22.86	2.13
B. Boilers	114.0	15.1	41.5	329	13.72	2.44
R. Boiler #1	11.0	1.4	38.4	344	17.68	2.59
R. Boiler #2	14.1	1.9	38.4	344	17.98	2.74
R. Boiler #3	14.1	1.9	38.4	344	16.76	2.74
Lime Kiln #1	0.5	0.07	21.0	344	5.18	1.80
Lime Kiln #2	0.5	0.07	22.9	339	7.62	1.43
Lime Kiln #3	0.5	0.07	22.9	339	10.36	1.13
SDT #1	0.2	0.03	36.6	344	3.96	1.07
SDT #2	0.3	0.04	37.8	344	4.27	1.22
SDT #3	0.3	0.04	37.8	347	4.27	1.22

[a]Based on FDER data; confirmed by AES calculations.

TABLE 5-2. EXISTING COMPOSITE SOURCE DATA

Source	SO^2 Emission Rate[a] g/sec	Stack Height m	Stack Exit Temperature K	Stack Exit Velocity m/sec	Stack Diameter m
P. Boilers	200.0	32.3	433	20.12	1.83
B. Boilers	114.0	41.5	329	13.72	2.44
R. Boilers	39.2	38.4	344	16.76	2.74
Lime Kilns	1.5	22.9	339	10.36	1.13
SDTs	0.8	37.8	344	4.27	1.22

[a]Based upon FDER data; confirmed by AES calculations.

5.3.2.2 Proposed Source Data. Table 5-3 summarizes the source data for the three fluidized bed boilers, recovery boiler, and smelt dissolving tank being proposed to replace the existing three oil-fired power boilers, two bark-fueled boilers, three recovery boilers, and three smelt dissolving tanks. The three fluidized bed boilers will exhaust pollutants through a common GEP stack. The recovery boiler will be equipped with a separate GEP stack. The smelt dissolving tank will exhaust through a vent stack. MEE emissions will be routed to the lime kilns for incineration, as they currently are at the Seminole Kraft Mill.

Estimated emission rates for the fluidized bed boilers, recovery boilers, and SDT are given in Table 5-4. The boiler stack heights represent GEP heights based on an enclosed CFB boiler structure of 170 feet in height and a projected width greater than that height. The CRB structure height is estimated at 210 feet; however, the horizontal dimensions are smaller so that the structure does not influence the GEP height of the stacks. A plot plan will be included in the permit application to identify building dimensions and support the GEP determinations.

5.4 RECEPTOR DATA

The ISCST dispersion model can predict ground-level concentrations for receptor locations expressed in either polar coordinates, Cartesian coordinates (x-y), or both. Polar receptor coordinates are proposed for this analysis with the proposed CFB boiler stack located at the center of the receptor array.

Receptor locations will be established at appropriate distances and with adequate density to predict maximum concentrations for the various averaging periods and to identify the significant impact areas for criteria pollutants with significant impacts in offsite locations. With a polar receptor grid, an initial receptor array will be established according to EPA modeling workshop guidance and the PTPLU-2 modeling results. Additional receptor rings (distances) will be selected after reviewing the initial ISCST modeling results. The purpose of the additional receptor rings can be to increase the resolution of receptor spacing in the vicinity of expected maximum predicted concentrations or to extend the grid to the

TABLE 5-3. PRELIMINARY SOURCE DATA FOR NEW SOURCES

Model Parameters	Fluidized Bed Boilers	Recovery Boiler	Smelt Dissolving Tanks
Nearby Building Height	170 feet	210 feet	210 feet
Stack Height	425 feet	425 feet	240 feet
Total Heat Input	3,200 MBtu/h	1,100 MBtu/h[a]	NA
Stack Exit Velocity	3,600 ft/min	3,600 ft/min	3,056 ft/min
Stack Exit Diameter	17 feet	11.5 feet	5 feet
Stack Exit Temperature	265 F	380 F	160 F

[a]Design feedrate of 4.1 million pounds black liquor solids per day.

