POLK POWER
PARTNERS

1125 U.S. 98 SOUTH
SUITE 100
LAKELAND, FLORIDA 33801
813-682-6338
FAX 813-683-8257

RECEIVED
SEP 26 1994
Bureau of
Air Regulation

September 22, 1994

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

RE: Mulberry Cogeneration Project, PSD-FL-187 (AC53-211670)
New Source Performance Standards (NSPS) - Compliance Test
FDEP Air Permit - Compliance Test

Dear Mr. Fancy:

This correspondence is submitted on behalf of Polk Power Partners, LP to request that the Mulberry Cogeneration Facility's NSPS compliance testing deadline be extended until December 31, 1994. The facility has recently experienced mechanical difficulties that would preclude it from completing the compliance testing within the original time frame. The NSPS and FDEP air permit compliance testing has been tentatively scheduled to begin on October 18, 1994.

Please notify me prior to October 4, 1994, if you need any further information in order for Polk Power Partners to satisfy the testing notification requirements. I may be contacted at (813) 683-6338.

Sincerely,

Nancy Henning Jones
Vice President & General Manager

cc: Jewell A. Harper
Dr. Richard D. Garrity
Mike Moran
Les Confair
Joe Emberger
William Malenius
Monty Jasper
John Paul Jones
Robert McCullom
Wendel Ellis
Kelly Spencer

Is your RETURN ADDRESS completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
   Mr. William R. Malenius
   Polk Power Partners
   23406 Avenida De La Carlota,
   Suite 400
   Laguna Hills, CA 92653

4a. Article Number
P 872 562 605

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
2-25-94

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 605

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. William R. Malenius	
Street and No. 23406 Avenida De La Carlota Ste 400	
P.O., State and ZIP Code Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 2-21-94 Permit: AC53-211670 PSD-FL-187	

PS Form **3800**, JUNE 1991

POWER OPERATIONS DIVISION
C · S · W
ENERGY
A CENTRAL AND SOUTH WEST COMPANY

Mulberry Cogen
P.O. Box 824 • 3600 Hwy. 555
Bartow, FL 33830
813-533-9073 • Fax 813-533-4092

RECEIVED
NOV 15 1994
Bureau of
Air Regulation

November 11, 1994

State of Florida
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Polk Power Partners, L.P.
Permit Number: AC 53-211670
PSD-FL-187

Dear Sir or Madam:

Please be advised that at the present time we are experiencing some difficulty with our engine which may cause a delay in our source testing (see letter dated October 28, 1994). We will continue to keep you informed of any changes. If you have any questions, please call me at (813) 533-9073.

Sincerely,

John Paul Jones
Manager of Cogeneration

/pcp
xc: Nancy Jones, Polk Power Partners
Linda Novak, Polk Co BCC
Bill Thomas, SWD } 11-15-94 RA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

4APT-AEB

OCT 19 1994

RECEIVED
OCT 24 1994
Bureau of
Air Regulation

Mr. Clair Fancy
Chief
Bureau of Air Regulation
Air Resources Management Division
Florida Department of Environmental
Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Extension of the New Source Performance Standard (NSPS) Initial Testing Deadline Requested for the Polk Power Partners Mulberry Cogeneration Project

Dear Mr. Fancy:

The purpose of this letter is to provide you with comments on the referenced test extension request that Polk Power Partners submitted jointly to the U.S. Environmental Protection Agency (EPA) Region IV and the Florida Department of Environmental Protection on September 22, 1994. The company is requesting an extension of the deadline to conduct an initial test on a cogeneration facility that is subject to NSPS. In accordance with 40 C.F.R. §60.8(a), initial testing must be conducted within 60 days after reaching maximum production, but not later than 180 days after initial startup. Because of mechanical problems, Polk Power Partners will not be able to conduct an initial test within 180 days after startup.

Based upon the review of the request from Polk Power Partners, an extension of the initial testing deadline would be appropriate if the extension is consistent with previous EPA policies regarding testing deadlines for facilities that cannot operate due to equipment malfunctions. The basic EPA policy on such extensions was established in a memo issued by EPA Headquarters in 1977, and a copy of this memo which was downloaded from the EPA Applicability Determination Index is enclosed. According to this memo, testing should be conducted as soon as practicable, but not more than 30 days after restarting, if a facility is shutdown due to equipment malfunctions and cannot conduct an initial test within 180 days after startup.

In addition to requiring that testing be conducted as soon as practicable after restarting the facility, the 1977 guidance also requires that a subsequent test be conducted after the facility reaches its maximum production rate if the facility cannot be operated at its maximum production rate during the initial test. The purpose for this requirement is to ensure that

the affected facility is able to comply with the applicable standard(s) under "worst case" operating conditions.

If initial testing extension requests are submitted to your agency in the future, it will not be necessary to submit them to Region IV for approval if extensions granted are consistent with the guidance issued in 1977 (i.e., testing is completed within 30 days after the facility restarts, and if necessary, two tests are conducted when a facility cannot be operated at its maximum production rate during the initial test). Any extension requests that deviate from this policy should be submitted to Region IV for review.

If you have any questions about the issues addressed in this letter, please contact Mr. David McNeal of my staff at 404/347-3555, voice mailbox 4158.

Sincerely yours,

Jewell A. Harper
Chief
Air Enforcement Branch
Air, Pesticides and Toxics
Management Division

cc: State and Local Air Directors

Enclosure

cc: J. Reynolds
B. Thomas, SW Dist
D. Martin, Polk Co.
J. Bunyak, NPS
K. Kosky, KBN
D. Roberts, HBGS
CHF/SB

DOWNLOAD REPORT

Selection Criteria:
REFERENCE = 113(a)

Control Number: A042
Title: NSPS PERFORMANCE TEST VIOLATION

Recipient: WU, JAMES, REGION IV

Author: REICH, EDWARD E., DSSE

Date: 09/29/77
Comments:

Keywords:
MALFUNCTION
OPERATION, CONTINUOUS
PERFORMANCE TEST
STARTUP

Subparts:
A

References:
113(a)
60.8(a)

What procedure should be followed when an affected facility has not been performance tested in the 180 day period following startup due to shutdowns caused by equipment malfunctions?

Consider issuing a CAA Section 113(a) order requiring the owner or operator to notify the Administrator upon re-startup (by telephone; to be followed by confirmation in writing) and also requiring a performance test as soon as practicable thereafter but no later than 30 days after re-startup. If the facility is unable to operate at the maximum production rate for the initial performance test, a subsequent performance test may be required when the facility achieves maximum production in order to assure compliance with the standard.

Control Number: A042

September 29 1977

MEMORANDUM

SUBJECT: NSPS Performance Test Violation

FROM: Director, DSSE

TO: James Wu, R-IV

This is in response to your phone call of September 1, 1977, requesting our thoughts on the procedure to be followed when an affected facility has not been performance tested in the 180-day period following startup, as required by 40 CFR ^U60.8(a). The subject source has not been in continuous operation during that period due to repeated shutdowns caused by process equipment malfunction. It seems appropriate to consider issuing an order pursuant to Section 113(a) of the Clean Air Act requiring that the owner or operator of the affected facility notify the Administrator upon restartup (by telephone; to be followed by confirmation in writing) and also requiring a performance test as soon as practicable thereafter but no later than 30 days after restartup. If the facility is unable to operate at the maximum production rate for the initial performance test, a subsequent performance test may be required when the facility achieves maximum production in order to assure compliance with the standard.

If you should have any further questions on this determination, please contact Craig Cobert (FTS-755-2546) of my staff.

Edward E. Reich

EN-341:Cobert:pas:9/27/77

Mulberry Cogen
Polk Power
AC 53-211670
PSD-FL-187

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

August 3, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William R. Malenius
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, CA 92653

Dear Mr. Malenius:

Re: Amendment to Construction Permit
AC53-211670 (PSD-FL-187)
Custom Fuel Monitoring Schedule
Mulberry Cogeneration Project

This is in response to your March 7, 1994, letter, requesting a Custom Fuel Monitoring Schedule for sulfur at the subject facility. The permit amendment fee was received on June 28, 1994. The facility is required to comply with Section 60.334(b) of Subpart GG of the New Source Performance Standards, which states that sources may apply for a custom fuel monitoring schedule. Therefore, the permit specific conditions are amended as follows:

New Specific Condition No. 10

A custom fuel monitoring schedule shall be followed for natural gas fired at this facility, as follows:

Custom Fuel Monitoring Schedule for Natural Gas

1. **Monitoring of fuel nitrogen content shall not be required since natural gas is the only fuel being fired in the gas turbines.**

2. **Sulfur Monitoring**

   a. **Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82 as referenced in 40 CFR 60.335(b)(2).**

   b. **This custom fuel monitoring schedule shall become effective on the date this permit becomes valid. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and**

indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is provided by the applicant which demonstrates consistent compliance with the requirements herein, the applicant may begin monitoring as per the requirements of 2(c).

c. If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

d. Should any sulfur analysis as required in items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be re-examined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

3. If there is a change in fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

Attachments to be Incorporated

KBN letter received March 9, 1994.
(Permit Amendment Fee Received June 28, 1994)

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the applicant of the amendment request/application and the parties listed below must be filed within 14 days of receipt of this

amendment. Petitions filed by other persons must be filed within 14 days of the amendment issuance or within 14 days of their receipt of this amendment, whichever occurs first. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information:

(a) The name, address and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action;
(g) A statement of the relief sought by petitioner, stating precisely the action the petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this amendment. Persons whose substantial interests will be affected by any decision of the Department with regard to the request/ application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this amendment in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

This letter amendment must be attached to Construction Permit No. AC53-211670 (PSD-FL-187), and shall become part of the permit.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes
Director
Division of Air Resources Management

HLR/JR/pm

Attachments

cc: B. Thomas, SWD
J. Harper, EPA
J. Bunyak, NPS
K. Kosky, KBN

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this AMENDMENT and all copies were mailed by certified mail before the close of business on 8/4/94 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara F. Boutwell 8/4/94
(Clerk) (Date)

Florida Department of

Memorandum **Environmental Protection**

TO: Howard L. Rhodes

FROM: C. H. Fancy

DATE: August 3, 1994

SUBJECT: Amendment to Construction Permit AC53-211670 (PSD-FL-187)
Mulberry Cogeneration Project

Attached for your approval and signature is a permit amendment prepared by the Bureau of Air Regulation for the above mentioned company to have a customized fuel monitoring schedule as provided by Subpart GG of the federal new source performance standards.

I recommend your approval and signature.

CHF/JR/bjb

Attachment

BEST AVAILABLE COPY

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

MS 5505

CERTIFIED
P 872 562 712
MAIL

8/4/94

Mr. William R. Malenius
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, CA 92653

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. William R. Malenius
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, CA 92653

4a. Article Number
P 872 562 712

4b. Service Type
☐ Registered ☐ Insured
XX Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)

PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 DOMESTIC RETURN RECEIPT

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. William R. Malenius
Polk Power Partners
23046 Avenida De La Carlota
Suite 400
Laguna Hills, California 92650

4a. Article Number
P 872 562 709

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)
Cindy Seale

PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 712

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to: Mr. Willam R. Malenius	
Street and No.: 23293 South Pointe Drive	
P.O., State and ZIP Code: Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 8/4/94 AC53-211670 (PSD-FL-187)	

PS Form 3800, JUNE 1991

P 872 562 709

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to: Mr. William R. Malenius	
Street and No.: 23046 Avenida De La Carlota	
P.O., State and ZIP Code: Laguna Hills, CA 92650	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 8/16/94 AC53-211670(PSD-FL-187)	

PS Form 3800, JUNE 1991

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

4APT-AEB

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

Re: Approval of NSPS Custom Fuel Monitoring Schedules for:
Mulberry Cogeneration Project, PSD-FL-187 (AC53-211670);
Lake Cogeneration Project, PSD-FL-176 (AC15-196459); and
Pasco Cogeneration Project, PSD-FL-177 (AC51-196460).

Dear Mr. Fancy:

This is to acknowledge letters from KBN Engineering and Applied Sciences, Inc. (KBN) dated March 7, 1994, and March 17, 1994, requesting approval of customized fuel monitoring schedules for the above referenced projects. These requests were jointly transmitted to the U.S. Environmental Protection Agency (EPA), and to you. Since the authority for implementing §60.334(b) of 40 CFR Part 60, Subpart GG has not been delegated to the State of Florida, we have reviewed KBN's custom fuel monitoring schedules.

Based on our review we have determined that the proposed schedules are acceptable, as long as each source also complies with items 2(d), 3, and 4 of the attachment to the custom fuel monitoring guidance memo issued by EPA Headquarters on August 14, 1987. A copy of this memo was included in KBN's request as attachment.

If you have any questions regarding this letter, please contact Mr. Mirza P. Baig of my staff at 404/347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, & Toxics
Management Division

cc: Kennard F. Kosky
KBN Engineering

Printed on Recycled Paper

MULBERRY COGENERATION FACILITY
POLK POWERS PARTNERS, L.P.
1125 US HIGHWAY 98 SOUTH, SUITE 100
LAKELAND, FLORIDA 33801
Telephone: (813) 682-6338
Fax: (813) 683-8257

RECEIVED
JUL 29 1994
Bureau of
Air Regulation

July 20, 1994

Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400
Attn: Bureau of Air Regulation

Re: Prevention of Significant Deterioration Construction Permit for Mulberry Cogeneration/CO_2 Facility Letter
Dated: November 20, 1992
DER File No./Permit No.: AC53-211670
Issue Date: November 20, 1992

POLK POWER PARTNERS, L.P. Qualified to do business in Florida as Polk Power Partners, L.P., Ltd.
NOTICE OF CHANGE OF ADDRESS

Please change the address and telephone number of the above-referenced Notice of Permit letter as noted below:

NEW ADDRESS

Polk Power Partners, L.P.
(dba Polk Power Partners, L.P., Ltd.)
c/o Polk Power GP, Inc.
1125 US Highway 98 South, Suite 100
Lakeland, FL 33801
Attention: Vice President, General Manager

Telephone: (813) 682-6338
Fax: (813) 683-8257

Please contact us should you have any questions regarding this change. Thank you in advance for your cooperation.

Vice President,
General Manager

File

POWER OPERATIONS DIVISION
C · S · W
ENERGY
A CENTRAL AND SOUTH WEST COMPANY
Mulberry Cogen
P.O. Box 824 • 3600 Hwy. 555
Bartow, FL 33830
813-533-9073 • Fax 813-533-4092

RECEIVED
JUL 21 1994
Bureau of
Air Regulation

July 18, 1994

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

Re: Mulberry Cogeneration Project, PSD-FL-187 (AC53-211670)
Notification of Combined Cycle Operation

Dear Mr. Fancy:

This correspondence is submitted on behalf of Polk Power Partners to serve as notification that the Mulberry Cogeneration Facility accomplished combined cycle operation, as scheduled, on July 14, 1994. This notification is given as required per 40 Code of Federal Regulations Part 60, Section 60.7(a) regarding New Source Performance Standards.

If you have any questions, please feel free to contact me at (813) 533-9073.

Sincerely,

John Paul Jones
Manager of Cogeneration

/pcp
xc: Ms. Jewell A. Harper, Chief
Air Enforcement Branch
Ms. Nancy Jones,
Polk Power Partners

PLEASE DETACH AND RETAIN FOR YOUR RECORDS

DATE		VOUCHER NO.	AMOUNT
06/28/94	Mulberry Cogeneration Project NSPS Custom Fuel Monitoring Permit No. AC53-211670, PSD-FL-187		250.00

PAY **********250*** DOLLARS AND 00 CENTS $ ******250.00

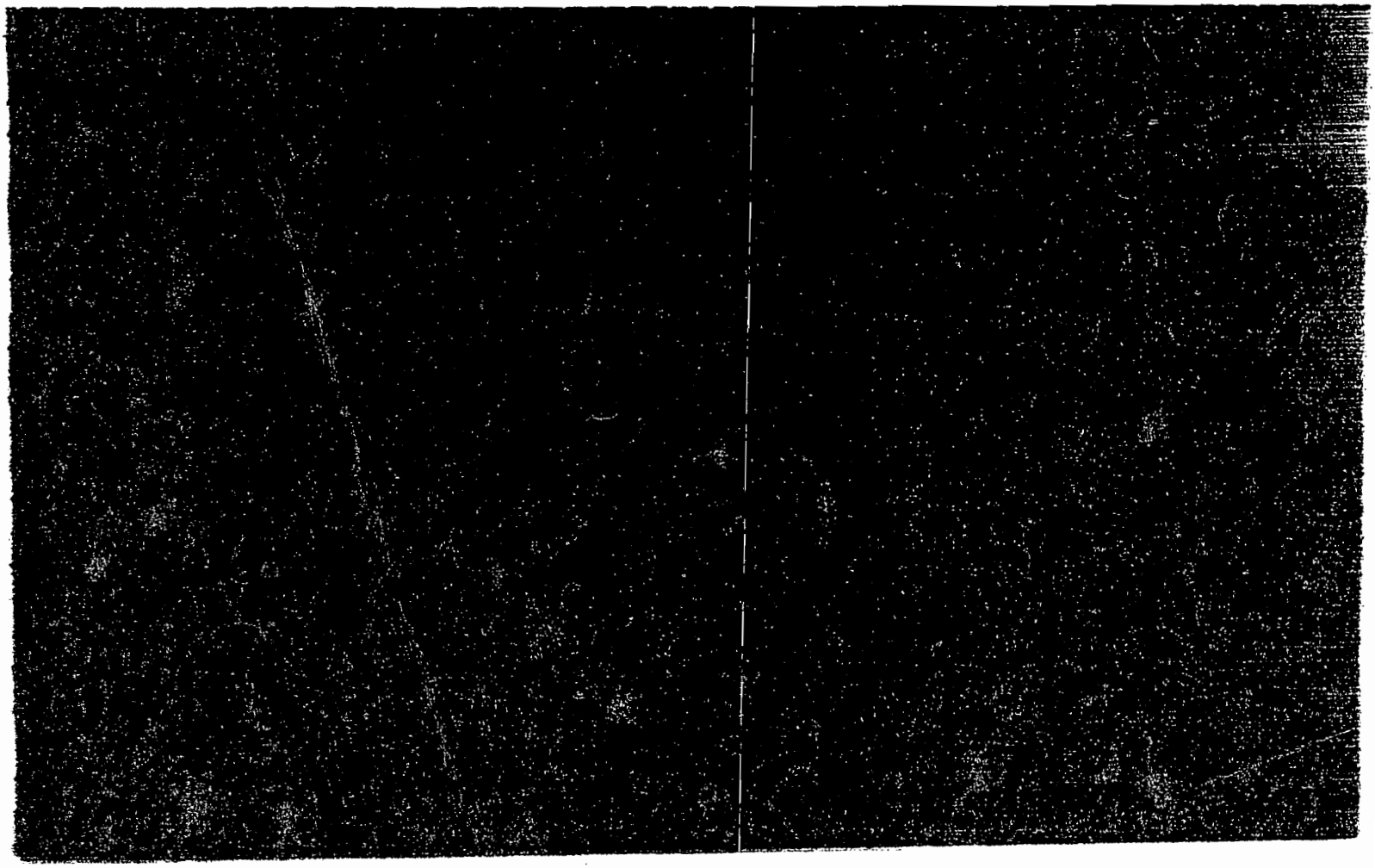
KBN ENGINEERING AND APPLIED SCIENCES, INC.

AUTHORIZED SIGNATURE

TO THE ORDER OF

Florida Department of Environmental Regulation
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee FL 32399-2400

[redacted]



POLK POWER PARTNERS

1125 US HIGHWAY 98 SOUTH
SUITE 100
LAKELAND, FLORIDA 33801
813-682-6338

RECEIVED
JUN 24 1994
Bureau of
Air Regulation

June 23, 1994

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

RE: Mulberry Cogeneration Project, PSD-FL-187 (AC53-211670)
New Source Performance Standards (NSPS) - Initial Facility Startup

Dear Mr. Fancy:

This correspondence is submitted on behalf of the Polk Power Partners to serve as notification that the Mulberry Cogeneration Facility's initial startup is scheduled to occur on July 14, 1994. This notification is given as required per 40 Code of Federal Regulations Part 60, Section 60.7(a) regarding New Source Performance Standards.

If you have any questions, please feel free to contact me at (813) 682-6338.