TABLE 5-4. ESTIMATED POLLUTANT EMISSION RATES

	Circulating Fluidized Bed Boilers		Chemical Recovery Boiler	SDT	
	Emission Rate lb/MBtu	Emissions[a] lb/h	Emissions[b] lb/h	Emission Rate[c] lb/ton BLS	Emissions[d] lb/h
CO	0.19	608	480	--	--
NO_x	0.36	1,152	300	--	--
SO_2	0.60	1,920	540	--	--
PM	0.02	64	73	0.2	11
PM_{10}[e]	0.02	64	73	0.2	11
VOC	0.016	51	72	--	--
TRS	--	--	8	0.03	2

NA based on BACT.

[a]Based upon 3,200 MBtu/h heat input to boilers.

[b]Based upon preliminary estimates from manufacturers' information and a feedrate of 4.1 million pounds black liquor solids (BLS)/day.

[c]One ton of BLS assumed to be 3,000 pounds.

[d]Based on feedrate of 4.1 million pounds BLS/day.

[e]Conservative assumption that all particulate emissions are PM_{10}.

outer bounds of significant impact areas. Higher resolution will be accomplished by bracketing the maximum predicted concentration locations by receptor rings at approximately 100 meter intervals.

6.0 AAQS ANALYSIS

The air quality impact assessment will determine the impact of the proposed facility on the Ambient Air Quality Standards (AAQS). Florida has established some air quality standards that are more restrictive than the National AAQS. The applicable federal and state ambient air quality standards are given in Table 6-1.

Since the air quality assessment will use a five-year meteorological data set, the highest second-highest modeled concentrations will be used to show compliance with all but the annual standards. As part of this assessment, it will be necessary to establish values for pollutant background concentrations.

6.1 POLLUTANT BACKGROUND CONCENTRATIONS

The state of Florida has been conducting air quality monitoring for criteria pollutants at locations throughout the state for many years. The plant site is considered to be in attainment for all criteria pollutants except ozone. Downtown Jacksonville was designated nonattainment for total suspended particulate (TSP), but was recently designated as unclassified for PM_{10}. Monitoring of PM_{10} has been performed in downtown Jacksonville (Adams Street) since early 1986. With the availability of this data and other representative monitoring data, the FDER has indicated that additional ambient air quality monitoring will not be required for this permit application.

The FDER document Ambient Air Quality in Florida 1986 (November 1987) provides the most recent monitoring data for use in establishing background concentrations for the criteria pollutants. FDER and EPA guidance would generally allow use of the highest, second-highest monitored concentrations to establish background concentrations for the project area. For this analysis, 1986 data from all Duval County monitoring sites were reviewed for each pollutant. Generally, data with the highest concentrations were selected; however, location of the samplers and monitoring objectives were also considered.

TABLE 6-1. FEDERAL AND FLORIDA AMBIENT AIR QUALITY STANDARDS

Pollutant	Sampling Period	Federal Standards Primary ug/m^3	Federal Standards Secondary ug/m^3	Florida Standards ug/m^3
Sulfur Dioxide (SO_2)	Annual	80	--	60
	24-hour	365	--	260
	3-hour	--	1,300	1,300
Nitrogen Dioxide (NO_2)	Annual	100	100	100
Particulate Matter (PM_{10})	Annual	50	50	50
	24-hour	150	150	150
Carbon Monoxide[a] (CO)	8-hour	10	--	10
	1-hour	40	--	40
Ozone (O_3)	1-hour	235	235	235
Lead (Pb)	Calendar Quarter	1.5	1.5	1.5

[a]Units are mg/m^3.

Table 6-2 summarizes the existing monitoring data being proposed as conservative values of the background pollutant concentrations for the plant area. These monitoring sites are all located within the vicinity of the proposed plant site or in the Jacksonville metropolitan area. The background concentrations for applicable criteria pollutants except for SO_2 will be combined with the predicted modeled concentrations to demonstrate compliance with the applicable standards.

6.2 APPROACH TO ADDRESS SO_2 MODELED EXCEEDENCE ISSUE

Modeling of the Jacksonville area by the FDER has indicated that if existing permitted sources were to operate at their permitted emission rates, a nonattainment area for SO_2 would exist. In accordance with FDER guidance, AES-CB will approach the permit application process in two segments.