Sincerely,

Nancy H. Jones/pw

Nancy H. Jones

cc: Ms. Jewell A. Harper, Chief Air Enforcement Branch
Mr. William Malenius, P.E., Ark Energy

[redacted]

KBN Engineering and Applied Sciences, Inc.
GENERAL DISBURSEMENT ACCOUNT
PH. 904-331-9000
1034 N.W. 57TH STREET
GAINESVILLE, FL 32605

First Union National Bank of Florida
Gainesville, Florida 32605
63-2/630
Branch 311

0004928 012830

28 June 1994

PAY **********250*** DOLLARS AND 00 CENTS $ ******250.00

KBN ENGINEERING AND APPLIED SCIENCES, INC.

AUTHORIZED SIGNATURE

TO THE ORDER OF
Florida Department of Environmental Regulation
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee FL 32399-2400

[redacted]

KBN ENGINEERING AND APPLIED SCIENCES, INC.
GAINESVILLE, FL 32605

V-3922 012830

PLEASE DETACH AND RETAIN FOR YOUR RECORDS

INVOICE NUMBER	DATE		VOUCHER NO.	AMOUNT
	06/28/94	Mulberry Cogeneration Project NSPS Custom Fuel Monitoring Permit No. AC53-211670, PSD-FL-187		250.00

[redacted]

BEST AVAILABLE COPY

0004928

Florida Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

June 22, 1994

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1994 JUN 29 PM 1:49

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Kennard F. Kosky, P.E.
President
KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605

Dear Mr. Kosky:

RE: Mulberry Cogeneration Project
NSPS Custom Fuel Monitoring Schedule
Permit No. AC53-211670, PSD-FL-187

The Bureau of Air Regulation received your March 7, 1994, request for the above referenced project. The changes requested in your letter will necessitate an amendment to your permit and, pursuant to Rule 17-4.050(4)(o), F.A.C., will require a $250 fee. As soon as the fee is received we will begin processing your request. If you have any questions, please call Patty Adams at (904)488-1344.

Sincerely,

Patty Adams

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

CHF/pa

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Mr. Kennard F. Kosky, P.E.
President
KBN ENgineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605

4a. Article Number
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PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 DOMESTIC RETURN RECEIPT

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PS Form 3800, JUNE 1991

Florida Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

June 22, 1994

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Kennard F. Kosky, P.E.
President
KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605

Dear Mr. Kosky:

RE: Mulberry Cogeneration Project
NSPS Custom Fuel Monitoring Schedule
Permit No. AC53-211670, PSD-FL-187

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Sincerely,

Patty Adams

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

CHF/pa

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MAR 9 1994
Bureau of
Air Regulation

March 7, 1994

RECEIVED
JUN 17 1994
Emissions Monitoring

Ms. Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics Management Division
U.S. Environmental Protection Agency
345 Courtland Street, N.E.
Atlanta GA 30365

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

Re: Mulberry Cogeneration Project
FDEP File No. AC53-211670; PSD-FL-187
NSPS Custom Fuel Monitoring Schedule

Dear Ms. Harper and Mr. Fancy:

This correspondence is submitted on behalf of Polk Power Partners, L.P. to request approval of a custom fuel monitoring schedule for the determination of sulfur content required under the New Source Performance Standards (NSPS) for Stationary Gas Turbines [40 Code of Federal Regulations (CFR) Part 60, Subpart GG). This request is made necessary by Section 60.334(b) and (b)(2) of Subpart GG, which states:

> *(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:*
>
> > *(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.*

It is my understanding that the U.S. Environmental Protection Agency (EPA) has not delegated the authority to implement Section 60.334(4) to the Florida Department of Environmental Protection (FDEP). Therefore, a copy of this request has been transmitted jointly to EPA Region IV and FDEP.

KBN ENGINEERING AND APPLIED SCIENCES. INC.

1034 Northwest 57th Street
Gainesville, Florida 32605
904-331-9000
FAX 904-332-4189

5405 West Cypress Street,
Suite 215
Tampa, Florida 33607
813-287-1717 FAX 813-287-1716

1801 Clint Moore Road, Suite 105
Boca Raton, Florida 33487
407-994-9910
FAX 407-994-9393

6821 Southpoint Drive North,
Suite 216
Jacksonville, Florida 32216
904-296-9663 FAX 904-296-0146

One Church Street, Suite 801
Rockville, Maryland 20850
301-738-1100
FAX 301-738-1105

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As indicated by Section 60.344(b)(2), the NSPS imply that daily sampling be performed when there is not an intermediate bulk storage tank, even if the fuel is pipeline natural gas. Discussions with EPA's Office of Air Quality Planning and Standards (OAQPS) confirm this interpretation of the rule and offer the attached memorandum as guidance. Specifically, a custom fuel monitoring schedule must be developed and approved for pipeline natural gas. The schedule should address the sulfur content of the fuel; the nitrogen content in natural gas is not required.

The sulfur content for natural gas submitted in the application was developed from data supplied by the natural gas pipeline company in Florida, i.e., Florida Gas Transmission Company (FGT). The data are summarized in Table 1. The emission limit proposed in the application was based on 1 grain sulfur per 100 cubic feet of gas (1 grain/100 cf) which is equivalent to about 0.003 percent sulfur by weight. This sulfur concentration was based on the highest recorded value over the 8-month study period (see Table 1) with a margin of 25 percent (i.e., 0.8 grains/100 cf times 1.25). The pipeline company (i.e., FGT) regularly samples for total sulfur in the natural gas to assure that the hydrogen sulfide content is low and that the concentrations of mercaptan are sufficient for safety reasons. Mercaptan is added to natural gas to assure that the gas has an odor that can be perceived if mistakenly released; otherwise natural gas would have no odor. Please note that the NSPS require that the sulfur content of the fuel be no more than 0.8 percent by weight; a difference of over two orders of magnitude from the basis of the emission limit. Thus, there is significant margin in complying with the NSPS limit.

The EPA guidance memorandum suggests that sampling be conducted twice monthly over the first six months, quarterly over the next six quarters and then during the first and third quarters of each calendar year. The 8 months of data listed in Table 1 (3 to 4 samples per month) demonstrate that the sulfur content meets the NSPS and is less than the basis of the emission limit for natural gas, i.e., 1 grain per 100 cf. FGT was recently contacted and supplied the following data from random analyses:

Analyses Date	Sulfur Content (grains/100cf)
03/10/92	0.50
06/30/92	0.40
09/29/92	0.26
01/05/93	0.31
03/02/93	0.27
06/01/93	0.16
09/28/93	0.12
12/14/93	0.42
02/09/94	0.04

Clearly, the data over that last several years have demonstrated that the NSPS limit is easily met. Thus, it is requested that EPA approve a custom fuel monitoring schedule that requires the facility to submit representative sulfur analyses supplied by the pipeline company each quarter over the first six quarters of turbine operation with the excess emissions report required under Section 60.7(c) of the CFR. After this

time period, sulfur analyses would be supplied during the first and third quarters of each calendar year. This would provide assurance to EPA and FDEP that the NSPS was being achieved.

Please call if you have any questions.

Sincerely,

Kennard F. Kosky, P.E.
President

KFK/lcb

cc: Ward Marshall, C&SW
William Malenius, Ark Energy
FDEP Southwest District
File (2)

Table 1. Sulfur Content, Heat Content, and SO_2 Emission Factors for Natural Gas

Date	Sulfur Content (gr/100 cf)	Heat Content (Btu)	SO_2 Emission Factor (lb/10^6 Btu)	SO_2 Emission Factor (lb/10^6 cf)
2/6/90	0.30	1,031	0.00083	0.857
2/13/90	0.05	1,028	0.00014	0.143
2/20/90	0.35	1,025	0.00098	1.000
2/27/90	0.45	1,024	0.00126	1.286
3/6/90	0.45	1,025	0.00125	1.286
3/13/90	0.30	1,026	0.00084	0.857
3/20/90	0.35	1,026	0.00097	1.000
3/27/90	0.35	1,025	0.00098	1.000
4/3/90	0.60	1,026	0.00167	1.714
4/10/90	0.25	1,022	0.00070	0.714
4/17/90	0.40	1,026	0.00111	1.143
4/24/90	0.30	1,022	0.00084	0.857
5/1/90	0.40	1,020	0.00112	1.143
5/8/90	0.25	1,034	0.00069	0.714
5/15/90	0.20	1,023	0.00056	0.571
6/5/90	0.45	1,020	0.00126	1.286
6/12/90	0.40	1,018	0.00112	1.143
6/19/90	0.70	1,017	0.00197	2.000
6/26/90	0.45	1,019	0.00126	1.286
7/3/90	0.55	1,022	0.00154	1.571
7/10/90	0.35	1,022	0.00098	1.000
7/17/90	0.45	1,021	0.00126	1.286
7/30/90	0.30	1,021	0.00084	0.857
8/7/90	0.50	1,024	0.00140	1.429
8/14/90	0.45	1,022	0.00126	1.286
8/21/90	0.40	1,022	0.00112	1.143
8/28/90	0.70	1,022	0.00196	2.000
9/4/90	0.55	1,029	0.00153	1.571
9/11/90	0.40	1,025	0.00111	1.143
9/18/90	0.45	1,026	0.00125	1.286
9/25/90	0.40	1,026	0.00111	1.143
10/2/90	0.45	1,029	0.00125	1.286
10/9/90	0.45	1,025	0.00125	1.286
10/16/90	0.70	1,028	0.00195	2.000
10/28/90	0.80	1,024	0.00223	2.286
Average:	0.43	1,024	0.00119	1.216
Maximum:	0.80	1,034	0.00223	2.286
Minimum:	0.05	1,017	0.00014	0.143
Std. Dev.	0.15	4	0.00042	0.427

Source: Florida Gas Transmission Company, 1990.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

AUG 14 1987

OFFICE OF
AIR AND RADIATION

MEMORANDUM

SUBJECT: Authority for Approval of Custom Fuel Monitoring Schedules Under NSPS Subpart GG

FROM: John B. Rasnic, Chief
Compliance Monitoring Branch

TO: Air Compliance Branch Chiefs
Regions II, III, IV, V, VI and IX

Air Programs Branch Chiefs
Regions I-X

The NSPS for Stationary Gas Turbines (Subpart GG) at 40 CFR 60.334(b)(2) allows for the development of custom fuel monitoring schedules as an alternative to daily monitoring of the sulfur and nitrogen content of fuel fired in the turbines. Regional Offices have been forwarding custom fuel monitoring schedules to the Stationary Source Compliance Division (SSCD) for consideration since it was understood that authority for approval of these schedules was not delegated to the Regions. However, in consultation with the Emission Standards and Engineering Division, it has been determined that the Regional Offices do have the authority to approve Subpart GG custom fuel monitoring schedules. Therefore it is no longer necessary to forward those requests to Headquarters for approval.

Over the past few years, SSCD has issued over twenty custom schedules for sources using pipeline quality natural gas. In order to maintain national consistency, we recommend that any schedules Regional Offices issue for natural gas be no less stringent than the following: sulfur monitoring should

be bimonthly, followed by quarterly, then semiannual, given at least six months of data demonstrating little variability in sulfur content and compliance with §60.333 at each monitoring frequency; nitrogen monitoring can be waived for pipeline quality natural gas, since there is no fuel-bound nitrogen and since the free nitrogen does not contribute appreciably to NO_x emissions. Please see the attached sample custom schedule for details. Given the increasing trend in the use of pipeline quality natural gas, we are investigating the possibility of amending Subpart GG to allow for less frequent sulfur monitoring and a waiver of nitrogen monitoring requirements where natural gas is used.

Where sources using oil request custom fuel monitoring schedules, Regional Offices are encouraged to contact SSCD for consultation on the appropriate fuel monitoring schedule. However, Regions are not required to send the request itself to CSCD for approval.

If you have any questions, please contact Sally M. Farrell at FTS 382-2875.

Attachment

cc: John Crenshaw
George Walsh
Robert Ajax
Earl Salo

Enclosure

Conditions for Custom Fuel Sampling Schedule for Stationary Gas Turbines

1. Monitoring of fuel nitrogen content shall not be required while natural gas is the only fuel fired in the gas turbine.

2. Sulfur Monitoring

   a. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measuremant of sulfur in gaseous fuels, or an approved alternative method. The reference methods are: ASTM D1072-80; ASTM D3031-81; ASTM D3246-81; and ASTM D4084-82 as referenced in 40 CFR 60.335(b)(2).

   b. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.

   c. If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample anaylsis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

   d. Should any sulfur analysis as required in items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the State Air Control Board of such excess emissions and the custom schedule shall be re-examined by the Environmental Protection Agency. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

3. If there is a change in fuel supply, the owner or operator must notify the State of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

AIR RES

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

MAR -7 1994

DEPARTMENT OF
ENVIRONMENTAL PROTECTION

MAR 10 1994

OFFICE OF THE SECRETARY

4APT-AEB

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

SUBJ: Polk Power Partners,
Mulberry Cogeneration Project (PSD-FL-187)

Dear Mr. Fancy:

This is to acknowledge receipt of the final determination and Prevention of Significant Deterioration (PSD) permit for the above referenced facility, by your correspondence dated February 21, 1994. The project will be a 126 megawatt combined cycle cogeneration unit, consisting of a combustion turbine exhausting through a primary heat recovery steam generator, which will produce steam for the steam-electric cycle, and a secondary heat recovery steam generator.

Your determination proposes to limit NO_x emissions from the combustion turbine through water injection and dry low-NO_x combustion technology (through 12/31/97) and through advanced dry low-NO_x combustion technology or selective catalytic reduction (after 12/31/97), to limit SO_2 and H_2SO_4 mist emissions from the combustion turbine through limiting the sulfur content of the No. 2 distillate fuel oil, to limit CO and VOC emissions from the combustion turbine through efficient combustion, and to limit PM/PM_{10}, Be, and As emissions from the combustion turbine through combustion control and the use of clean fuel.

We have reviewed the package as submitted and have no adverse comments. Thank you for the opportunity to review and comment on this package. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides and Toxics
Management Division

cc: J. Reynolds
B. Thomas, SW Dist.
D. Martin, Polk Co.
J. Bunyak, NPS
K. Kosky, KBN
D. Roberts, 14130 S

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3. Article Addressed to:
Mr. Farzie Shelton
McIntosh Power Plant
3030 E. Lake Parker Drive
Lakeland, Florida 33805

4a. Article Number
Z 751 860 000

4b. Service Type
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☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
11-23-94

5. Signature (Addressee)

6. Signature (Agent)

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PS Form **3800**, March 1993

POWER OPERATIONS DIVISION
C · S · W
ENERGY
A CENTRAL AND SOUTH WEST COMPANY

Mulberry Cogen
P.O. Box 824
Bartow, FL 33830

Bureau of Air MS# 5505

State of Florida
Department of ~~Environmental Protection~~
Twin Towers Office Building
2600 ~~Blair Stone Road~~
~~Tallahassee~~, FL 32399-2400

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POWER OPERATIONS DIVISION
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ENERGY
A CENTRAL AND SOUTH WEST COMPANY
Mulberry Cogen
P.O. Box 824 • 3600 Hwy. 555
Bartow, FL 33830
813-533-9073 • Fax 813-533-4092

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NOV 18 1994
Bureau of
Air Regulation

October 28, 1994

State of Florida
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Polk Power Partners, L.P.
Permit Number: AC 53-211670
PSD-FL-187

Dear Sir or Madam:

In compliance with Paragraph 5 of the above-referenced permit, please consider this our 30 days notification of compliance testing at the Mulberry Cogeneration Facility. If you require additional information, please feel free to contact me at (813) 533-9073.

Sincerely,

John Paul Jones
Manager of Cogeneration

/pcp
xc: Nancy Jones, Polk Power Partners
T. Reynolds
M. Harley
B. Thomas, SW Dist
S. Kleopfer, EPA

POWER OPERATIONS DIVISION
C · S · W
ENERGY
A CENTRAL AND SOUTH WEST COMPANY
Mulberry Cogen
P.O. Box 824 • 3600 Hwy. 555
Bartow, FL 33830
813-533-9073 • Fax 813-533-4092

RECEIVED
NOV 18 1994
Bureau of
Air Regulation

October 28, 1994

State of Florida
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Polk Power Partners, L.P.
Permit Number: AC 53-211670
PSD-FL-187

Dear Sir or Madam:

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Sincerely,

John Paul Jones
Manager of Cogeneration

/pcp
xc: Nancy Jones, Polk Power Partners
B. Reynolds
M. Harley
B. Thomas, SW Dist
G. Harper, EPA

Florida Department of
Environmental Protection

Memorandum

TO: Virginia Wetherell

FROM: Howard L. Rhodes

DATE: February 15, 1994

SUBJECT: Approval of Construction Permit AC53-211670 (PSD-FL-187)
Polk Power Partners

Attached for your approval and signature is a reissued permit prepared by the Bureau of Air Regulation for the above mentioned company to construct a cogeneration facility near Bartow.

The Department issued the permit initially on November 24, 1992. Since that time, the permittee submitted new information justifying revised gas turbine emission limits for carbon monoxide and a deletion of the carbon dioxide recovery facility that had been included in the original permit. Since the changes resulting from the revised objectives were substantial, the permit was rewritten to reflect the removal of the carbon dioxide facility and the revised turbine limits. The Notice of Intent to Issue was published in the Polk County Democrat on January 5, 1994.

I recommend your approval and signature.

HLR/JR/bjb

Attachments

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

FEB -4 1994

RECEIVED
FEB 10 1994
Bureau of Air Regulation
DEPARTMENT OF ENVIRONMENTAL PROTECTION
FEB 11 1994
OFFICE OF THE SECRETARY

4APT-AEB

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

SUBJ: Polk Power Partners,
Mulberry Cogeneration Project (PSD-FL-187)

Dear Mr. Fancy:

This is to acknowledge receipt of the revised preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility, by your letter dated December 29, 1993. The revised project will be a 126 megawatt combined cycle cogeneration unit, consisting of a combustion turbine exhausting through a primary heat recovery steam generator, which will produce steam for the steam-electric cycle, and a secondary heat recovery steam generator. The revised preliminary determination and draft PSD permit includes new emission limits for CO and deletion of the earlier proposed CO_2 recovery facility. The only increase in allowable emissions for the revised permit is 47.4 tons of CO per year. The CO_2 plant has been deleted and replaced by an ethanol plant to be constructed by different owners under a separate permit.

Your determination proposes to limit NO_x emissions from the combustion turbine through water injection and dry low-NO_x combustion technology (through 12/31/97) and through advanced dry low-NO_x combustion technology or selective catalytic reduction (after 12/31/97), to limit SO_2 and H_2SO_4 mist emissions from the combustion turbine through limiting the sulfur content of the No. 2 distillate fuel oil, to limit CO and VOC emissions from the combustion turbine through efficient combustion, and to limit PM/PM_{10}, Be, and As emissions from the combustion turbine through combustion control and the use of clean fuel.

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We have reviewed the package as submitted and have no adverse comments. Thank you for the opportunity to review and comment on this package. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 347-5014.

Sincerely yours,

for

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: J. Reynolds
B. Thomas, SW Dist
G. Bunyak, NPS
K. Kosky, KBN

RECEIVED

FEB 07 1994

Bureau of
Air Regulation

January 28, 1994

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

Re: Mulberry Cogeneration Project
DER File No. AC53-211670, PSD-FL-187
Comments on Revised Technical Evaluation and Preliminary Determination and Revised Permit

Dear Clair:

Enclosed are our comments concerning the revised technical evaluation and preliminary determination and revised permit for the Polk Power Partners to construct a cogeneration facility in Polk County.

1. Specific Condition No. 2

As identified in footnote (1), the nitrogen oxides (NO_x) emission rate for the combustion turbine is limited to 15 parts per million corrected to dry conditions (ppmvd) and 15 percent oxygen after December 31, 1997 but may be achievable by April 30, 1997. This NO_x emission rate is coincident with the emission limit for carbon monoxide (CO) of 25 ppmvd (as identified in footnote(2). Similarly, through December 31, 1997, the NO_x emissions are limited to 25 ppmvd with a coincident CO emission limit of 20. Although the potential NO_x emission rate of 15 ppmvd may be achievable when the turbine is initially operated (prior to December 31, 1997), the CO emission limit of 25 ppmvd that is coincident with the lower NO_x emission limit of 15 ppmvd is not allowed through December 31, 1997. As a result, it is recommended that the following footnote be inserted in the table for the emission limits through December 31, 1997:

Addendum to Footnote (1)

Should the NO_x emission limit for the turbine based on 15 ppmvd (gas firing) be achieved prior to 12/31/97, the CO emission limit prior to 12/31/97 will be based on 25 ppmvd.

2. Best Available Control Technology/ Nitrogen Oxides

On page 5, the last sentence regarding the BACT for NO_x emissions states that the lower NO_x limit will be achieved by application of low-NO_x burners or SCR. This is a change from the project's final determination, dated November 19, 1992, which stated (page 5, last sentence of the NO_x BACT):

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street
Gainesville, Florida 32605
904-331-9000
FAX 904-332-4189

5405 West Cypress Street,
Suite 215
Tampa, Florida 33607
813-287-1717 FAX 813-287-1716

1801 Clint Moore Road, Suite 105
Boca Raton, Florida 33487
407-994-9910
FAX 407-994-9393

6821 Southpoint Drive North,
Suite 216
Jacksonville, Florida 32216
904-296-9663 FAX 904-296-0146

One Church Street, Suite 801
Rockville, Maryland 20850
301-738-1100
FAX 301-738-1105

EQUAL EMPLOYMENT OPPORTUNITY

AN AFFIRMATIVE ACTION EMPLOYER

If the 15(gas)/42(oil) ppmvd emission rates cannot be met, SCR or another technology will be required no later than December 31, 1997.

We request that this language be retained in the revised permit.

On behalf of Polk Power Partners, L.P. and KBN, we appreciate you and your staff's review of this requested changes to the revised permit.

Sincerely,

Kennard F. Kosky, P.E.
President
Registration No. 14996

cc: Mr. William R. Malenius, Ark Energy, Inc.
Mr. Ward C. Marshall, Central and South West Services, Inc.
John Reynolds, FDEP

RECEIVED

JAN 07 1994

Bureau of
Air Regulation

January 6, 1994

Ms. Patty Adams
Air Permitting and Standards
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: Polk Power Partners
PSD-FL-187 (AC53-211670)

Dear Ms. Adams:

Enclosed is the affidavit of publication for the Notice of Intent to Reissue for the above referenced permit application. Please call Bob McCann at our Gainesville office with any questions or comments.

Sincerely,

A. C. Kimball
Staff Environmental Planner

ACK/abb.1

Enclosure

xc: W. Malenius
J. Reese
W. Marshall
R. McCann
R. Anderson
91193-1600(2.4)(DD)
Q. Reynolds
C. Holladay
Q. Harper, EPA
Q. Bunyak, NPS
L. Novak, Polk Co.

1-10-94
BB

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street
Gainesville, Florida 32605
904-331-9000
FAX 904-332-4189

5405 West Cypress Street,
Suite 215
Tampa, Florida 33607
813-287-1717 FAX 813-287-1716

1801 Clint Moore Road, Suite 105
Boca Raton, Florida 33487
407-994-9910
FAX 407-994-9393

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One Church Street, Suite 801
Rockville, Maryland 20850
301-738-1100
FAX 301-738-1105

EQUAL EMPLOYMENT OPPORTUNITY

AN AFFIRMATIVE ACTION EMPLOYER

AFFIDAVIT OF PUBLICATION

The Polk County Democrat

Published Semi-Weekly
Bartow, Polk County, Florida

Case No. _____

STATE OF FLORIDA
COUNTY OF POLK

Before the undersigned authority personally appeared _____ Mary G. Frisbie _____, who on oath says that (s)he is _____ Treasurer _____ of The Polk County Democrat, a newspaper published at Bartow, Polk County, Florida; that the attached copy of advertisement, being a Notice of Intent to Reissue Permit in the matter of The Department of Environmental Protection permit to Polk Power Partners, (PSD) in the _____ Court, was published in said newspaper in the issues of Dec. 30, 1993.

Affiant further says that The Polk County Democrat is a newspaper published at Bartow, in said Polk County, Florida, and that said newspaper has heretofore been continuously published in said Polk County, Florida, each Monday and Thursday, and has been entered as second class matter at the post office in Bartow, in said Polk County, Florida, for a period of one year next preceeding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm, or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

Signed Mary G. Frisbie

Sworn to and subscribed before me this 5th day of Jan., 1994,

by Mary G. Frisbie,

who is personally known to me.

Teresa M Pacetti
(Signature of Notary Public)

Teresa M. Pacetti
(Printed or typed name of Notary Public)
Notary Public

My Commission Expires:

Notary Public, State of Florida
TERESA M. PACETTI
My Comm. Exp. Dec. 19, 1995
Comm. No. CC 169408

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION NOTICE OF INTENT TO REISSUE PERMIT

The Department of Environmental Protection gives notice of its intent to reissue a permit to Polk Power Partners, 23293 South Pointe Drive, Laguna Hills, California 92653, to construct a cogeneration facility 3.7 miles southwest of Bartow, Polk County, Florida. A determination of Best Available Control Technology is required. The proposed project is subject to Prevention of Significant Deterioration (PSD(regulations and federal new source performance standards. Modeling results show that increases in ground-level concentrations are less than PSD significant impact levels. The Department is issuing this Intent to Reissue for the reasons stated in the Technical Evaluation and Preliminary Determination.

The Department issued the permit initially on November 24, 1992. Since that time, the permittee submitted new information justifying revised gas turbine emission limits for carbon monoxide (CO) and a deletion of the carbon dioxide (CO2) recovery facility. Therefore, the Department is reissuing the permit to include these changes and provide additional time to accomplish the revised objectives.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within fourteen (14) days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be diffe-

rent from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within fourteen (14) days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application is available for public inspection during normal business hours, 8:00 a. m. to 5:00 p. m., Monday through Friday, except legal holidays, at: Department of Environmental Protection, Bureau of Air Regulation, 111 S. Magnolia Park Courtyard, Tallahassee, Florida 32301, Department of Environmental Protection, Southwest District, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Dec. 30, 1993—3293

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DEP File No. AC53-211670
PSD-FL-187
Polk County

Mr. William R. Malenius
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, CA 92653

/

Enclosed is Permit Number AC53-211670 to construct a cogeneration facility at County Road 555 approximately 3.7 miles southwest of Bartow, Polk County, Florida, issued pursuant to Section (s) 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on Feb. 21, 1994 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED,
on this date, pursuant to
§120.52(11), Florida Statutes,
with the designated Department
Clerk, receipt of which is hereby
acknowledged.

Charlotte J. Hayes (Clerk) 2/21/94 (Date)

Copies furnished to:
W. Thomas, SWD
D. Martin, Polk Co.
J. Harper, EPA
J. Bunyak, NPS
K. Kosky, KBN
D. Roberts, HBGS

Final Determination

Polk Power Partners
Mulberry Cogeneration Project
Polk County, Florida

Permit No. AC 53-211670
PSD-FL-187

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

February 9, 1994

Final Determination

The Revised Technical Evaluation and Preliminary Determination for the permit to construct a cogeneration facility approximately 3.7 miles southwest of Bartow in Polk County, Florida, was distributed on December 29, 1994. The Notice of Intent to Issue was published in the Polk County Democrat on January 5, 1994. Copies of the evaluation were available for public inspection at the Department's Tallahassee and Tampa offices.

Comments were received from the applicant on January 28, 1994 requesting minor modifications of certain specific conditions. The Department made the following changes to the permit:

Specific Condition No. 2 - A statement was added clarifying that if the NO_X limit of 15 ppmvd is achieved prior to 12/31/97, the CO emission limit prior to 12/31/97 will be based on 25 ppmvd.

Specific Condition No. 4 - A statement was added to emphasize a rule requirement that sampling ports and access platforms be provided.

BACT Determination - Minor revisions were made to the last paragraph of the NO_X section to clarify that SCR or another technology may be required if the emission limits are not achieved.

The final action of the Department will be to issue construction permit AC53-211670 (PSD-FL-187) as modified.

Florida Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Polk Power Partners, L.P.
23293 South Pointe Drive
Laguna Hills, CA 92653

Permit Number: AC 53-211670
PSD-FL-187
Expiration Date: December 31, 1995
County: Polk
Latitude/Longitude: 27°50'56"N
81°52'39"W
Project: Mulberry Cogeneration Project

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-212 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 specifically described as follows:

For the construction of a 126 Megawatt cogeneration unit. The facility will be located off County Road 555 approximately 3.7 miles southwest of Bartow in Polk County, Florida. UTM coordinates of the site are: Zone 17, 413.6 km E and 3080.6 km N.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be controlled by proper combustion techniques. NO_x emissions shall be initially controlled by water injection and Low NO_x Burners. Future control technology for NOx will depend on whether the Low NO_x Burners can achieve the levels specified by this permit.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. DER letter dated May 5, 1992.
2. KBN letter dated April 15, 1992.
3. KBN letter dated June 2, 1992.
4. EPA letter dated July 1, 1992.
5. KBN submittal dated July 8, 1992.
6. KBN letter dated July 29, 1992.
7. KBN letter dated August 12, 1992.
8. DER letter dated August 13, 1992.
9. KBN letter dated August 26, 1992.
10. KBN letter dated October 12, 1992.
11. KBN letter dated November 2, 1992.

Printed on recycled paper.

Attachments are listed below: (Cont'd)
12. EPA letter dated December 16, 1992.
13. KBN letter dated February 19, 1993.
14. DER letter dated March 19, 1993.
15. KBN letter dated August 17, 1993.
16. DER letter dated August 19, 1993.
17. KBN letter dated August 27, 1993.
18. HBG&S letter dated November 16, 1993.
19. DEP letter dated November 18, 1993.
20. HBG&S letter dated December 20, 1993.
21. PPP letter dated December 17, 1993.
22. GECC letter dated December 16, 1993.
23. HBG&S letter dated December 22, 1993.
24. KBN letter dated January 28, 1994.

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.

GENERAL CONDITIONS:

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.

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

GENERAL CONDITIONS:

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 prescribed 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, 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 (NSPS)

GENERAL CONDITIONS:

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.

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. This permit supersedes the initial permit issued on November 24, 1992. Unless otherwise indicated, the construction and operation of the subject facilities shall be in accordance with the capacities and specifications stated in the application and subsequent submittals by the permittee.

SPECIFIC CONDITIONS:

2. Emissions from the facility shall not exceed the limits listed below based on operation at 59°F and 60% relative humidity (ISO conditions):

Pollutant	Source	Fuel	Through 12/31/97 lbs/hr	Through 12/31/97 tons/yr	After 12/31/97 (See notes) lbs/hr	After 12/31/97 (See notes) tons/yr
NOx	HRSG Stack 1	Gas	87.8	384.5	52.7	230.7
	HRSG Stack 2	Gas	19.9	87.1	18.3	80.0
	HRSG Stack 1	Oil	164.0	718.2	164.0	59.0
	HRSG Stack 2	Oil	23.4	102.4	23.4	8.4
SO2	HRSG Stack 1	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	HRSG Stack 2	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack 1	Gas	10% Opacity		10% Opacity	
	HRSG Stack 2	Gas	10% Opacity		10% Opacity	
	HRSG Stack 1	Oil	20% Opacity		20% Opacity	
	HRSG Stack 2	Oil	20% Opacity		20% Opacity	
VOC	HRSG Stack 1	Oil	9.2	40.4	--	--
CO	HRSG Stack 1	Gas	42.9	187.8	53.0	232.0
	HRSG Stack 2	Gas	11.9	52.0	12.6	55.2
	HRSG Stack 1	Oil	75.3	329.9	75.3	27.1
	HRSG Stack 2	Oil	13.4	58.5	13.4	4.8

Notes:
(1) NO_x limits for turbine after 12/31/97 based on 15 ppmvd (gas firing) achievable by 4/30/97 but not effective until after 12/31/97.
(2) CO limits for turbine after 12/31/97 based on 25 ppmvd (gas firing). Should the NO_x emission limit for the turbine based on 15 ppmvd (gas firing) be achieved prior to 12/31/97, the CO emission limit prior to 12/31/97 will be based on 25 ppmvd.
(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.
(4) HRSG Stack 1 = primary; HRSG Stack 2 = secondary (portion of exhaust from combustion turbine is vented through secondary stack along with exhaust from gas-fired duct burner).

3. The cogeneration facility shall be permitted to fire natural gas and No. 2 fuel oil until December 31, 1997, after which the primary fuel will be natural gas. Fuel consumption rates (based on operation at 20°F) and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr	MM ft3/yr	hrs/yr	M lb/hr	MM lb/yr	hrs/yr
Turbine	1013.4	8877.4	8760	55.6	379.9	6833(1)
Duct Burner	104.2	450.2(2)	8760	0	0	0

SPECIFIC CONDITIONS:

(1) After December 31, 1997, fuel oil can be used permanently as backup fuel for no more than 720 hours per year.
(2) Based on maximum firing rate for 4,320 hours per year.

4. Before this construction permit expires, the cogeneration facility stack and secondary HRSG stack shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 95% to 100% of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_X: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10
VOC: EPA Method 25A

The Permittee shall provide sampling ports in the air pollution control equipment outlet duct or stack and shall provide access to the sampling ports in accordance with Rule 17-297, F.A.C. Detailed drawings of the stacks showing testing facilities and sampling port locations as required by Rule 17-297.345 shall be submitted to the Southwest District Office for approval at least 60 days prior to construction of the duct and stack.

5. The Southwest District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the Southwest District office in Tampa and the Bureau of Air Regulation office in Tallahassee (third annual compliance test only) within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and water injection flows to the cogeneration turbine along with the power output of the generators shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DEP upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent NOx control systems. The Bureau of Air Regulation shall, if NO_X emission limits are not met, review the

SPECIFIC CONDITIONS:

need for making a revised determination of Best Available Control Technology. If test results show that it is unlikely that NO_x limits can be met, a revised BACT determination shall be made. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. The retrofit costs associated with not making provisions for such technology initially shall not be considered by the Department in the retrofit cost analysis.

8. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

9. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this 21st day
of February, 1994

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary

Best Available Control Technology (BACT) Determination
Mulberry Cogeneration Project
Polk County

The applicant proposes to install a 126 MW combined cycle cogeneration unit. The Polk County facility will consist of a General Electric PG7111EA Gas Turbine Generator exhausting through a primary heat recovery steam generator which will produce steam for the steam-electric cycle. Initially, the turbine will be fired by natural gas and No. 2 fuel oil, with natural gas becoming the permanent fuel after December 31, 1997. A secondary heat recovery steam generator will be auxiliary-fired by natural gas.

BACT Determination Requested by Applicant

NO_x	- Dry Low NO_x Combustion
CO	- Combustion Design
H_2SO_4/SO_2	- Low Sulfur Fuel Oil (0.1%S)
PM/PM_{10}	- Combustion Design/Clean Fuel
VOC	- Combustion Design

BACT Determination by the Department

NO_x	- Dry Low NO_x Combustion with potential future SCR capability
CO	- Combustion Design
H_2SO_4/SO_2	- Low Sulfur Fuel Oil (0.1%S)
PM/PM_{10}	- Combustion Design/Clean Fuel
VOC	- Combustion Design

Proposed Emissions (tons per year)

	Through 12/31/97 (22% Gas/78% Oil)			After 12/31/97 (100% Gas)			PSD
	HRSG	Secondary HRSG	Total	HRSG	Secondary HRSG	Total	
NO_x	644.8	99.1	743.9	230.7	80.0	310.7	40.0
SO_2	327.4	16.4	343.8	11.4	1.8	13.2	40.0
PM/PM_{10}	58.0	28.9	86.9	30.7	27.7	58.4	25/15
CO	298.6	57.1	355.7	232.0	55.2	287.2	100.0
VOC	37.7	--	37.7*	28.2	--	28.2	40.0
H_2SO_4	26.4	1.3	27.7	0.9	0.1	1.0	7.0
Be	.008	--	.008	--	--	--	0.0004
As	0.13	--	.013	--	--	--	0.0

*Would be 40.4 TPY at 100% oil firing

Emissions after December 31, 1997, are based on firing only natural gas at 868.8 MMBtu/hr. Turbine performance under natural gas firing is based on NOx emissions of 25 ppm (corrected to 15 percent O_2) through December 31, 1997 and 15 ppm thereafter. Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O_2). SO_2 emissions are based on 0.1 percent sulfur.

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-212, 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.

BACT Determination Rationale

Particulate Matter (PM/PM_{10})

Particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not cause visible emissions to exceed 10% and 20% opacity, respectively.

Arsenic and Beryllium (As, Be)

The Department agrees that there are no feasible methods to control beryllium and arsenic except by specifying the quality of the fuel.

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The majority of BACT emissions limitations have been based on controlling carbon monoxide and volatile organic compounds through efficient combustion. Advanced control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalyst systems are not considered to be technically feasible for gas turbines fired with fuel oil. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for a natural gas-fired unit; however, the cost effectiveness of over $6,000 per ton of CO removed will have a significant economic impact on this project. Therefore, efficient combustion will be the control method for CO and VOC.

Nitrogen Oxides (NO_x)

The applicant requested that BACT for nitrogen oxides through December 31, 1997, be water injection and Low NO_x Burners. This would limit emissions to 25 ppmvd when burning natural gas and 42 ppmvd when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest emission limit established to date for a combustion turbine is 4.5 ppmvd (corrected to 15% 0_2). This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

Although feasible, the applicant rejected using SCR because of economic, energy, and environmental impacts. The following factors were considered in the decision not to propose SCR:

a) Disposal of hazardous waste generated (spent catalyst).
b) An energy penalty of $0.05/KWH due to back pressure from the catalyst bed.
c) A power loss penalty based on lost capacity.
d) Potential for public exposure to high concentrations from ammonia storage and handling leaks and ammonia slip.
e) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
f) Cost effectiveness for SCR technology was determined to be in the range of $6,000 per ton of NO_x removed.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate which can be formed by reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. The latest information available indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing, NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 75 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. SCR has been established as BACT for oil fired combined cycle facilities with NO_x emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control.

The applicant determined that the total annual cost of SCR for this project is $1,957,700 with an average cost effectiveness in the range of $6,000 to $7,000 per ton of NO_x removed. The maximum annual NO_x emissions using water injection and Low NO_x combustor design will be 744 tons/year through December 31, 1997. Assuming that SCR would reduce the NO_x emissions by 65%, about 484 tons/year of NO_x would be removed initially followed by 200 tons/year thereafter. When this reduction is factored into the total annual cost, the cost per ton of controlling NO_x is in the range of $6,000

to $6,500. This calculated cost is higher than has previously been approved as BACT.

The latest DEP BACT determinations have a NO_x limit of 15 ppmvd (natural gas) using Low-NO_x burner technology. Although the turbine manufacturer does not presently guarantee this limit, they have agreed to lower NO_x to 15 ppm by April 30, 1997. If the 15 (gas)/42 (oil) ppmvd emission rates cannot be met, SCR or another technology will be required no later than December 31, 1997.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

In accordance with "top down" BACT review, only two alternatives exist that would result in stringent SO_2 emissions; using low sulfur content fuel oil or flue gas desulfurization (FGD). EPA has recognized that FGD technology is inappropriate to apply to these combustion units due to negative environmental, economic and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

This leaves the use of low sulfur fuel oil as the best option. The Department accepts the use of No. 2 fuel oil with a 0.1% sulfur by weight as BACT for this project.

Details of the Analysis May be Obtained by Contacting:

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

Recommended by:

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

February 16, 1994
Date

Approved by:

Virginia B. Wetherell,
Secretary
Dept. of Environmental Protection

February 21, 1994
Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DEP File No. AC53-211670
PSD-FL-187
Polk County

Mr. William R. Malenius
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, CA 92653

/

Enclosed is Permit Number AC53-211670 to construct a cogeneration facility at County Road 555 approximately 3.7 miles southwest of Bartow, Polk County, Florida, issued pursuant to Section (s) 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on Feb. 21, 1994 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED,
on this date, pursuant to
§120.52(11), Florida Statutes,
with the designated Department
Clerk, receipt of which is hereby
acknowledged.

Charlotte J. Hayes (Clerk) 2/21/94 (Date)

Copies furnished to:
W. Thomas, SWD
D. Martin, Polk Co.
J. Harper, EPA
J. Bunyak, NPS
K. Kosky, KBN
D. Roberts, HBGS

Final Determination

Polk Power Partners
Mulberry Cogeneration Project
Polk County, Florida

Permit No. AC 53-211670
PSD-FL-187

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

February 9, 1994

Final Determination

The Revised Technical Evaluation and Preliminary Determination for the permit to construct a cogeneration facility approximately 3.7 miles southwest of Bartow in Polk County, Florida, was distributed on December 29, 1994. The Notice of Intent to Issue was published in the Polk County Democrat on January 5, 1994. Copies of the evaluation were available for public inspection at the Department's Tallahassee and Tampa offices.