First, AES-CB will demonstrate that net ambient impacts resulting from the project (i.e., ambient impacts from the new circulating fluidized bed and recovery boilers and SDT minus impacts from the existing power, bark and recovery boilers and SDTs, assuming Seminole Kraft permitted emission rates) will be less than significant impact levels at modeled exceedence points. That is, less than 25 ug/m^3 for a 3-hour average, 5 ug/m^3 for a 24-hour average, and 1 ug/m^3 for an annual average.

This expected demonstration is based upon both the use of offsetting emissions and the installation of good engineering practice (GEP) stacks on the new sources at the facility. Present sources are equipped with short stacks which are heavily influenced in the modeling by building downwash effects. GEP stack heights will eliminate the downwash effects of the model.

This analysis is intended to address the FDER concern for the project's impact on the SO_2 modeled exceedence issue in Jacksonville, and is our understanding of the FDER's requirement of an applicant before a permit for new construction can be considered.

Once the above criteria are met, SO_2 ambient impacts will be evaluated in the typical fashion, as described in Section 6.3 for AAQS and Section 7 for PSD increment. There will be no further evaluation relative to the modeled SO_2 exceedence issue beyond that described above.

TABLE 6-2. EXISTING AMBIENT AIR QUALITY MONITORING DATA[a]

	Measured Concentration	Location	Year
Sulfur Dioxide (ug/m^3)			
Annual	10	1960-081-H	1986
24-Hour	63	1960-081-H	1986
3-Hour	321	1960-081-H	1986
Nitrogen Dioxide (ug/m^3)			
Annual	29	1960-032-H	1985[b]
PM_{10} (ug/m^3)			
Annual	31	1960-004-H	c
24-Hour	65	1960-004-H	c
Carbon Monoxide (PPM)			
8-Hour	6	1960-082-H	1986
1-Hour	13	1960-082-H	1986
Lead (ug/m^3)			
Calendar Quarter	0.3	1960-084-H	1986

TSP

Add TSP

[a]From Ambient Air Quality in Florida 1986, Florida Department of Environmental Regulation, November 1987.

[b]1986 not available.

[c]April 1986-March 1987.

6.3 MODELED POLLUTANT CONCENTRATIONS

The net modeled impacts of applicable criteria pollutants will be assessed with regard to compliance with applicable AAQS. First, actual emissions from the existing Seminole Kraft sources, as defined in Section 3.0, will be modeled to establish "base" ambient concentrations. Next, the new sources proposed to replace the existing sources will be modeled with the same receptors. If the net changes of all offsite ambient concentrations are below significant ambient impact levels, then no additional modeling will be performed for that pollutant.

For those criteria pollutants with offsite net impacts greater than significant levels, an emissions inventory of other appropriate existing sources will be established. The inventory will be developed based on the "Screening Threshold" Method for PSD Modeling used by the North Carolina Air Quality Section. This method was previously recommended by the FDER to develop a list of sources to be included in AAQS analyses.

A background concentration for each applicable pollutant and averaging period will then be added to the total modeled impact. The background concentration, as discussed in Section 6.1, very conservatively represents the contributions from all other sources not included in the modeling analysis.

7.0 PSD INCREMENT ANALYSIS

Prevention of Significant Deterioration (PSD) regulations were promulgated as a result of the 1977 Clean Air Act Amendments to ensure that air quality in a defined area does not significantly deteriorate or exceed AAQS while providing a margin for future growth.

PSD regulations apply to areas designated as "attainment" for criteria pollutants. New sources or major modifications to existing sources that emit regulated air pollutants in "significant" amounts must comply with these regulations. As previously discussed, emission rates for the AES-CB analysis will be the net difference between emissions from the new CFBs, recovery boiler, and SDT and emissions from the existing equipment to be replaced. PSD regulations classify all areas of the country. The proposed project site has been classified a Class II PSD area. As a result of this classification, Class II PSD increments will be applicable for this analysis in all areas surrounding the facility.

In addition, any Class I area within 100 kilometers of a proposed source must be assessed to ensure that modeled impacts will not exceed Class I increments. The closest Class I area is the Okefenokee National Wilderness Area in southeastern Georgia. This area is approximately 60 kilometers from the project site. PSD Class I increment consumption will be modeled for this area in addition to the analysis of maximum Class II increment consumption. The modeling of SO_2 for Class I increment consumption will be performed using the ISC model's plume chemical transformation feature. A half-life of 4 hours will be applied for the analysis.

The PSD Class I and II maximum allowable increments are listed in Table 7-1. A source inventory of appropriate PSD increment consumers will be developed in the same manner as for the AAQS analysis. A list of potential PSD consuming sources will be obtained from FDER to use in developing the final source inventory.

TABLE 7-1. PSD CLASS I AND CLASS II AIR QUALITY INCREMENTS

Pollutant	Class I Increment ug/m^3	Class II Increment ug/m^3
SO_2		
Annual	2	20
24-Hour	5	91
3-Hour	25	512
Particulates		
Annual	5	19
24-Hour	10	37
NO_x[a]		
Annual	2.5	25.0

[a]Proposed February 8, 1988.

8.0 ADDITIONAL IMPACT ANALYSIS

8.1 VISIBILITY

The nearest PSD Class I area is the Okefenokee National Wilderness Area in southeastern Georgia. This Class I area is approximately 60 kilometers from the site. An analysis of potential visibility degradation will be performed based on EPA guidance materials. A Level-1 assessment is expected to show no significant effect on the visibility in the Class I area. It is anticipated that the removal of the existing boilers and installation of the newer boilers will have a favorable affect on the overall visibility in the project site area as well.

8.2 SOILS AND VEGETATION

The analysis will examine the levels at which the soil and vegetation in the area are adversely impacted by various pollutants and compare these levels with the predicted net impacts due to the proposed facility.

8.3 GROWTH

The potential for secondary effects on air quality will also be assessed. The possible effects of the proposed facility on economic and population growth will be discussed.

Jeffrey V. Swain
Project ~~Development Manager~~ Director

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2-4-88

AES JACKSONVILLE PPS.

Owner/Operator of PP facility (Rt) cogen trend
Try to have facility get competitive with utilities

140MW @ TX 110 mill. (40%) was controls on PP built before. (Acid control inclu)
120MW @ PA. coal.

2 under Construction in California (natural gas)
Most recent project 300MW (Oklahoma) Coal fired (fluid bed)

Seminole Kraft
- Oil / Bark Power Boilers { 3 coal/bark, 1 oil, 1 R. Boiler
- Recovery Boiler odor problem

Generate 250
New 225 MW Cogeneration [1 low odor R. Boiler, 3 coal/Bark boilers (fluidized bed)
Replace the above Boilers.

Steam to S.K.
225 MW thru JEA & FPL

Recovery Boiler needs to comply with TRS rule.

March 10 will have 80% meeting in Jacksonville, MAX.

Bruce feels time frame: at least 10 MO after complete application
: or later if litigation.

Check water discharge with EPA for significant change from NPDES.
Steve Day feels the NPDES permit is needed regardless just cause its new.

FPL expects need for 1600 MW by mid 90's.

This project may substitute for FPL plans for gas fired combined cycle unit next.

PM10 monitoring data source questions for Bay/Mear
Other requirements past EPA approval of SIP. (1 yr maybe).

AN OVERVIEW OF

AES JACKSONVILLE

COGENERATION FACILITY

FEBRUARY 1988

APPLIED ENERGY SERVICES, INC.

OVERVIEW

- AES has been developing a cogeneration facility on an existing industrial site in Jacksonville, Florida
    - Steam will be sold to the Seminole Kraft paper mill that was refurbished by Stone Container Corporation in the fall of 1986 and restarted in February 1987, and
    - 225 MW of electricity will be wheeled through Jacksonville Electric Authority (JEA) and sold to Florida Power and Light
- The new power facility, valued at approximately $400 million, will consist of the following:
    - one new low-odor recovery boiler and an associated turbine, and
    - three new circulating fluidized bed (CFB) boilers and associated turbine
- The project will replace older, less efficient equipment, improving Seminole Kraft's competitive position and reducing odor emissions.
- Bark and coal will be fired in the CFB boilers to generate steam
- This document provides information about the planned cogeneration facility and AES.