Comments were received from the applicant on January 28, 1994 requesting minor modifications of certain specific conditions. The Department made the following changes to the permit:

Specific Condition No. 2 - A statement was added clarifying that if the NO_x limit of 15 ppmvd is achieved prior to 12/31/97, the CO emission limit prior to 12/31/97 will be based on 25 ppmvd.

Specific Condition No. 4 - A statement was added to emphasize a rule requirement that sampling ports and access platforms be provided.

BACT Determination - Minor revisions were made to the last paragraph of the NO_x section to clarify that SCR or another technology may be required if the emission limits are not achieved.

The final action of the Department will be to issue construction permit AC53-211670 (PSD-FL-187) as modified.

Florida Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Polk Power Partners, L.P.
23293 South Pointe Drive
Laguna Hills, CA 92653

Permit Number: AC 53-211670
PSD-FL-187
Expiration Date: December 31, 1995
County: Polk
Latitude/Longitude: 27°50'56"N
81°52'39"W
Project: Mulberry Cogeneration Project

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-212 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 specifically described as follows:

For the construction of a 126 Megawatt cogeneration unit. The facility will be located off County Road 555 approximately 3.7 miles southwest of Bartow in Polk County, Florida. UTM coordinates of the site are: Zone 17, 413.6 km E and 3080.6 km N.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be controlled by proper combustion techniques. NO_x emissions shall be initially controlled by water injection and Low NO_x Burners. Future control technology for NOx will depend on whether the Low NO_x Burners can achieve the levels specified by this permit.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. DER letter dated May 5, 1992.
2. KBN letter dated April 15, 1992.
3. KBN letter dated June 2, 1992.
4. EPA letter dated July 1, 1992.
5. KBN submittal dated July 8, 1992.
6. KBN letter dated July 29, 1992.
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8. DER letter dated August 13, 1992.
9. KBN letter dated August 26, 1992.
10. KBN letter dated October 12, 1992.
11. KBN letter dated November 2, 1992.

Printed on recycled paper.

Attachments are listed below: (Cont'd)
12. EPA letter dated December 16, 1992.
13. KBN letter dated February 19, 1993.
14. DER letter dated March 19, 1993.
15. KBN letter dated August 17, 1993.
16. DER letter dated August 19, 1993.
17. KBN letter dated August 27, 1993.
18. HBG&S letter dated November 16, 1993.
19. DEP letter dated November 18, 1993.
20. HBG&S letter dated December 20, 1993.
21. PPP letter dated December 17, 1993.
22. GECC letter dated December 16, 1993.
23. HBG&S letter dated December 22, 1993.
24. KBN letter dated January 28, 1994.

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.

GENERAL CONDITIONS:

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.

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

GENERAL CONDITIONS:

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 prescribed 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, 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 (NSPS)

GENERAL CONDITIONS:

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.

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. This permit supersedes the initial permit issued on November 24, 1992. Unless otherwise indicated, the construction and operation of the subject facilities shall be in accordance with the capacities and specifications stated in the application and subsequent submittals by the permittee.

SPECIFIC CONDITIONS:

2. Emissions from the facility shall not exceed the limits listed below based on operation at 59°F and 60% relative humidity (ISO conditions):

Pollutant	Source	Fuel	Through 12/31/97 lbs/hr	Through 12/31/97 tons/yr	After 12/31/97 (See notes) lbs/hr	After 12/31/97 (See notes) tons/yr
NOx	HRSG Stack 1	Gas	87.8	384.5	52.7	230.7
	HRSG Stack 2	Gas	19.9	87.1	18.3	80.0
	HRSG Stack 1	Oil	164.0	718.2	164.0	59.0
	HRSG Stack 2	Oil	23.4	102.4	23.4	8.4
SO2	HRSG Stack 1	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	HRSG Stack 2	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack 1	Gas	10% Opacity		10% Opacity	
	HRSG Stack 2	Gas	10% Opacity		10% Opacity	
	HRSG Stack 1	Oil	20% Opacity		20% Opacity	
	HRSG Stack 2	Oil	20% Opacity		20% Opacity	
VOC	HRSG Stack 1	Oil	9.2	40.4	--	--
CO	HRSG Stack 1	Gas	42.9	187.8	53.0	232.0
	HRSG Stack 2	Gas	11.9	52.0	12.6	55.2
	HRSG Stack 1	Oil	75.3	329.9	75.3	27.1
	HRSG Stack 2	Oil	13.4	58.5	13.4	4.8

Notes:
(1) NO_x limits for turbine after 12/31/97 based on 15 ppmvd (gas firing) achievable by 4/30/97 but not effective until after 12/31/97.
(2) CO limits for turbine after 12/31/97 based on 25 ppmvd (gas firing). Should the NO_x emission limit for the turbine based on 15 ppmvd (gas firing) be achieved prior to 12/31/97, the CO emission limit prior to 12/31/97 will be based on 25 ppmvd.
(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.
(4) HRSG Stack 1 = primary; HRSG Stack 2 = secondary (portion of exhaust from combustion turbine is vented through secondary stack along with exhaust from gas-fired duct burner).

3. The cogeneration facility shall be permitted to fire natural gas and No. 2 fuel oil until December 31, 1997, after which the primary fuel will be natural gas. Fuel consumption rates (based on operation at 20°F) and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr	MM ft3/yr	hrs/yr	M lb/hr	MM lb/yr	hrs/yr
Turbine	1013.4	8877.4	8760	55.6	379.9	6833(1)
Duct Burner	104.2	450.2(2)	8760	0	0	0

SPECIFIC CONDITIONS:

(1) After December 31, 1997, fuel oil can be used permanently as backup fuel for no more than 720 hours per year.
(2) Based on maximum firing rate for 4,320 hours per year.

4. Before this construction permit expires, the cogeneration facility stack and secondary HRSG stack shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 95% to 100% of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_X: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10
VOC: EPA Method 25A

The Permittee shall provide sampling ports in the air pollution control equipment outlet duct or stack and shall provide access to the sampling ports in accordance with Rule 17-297, F.A.C. Detailed drawings of the stacks showing testing facilities and sampling port locations as required by Rule 17-297.345 shall be submitted to the Southwest District Office for approval at least 60 days prior to construction of the duct and stack.

5. The Southwest District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the Southwest District office in Tampa and the Bureau of Air Regulation office in Tallahassee (third annual compliance test only) within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and water injection flows to the cogeneration turbine along with the power output of the generators shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DEP upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent NOx control systems. The Bureau of Air Regulation shall, if NO_X emission limits are not met, review the

SPECIFIC CONDITIONS:

need for making a revised determination of Best Available Control Technology. If test results show that it is unlikely that NO_x limits can be met, a revised BACT determination shall be made. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. The retrofit costs associated with not making provisions for such technology initially shall not be considered by the Department in the retrofit cost analysis.

8. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

9. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this 21st day
of February, 1994

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell, Secretary

Florida Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Polk Power Partners, L.P.
23293 South Pointe Drive
Laguna Hills, CA 92653

Permit Number: AC 53-211670
PSD-FL-187
Expiration Date: December 31, 1995
County: Polk
Latitude/Longitude: 27°50'56"N
81°52'39"W
Project: Mulberry Cogeneration Project

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-212 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 construction of a 126 Megawatt cogeneration unit. The facility will be located off County Road 555 approximately 3.7 miles southwest of Bartow in Polk County, Florida. UTM coordinates of the site are: Zone 17, 413.6 km E and 3080.6 km N.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be controlled by proper combustion techniques. NO_x emissions shall be initially controlled by water injection and Low NO_x Burners. Future control technology for NOx will depend on whether the Low NO_x Burners can achieve the levels specified by this permit.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
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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.

GENERAL CONDITIONS:

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.

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

GENERAL CONDITIONS:

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 prescribed 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, 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 (NSPS)

GENERAL CONDITIONS:

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.

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. This permit supersedes the initial permit issued on November 24, 1992. Unless otherwise indicated, the construction and operation of the subject facilities shall be in accordance with the capacities and specifications stated in the application and subsequent submittals by the permittee.

SPECIFIC CONDITIONS:

2. Emissions from the facility shall not exceed the limits listed below based on operation at 59°F and 60% relative humidity (ISO conditions):

Pollutant	Source	Fuel	Through 12/31/97 lbs/hr	Through 12/31/97 tons/yr	After 12/31/97 (See notes) lbs/hr	After 12/31/97 (See notes) tons/yr
NOx	HRSG Stack 1	Gas	87.8	384.5	52.7	230.7
	HRSG Stack 2	Gas	19.9	87.1	18.3	80.0
	HRSG Stack 1	Oil	164.0	718.2	164.0	59.0
	HRSG Stack 2	Oil	23.4	102.4	23.4	8.4
SO2	HRSG Stack 1	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	HRSG Stack 2	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack 1	Gas	10% Opacity		10% Opacity	
	HRSG Stack 2	Gas	10% Opacity		10% Opacity	
	HRSG Stack 1	Oil	20% Opacity		20% Opacity	
	HRSG Stack 2	Oil	20% Opacity		20% Opacity	
VOC	HRSG Stack 1	Oil	9.2	40.4	--	--
CO	HRSG Stack 1	Gas	42.9	187.8	53.0	232.0
	HRSG Stack 2	Gas	11.9	52.0	12.6	55.2
	HRSG Stack 1	Oil	75.3	329.9	75.3	27.1
	HRSG Stack 2	Oil	13.4	58.5	13.4	4.8

Notes:
(1) NO_x limits for turbine after 12/31/97 based on 15 ppmvd (gas firing) achievable by 4/30/97 but not effective until after 12/31/97.
(2) CO limits for turbine after 12/31/97 based on 25 ppmvd (gas firing).
(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.
(4) Oil may be used as backup fuel for up to 30 days per year.
(5) HRSG Stack 1 = primary; HRSG Stack 2 = secondary (portion of exhaust from combustion turbine is vented through secondary stack along with exhaust from gas-fired duct burner).

3. The cogeneration facility shall be permitted to fire natural gas and No. 2 fuel oil until December 31, 1997, after which the primary fuel will be natural gas. Fuel consumption rates (based on operation at 20°F) and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr	MM ft3/yr	hrs/yr	M lb/hr	MM lb/yr	hrs/yr
Turbine	1013.4	8877.4	8760	55.6	379.9	6833(1)
Duct Burner	104.2	450.2(2)	8760	0	0	0

(1) After December 31, 1997, fuel oil can be used permanently as backup fuel for no more than 720 hours per year.
(2) Based on maximum firing rate for 4,320 hours per year.

SPECIFIC CONDITIONS:

4. Before this construction permit expires, the cogeneration facility stack and secondary HRSG stack shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96% to 100% of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_X: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10
VOC: EPA Method 25A

5. The Southwest District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the Southwest District office in Tampa and the Bureau of Air Regulation office in Tallahassee (third annual compliance test only) within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and water injection flows to the cogeneration turbine along with the power output of the generators shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DEP upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent NOx control systems. The Bureau of Air Regulation shall, if NO_X emission limits are not met, review the need for making a revised determination of Best Available Control Technology. If test results show that it is unlikely that NO_X limits can be met, a revised BACT determination shall be made. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. The retrofit costs associated with not making provisions for such technology initially shall not be considered by the Department in the retrofit cost analysis.

SPECIFIC CONDITIONS:

8. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

9. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this _____ day
of _____, 1994

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

_____
Virginia B. Wetherell, Secretary

Best Available Control Technology (BACT) Determination
Mulberry Cogeneration Project
Polk County

The applicant proposes to install a 126 MW combined cycle cogeneration unit. The Polk County facility will consist of a General Electric PG7111EA Gas Turbine Generator exhausting through a primary heat recovery steam generator which will produce steam for the steam-electric cycle. Initially, the turbine will be fired by natural gas and No. 2 fuel oil, with natural gas becoming the permanent fuel after December 31, 1997. A secondary heat recovery steam generator will be auxiliary-fired by natural gas.

BACT Determination Requested by Applicant

NO_x	- Dry Low NO_x Combustion
CO	- Combustion Design
H_2SO_4/SO_2	- Low Sulfur Fuel Oil (0.1%S)
PM/PM_{10}	- Combustion Design/Clean Fuel
VOC	- Combustion Design

BACT Determination by the Department

NO_x	- Dry Low NO_x Combustion with potential future SCR capability
CO	- Combustion Design
H_2SO_4/SO_2	- Low Sulfur Fuel Oil (0.1%S)
PM/PM_{10}	- Combustion Design/Clean Fuel
VOC	- Combustion Design

Proposed Emissions (tons per year)

	Through 12/31/97 (22% Gas/78% Oil)			After 12/31/97 (100% Gas)			PSD
	HRSG	Secondary HRSG	Total	HRSG	Secondary HRSG	Total	
NO_x	644.8	99.1	743.9	230.7	80.0	310.7	40.0
SO_2	327.4	16.4	343.8	11.4	1.8	13.2	40.0
PM/PM_{10}	58.0	28.9	86.9	30.7	27.7	58.4	25/15
CO	298.6	57.1	355.7	232.0	55.2	287.2	100.0
VOC	37.7	--	37.7*	28.2	--	28.2	40.0
H_2SO_4	26.4	1.3	27.7	0.9	0.1	1.0	7.0
Be	.008	--	.008	--	--	--	0.0004
As	0.13	--	.013	--	--	--	0.0

*Would be 40.4 TPY at 100% oil firing

Emissions after December 31, 1997, are based on firing only natural gas at 868.8 MMBtu/hr. Turbine performance under natural gas firing is based on NOx emissions of 25 ppm (corrected to 15 percent O_2) through December 31, 1997 and 15 ppm thereafter. Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O_2). SO_2 emissions are based on 0.1 percent sulfur.

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-212, 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.

BACT Determination Rationale

Particulate Matter (PM/PM_{10})

Particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not cause visible emissions to exceed 10% and 20% opacity, respectively.

Arsenic and Beryllium (As, Be)

The Department agrees that there are no feasible methods to control beryllium and arsenic except by specifying the quality of the fuel.

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The majority of BACT emissions limitations have been based on controlling carbon monoxide and volatile organic compounds through efficient combustion. Advanced control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalyst systems are not considered to be technically feasible for gas turbines fired with fuel oil. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for a natural gas-fired unit; however, the cost effectiveness of over $6,000 per ton of CO removed will have a significant economic impact on this project. Therefore, efficient combustion will be the control method for CO and VOC.

Nitrogen Oxides (NO_x)

The applicant requested that BACT for nitrogen oxides through December 31, 1997, be water injection and Low NO_x Burners. This would limit emissions to 25 ppmvd when burning natural gas and 42 ppmvd when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest emission limit established to date for a combustion turbine is 4.5 ppmvd (corrected to 15% O_2). This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

Although feasible, the applicant rejected using SCR because of economic, energy, and environmental impacts. The following factors were considered in the decision not to propose SCR:

a) Disposal of hazardous waste generated (spent catalyst).
b) An energy penalty of $0.05/KWH due to back pressure from the catalyst bed.
c) A power loss penalty based on lost capacity.
d) Potential for public exposure to high concentrations from ammonia storage and handling leaks and ammonia slip.
e) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
f) Cost effectiveness for SCR technology was determined to be in the range of $6,000 per ton of NO_x removed.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate which can be formed by reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. The latest information available indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing, NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 75 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. SCR has been established as BACT for oil fired combined cycle facilities with NO_x emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control.

The applicant determined that the total annual cost of SCR for this project is $1,957,700 with an average cost effectiveness in the range of $6,000 to $7,000 per ton of NO_x removed. The maximum annual NO_x emissions using water injection and Low NO_x combustor design will be 744 tons/year through December 31, 1997. Assuming that SCR would reduce the NO_x emissions by 65%, about 484 tons/year of NO_x would be removed initially followed by 200 tons/year thereafter. When this reduction is factored into the total annual cost, the cost per ton of controlling NO_x is in the range of $6,000

to $6,500. This calculated cost is higher than has previously been approved as BACT.

The latest DEP BACT determinations have a NO_x limit of 15 ppmvd (natural gas) using Low-NO_x burner technology. Although the turbine manufacturer does not presently guarantee this limit, they have agreed to lower NO_x to 15 ppm by April 30, 1997. This lower NO_x limit will be achieved by application of low-NO_x burners or SCR.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

In accordance with "top down" BACT review, only two alternatives exist that would result in stringent SO_2 emissions; using low sulfur content fuel oil or flue gas desulfurization (FGD). EPA has recognized that FGD technology is inappropriate to apply to these combustion units due to negative environmental, economic and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

This leaves the use of low sulfur fuel oil as the best option. The Department accepts the use of No. 2 fuel oil with a 0.1% sulfur by weight as BACT for this project.

Details of the Analysis May be Obtained by Contacting:

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

Recommended by:	Approved by:
C. H. Fancy, P.E., Chief	Virginia B. Wetherell, Secretary
Bureau of Air Regulation	Dept. of Environmental Protection
_____, 1994	_____, 1994
Date	Date

BEST AVAILABLE COPY

CERTIFIED

P 872 562 591

MAIL

FROM: STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL
TWIN TOWERS OFFICE
2600 BLAIR STONE
TALLAHASSEE, FLORIDA

TALLAHASSEE FL DEC 30'93

U.S.POSTAGE 3 4

Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, CA 92653

POLK293 926534006 1C93 01/10/94

POLK POWER GP INC
MOVED LEFT NO ADDRESS
UNABLE TO FORWARD
RETURN TO SENDER

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DEP File No. AC 53-211670
PSD-FL-187
Polk County

Polk Power Partners
23293 South Pointe Drive
Laguna Hills, California 92653
_____/

INTENT TO REISSUE

The Department of Environmental Protection gives notice of its intent to reissue a permit (copy attached) for the proposed project as detailed in the application specified above, for the reasons stated in the attached Technical Evaluation and Preliminary Determination.

The permittee, Polk Power Partners, applied on April 6, 1992, to the Department of Environmental Protection for a permit to construct a cogeneration and CO_2 recovery facility 3.7 miles southwest of Bartow in Polk County, Florida. The Department issued the permit initially on November 24, 1992. Since that time, the permittee submitted new information justifying revised gas turbine emission limits for carbon monoxide (CO) and a deletion of the carbon dioxide (CO_2) recovery facility. Therefore, the Department is reissuing the permit to include these changes and provide additional time to accomplish the revised objectives. The only increase in allowable emissions for this reissued permit is 47.4 tons of CO per year.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes and Florida Administrative Code (F.A.C.) Chapters 17-212 and 17-4. The project is not exempt from permitting procedures. The Department has determined that a construction permit is required for the proposed work.

Pursuant to Section 403.815, Florida Statutes and Rule 17-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Reissue Permit. The notice shall be published one time only within 30 days in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within seven days of publication.

Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

The Department will reissue the permit with the attached conditions unless a petition for an administrative proceeding (hearing) is filed pursuant to the provisions of Section 120.57, F.S.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a

waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO REISSUE and all copies were mailed by certified mail before the close of business on 12/30/93 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Barbara J. Boutwell 12/30/93
Clerk Date

Copies furnished to:
B. Thomas, SWD
J. Harper, EPA
C. Shaver, NPS
K. Kosky, KBN
D. Roberts, HBGS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO REISSUE PERMIT

The Department of Environmental Protection gives notice of its intent to reissue a permit to Polk Power Partners, 23293 South Pointe Drive, Laguna Hills, California 92653, to construct a cogeneration facility 3.7 miles southwest of Bartow, Polk County, Florida. A determination of Best Available Control Technology (BACT) is required. The proposed project is subject to Prevention of Significant Deterioration (PSD) regulations and federal new source performance standards. Modeling results show that increases in ground-level concentrations are less than PSD significant impact levels. The Department is issuing this Intent to Reissue for the reasons stated in the Technical Evaluation and Preliminary Determination.

The Department issued the permit initially on November 24, 1992. Since that time, the permittee submitted new information justifying revised gas turbine emission limits for carbon monoxide (CO) and a deletion of the carbon dioxide (CO_2) recovery facility. Therefore, the Department is reissuing the permit to include these changes and provide additional time to accomplish the revised objectives.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of

the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Park Courtyard
Tallahassee, Florida 32301

Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8218

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Florida Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

December 29, 1993

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, California 92653

Dear Mr. Malenius:

Attached is one copy of the Revised Technical Evaluation and Preliminary Determination and revised permit for Polk Power Partners to construct a cogeneration facility in Polk County.