ATTRACTIVE FEATURES OF THE PROJECT

Economic

- Provides attractively priced electricity to Florida ratepayers under a stable rate structure
- Steam at below-market prices improves Seminole Kraft's competitive position, thus improving employment stability.
- $400 million cogeneration project provides up to 660 construction jobs and 95 new permanent jobs at the AES plant;
- Facility increases the tax base in the City of Jacksonville, resulting in expanded tax revenues.
- Supports diversification of industrial mix in Jacksonville

Energy

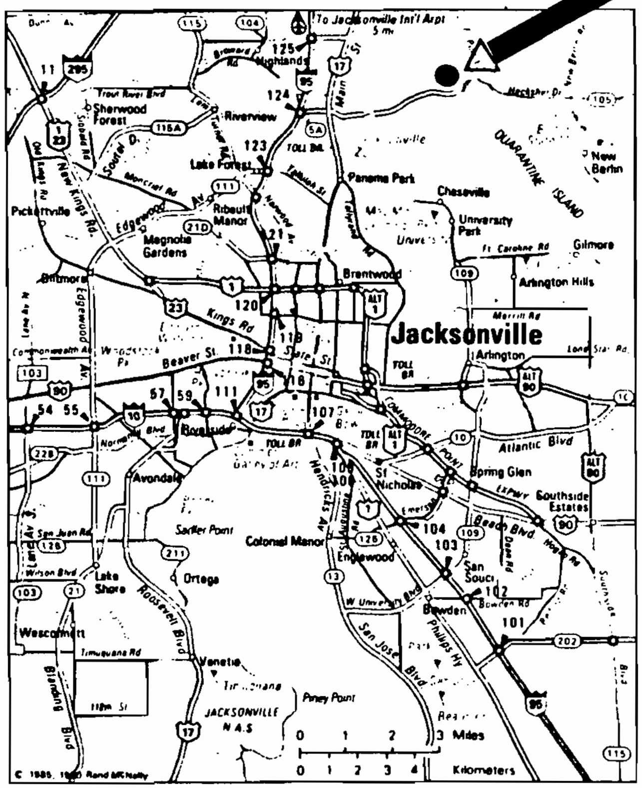
- Facility displaces oil use at the Seminole Kraft mill
- Coal abundantly available and not dependent on foreign suppliers
- Adds needed electric generating capacity in Florida for mid 1990's and beyond
- Consistent with State energy policy that favors coal in new generating facilities

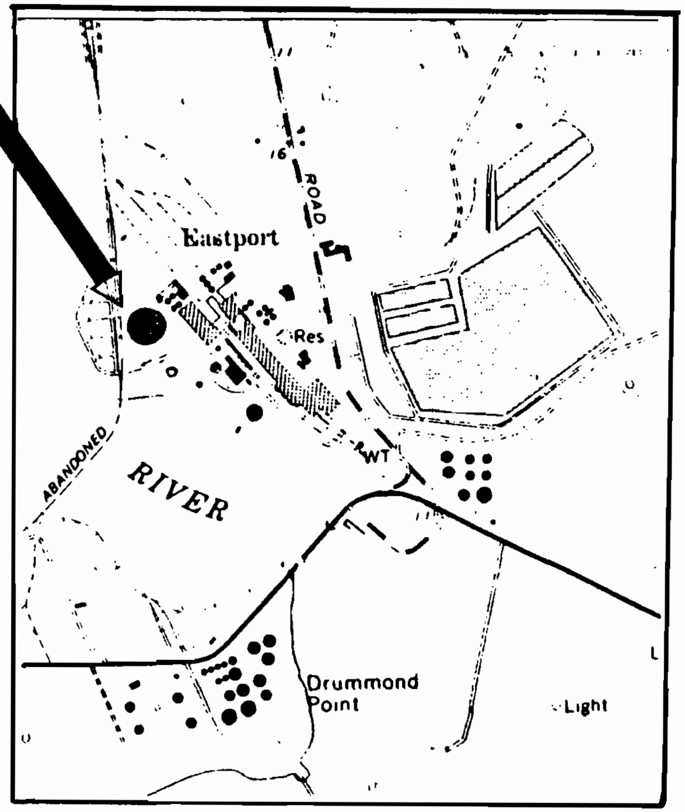
Environmental

- Located on an existing industrial site adjacent to Seminole Kraft.
- New recovery boiler reduces odor and particulate emissions from the mill
- Offsets emissions from oil-fired boilers at Seminole Kraft mill
- Allows coal to be used with minimal air pollution through application of new technology (i.e., circulating fluidized bed boilers)

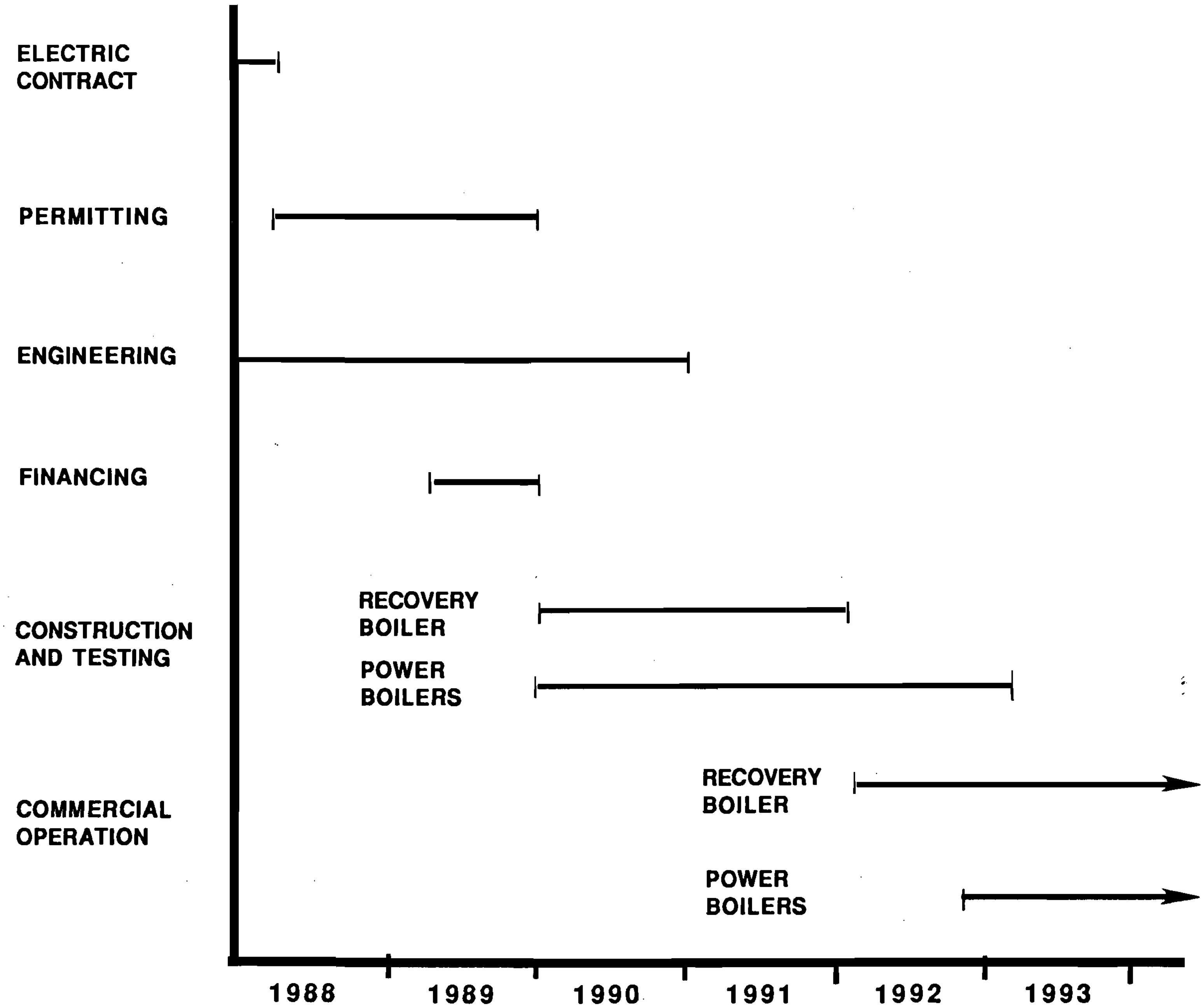
AES JACKSONVILLE LOCATION

- The plant will be located on the site of the Seminole Kraft paper mill on Eastport Road





PROJECT SCHEDULE



APPLIED ENERGY SERVICES, INC.