Please submit any written comments for consideration concerning the Department's proposed action to Mr. Preston Lewis, P.E., at the above address.

Sincerely,

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

CHF/JR/plm

Attachments

cc: B. Thomas, SWD
J. Harper, EPA
C. Shaver, NPS
K. Kosky, KBN
D. Roberts, HBGS
D. Martin, Polk Co.

242805
PATS updated
12/30/93

Printed on recycled paper.

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23046 Avenida De La Carlota, Ste 400
Laguna Hills, CA 92653

4a. Article Number
P 872 562 596

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
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7. Date of Delivery 1-24-94

5. Signature (Addressee)

6. Signature (Agent)
D Pangen

8. Addressee's Address (Only if requested and fee is paid)

PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

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P 872 562 596

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UNITED STATES POSTAL SERVICE

Sent to: Mr. William R. Malenius	
Street and No.: 23046 Avenida De La Carlota, Ste 400	
P.O., State and ZIP Code: Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 1-20-94 Permit: AC53-211670 PSD-FL-187	

PS Form 3800, JUNE 1991

P 872 562 591

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to: Mr. William R. Malenius	
Street and No.: 23293 South Point Dr. Polk Power Partners	
P.O., State and ZIP Code: Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 12-30-93 Permit: AC 53-211670 PSD-FL-187	

PS Form 3800, JUNE 1991

Best Available Copy

KBN

October 12, 1992

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

RE: Polk County--A.P.
Polk Power Partners, L.P.--Mulberry Cogeneration Project
Permit Application AC 53-211670 and PSD-FL-187

Dear Clair:

Enclosed please find a copy of the notice of intent to issue the air construction permit for this project which was published in The Polk County Democrat on October 8, 1992.

We have provided several minor clarifications to the draft permit to John Reynolds, which he indicated would be made in the final permit. These clarifications involved:

1. Presenting emission limits for NO_x, sulfur content for SO_2, and opacity limits using fuel oil as backup after the first 3 years of operation (Specific Condition No. 2).

2. Specifying that natural gas and fuel oil can be fired until December 31, 1997 (3 years after the construction permit expiration date). After that date, the primary fuel will be natural gas; fuel oil can be used as a backup for no more than 30 days (Specific Condition No. 3). Fuel consumption rates for natural gas and fuel oil will be based on a temperature of 59°F or the benchmark. The number of hours of operation for the turbine firing fuel oil is 6,833, or 78 percent of the year.

In addition, a few clarifications to the BACT determination were discussed which made it more consistent with the specific conditions.

I greatly appreciate your staff's efforts in completing the review and issuing the draft permit.

Sincerely,

Robert C. McCamish

Kennard F. Kosky, P.E.
President

RECEIVED
OCT 13 1992
Division of Air Resources Management

KFK/tyf

cc: Mr. William Malenius, Ark Energy, Inc.
Mr. Ward Marshall, Central and South West Services, Inc.
File (2)

91193A1/13

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

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QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL PACKAGE TRACKING NUMBER 1028817643

1028817643

RECIPIENT'S COPY

1 Date: 10/12/92

From (Your Name) Please Print: M.F. Kosky/VJP

Your Phone Number (Very Important):

Company:

Department/Floor No.:

Street Address:

City:

State:

ZIP Required:

2 To (Recipient's Name) Please Print: Clair H. Fancy

Recipient's Phone Number (Very Important): (904) 488-1344

Company: Florida Dept. of Environmental Regula

Department/Floor No.:

Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip Codes.): 2600 Blair Stone Road

City: Tallahassee

State: Fl.

ZIP Required: 32399

YOUR INTERNAL BILLING REFERENCE INFORMATION (First 24 characters will appear on invoice.): 91193-0200

H IF HOLD FOR PICK-UP, Print FEDEX Address Here

Street Address:

City:

State:

ZIP Required:

3 PAYMENT 1 [X] Bill Sender 2 [ ] Bill Recipient's FedEx Acct. No. 3 [ ] Bill 3rd Party FedEx Acct. No. 4 [ ] Bill Credit Card 5 [ ] Cash/Check

4 SERVICES (Check only one box)

Priority Overnight (Delivery by next business morning†)		Standard Overnight (Delivery by next business afternoon†)	
11	YOUR PACKAGING	51	YOUR PACKAGING
16	[X] FEDEX LETTER *	56	FEDEX LETTER *
12	FEDEX PAK *	52	FEDEX PAK *
13	FEDEX BOX	53	FEDEX BOX
14	FEDEX TUBE	54	FEDEX TUBE
Economy Two-Day (Delivery by second business day†)		**Government Overnight** (Restricted to authorized users only)	
30	ECONOMY	46	GOVT LETTER
		41	GOVT PACKAGE

Freight Service (for Extra Large or any package over 150 lbs.)

70 OVERNIGHT FREIGHT ** (Confirmed reservation required)

80 TWO-DAY FREIGHT **

†Delivery commitment may be later in some areas.

*Declared Value Limit $100

**Call for delivery schedule.

5 DELIVERY AND SPECIAL HANDLING (Check services required)

1 [ ] HOLD FOR PICK-UP (Fill in Box H)

2 [X] DELIVER WEEKDAY

3 DELIVER SATURDAY (Extra charge) (Not available to all locations) [ ]

4 DANGEROUS GOODS (Extra charge)

5

6 DRY ICE ____ Lbs

7 OTHER SPECIAL SERVICE

8

9 SATURDAY PICK-UP (Extra charge)

10

11

12 HOLIDAY DELIVERY (If offered) (Extra charge)

6 PACKAGES / WEIGHT In Pounds Only

Total / Total

DIM SHIPMENT (Chargeable Weight)

[ ] lbs.

____ X ____ X ____ = ____

Received At

1 [ ] Regular Stop 3 [ ] Drop Box

2 [ ] On-Call Stop 4 [ ] BSC 5 [ ] Station

Emp. No. / Date

[ ] Cash Received

[ ] Return Shipment

[ ] Third Party [ ] Chg. To Del. [ ] Chg. To Hold

Street Address

City / State / Zip

Received By: X

Date/Time Received / FedEx Employee Number

7 Release Signature:

FedEx Emp. No. / Date/Time

Federal Express Use

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Declared Value Charge

Other 1

Other 2

Total Charges

REVISION DATE 4/91

PART #13704 FXEM 6/91

FORMAT #082

082

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AFFIDAVIT OF PUBLICATION

The Polk County Democrat

Published Semi-Weekly
Bartow, Polk County, Florida

Case No. _____

STATE OF FLORIDA
COUNTY OF POLK

Before the undersigned authority personally appeared _____ S. L. Frisbie, IV _____, who on oath says that (s)he is _____ Publisher _____ of The Polk County Democrat, a newspaper published at Bartow, Polk County, Florida; that the attached copy of advertisement, being a _____ Notice of Intenet to Issue Permit _____ in the matter of _____ POLK POWER PARTNERS _____

in the _____ Court, was published in said newspaper in the issues of _____ October 8, 1992 _____.

Affiant further says that The Polk County Democrat is a newspaper published at Bartow, in said Polk County, Florida, and that said newspaper has heretofore been continuously published in said Polk County, Florida, each Monday and Thursday, and has been entered as second class matter at the post office in Bartow, in said Polk County, Florida, for a period of one year next preceeding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm, or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

Signed _____

The foregoing instrument was acknowledged before me this 9th day of Oct., 1992, by _____ S. L. Frisbie, IV _____,

who is personally known to me.

Teresa M Pacetti
(Signature of Notary Public)

Teresa M. Pacetti
(Printed or typed name of Notary Public)
Notary Public

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA

Notary Public, State of Florida
TERESA M. PACETTI
My Comm. Exp. Dec. 19, 1995
Comm. No. CC 169408

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION NOTICE OF INTENT TO ISSUE PERMIT

The Department of Environmental Regulation gives notice of its intent to issue a permit to POLK POWER PARTNERS, 23293 South Pointe Drive, Laguna Hills, California 92653, to construct a cogeneration and CO2 recovery facility 3.7 miles southwest of Bartow, Polk County, Florida. A determination of Best Available Control Technology (BACT) is required. The proposed project is subject to Prevention of Significant Deterioration (PSD) regulations and federal new source performance standards. Modeling results show that increases in ground-level concentrations are less than PSD significant impact levels. The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within (14) days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received)

within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application is available for public inspection during normal business hours, 8:00 a. m. to 5:00 p. m., Monday through Friday, except legal holidays, at Department of Environmental Regulation, Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and Department of Environmental Regulation, Southwest District, 4520 Oak Fair Boulevard, Tampa, Florida 33610-7347.

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person. Such requests must be submitted within 30 days of this notice.

Oct. 8, 1992—2911

Best Available Copy

0102473

139

POLK POWER PARTNERS, L.P.
1125 US 98 SOUTH, SUITE 100
LAKELAND, FL 33801
PH. (813) 682-6338

CITRUS & CHEMICAL BANK
LAKELAND, FL 33801

63-597/631

'IFTY DOLLARS AND NO/100----------

DATE	AMOUNT
4/11/95	$50.00

PAY TO THE ORDER OF
FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR REGULATION
2600 BLAIR STONE ROAD
TALLAHASSEE, FL 32399

Timothy L Burke
AUTHORIZED SIGNATURE

[redacted]

POLK POWER PARTNERS, L.P.

1394

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR REGULATION
2600 BLAIR STONE ROAD
TALLAHASSEE, FL 32399

CONSTRUCTION PERMIT EXTENSION FOR MULBERRY COGEN
PERMIT # AC53-211670 PSD-FL-187

$50.00

[redacted]

POLK POWER
PARTNERS

0102473
1125 U.S. 98 SOUTH
SUITE 100
LAKELAND, FLORIDA 33801
813-682-6338
FAX 813-683-8257

April 11, 1995

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

RE: Mulberry Cogeneration Facility PSD-FL-187, Permit Number AC 53-211670
Extension of Construction Permit

1995 APR 13 RECEIVED
BAR - MAIL ROOM

Dear Mr. Fancy:

This correspondence is submitted on behalf of Polk Power Partners, LP to request that the construction permit for the Mulberry Cogeneration Facility be extended until December 31, 1998. The current construction permit expires December 31, 1995. David Zell, permit engineer from the Southwest District, recommended that we make this request to ensure that the facility has a permit in effect until a Title V permit is issued. A Title V permit application will be submitted for the facility as required by FDEP rules and policies. However, we were told that FDEP has up to three years to review a Title V permit application before issuing a permit. It is probable that a Title V permit will not be issued prior to the expiration of our construction permit. Specific condition (8.) of our construction permit states that the permittee, for good cause, may request that the construction permit be extended (FAC 62-4.090).

All of the compliance testing required by the construction permit has been completed and the results have been forwarded to both your office and the Southwest District office in Tampa.

I have enclosed the Fifty Dollar ($50.00) fee required by FAC 62-4.050(4)(q) for a minor modification to a permit. If you have any questions concerning this request, please call me at (813)682-6338.

Sincerely,

Wade Smith
Business Operations Director
Polk Power GP, Inc.

cc: Jerry Kissel, FDEP Southwest District
Roger Anderson, KBN
Les Confair, Ark Energy
Charlie Costenbader, GECC
John Paul Jones, CSWE Operations
Nancy Jones, PPP
Bill Malenius, Ark Energy
Mike Moran, CSWE

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

September 27, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Nancy Henning Jones
Vice President & General Manager
Polk Power Partners
1125 U.S. 98 South - Suite 100
Lakeland, Florida 33801

Re: Permit No. AC53-211670, PSD-FL-187

Dear Ms. Jones:

This is in reply to your September 22 letter requesting an extension of the 180-day period for initial performance testing of the Polk Power facility pursuant to 40 CFR 60.8(a). Also, this confirms our phone discussion today with Mr. Kelly Spencer of your firm concerning this request. As discussed with Mr. Kelly, the federal requirements under 40 CFR 60.8(a) do not provide for an automatic extension of the performance testing period. Therefore, such a request must be approved by the EPA. Mr. Kelly indicated that he will provide the Department with more detailed documentation of the mechanical difficulties sufficient to allow the EPA to make a decision on this request.

Sincerely,

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

CHF/JR/bb

cc: W. Thomas, SWD
J. Harper, EPA
D. Martin, Polk Co.
J. Bunyak, NPS
K. Kosky, KBN
D. Roberts, HBGS

Is your RETURN ADDRESS completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
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- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

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1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ms. Nancy Henning Jones
Vice President & General Manager
Polk Power Partners
1125 U.S. 98 South Suite 100
Lakeland, Florida 33801

4a. Article Number
P 872 562 689

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
9-30-94

5. Signature (Addressee)
Janet Wysocki

6. Signature (Agent)

8. Addressee's Address (Only if requested and fee is paid)

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

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UNITED STATES POSTAL SERVICE

Sent to Ms. Nancy Henning Jones	
Street and No. 1125 U.S. 98 South -	
P.O., State and ZIP Code Lakeland, FL 33801	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 9/27/94 AC53-211670 PSD-FL-187	

PS Form **3800**, JUNE 1991

HOPPING BOYD GREEN & SAMS
ATTORNEYS AND COUNSELORS
123 SOUTH CALHOUN STREET
POST OFFICE BOX 6526
TALLAHASSEE, FLORIDA 32314
(904) 222-7500
FAX (904) 224-8551
FAX (904) 681-2964

CARLOS ALVAREZ
JAMES S. ALVES
BRIAN H. BIBEAU
KATHLEEN BLIZZARD
ELIZABETH C. BOWMAN
WILLIAM L. BOYD, IV
RICHARD S. BRIGHTMAN
PETER C. CUNNINGHAM
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DOUGLAS S. ROBERTS
R. SCOTT RUTH
JULIE ROME STEINMEYER

OF COUNSEL
W. ROBERT FOKES

MEMORANDUM

TO: Clair Fancy

FROM: Doug Roberts DR

RE: BACT Analysis for Mulberry Cogen. Project

DATE: December 23, 1993

==========

Per your request we have typed up the BACT determination for the Mulberry Cogeneration Project. A copy of the document is attached along with the original marked up copy you gave us. Also enclosed is a disk with the document in Wordperfect 5.1. You may need to conform the type face.

It appears there is a discrepancy in the permit over the date for compliance with the lower NOx limits. The table of permitted emissions in the permit states the new limits apply on December 31, 1997 (incorrectly labeled originally as Dec. 31, 1987). The final determination (attached) and preliminary determination have the date as April 30, 1997. This leaves an eight month difference in the dates. While we did not make such a change, it may be appropriate for the Department to correct the revised BACT determination to reflect the date of December 31, 1997 for both the new NOx (and CO) limits and the date to switch to 100% natural gas.

We would like to publish notice of this within a day or two of its issuance. If you could send over the needed notice early, we can get KBN to arrange for publication. We assume it will be like an original intent to issue permit action with some changes to text to reflect it is an amended PSD permit.

Thanks for all your help on this. Please call Gary Sams or Laura Stewart at our firm when the permit is ready and we will pick it up. I will be out of the office the week of Dec. 27th.

Encls.

Final Determination

The Technical Evaluation and Preliminary Determination for the permit to construct a cogeneration and CO_2 recovery facility approximately 3.7 miles southwest of Bartow in Polk County, Florida, was distributed on September 22, 1992. The Notice of Intent to Issue was published in the Polk County Democrat on October 8, 1992. Copies of the evaluation were available for public inspection at the Department's Tallahassee and Tampa offices.

On October 26, 1992, a letter was received from the EPA concurring with the Department's proposed action. Comments were received from the applicant on October 13 and November 4, 1992, requesting minor modifications of certain specific conditions. The Department made the following changes in response to those comments:

Specific Condition No. 2 - The emission limits were modified to show fuel oil use as backup after the first three years of operation. Oil use is limited to 30 days per year after December 31, 1997.

Specific Condition No. 3 - Fuel consumption rates and hours of operation were modified to show fuel oil use as backup after the first three years of operation and limited use (30 days per year) after December 31, 1997.

BACT Determination - Minor revisions were made to the last paragraph of the NO_x section to clarify that SCR may be required if the emission limits are not achieved by ~~April 30, 1997.~~ DECEMBER 31, 1997

The final action of the Department will be to issue construction permit AC53-211670 (PSD-FL-187) as modified.

William Malenius
Polk Power Partners
23923 South Pointe Drive
Laguna Hills, California 92653

Re: Polk County - A.P.
Polk Power Partners, L.P.
Mulberry Cogeneration Project
PSD-FL-187; Permit Modification

Dear Mr. Malenius:

The Department received a request from Mr. Douglas S. Roberts on November -, 1993, for administrative changes to the prevention of significant deterioration permit (PSD-FL- 187) issued to Polk Power Partners for the above referenced project. That request sought formal approval of various project changes that had received previous preliminary approval by the Department. The Department concurs with that request as authorized herein. The Department modifies the permit to delete references to the carbon dioxide recovery plant which is no longer proposed to be constructed as part of the project. The emissions identified as associated with the CO2 plant and the secondary heat recovery steam generator jointly are now assigned solely to the secondary heat recovery steam generator. The Department authorizes an increase in the carbon monoxide emissions from the Project at such time as the nitrogen oxide emissions from the plant are reduced.

The proposed changes are acceptable to the Department and will not result in the increase in permitted annual emissions of any pollutant subject to PSD regulations. As an administrative change, this revision will not require additional public participation procedures.

The Department grants the following amendments to the above referenced permit:

SPECIFIC CONDITION NO. 2

Change From:

2. Emissions from these facilities shall not exceed the limits listed below (based on operation at 59°F):

			Through 12/31/97		After 12/31/97 (See notes) 9	
Pollutant	Source	Fuel	lbs/hr	tons/yr	lbs/hr	tons/yr
NO_x	HRSG Stack	Gas	87.8	384.5	52.7	230.7
	CO_2 Plant Stack[1]	Gas	19.9	87.1	18.3	80.0
	HRSG Stack	Oil	164.0	718.2	164.0	59.0
	CO_2 Plant Stack[1]	Oil	23.4	102.4	23.4	8.4
SO_2	HRSG Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	CO_2 Plant Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack	Gas	10% Opacity		10% Opacity	
	CO_2 Plant Stack	Gas	10% Opacity		10% Opacity	
	HRSG Stack	Oil	20% Opacity		20% Opacity	
	CO_2 Plant Stack	Oil	20% Opacity		20% Opacity	
VOC	CO_2 Plant Stack	--	18.2	79.6	17.7	77.6
CO	HRSG Stack	Gas	42.9	187.8	42.9	187.8
	CO_2 Plant Stack[a]	Gas	11.9	52.0	11.9	52.0
	HRSG Stack	Oil	75.3	329.9	75.3	27.1
	CO_2 Plant Stack[a]	Oil	13.4	58.5	13.4	4.8

Notes:
(1) Oil may be used as backup fuel for up to 30 days per year.
(2) NO_x limits after 12/31/97 based on 15 ppmvd.
(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.

[1] Or secondary HRSG Stack.

Change To:

2. Emissions from these facilities shall not exceed the limits listed below (based on operation at 59°F):

Pollutant	Source	Fuel[5]	Through 12/31/97[3] lbs/hr	Through 12/31/97[3] tons/yr	After 12/31/97 [1][2][3][4] lbs/hr	After 12/31/97 [1][2][3][4] tons/yr
NO_x	HRSG Stack	Gas	87.8	384.5	52.7	230.7
	Secondary HRSG Stack	Gas	19.9	87.1	18.3	80.0
	HRSG Stack	Oil	164.0	718.2	164.0	59.0
	Secondary HRSG Stack	Oil	23.4	102.4	23.4	8.4
SO_2	HRSG Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	Secondary HRSG Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack	Gas	10% Opacity		10% Opacity	
	Secondary HRSG Stack	Gas	10% Opacity		10% Opacity	
	HRSG Stack	Oil	20% Opacity		20% Opacity	
	Secondary HRSG Stack	Oil	20% Opacity		20% Opacity	
CO	HRSG Stack	Gas	42.9	187.8	**53**	**232**
	Secondary HRSG Stack	Gas	11.9	52.0	**12.6**	**55.2**
	HRSG Stack	Oil	75.3	329.9	75.3	27.1
	Secondary HRSG Stack	Oil	13.4	58.5	13.4	4.8

Note: (1) Oil may be used as backup fuel for up to 30 days per year.

(2) NO_x limits **for combustion turbine firing natural gas** after 12/31/97 based on 15 ppmvd.

(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.

(4) CO limits during natural gas firing are based on CO emission basis of 25 ppmvd from the combustion turbine. CO emission limits applicable prior to December 31, 1997, upon unit achieving NO_x emissions limits based on emission basis of 15 ppmvd during natural gas firing.

(5) Although only natural gas will be combusted in the duct burner and vented through the secondary HRSG stack, a portion of the exhaust flow from the combustion turbine which serves as combustion air to the secondary HRSG will also be vented through the secondary HRSG stack.

2. SPECIFIC CONDITIONS NO. 3

Change From:

3. The cogeneration facility shall be permitted to fire natural gas and No. 2 fuel oil until December 31, 1997, after which the primary fuel will be natural gas. Fuel consumption rates (based on operation at 20°F) and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft^3/hr	MM ft^3/yr	hrs/yr	Mlb/hr	M lb/yr	hrs/yr
Turbine	1,013.4	8,877.4	8,760	55.6	379.9	6,833[1]
Duct Burner	104.2	912.8	8,760	0	0	0

[1] After December 31, 1997, fuel oil can be used permanently as backup fuel for no more than 720 hours per year.

Change To:

3. The cogeneration facility shall be permitted to fire natural gas and No. 2 fuel oil until December 31, 1997, after which the primary fuel will be natural gas. Fuel consumption rates (based on operation at 20°F) and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft^3/hr	MM ft^3/yr	hrs/yr	lb/hr	M lb/yr	hrs/yr
Turbine	1,013.4	8,877.4	8,760	55.6	379.9	6,833[1]
Duct Burner	104.2	450.2[2]	8,760	0	0	0

[1] After December 31, 1997, fuel oil can be used permanently as backup fuel for no more than 720 hours per year.

[2] **Effective annual fuel consumption based on the duct burner operating for 4,320 hours and firing at the maximum hourly fuel consumption rate.**

3. SPECIFIC CONDITION NO. 4

Change From:

4. Before this construction permit expires, the cogeneration facility and CO_2 Recovery Plant stacks shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96 percent to 100 percent of the maximum capacity achievable for the

average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_x: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10
VOC: EPA Method 25A

Change To:
4. Before this construction permit expires, the cogeneration facility and **secondary HRSG** stacks shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96 percent to 100 percent of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_x: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10

All other conditions remain as issued. This letter must be attached to the PSD-FL-187 permit and shall become a part of the permit.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information:

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;

(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

Sincerely,

Virginia Wetherell
Secretary

cc: Jewell A. Harper, EPA
William Thomas, SWD
James W. Coleman, Jr., NPS
D. Martin, Polk County
Ken Kosky, KBN

HOPPING BOYD GREEN & SAMS

ATTORNEYS AND COUNSELORS

123 SOUTH CALHOUN STREET

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FAX (904) 224-8551

FAX (904) 681-2964

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BRIAN H. BIBEAU
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WILLIAM L. BOYD, IV
RICHARD S. BRIGHTMAN
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ANGELA R. MORRISON
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GARY V. PERKO
KAREN M. PETERSON
MICHAEL P. PETROVICH
DOUGLAS S. ROBERTS
R. SCOTT RUTH
JULIE ROME STEINMEYER

OF COUNSEL
W. ROBERT FOKES

December 22, 1993

BY HAND DELIVERY

Clair Fancy, Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Fla. 32399

RECEIVED
DEC 22 1993
Bureau of
Air Regulation

RE: Mulberry Cogeneration Project;
PSD-FL-187

Dear Clair:

On behalf of Polk Power Partners, I am renewing the request in my letter of November 18, 1993, for the Department to amend the PSD permit for the above referenced project. To assist the Department's actions on this request, a draft letter approving the request is attached. This draft letter contains revised language for Footnote 4 of revised Specific Condition 2 from that contained in the November 18th request concerning the CO emission rate once the unit reaches a NOx emission rate based upon a 15 PPMVD NOx emission basis.

By copy of this letter, I am submitting to Patti Adams a check payable to the Department for $250.00 as the fee for this request.

We appreciated the opportunity to meet with you, John Brown and John Reynolds yesterday to discuss this request. Your willingness to issue this revision expeditiously is also greatly appreciated. We are prepared to publish the required notice as soon as the Department issues the revision. Should there be any questions concerning this matter, please do not hesitate to contact either Ken Kosky (903/331-9000) or me.

Sincerely,

Douglas S. Roberts

cc: John Brown
John Reynolds
Patti Adams (w/check)
B. Thomas, SW Dist
C. Halladay
J. Harper, EPA
J. Bunyak, NPS
C. Martin, Polk Co.

HOPPING BOYD GREEN & SAMS
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JULIE ROME STEINMEYER

OF COUNSEL
W. ROBERT FOKES

November 16, 1993

RECEIVED
NOV 16 1993
Division of Air
Resources Management

Clair Fancy, Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Mulberry Cogeneration Project
PSD-FL-187

Dear Mr. Fancy:

On behalf of Polk Power Partners, L.P. (Polk Power), I am writing concerning the above-referenced prevention of significant deterioration (PSD) permit. Polk Power is in the process of obtaining financing for the project and is requesting corrections and updates of the permit to reflect the permitted facilities and the applicable emission limits. Such changes are needed to satisfy the lenders that the permits for the Mulberry Project are complete and current.

Deletion of Carbon Dioxide Plant.

As conceived and described in the PSD permit, the Mulberry Cogeneration Project consisted of a 125 MW combined cycle electrical power plant unit and a carbon dioxide recovery plant which would serve as the thermal host for the cogeneration plant. Recent economic factors have caused Polk Power to eliminate the planned CO2 plant. To qualify as a cogeneration facility, steam from Mulberry project will now serve an ethanol production plant to be located adjacent to the project site. This ethanol plant will be developed by a legally separate entity not under the control of Polk Power. Necessary permits are now being obtained separately for that ethanol plant. It would therefore be appropriate to now revise the PSD permit for the Mulberry Project to delete references to the CO2 plant, including the reference to the CO2 plant in the table of permitted emissions.

Recent design changes to the plant identified the necessity for a separate stack for the secondary heat recovery steam

generator (duct burner). This change was described in a February 19, 1993 letter to you from Ken Kosky of KBN Engineering and Applied Sciences and was approved by the Department by letter on March 19, 1993. This secondary HRSG stack is an alternate to the CO2 plant stack, as identified in the KBN letter and in the revised table of emissions. In revising the table of permitted emissions in Specific Condition 2, the CO2 stack and its emissions should now be labeled solely as the "secondary HRSG stack".

Carbon Monoxide Emission Rates

As you are aware, NOx and CO emission rates in combined cycle units move in opposite directions from one another, such that if NOx emissions are reduced, CO emissions often increase. The current permitted emissions for the Mulberry project establish one set of NOX and CO emissions through December 31, 1997 and a lower set of NOx (but not CO) emissions after December 31, 1997. The PSD permit initially limits NOx emissions to 87.8 lbs/hr, based on an emission rate of 25 PPM NOx, and CO to 42.9 lbs/hr, based on an emission rate of 20 PPM. The permit then establishes a limit of 52.7 lbs/hr NOx based on an emission rate of 15 PPM after December 31, 1997. However, the permitted emissions for CO after December 31, 1997, were not changed to account for this lower NOx emission rate.

In a second letter to you from KBN (attached) dated August 17, 1993, the Department was requested to approve a change in the CO emissions from the unit when the emission limit for NOx is reduced in December 1997. This was based upon subsequent information from General Electric that the unit could only meet 25 PPM CO when NOx emissions are at 15 PPM.

In a reply letter dated August 19, 1993 (attached), signed by John Brown on your behalf, the Department deferred making any further changes to the permit until the initial performance tests were completed, at which time the Department would adjust permit limits.

Polk Power requests that the Department grant the above requested change in CO emissions at this time and not defer such revisions until the completion of the performance tests. Based on past experience, the financial lenders for this project will require that the permits reflect the design emissions for the project at the time financial closing for this Project occurs. Leaving the permitted emission limits for CO unchanged at this time may cause the lenders to withhold financing since the permit will include a CO emission limit the project is known to be unable to meet when NOx emissions are reduced in the future. Polk Power therefore requests that the Department modify the PSD permit to approve the change in the CO emissions, consistent with the values

requested in the August 17, 1993, KBN letter, to be applicable upon the change in the permitted NOx emissions, whenever that change may occur.

Revised Permit Conditions

Polk Power requests that the Department issue a formal letter modification of the PSD permit to reflect the recent design changes, including deletion of the CO2 plant, addition of the secondary HRSG stack and the changed CO emissions as requested. Several recent letters from the Department have approved these changes. However, it would seem appropriate to issue a formal change to the permit that incorporates all of these approved changes.

To facilitate your issuance of such a letter, a draft letter is enclosed (along with a disk version in WordPerfect 5.1), which reflects the several changes to the PSD permit that have been proposed and we believe concurred in by the Department. The suggested revised conditions also reflect deletion of VOC limits for the CO2 plant as a result of the elimination of the CO2 plant and its VOC producing processes and reduced limits on hours of operation of the secondary HRSG consistent with the recent identified design changes. None of these changes will result in a significant increase in permitted emissions from the Project.

We appreciate your attention to this request and the Department's past cooperation in this permitting effort. Polk Power realizes many of these changes and requests may seem minor and somewhat annoying. However, it reflects the circumstances that arise when obtaining significant financial investment in projects such as this.

Should you have any questions concerning this matter, please do not hesitate to call either Ward Marshall of Central and Southwest Services (214/777-1374, Ken Kosky or Bob McCann of KBN (904/331-9000) or myself.

Sincerely,

Douglas S. Roberts

Attachments

cc: Preston Lewis, DEP

Florida Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

November 18, 1993

Mr. Douglas S. Roberts
Hopping Boyd Green & Sams
P.O. Box 6526
Tallahassee, Florida 32314

Dear Mr. Roberts:

The Department received your November 16 letter making another request for increased carbon monoxide (CO) limits for the Polk Power Partners, L.P./Mulberry Cogeneration Project (PSD-FL-187). Since the original request was based on information not available at the time the permit was issued, the Department agreed on August 19, 1993, to adjust the CO limits higher if necessary based on results of the compliance test. That agreement should provide sufficient assurance to lenders that the facility will not be faced with unattainable limits in the operation permit. We are not aware of any case involving financing being withheld where the Department has agreed to adjust emission limits as required by the test data.

As indicated in Specific Condition No. 9 of the permit, the Department's practice is to address deviations from the original design at the time the operation permit is issued. Otherwise, considerable paperwork and staff time would be consumed making modifications that would be made anyway in the process of issuing the operation permit. Moreover, if the construction permit is modified, another public notice and comment period would be required due to emissions being higher than previously stated in the permit.

In summary, neither Polk Power Partners, L.P., nor their lenders should doubt that the Department will adjust limits so that the Mulberry Cogeneration Facility can be operated and in a manner that is environmentally responsible.

Sincerely,

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

CHF/JR/bb

c: K. Kosky, P.E., KBN

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RECEIVED
AUG 30 1993
Division of Air
Resources Management

August 27, 1993

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

Polk Power Partners

Subject: Mulberry Cogeneration Project
DER File No. AC53-211670, PSD-FL-187
Request for Change in Permit Specific Condition

Dear Clair:

In my letter to you dated August 17, 1993, a request was made to change the carbon monoxide (CO) emission limitation for the combustion turbine when firing natural gas. Also, a discussion was presented that addressed the potential reduction of the maximum allowable nitrogen oxides (NO_x) emission rate to 15 parts per million corrected to dry conditions (ppmvd) and 15 percent oxygen prior to December 31, 1997, (the current permit conditions limit NO_x emissions to 25 ppmvd prior to December 31, 199,7 and to 15 ppmvd after December 31, 1997). Although discussions with GE (the combustion turbine vendor selected for the project) have indicated the potential emission rate of 15 ppmvd may be achievable when the turbine is initially operated, GE provides no guarantee that the emission limit will be met throughout the period from initial operation in November, 1994 to December, 1997. As a result, this potential reduction in NO_x emission rate is not considered a viable option for this project.

Based on this correspondence, the proposed change to the air construction permit is limited to the CO emission limitation for the combustion turbine when firing natural gas as requested on August 17, 1993. No change to the NO_x emission rate is proposed at this time. Attachment 1 contains the requested change to the CO emission limit (see Note 4).

If you have any questions or concerns regarding the requested change, please don't hesitate to call me. Again, on behalf of Polk Power Partners, L.P. and KBN, we appreciate you and your staff's review of this requested change to the permit.

Sincerely,

Kennard F. Kosky, P.E.
President
Registration No. 14996

cc: Mr. William R. Malenius, Ark Energy, Inc.
Mr. Ward C. Marshall, Central and South West Services, Inc.
J. Reynolds

91193A3/1

KBN ENGINEERING AND APPLIED SCIENCES, INC.

1034 Northwest 57th Street
Gainesville, Florida 32605
904-331-9000
FAX 904-332-4189

5680 West Cypress Street, Suite I
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Rockville, Maryland 20850
301-738-1100
FAX 301-738-1105

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ATTACHMENT 1

SPECIFIC CONDITIONS:

2. Emissions from these facilities shall not exceed the limits listed below (based on operation at 59°F):

Pollutant	Source	Fuel	Through 12/31/97 lbs/hr	Through 12/31/97 tons/yr	After 12/31/97 (See notes) [9] lbs/hr	After 12/31/97 (See notes) [9] tons/yr
NO_x	HRSG Stack	Gas	87.8	384.5	52.7	230.7
	CO_2 Plant Stack[a]	Gas	19.9	87.1	18.3	80.0
	HRSG Stack	Oil	164.0	718.2	164.0	59.0
	CO_2 Plant Stack[a]	Oil	23.4	102.4	23.4	8.4
SO_2	HRSG Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	CO_2 Plant Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack	Gas	10% Opacity		10% Opacity	
	CO_2 Plant Stack	Gas	10% Opacity		10% Opacity	
	HRSG Stack	Oil	20% Opacity		20% Opacity	
	CO_2 Plant Stack	Oil	20% Opacity		20% Opacity	
VOC	CO_2 Plant Stack	--	18.2	79.6	17.7	77.6
CO	HRSG Stack	Gas	42.9	187.8	53	232
	CO_2 Plant Stack[a]	Gas	11.9	52.0	12.6	55.2
	HRSG Stack	Oil	75.3	329.9	75.3	27.1
	CO_2 Plant Stack[a]	Oil	13.4	58.5	13.4	4.8

Notes: (1) Oil may be used as backup fuel for up to 30 days per year.
(2) NO_x limits after 12/31/97 based on 15 ppmvd.
(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.
(4) CO limits after 12/21/97 based on CO emission rate of 25 ppmvd from the combustion turbine and is coincident with NO_x limit of 15 ppmvd.

[a] Or secondary HRSG Stack.

Florida Department of
Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

August 19, 1993

Mr. Kennard F. Kosky, P.E.
President
KBN Engineering and Applied Sciences, Inc.
1034 Northwest 57th Street
Gainesville, Florida 32605

Re: Permit No. AC53-211670, PSD-FL-187
Mulberry Cogeneration Project

Dear Mr. Kosky:

This is in reply to your August 17 letter requesting revised emission limits for the Mulberry combustion turbine project. The requested changes are based on recent information from the turbine manufacturer and would result in an increase in allowable emissions of 47.4 TPY of CO and a decrease of 153.8 TPY of NO_X.

Although we understand the reasons for requesting the changes now, we recommend waiting until the performance test has been completed. At that time the Department will adjust the limits as called for by the data. This approach avoids the need for further changes later. Your letter will remain on file as a pending request for adjustment of the limits prior to issuing the operation permit.

Sincerely,

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

CHF/JR/bb

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Is your RETURN ADDRESS completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Mr. Kennard F. Kosky, P.E.
President
KBN Engineering & Applied Sciences
1034 Northwest 57th Street
Gainesville, Florida 32605

4a. Article Number

P 230 524 385

4b. Service Type

☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery

8-23-93

5. Signature (Addressee)

Alysa Lancaster

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 230 524 385

Receipt for Certified Mail

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to: Mr. Kennard F. Kosky, P.E.	
Street and No.: 1034 Northwest 57th Street	
P.O., State and ZIP Code: Gainesville, FL 32605	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 8/20/93 AC53-211670	

PS Form **3800**, June 1991

August 17, 1993

RECEIVED
AUG 18 1993
Division of Air
Resources Management

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

Subject: Mulberry Cogeneration Project
DER File No. AC53-211670, PSD-FL-187
Request for Change in Permit Specific Condition

Dear Clair:

This correspondence is submitted on behalf of Polk Power Partners, L.P. to request a change in the carbon monoxide (CO) emission limitation for the combustion turbine when firing natural gas and provide a potential reduction of the maximum allowable nitrogen oxides (NO_x) emission rate when the unit becomes operational. These changes affect Specific Condition No. 2 of the air construction permit (AC53-211670).

CARBON MONOXIDE EMISSIONS FOR NATURAL GAS FIRING

The request for this change is based on recent performance information obtained for the General Electric PG7111(EA) combustion turbine when it achieves a maximum NO_x emission rate of 15 parts per million (ppm), corrected for dry conditions (ppmvd) and 15 percent oxygen (O_2). At this NOx emission level, GE expects only a maximum CO emission rate of 25 ppmvd. As a result, the CO emission limit would be revised from the current limit of 20 ppmvd to 25 ppmvd and would be in effect when the NO_x emission rate is equal to or less than 15 ppmvd, corrected to 15 percent O_2 (i.e., after December 31, 1997). Prior to December 31, 1997, the CO emission limit of 20 ppmvd is achievable with a NO_x emission limit of 25 ppmvd, corrected to 15 percent O_2, respectively.

The net change in maximum allowable CO emissions is approximately 44.2 TPY for the HRSG stack (i.e., 232 TPY at 25 ppmvd compared to 187.8 TPY at 20 ppmvd) and 3.2 TPY for the CO_2 stack (or secondary boiler) (i.e., 55.2 TPY with the turbine's emissions at 25 ppmvd compared to 52.0 TPY at 20 ppmvd) These increases in CO emissions are not significant and do not significantly change conclusions drawn from the economic, environmental, and energy analyses performed as part of the Best Available Control Technology (BACT) review for this project. Combustion design is still proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on combustion turbines. Catalytic oxidation is considered unreasonable for the following reasons:

KBN ENGINEERING AND APPLIED SCIENCES, INC.

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Gainesville, Florida 32605
904-331-9000
FAX 904-332-4189

5680 West Cypress Street, Suite I
Tampa, Florida 33607
813-287-1717
FAX 813-287-1716

1801 Clint Moore Road, Suite 105
Boca Raton, Florida 33487
407-994-9910
FAX 407-994-9393

6821 Southpoint Drive North,
Suite 216
Jacksonville, Florida 32216
904-296-9663 FAX 904-296-0146

One Church Street, Suite 801
Rockville, Maryland 20850
301-738-1100
FAX 301-738-1105

EQUAL EMPLOYMENT OPPORTUNITY

AN AFFIRMATIVE ACTION EMPLOYER

1. Catalytic oxidation will not produce a measurable reduction in air quality impacts from those produced using combustion controls. The maximum air quality impacts produced from either the oxidation catalyst or combustion design control techniques are below the significant impact levels for CO.

2. Based on an estimated annualized cost of a CO oxidation catalyst of $1,041,267 (see Table 4-9 in the air construction permit application), the cost effectiveness is approximately $5,570/ton of CO removed (i.e., oxidation catalyst will remove 187 TPY more than combustion design). The cost effectiveness is based on 50 percent operation on gas and 50 percent operation on oil, both at 10 ppmvd, for a maximum total emissions of 94 TPY (i.e., 47 TPY for both gas and oil). With combustion design controls and based on 50 percent operation on gas at 25 ppmvd and 50 percent operation on oil at 35 ppmvd, the maximum emissions are 281 TPY (i.e., 116 TPY on gas and 165 TPY on oil).

Indeed, recent BACT decisions for combustion turbines have set limits in the 30 ppmvd range. The recent air construction permit for the Cane Island Combustion Turbine Project for Kissimmee Utility Authority (AC49-205703/PSD-FL-182) established the CO emission limit as 54 lb/hr, equivalent to 25 ppmvd, for the GE 7EA turbine. This CO limit was established when the proposed unit is limited to NO_x emissions of either 15 or 25 ppmvd.