NEXT STEPS

- Signing of power supply contract with Florida Power and Light (FP&L) expected in the next several weeks
- Initiating site certification and permitting effort; looking forward to working closely with appropriate agencies to facilitate the permitting process
- Engineering, Fuel Procurement, Steam and Wheeling Contract development efforts are underway
- AES looks forward to developing a plant adjacent to Stone Container in Jacksonville as we did in Connecticut (see enclosed press release)
- Questions regarding AES Jacksonville can be directed to Jeffrey V. Swain, Project Director, AES Jacksonville at (703-522-1315)

AES OFFICERS AND DIRECTORS

BOARD OF DIRECTORS

DENNIS W. BAKKE	COO of AES, Former Deputy Assistant Administrator at the Federal Energy Administration
FRANK JUNGERS	Retired Chairman of the Board and Chief Executive Officer of Arabian American Oil Company (ARAMCO).
HENRY R. LINDEN	Frank Gunsalus Professor of Engineering at Illinois Institute of Technology and Former President of the Gas Research Institute.
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ROGER W. SANT	Chairman/CEO of AES, Former Assistant Administrator for Energy Conservation and Environment at the Federal Energy Administration.
RUSSEL E. TRAIN	President and Chief Executive Officer of World Wildlife Fund, U.S. and former Administrator, Environmental Protection Agency.
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ROBERT H. WATERMAN, JR.	Founder of Waterman & Company, former director of McKinsey & co-author of the bestseller In Search of Excellence, and author of The Renewal Factor published in September 1987.

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AES EXPERIENCE

AES FACILITY/ LOCATION	CUSTOMERS	COST Million	FUEL	STEAM (#/HR)	POWER (MW)	CONT. START	ON LINE
Deepwater Houston, Texas	Texas Utilities Lyondell Petrochemical	$280	Petcoke	30,000	139	December 1983	June 1986
Beaver Valley Monaca, Pennsylvania	West Penn Power Arco Chemical	116	Coal	145,000	118	September 1985	July 1987
Placerita Newhall, California	Southern California Edison, TOSCO	120	Gas	250,000	99	July 1986	July 1987
Thames Montville, Connecticut	Northeast Utilities Stone Container	250	Coal	65,000	180	December 1986	November 1989
Shady Point Poteau, Oklahoma	Oklahoma G&E AES CO_2 Plant	475	Coal	100,000	320	June 1987	January 1991
Riverside Woonsocket, Rhode Island	New England Electric Boston Edison Eastern Utilities Associates	260	Coal	50,000	180	1989	1991
Barbers Point Oahu, Hawaii	Hawaiian Electric Chevron*	250	Coal	30,000	146	1989	1992
Petrolia Petrolia, Pennsylvania	West Penn Power	280	Coal	30,000	180	1992	1995
Ballinger Creek Frederick, Maryland	Potomac Electric*	270	Coal	30,000	180	1990	1993
Jacksonville	Florida Power & Light Stone Container*	400	Coal	600,000	225	1990	1993
TOTAL		$2701 Million		1,330,000 lb/hr	1767 MW		

* Letter of Intent agreements signed

This announcement appears as a matter of record only.

Non-Recourse Project Financing for a 180 Megawatt Cogeneration Facility

$250,000,000

AES Thames Inc.

a wholly-owned subsidiary of

Applied Energy Services, Inc.