POTENTIAL REDUCTION IN NITROGEN OXIDES EMISSIONS

From discussions with GE, the combustion turbine may achieve a maximum NO_x emission rate of 15 ppmvd, corrected to 15 percent O_2, when the turbine is initially operated. As a result, a change in the specific permit condition would be submitted to DER to limit the NO_x emission rate from 25 ppmvd to 15 ppmvd. If this occurs, the total reduction in NO_x emissions from the HRSG stack would be approximately 153.8 TPY each year (i.e., 384.5 TPY at 25 ppmvd minus 230.7 TPY at 15 ppmvd) until after December 31, 1997 (when 15 ppmvd is required to be achieved). However, the CO emission limit would need to be revised from the current limit of 20 ppmvd to 25 ppmvd for the reasons previously cited. Again, the combustion design is still considered as BACT as a result of the technical and economic consequences of using catalytic oxidation on combustion turbines. The cost of an oxidation catalyst would be significant and not cost-effective given the proposed CO emission limit of 25 ppmvd when firing gas and 35 ppmvd when firing distillate oil.

Should the combustion turbine achieve a maximum NO_x emission rate of 15 ppmvd, corrected to 15 percent O_2, when initially operated in November, 1994, the revision to Specific Condition No. 2 is attached that would allow a CO emission rate of 25 ppmvd and limit the NO_x emission rate to 15 ppmvd, corrected to 15 percent O_2 prior to December 31, 1997 (see Attachment 1).

We will contact you in several days to discuss any questions or concerns you may have with regards to these requested changes. On behalf of Polk Power Partners, L.P. and KBN, we greatly appreciated you and your staff's review of these requested changes to the permit. Your continued cooperation is appreciated.

Sincerely,

Kennard F. Kosky, P.E.
President
Registration No. 14996

ATTACHMENT 1

SPECIFIC CONDITIONS:

2. Emissions from these facilities shall not exceed the limits listed below (based on operation at 59°F):

Pollutant	Source	Fuel	Through 12/31/97 lbs/hr	Through 12/31/97 tons/yr	After 12/31/97 (See notes) 9 lbs/hr	After 12/31/97 (See notes) 9 tons/yr
NO_x	HRSG Stack	Gas	87.8[b]	384.5[b]	52.7	230.7
	CO_2 Plant Stack[a]	Gas	19.9[b]	87.1[b]	18.3	80.0
	HRSG Stack	Oil	164.0	718.2	164.0	59.0
	CO_2 Plant Stack[a]	Oil	23.4	102.4	23.4	8.4
SO_2	HRSG Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	CO_2 Plant Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack	Gas	10% Opacity		10% Opacity	
	CO_2 Plant Stack	Gas	10% Opacity		10% Opacity	
	HRSG Stack	Oil	20% Opacity		20% Opacity	
	CO_2 Plant Stack	Oil	20% Opacity		20% Opacity	
VOC	CO_2 Plant Stack	--	18.2	79.6	17.7	77.6
CO	HRSG Stack	Gas	42.9[b]	187.8[b]	53	232
	CO_2 Plant Stack[a]	Gas	11.9[b]	52.0[b]	12.6	55.2
	HRSG Stack	Oil	75.3	329.9	75.3	27.1
	CO_2 Plant Stack[a]	Oil	13.4	58.5	13.4	4.8

Notes: (1) Oil may be used as backup fuel for up to 30 days per year.
(2) NO_x limits after 12/31/97 based on 15 ppmvd.
(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.
(4) CO limits after 12/21/97 based on CO emission rate of 25 ppmvd from the combustion turbine and is coincident with NO_x limit of 15 ppmvd.

[a] Or secondary HRSG Stack.

[b] Should the combustion turbine achieve a maximum NO_x emission rate of 15 ppmvd, corrected to 15 percent O_2, when initially operated, the NO_x and CO limits would be identical to those conditions specified after 12/31/97.

BEST AVAILABLE COPY

August 17, 1993

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

Subject: Mulberry Cogeneration Project
DER File No. AC53-211670, PSD-FL-187
Request for Change in Permit Specific Condition

Dear Clair:

This correspondence is submitted on behalf of Polk Power Partners, L.P. to request a change in the carbon monoxide (CO) emission limitation for the combustion turbine when firing natural gas and provide a potential reduction of the maximum allowable nitrogen oxides (NO_x) emission rate when the unit becomes operational. These changes affect Specific Condition No. 2 of the air construction permit (AC53-211670).

CARBON MONOXIDE EMISSIONS FOR NATURAL GAS FIRING

The request for this change is based on recent performance information obtained for the General Electric PG7111(EA) combustion turbine when it achieves a maximum NO_x emission rate of 15 parts per million (ppm), corrected for dry conditions (ppmvd) and 15 percent oxygen (O_2). At this NOx emission level, GE expects only a maximum CO emission rate of 25 ppmvd. As a result, the CO emission limit would be revised from the current limit of 20 ppmvd to 25 ppmvd and would be in effect when the NO_x emission rate is equal to or less than 15 ppmvd, corrected to 15 percent O_2 (i.e., after December 31, 1997). Prior to December 31, 1997, the CO emission limit of 20 ppmvd is achievable with a NO_x emission limit of 25 ppmvd, corrected to 15 percent O_2, respectively.

The net change in maximum allowable CO emissions is approximately 44.2 TPY for the HRSG stack (i.e., 232 TPY at 25 ppmvd compared to 187.8 TPY at 20 ppmvd) and 3.2 TPY for the CO_2 stack (or secondary boiler) (i.e., 55.2 TPY with the turbine's emissions at 25 ppmvd compared to 52.0 TPY at 20 ppmvd). These increases in CO emissions are not significant and do not significantly change conclusions drawn from the economic, environmental, and energy analyses performed as part of the Best Available Control Technology (BACT) review for this project. Combustion design is still proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on combustion turbines. Catalytic oxidation is considered unreasonable for the following reasons:

KBN ENGINEERING AND APPLIED SCIENCES, INC.

Tampa, Florida 33607
813-287-1717
FAX 813-287-1716

Reston, Virginia 22090
703-709-9490
FAX 703-709-9751

Rockville, Maryland 20850
301-738-1100
FAX 301-738-1105

April 14, 1993

RECEIVED
APR 16 1993
Division of Air
Resources Management

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

Re: Mulberry Cogeneration Project
DER File No. AC53-211670
PSD-FL-187
Computer Modeling Printouts/Analysis of Separate Stack for the Secondary HRSG Stack Analysis

Dear Clair:

Enclosed are the computer modeling printouts and a diskette copy of the modeling input and output files in support of the separate stack analysis performed for the above-referenced project. The results of this analysis were submitted to the Department in a letter report dated February 19, 1993. Included with the enclosed printouts is a summary and description of the modeling files included on the diskette.

Please contact me or Gail Rampersaud if you have any questions concerning the enclosed material.

Sincerely,

Robert C. McCann Jr.

Robert C. McCann, Jr.
Principal Scientist

RCM/dmpm

Enclosures

cc: William Malenius, Ark Energy
Ward Marshall, Central and South West Services
Gary Sams, Hopping Boyd Green & Sams
Roger Anderson, KBN
Gail Rampersaud, KBN
Ken Kosky, KBN
File (2)

904-336-5600

91193A2/2

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

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- Complete items 3, and 4a & b.
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- The Return Receipt will show to whom the article was delivered and the date delivered.

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2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ken Kosky, PE
KBN Engineering + App. Sc.
1034 NW 57th St.
Gainesville, Fl 32605

4a. Article Number
P 062 921 977

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
3-22-93

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)
R. Mitchell

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Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 3-19-93	

PS Form 3800, June 1991

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Virginia B. Wetherell, Secretary

March 19, 1993

Mr. Kennard F. Kosky, P.E.
President
KBN Engineering and Applied Sciences, Inc.
1034 N.W. 57th Street
Gainesville, Florida 32605

Dear Mr. Kosky:

This is in response to your recent letter notifying the Department of a design change for the Mulberry Cogeneration Project (PSD-FL-187) consisting of a separate stack for the secondary HRSG. This design change will involve no increase in emissions or result in a substantially different ambient impact. The secondary HRSG stack will have no impact as far as the construction permit emission limits are concerned since normal compliance testing will not involve this secondary stack. It will be in use only during atypical operating situations. Consequently, a construction permit modification is not required for this design change. However, it is required that this and all other substantive changes in the final design and construction be reported in the operation permit application.

If you have further questions, please contact Preston Lewis or John Reynolds at (904) 488-1344.

Sincerely,

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

CHF/JR/kbw

cc: W. Thomas, SWD
D. Martin, Polk County

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February 19, 1993

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MAR 0 5 1993
Division of Air
Resources Management

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

Re: Mulberry Cogeneration Project
DER File No. AC53-211670
PSD-FL-187
Specific Condition Request

Dear Clair:

This correspondence is submitted on behalf of Polk Power Partners, L.P. to notify the Department Florida Department of Environmental Regulation (FDER) of a design change for the facility (stack addition).

The design for the facility permitted by FDER includes stacks for the primary heat recovery steam generator (HRSG) and carbon dioxide (CO_2) plant. The emissions from the CO_2 plant include a portion of the emissions from the combustion turbine, the emissions generated by the secondary HRSG, and emissions associated with the CO_2 absorption process. A stack for the secondary HRSG was not originally included in the design. Based on the final design requirements for the facility, a separate stack for the secondary HRSG is necessary. Emissions will occur at the secondary HRSG stack when:

1. The power plant, including the combustion turbine and duct burner are operating and the CO_2 plant may be either down or experiencing additional problems; or

2. The duct burner is operating alone.

For air quality impact assessments, the highest emissions will occur when the power plant is in operation (CO_2 plant not operating). The secondary HRSG stack would be operated only as necessary during such conditions that would not exceed 180 days per year. The emissions from the facility would not change. A footnote to the specific conditions of the permit (see Attachment 1) would be sufficient to allow emissions from a secondary HRSG stack.

Since the addition of a stack will affect the manner by which emissions from the facility are discharged to the atmosphere, the air quality impacts may change even though no increase in emissions will occur. To address this issue, air quality modeling analyses have been performed and are attached (see Attachment 2). The analyses demonstrate that the facility's impacts are not significantly different from those presented in the air construction permit application. Based on these results, the facility's impacts are expected to comply with the applicable ambient air quality standards (AAQS), prevention of significant deterioration (PSD) increments, and Florida's no threat levels (NTLs) for toxic air pollutants.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

On behalf of Polk Power Partners, L.P., and KBN, we greatly appreciated the efforts in completing the permits. Your continued cooperation is appreciated.

Sincerely,

Kennard F. Kosky, P.E.
President
Registration No. 14996

KFK/ehj

cc: W. Malenius, Ark Energy
W. Marshall, Central and South West Services
R. Anderson, KBN
G. Sams, HBG&S
J. Reynolds / C. Halladay
B. Thomas, SW Dist.
J. Harper, EPA
J. Bunyak, NPS
D. Martin, Polk Co.

91193A2/1

ATTACHMENT 1

SPECIFIC CONDITIONS:

2. Emissions from these facilities shall not exceed the limits listed below (based on operation at 59°F):

Pollutant	Source	Fuel	Through 12/31/97 lbs/hr	Through 12/31/97 tons/yr	After 12/31/97 (See notes) 9 lbs/hr	After 12/31/97 (See notes) 9 tons/yr
NO_x	HRSG Stack	Gas	87.8	384.5	52.7	230.7
	CO_2 Plant Stack[a]	Gas	19.9	87.1	18.3	80.0
	HRSG Stack	Oil	164.0	718.2	164.0	59.0
	CO_2 Plant Stack[a]	Oil	23.4	102.4	23.4	8.4
SO_2	HRSG Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	CO_2 Plant Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack	Gas	10% Opacity		10% Opacity	
	CO_2 Plant Stack	Gas	10% Opacity		10% Opacity	
	HRSG Stack	Oil	20% Opacity		20% Opacity	
	CO_2 Plant Stack	Oil	20% Opacity		20% Opacity	
VOC	CO_2 Plant Stack	--	18.2	79.6	17.7	77.6
CO	HRSG Stack	Gas	42.9	187.8	42.9	187.8
	CO_2 Plant Stack[a]	Gas	11.9	52.0	11.9	52.0
	HRSG Stack	Oil	75.3	329.9	75.3	27.1
	CO_2 Plant Stack[a]	Oil	13.4	58.5	13.4	4.8

Notes: (1) Oil may be used as backup fuel for up to 30 days per year.
(2) NO_x limits after 12/31/97 based on 15 ppmvd.
(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.

[a] Or secondary HRSG Stack.

ATTACHMENT 2
AIR QUALITY IMPACT ANALYSES FOR THE PROPOSED COMBUSTION TURBINE AND DUCT BURNER WITH SEPARATE STACKS FOR THE MULBERRY COGENERATION FACILITY

1.0 INTRODUCTION

KBN Engineering and Applied Sciences, Inc. (KBN) has performed air quality impact analyses to determine the maximum concentrations for the operation of the combustion turbine (CT) and duct burner with separate stacks for the integrated cogeneration facility proposed by Polk Power Partners, L.P., dba Polk Power Partners, L.P., Ltd. The modeling analyses assumed that the exhaust gases from the duct burner are vented through a stack separate from the CT and CO_2 stacks and that the CO_2 plant is not in operation (i.e., no emissions occur at the CO_2 plant). Air quality impacts have been performed already for the facility, which is referred to as the Mulberry Cogeneration Facility, as part of the air construction permit application for the CT and CO_2 plant. The results presented in the present analysis supplement the previous analyses and compare the maximum concentrations predicted for the operation of the CT and duct burner alone with those predicted for the CT and CO_2 plant. These results are also compared to the significance levels and *de minimis* monitoring levels under the prevention of significant deterioration (PSD) regulations to determine if additional analyses would be required due to emissions from the duct burner stack (i.e., analyses that were not performed for the permit application). For toxic air pollutants, the maximum predicted concentrations are compared to the no threat levels (NTL) established by the Florida Department of Environmental Regulation (FDER).

The following sections present the approaches, methods, and results of the air quality impact analyses.

2.0 EMISSION DATA AND AIR QUALITY IMPACTS METHODS

An air quality modeling analysis was performed to determine the maximum pollutant concentrations, including the regulated pollutants of sulfur dioxide (SO_2), particulate matter (PM), nitrogen dioxide (NO_2), carbon monoxide (CO), beryllium (Be), and toxic air pollutants, from the operation of the CT and duct burner. This analysis included modeling with the Industrial Source Complex Short-Term (ISCST) model using the emissions from the proposed combustion turbine using distillate fuel oil for the maximum emission case (i.e., 20°F) and minimum exit gas flow rate (i.e., 100°F). Emission data for fuel oil were used because the emissions for natural gas, the other fuel proposed for this project, were lower and would result in lower ambient impacts. The

with other sources or submittal of preconstruction monitoring data are not warranted for these pollutants.

For SO_2, although the maximum impacts with the CT and duct burner operating alone are predicted to be greater than the significance and *de minimis* levels, these results are similar to those produced with the CO_2 plant in operation. The permit application for the CT and CO_2 plant did include air quality modeling analyses with other sources and preconstruction monitoring data. Since the addition of the proposed stack for the duct burner does not produce a significant increase in impacts from the previous model results, no additional modeling is warranted. The proposed facility's impacts are still expected to comply with ambient air quality standards (AAQS) and maximum allowable PSD increments.

For NO_2, the maximum impacts with the CT and duct burner operating alone are predicted to be greater than the significance level for the annual averaging period. These results are conservative (i.e., higher than expected) since they assume that the duct burner is in operation for the entire year while the CO_2 plant is shutdown. By operating the duct burner for no more than 180 days per year when the CO_2 plant is shutdown, the annual average NO_2 impacts are expected to be less than the significance level of 1 $\mu g/m^3$.

Maximum impacts of toxic air pollutants predicted for the proposed facility with the CT and duct burner in operation are presented in Table 4. These results show that the maximum impacts are below the Florida NTL.

4.0 CONCLUSIONS

The proposed facility's impacts are expected to comply with AAQS, maximum allowable PSD increments, and Florida's NTL with the CO_2 plant operating or shutdown. For all pollutants except SO_2 and NO_2, the maximum concentrations are predicted to be less than significance levels and *de minimis* monitoring levels and, therefore, additional modeling analyses with other sources or submittal of preconstruction monitoring data are not warranted.

For SO_2, the maximum impacts with the CT and duct burner operating alone are similar to those produced with the CO_2 plant in operation (i.e., also greater than the significance and *de minimis* levels). Since the addition of the proposed stack for the duct burner does not produce a

other fuel proposed for this project, were lower and would result in lower ambient impacts. The duct burner was assumed to have a maximum heat input rate of 99 pounds per million British thermal units (10^6 Btu/hr) and use natural gas only. The design information and stack parameters of the duct burner are presented in Table 1-A (the design information, stack parameters, and emissions for the CT are presented in the permit application). The maximum emission rates from the duct burner for the applicable pollutants are presented in Tables 1-B through 1-E. Summaries of the total project's emissions for the CT using fuel oil and duct burner, including each unit's contribution, for ambient temperatures of 20, 59, and 100°F are presented in Tables 2-A through 2-D.

The impacts were predicted using the ISCST2 (Version 92273) model at 360 receptors surrounding the proposed facility. The receptors were located in a radial grid, which was the same as that used in the permit application. The grid consisted of 36 receptors along the plant property and 324 receptors along 36 radials with each radial spaced at 10-degree increments. Along each radial, receptors were located at distances of 300; 500; 700; 1,000; 1,500; 2,000; 3,000; 4,000; and 5,000 meters (m) from the CT stack. The impacts were predicted using a 5-year meteorological record (1982 through 1986) of surface and mixing height data from the National Weather Service (NWS) stations in Tampa and Ruskin, respectively.

The proposed duct burner's stack will be 125 feet (ft) tall and located near the CT stack. Similar to the proposed CT's stack of 125 ft, the proposed duct burner's stack will be less than good engineering practice (GEP) height. As a result, building downwash effects were included in the modeling using the same building data assigned to the CT's stack.

3.0 MODEL RESULTS

Maximum impacts predicted for the proposed facility with the CT and duct burner in operation using 5 years of meteorological data are presented in Table 3. These results indicate that, except for PM, there is a slight increase in predicted impacts with the emissions from the stacks of the CT and duct burner compared to the impacts from stack emissions of the CT and CO_2 plant. For PM, the maximum impacts are lower for the facility with the CT and duct burner operating only (i.e., CO_2 plant not operating) than when the CO_2 plant is operating.

For all pollutants except SO_2 and NO_2, the maximum concentrations are predicted to be less than significance levels and *de minimis* monitoring levels. Therefore, additional modeling analyses

significant increase in impacts from the previous model results, no additional modeling is warranted.

For NO_2, although the maximum impacts with the CT and duct burner operating alone are predicted to be greater than the significance level for the annual averaging period, these results assume that the duct burner is in operation for the entire year while the CO_2 plant is shutdown. By operating the duct burner for no more than 30 days per year when the CO_2 plant is shutdown, the annual average NO_2 impacts are expected to be less than the significance level of 1 $\mu g/m^3$.

Table 1-A. Design Information and Stack Parameters for Mulberry Cogeneration Project--Duct Burner, Natural Gas

Data	Duct Burner Data at Ambient Temperature				
	20°F	40°F	59°F	80°F	100°F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (MMBtu/hr)	99.0	99.0	99.0	99.0	99.0
Fuel Natural Gas (lb/hr)	5,128.7	5,128.7	5,128.7	5,128.7	5,128.7
(cf/hr)	104,211	104,211	104,211	104,211	104,211
Fuel:					
Heat Content,LHV (Btu/lb)	19,303	19,303	19,303	19,303	19,303
(Btu/cf)	950.0	950.0	950.0	950.0	950.0
From CT and Duct Burner Exhaust:					
Volume Flow (acfm)	41,273	41,273	41,273	41,273	41,273
Volume Flow (scfm)	28,674	28,674	28,674	28,674	28,674
Mass Flow (lb/hr)^a	125,000	125,000	125,000	125,000	125,000
Temperature (°F)	300	300	300	300	300
Moisture (% Vol.)					
Oxygen (% Vol.)					
Molecular Weight	28.00	28.00	28.00	28.00	28.00
By-pass Stack:					
Volume Flow (acfm)	41,273	41,273	41,273	41,273	41,273
Temperature (°F)	300	300	300	300	300
Diameter (ft)	6.50	6.50	6.50	6.50	6.50
Velocity (ft/sec)	20.7	20.7	20.7	20.7	20.7
Stack Height (ft)	125	125	125	125	125

^a Based on 120,000 lb/hr from CT; 5,000 lb/hr from duct burner.