Senior Debt Provided by:

Agent

The Fuji Bank, Limited
New York Branch

Lead Managers

The Fuji Bank, Limited New York Branch | **Bank of New England N.A.** | **The Bank of Nova Scotia**

The Nippon Credit Bank, Limited New York Branch | **Westpac Banking Corporation**

Participants

The Chuo Trust & Banking Co., Limited New York Agency | **The Daiwa Bank, Limited** New York Branch

The Hokkaido Takushoku Bank, Limited New York Branch | **The Saitama Bank, Ltd.** New York Branch | **The Tokai Bank, Limited** New York Branch

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Subordinated Debt Provided by:

Marubeni America Corporation | **Combustion Engineering, Inc.** | **CSX Transportation, Inc.**

Toshiba International Corporation

The undersigned acted as financial advisor to Applied Energy Services, Inc.

Salomon Brothers Inc

One New York Plaza, New York, New York 10004
Atlanta, Boston, Chicago, Dallas, Los Angeles, San Francisco, Zurich.
Affiliates: Frankfurt, London, Tokyo.
Member of Major Securities and Commodities Exchanges.

Applied
Energy
Services,
Inc.

Contact: Mr. Robert F. Hemphill, Jr.
703/522-1315
November 26, 1986

For Immediate Release

AES AWARDS $180 MILLION POWER PLANT CONSTRUCTION CONTRACT TO JAPANESE-AMERICAN JOINT VENTURE. $250 MILLION PROJECT FINANCING COMPLETE.

ARLINGTON, VA, November, 1986: Applied Energy Services, Inc. (AES) announced today that it has awarded a $180 million contract to a joint venture of Marubeni, Toshiba and Pritchard to construct its AES Thames Cogeneration plant in Montville, Connecticut. "We are pleased not only because the Thames plant is our largest project to date but because it incorporates many advanced features to minimize impact on the environment," stated Roger Sant, President and CEO of AES.

The project will cost $250 million and is being financed by a syndicate of banks led by Fuji Bank, Ltd. as Agent. Other participating banks include the Bank of New England, N.A., the Nippon Credit Bank, Ltd., the Bank of Nova Scotia, the Westpac Banking Corporation, the Chuo Trust & Banking Co., Ltd., the Daiwa Bank, Ltd., the Hokkaido Takushoku Bank, Ltd., and the Saitama Bank, Ltd. Salomon Brothers Inc. is serving as Financial Advisor for AES. AES Executive Vice President Dennis W. Bakke praised the leadership of Fuji and the cooperation of the bank group. "Additionally, the subordinated lenders including Marubeni America Corporation, Combustion Engineering Corporation, CSX Transportation and Toshiba International were also critical to a timely and successful financing."

The plant, which is being engineered by Black and Veatch of Kansas City, Missouri, consists of two Combustion Engineering circulating fluidized bed boilers and a Toshiba steam turbine-generator. The plant is scheduled to begin operation in mid-1989. It is expected to produce 180 megawatts of electricity (sufficient to supply 36,000 homes) for sale to Connecticut Light & Power on a 25-year contract, and 60,000 pounds an hour of steam to be sold to a

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subsidiary of Stone Container Corporation. "The plant will be supplied with approximately 600,000 tons of coal each year through an innovative contract with CSX Transportation," explained AES Senior Vice President Robert F. Hemphill, Jr. "This is the first coal plant to be built in New England in many years and our design incorporates the advanced fluidized bed combustion technology."

AES is a privately held company formed in 1981. The company is an independent supplier of steam and electricity and was recently designated the twelfth fastest growing private company in the United States by INC. Magazine. It operates a 140 megawatt petroleum coke fired cogeneration plant in Houston, Texas, is refurbishing a 120 megawatt coal fired cogeneration plant near Pittsburgh, Pennsylvania and is constructing a 100 megawatt natural gas-fired cogeneration plant near Los Angeles, California. In addition, AES is developing several other power plants around the country.

10-28-87

Seminole
[redacted] KRAFT

AES Inc

will build cogen, they will run & own the facility. Jax Kraft's property will be used & also they will buy the steam
250 MW

Problem with SO_2 short term & any ambient.

New Replaces old.

OLD - are oil fired boiles
New - coal fired lime injection fluidized.
(better SO_2 control.)

Duval C. unclassifiable for SO_2