Table 1-B. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Project--Duct Burner, Natural Gas

Pollutant	Duct Burner Data at Ambient Temperature				
	20°F	40°F	59°F	80°F	100°F
Particulate:					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	0.99	0.99	0.99	0.99	0.99
TPY	4.3	4.3	4.3	4.3	4.3
Sulfur Dioxide:					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.3	1.3	1.3	1.3	1.3
Nitrogen Oxides:					
Basis, lb/MMBtu	0.13	0.13	0.13	0.13	0.13
lb/hr	12.87	12.87	12.87	12.87	12.87
TPY	56.4	56.4	56.4	56.4	56.4
Carbon Monoxide:					
Basis, lb/MMBtu	0.1	0.1	0.1	0.1	0.1
lb/hr	9.9	9.9	9.9	9.9	9.9
TPY	43.4	43.4	43.4	43.4	43.4
VOCs:					
Basis, lb/MMBtu	0.03	0.03	0.03	0.03	0.03
lb/hr	2.97	2.97	2.97	2.97	2.97
TPY	13.0	13.0	13.0	13.0	13.0
Lead:					
Basis, lb/10E+12 Btu	Neg.	Neg.	Neg.	Neg.	Neg.
lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
TPY	0.000	0.000	0.000	0.000	0.000

Table 1-C. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Project--Duct Burner, Natural Gas

		Duct Burner Data at Ambient Temperature				
Pollutant	Units	20°F	40°F	59°F	80°F	100°F
Arsenic	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Beryllium	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Mercury	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoride	lb/10E+12 Btu (2)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sulfuric Acid	% of SO_2	5	5	5	5	5
Mist	lb/hr	2.40E-02	2.40E-02	2.40E-02	2.40E-02	2.40E-02
	TPY	1.05E-01	1.05E-01	1.05E-01	1.05E-01	1.05E-01

Sources: (1) EPA, 1990; (2) EPA, 1980.

Table 1-D. Maximum Nonregulated Pollutant Emissions for Mulberry Cogeneration Project--Duct Burner, Natural Gas

Pollutant	Units	Duct Burner Data at Ambient Temperature 20°F	40°F	59°F	80°F	100°F
Manganese	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Nickel	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cadmium	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Copper	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Vanadium	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Selenium	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Polycyclic	pg/J (1)	0.48	0.48	0.48	0.48	0.48
Organic	lb/hr	1.10E-04	1.10E-04	1.10E-04	1.10E-04	1.10E-04
Matter	TPY	4.84E-04	4.84E-04	4.84E-04	4.84E-04	4.84E-04
Formaldehyde	lb/10E+12 Btu (1)	38	38	38	38	38
	lb/hr	3.76E-03	3.76E-03	3.76E-03	3.76E-03	3.76E-03
	TPY	1.65E-02	1.65E-02	1.65E-02	1.65E-02	1.65E-02
Carbon Dioxide	% Exhaust Gas	8.04	0.00	0.00	0.00	0.00
	lb/hr	1.42E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	6.23E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990.

Table 1-E. Maximum Emissions for Additional Nonregulated Pollutant--Duct Burner, Natural Gas

Pollutant		Duct Burner Data at Ambient Temperature				
		20°F	40°F	59°F	80°F	100°F
Antimony	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Barium	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Colbalt	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Zinc	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chlorine	ppm	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Table 2-A. Emissions for CT and Duct Burner Stack Exhausts--Criteria Pollutants

Pollutant	Fuel Oil at 20°F			Ratio CT/DB Emission	Fuel Oil at 59°F			Ratio CT/DB Emission	Fuel Oil at 100°F			Ratio CT/DB Emission
	CT	Duct Burner	Total		CT	Duct Burner	Total		CT	Duct Burner	Total	
Particulate:												
lb/hr	14.31	1.68	15.99	8.51	14.24	1.75	15.99	8.16	14.16	1.83	15.99	7.72
TPY	62.67	7.36	70.04	8.51	62.39	7.64	70.04	8.16	62.01	8.03	70.04	7.72
Sulfur Dioxide:												
lb/hr	100.78	5.16	105.95	19.51	90.30	5.08	95.38	17.76	78.17	4.96	83.13	15.77
TPY	441.42	22.62	464.04	19.51	395.51	22.27	417.77	17.76	342.40	21.71	364.10	15.77
Nitrogen Oxides:												
lb/hr	173.81	21.26	195.07	8.17	155.72	21.12	176.84	7.37	134.79	20.90	155.69	6.45
TPY	761.27	93.13	854.40	8.17	682.05	92.52	774.57	7.37	590.40	91.55	681.94	6.45
Carbon Monoxide:												
lb/hr	78.77	13.70	92.47	5.75	71.53	13.69	85.22	5.22	62.81	13.64	76.45	4.60
TPY	345.01	60.02	405.04	5.75	313.31	59.97	373.28	5.22	275.12	59.75	334.87	4.60
VOCs:												
lb/hr	9.65	3.44	13.08	2.81	8.76	3.43	12.19	2.55	7.69	3.43	11.12	2.24
TPY	42.25	15.05	57.30	2.81	38.36	15.04	53.41	2.55	33.69	15.02	48.70	2.24
Lead:												
lb/hr	8.76E-03	4.23E-04	9.18E-03	20.71	7.85E-03	4.16E-04	8.26E-03	18.87	6.79E-03	4.05E-04	7.20E-03	16.78
TPY	3.84E-02	1.85E-03	4.02E-02	20.71	3.44E-02	1.82E-03	3.62E-02	18.87	2.98E-02	1.77E-03	3.15E-02	16.78

Table 2-B. Emissions for CT and Duct Burner Stack Exhausts--Other Regulated Pollutants

Pollutant	Units	Fuel Oil at 20°F			Ratio CT/DB Emission	Fuel Oil at 59°F			Ratio CT/DB Emission	Fuel Oil at 100°F			Ratio CT/DB Emission
		CT	Duct Burner	Total		CT	Duct Burner	Total		CT	Duct Burner	Total	
Arsenic													
	lb/hr	4.13E-03	2.00E-04	4.33E-03	20.71	3.70E-03	1.96E-04	3.90E-03	18.87	3.21E-03	1.91E-04	3.40E-03	16.78
	TPY	1.81E-02	8.74E-04	1.90E-02	20.71	1.62E-02	8.60E-04	1.71E-02	18.87	1.40E-02	8.37E-04	1.49E-02	16.78
Beryllium													
	lb/hr	2.46E-03	1.19E-04	2.58E-03	20.71	2.20E-03	1.17E-04	2.32E-03	18.87	1.91E-03	1.14E-04	2.02E-03	16.78
	TPY	1.08E-02	5.20E-04	1.13E-02	20.71	9.65E-03	5.12E-04	1.02E-02	18.87	8.36E-03	4.98E-04	8.86E-03	16.78
Mercury													
	lb/hr	2.95E-03	1.43E-04	3.09E-03	20.71	2.64E-03	1.40E-04	2.78E-03	18.87	2.29E-03	1.36E-04	2.43E-03	16.78
	TPY	1.29E-02	6.24E-04	1.36E-02	20.71	1.16E-02	6.14E-04	1.22E-02	18.87	1.00E-02	5.98E-04	1.06E-02	16.78
Fluoride													
	lb/hr	3.20E-02	1.54E-03	3.35E-02	20.71	2.87E-02	1.52E-03	3.02E-02	18.87	2.48E-02	1.48E-03	2.63E-02	16.78
	TPY	1.40E-01	6.76E-03	1.47E-01	20.71	1.25E-01	6.65E-03	1.32E-01	18.87	1.09E-01	6.47E-03	1.15E-01	16.78
Sulfuric Acid Mist	lb/hr	8.12E+00	4.16E-01	8.54E+00	19.51	7.28E+00	4.10E-01	7.69E+00	17.76	6.30E+00	3.99E-01	6.70E+00	15.77
	TPY	3.56E+01	1.82E+00	3.74E+01	19.51	3.19E+01	1.79E+00	3.37E+01	17.76	2.76E+01	1.75E+00	2.93E+01	15.77

Table 2-C. Emissions for CT and Duct Burner Stack Exhausts--Nonregulated Pollutants

Pollutant	Units	Fuel Oil at 20°F			Ratio CT/DB Emission	Fuel Oil at 59°F			Ratio CT/DB Emission	Fuel Oil at 100°F			Ratio CT/DB Emission
		CT	Duct Burner	Total		CT	Duct Burner	Total		CT	Duct Burner	Total	
Manganese													
	lb/hr	6.34E-03	3.06E-04	6.64E-03	20.71	5.68E-03	3.01E-04	5.98E-03	18.87	4.92E-03	2.93E-04	5.21E-03	16.78
	TPY	2.78E-02	1.34E-03	2.91E-02	20.71	2.49E-02	1.32E-03	2.62E-02	18.87	2.15E-02	1.28E-03	2.28E-02	16.78
Nickel													
	lb/hr	1.67E-01	8.08E-03	1.75E-01	20.71	1.50E-01	7.94E-03	1.58E-01	18.87	1.30E-01	7.73E-03	1.37E-01	16.78
	TPY	7.33E-01	3.54E-02	7.68E-01	20.71	6.56E-01	3.48E-02	6.91E-01	18.87	5.68E-01	3.39E-02	6.02E-01	16.78
Cadmium													
	lb/hr	1.03E-02	4.99E-04	1.08E-02	20.71	9.26E-03	4.91E-04	9.75E-03	18.87	8.01E-03	4.77E-04	8.49E-03	16.78
	TPY	4.53E-02	2.19E-03	4.74E-02	20.71	4.05E-02	2.15E-03	4.27E-02	18.87	3.51E-02	2.09E-03	3.72E-02	16.78
Chromium													
	lb/hr	4.67E-02	2.26E-03	4.90E-02	20.71	4.19E-02	2.22E-03	4.41E-02	18.87	3.63E-02	2.16E-03	3.84E-02	16.78
	TPY	2.05E-01	9.89E-03	2.15E-01	20.71	1.83E-01	9.72E-03	1.93E-01	18.87	1.59E-01	9.46E-03	1.68E-01	16.78
Copper													
	lb/hr	2.76E-01	1.33E-02	2.89E-01	20.71	2.47E-01	1.31E-02	2.60E-01	18.87	2.14E-01	1.27E-02	2.26E-01	16.78
	TPY	1.21E+00	5.83E-02	1.26E+00	20.71	1.08E+00	5.73E-02	1.14E+00	18.87	9.36E-01	5.58E-02	9.92E-01	16.78
Vanadium													
	lb/hr	6.86E-02	3.31E-03	7.19E-02	20.71	6.15E-02	3.26E-03	6.47E-02	18.87	5.32E-02	3.17E-03	5.64E-02	16.78
	TPY	3.00E-01	1.45E-02	3.15E-01	20.71	2.69E-01	1.43E-02	2.83E-01	18.87	2.33E-01	1.39E-02	2.47E-01	16.78
Selenium													
	lb/hr	2.31E-02	1.12E-03	2.42E-02	20.71	2.07E-02	1.10E-03	2.18E-02	18.87	1.79E-02	1.07E-03	1.90E-02	16.78
	TPY	1.01E-01	4.88E-03	1.06E-01	20.71	9.06E-02	4.80E-03	9.54E-02	18.87	7.85E-02	4.68E-03	8.31E-02	16.78
Polycyclic Organic Matter	lb/hr	2.74E-04	1.24E-04	3.98E-04	2.22	2.46E-04	1.23E-04	3.69E-04	1.99	2.13E-04	1.23E-04	3.36E-04	1.73
	TPY	1.20E-03	5.42E-04	1.74E-03	2.22	1.08E-03	5.41E-04	1.62E-03	1.99	9.32E-04	5.39E-04	1.47E-03	1.73
Formaldehyde													
	lb/hr	3.98E-01	2.30E-02	4.22E-01	17.32	3.57E-01	2.27E-02	3.80E-01	15.74	3.09E-01	2.22E-02	3.31E-01	13.94
	TPY	1.75E+00	1.01E-01	1.85E+00	17.32	1.56E+00	9.94E-02	1.66E+00	15.74	1.35E+00	9.71E-02	1.45E+00	13.94
Carbon Dioxide													
	lb/hr	1.58E+05	2.99E+04	1.88E+05	5.30	1.41E+05	1.54E+04	1.57E+05	9.19	1.21E+05	1.49E+04	1.36E+05	8.15
	TPY	6.94E+05	1.31E+05	8.25E+05	5.30	6.19E+05	6.73E+04	6.86E+05	9.19	5.32E+05	6.53E+04	5.97E+05	8.15

Table 2-D. Emissions for CT and Duct Burner Stack Exhausts--Additional Nonregulated Pollutants

Pollutant	Units	Fuel Oil at 20°F			Ratio CT/DB Emission	Fuel Oil at 59°F			Ratio CT/DB Emission	Fuel Oil at 100°F			Ratio CT/DB Emission
		CT	Duct Burner	Total		CT	Duct Burner	Total		CT	Duct Burner	Total	
Antimony													
	lb/hr	2.15E-02	1.04E-03	2.25E-02	20.71	1.93E-02	1.02E-03	2.03E-02	18.87	1.67E-02	9.93E-04	1.77E-02	16.78
	TPY	9.41E-02	4.55E-03	9.87E-02	20.71	8.44E-02	4.47E-03	8.88E-02	18.87	7.30E-02	4.35E-03	7.74E-02	16.78
Barium													
	lb/hr	1.92E-02	9.28E-04	2.01E-02	20.71	1.72E-02	9.12E-04	1.81E-02	18.87	1.49E-02	8.88E-04	1.58E-02	16.78
	TPY	8.41E-02	4.06E-03	8.82E-02	20.71	7.54E-02	4.00E-03	7.94E-02	18.87	6.53E-02	3.89E-03	6.91E-02	16.78
Colbalt													
	lb/hr	8.92E-03	4.31E-04	9.35E-03	20.71	7.99E-03	4.24E-04	8.41E-03	18.87	6.92E-03	4.12E-04	7.33E-03	16.78
	TPY	3.91E-02	1.89E-03	4.09E-02	20.71	3.50E-02	1.86E-03	3.69E-02	18.87	3.03E-02	1.81E-03	3.21E-02	16.78
Zinc													
	lb/hr	6.72E-01	3.25E-02	7.05E-01	20.71	6.02E-01	3.19E-02	6.34E-01	18.87	5.21E-01	3.11E-02	5.53E-01	16.78
	TPY	2.94E+00	1.42E-01	3.09E+00	20.71	2.64E+00	1.40E-01	2.78E+00	18.87	2.28E+00	1.36E-01	2.42E+00	16.78
Chlorine													
	lb/hr	2.65E-02	1.28E-03	2.78E-02	20.71	2.38E-02	1.26E-03	2.50E-02	18.87	2.06E-02	1.23E-03	2.18E-02	16.78
	TPY	1.16E-01	5.61E-03	1.22E-01	20.71	1.04E-01	5.52E-03	1.10E-01	18.87	9.01E-02	5.37E-03	9.55E-02	16.78

Table 3. Summary of Maximum Pollutant Impacts for the Mulberry Cogeneration Project--Comparison of CT and CO2 Plant Impacts to CT and Duct Burner Stack Impacts (CT- Oil, DB-Nat.Gas) (Page 1 of 2)

Pollutant	Averaging Period	Year	Maximum Predicted Impacts ($\mu g/m^3$) 20°F CT,CO2	20°F CT,DB	100°F CT,CO2	100°F CT,DB	Regulatory Levels ($\mu g/m^3$) Significance	De minimis Monitoring	More Analysis Required for CT,DB ?
SO_2	3-hour	1982	23.9	28.1	26.8	31.0	25	NA	No^a
		1983	18.1	23.1	19.1	23.4	25	NA	
		1984	33.1	38.7	37.5	43.1	25	NA	
		1985	23.0	26.3	26.7	29.9	25	NA	
		1986	12.1	17.1	12.5	19.6	25	NA	
	24-hour	1982	4.9	6.2	5.7	7.3	5	13	No^a
		1983	5.1	7.4	6.5	8.8	5	13	
		1984	11.2	14.5	15.1	18.4	5	13	
		1985	9.0	11.1	10.2	12.7	5	13	
		1986	3.1	4.7	3.5	5.1	5	13	
	Annual	1982	0.25	0.25	0.25	0.32	1	NA	No
		1983	0.19	0.19	0.19	0.24	1	NA	
		1984	0.24	0.24	0.24	0.27	1	NA	
		1985	0.24	0.23	0.23	0.28	1	NA	
		1986	0.28	0.27	0.27	0.27	1	NA	
PM	24-hour	1982	1.90	1.11	1.98	1.54	5	10	No
		1983	2.08	1.46	2.14	2.00	5	10	
		1984	1.76	2.63	2.74	3.89	5	10	
		1985	1.86	2.01	1.92	2.75	5	10	
		1986	1.88	0.96	1.94	1.21	5	10	
	Annual	1982	0.18	0.076	0.19	0.099	1	NA	No
		1983	0.15	0.057	0.16	0.073	1	NA	
		1984	0.18	0.071	0.19	0.088	1	NA	
		1985	0.17	0.067	0.18	0.086	1	NA	
		1986	0.22	0.055	0.23	0.065	1	NA	
NO_2	Annual	1982	0.75	0.97	0.76	1.10	1	14	No^b
		1983	0.61	0.73	0.62	0.81	1	14	
		1984	0.73	0.90	0.74	0.99	1	14	
		1985	0.67	0.85	0.69	0.96	1	14	
		1986	0.83	0.69	0.85	0.71	1	14	
CO	1-hour	1982	32.3	51.2	36.6	55.6	2000	NA	No
		1983	37.3	45.9	37.0	50.9	2000	NA	
		1984	46.0	48.8	50.7	53.6	2000	NA	
		1985	31.0	50.6	33.9	57.8	2000	NA	
		1986	23.7	38.8	27.5	44.2	2000	NA	

Table 3. Summary of Maximum Pollutant Impacts for the Mulberry Cogeneration Project--Comparison of CT and CO2 Plant Impacts to CT and Duct Burner Stack Impacts (CT- Oil, DB-Nat.Gas) (Page 2 of 2)

Pollutant	Averaging Period	Year	Maximum Predicted Impacts ($\mu g/m^3$) 20°F CT,CO2	20°F CT,DB	100°F CT,CO2	100°F CT,DB	Regulatory Levels ($\mu g/m^3$) Significance	De minimis Monitoring	More Analysis Required for CT,DB ?
	8-hour	1982	8.9	14.2	10.2	15.4	500	575	No
		1983	10.8	20.4	11.7	21.6	500	575	
		1984	16.1	30.9	19.8	34.7	500	575	
		1985	12.3	21.9	15.3	25.2	500	575	
		1986	11.0	13.2	10.9	15.8	500	575	
Be	24-hour	1982	0.00013	0.00015	0.00014	0.00017	NA	0.001	No
		1983	0.00014	0.00018	0.00017	0.00021	NA	0.001	
		1984	0.00029	0.00035	0.00038	0.00044	NA	0.001	
		1985	0.00024	0.00027	0.00025	0.00030	NA	0.001	
		1986	0.00009	0.00011	0.00011	0.00012	NA	0.001	

Note: For 20°F condition, modeled CT exit gas temperature is 220°F and velocity is 67.8 ft/sec.
For 100°F condition, modeled CT exit gas temperature is 220°F and velocity is 55.5 ft/sec.

NA - Not applicable because pollutant has no ambient standard or measurement method.

^a Additional analyses were performed in permit application to address CT and CO_2 plant impacts.

^b Based on emissions from DB stack for 8,760 hours. If emissions from stack are limited to 180 days per year, predicted impacts will be less than the significance level.

Table 4. Summary of Maximum Pollutant Emission Rates and Concentrations for the Air Toxic Modeling Analysis For Combustion Turbine and Duct Burner Stacks (Page 1 of 3)

Pollutant	Emission Rate (lb/hr) at 20°F Temperature CT	Emission Rate (lb/hr) at 20°F Temperature DB	Emission Rate (lb/hr) at 100°F Temperature CT	Emission Rate (lb/hr) at 100°F Temperature DB	Averaging Period	Maximum Predicted Concentration ($\mu g/m^3$) 20°F Temperature CT (A)	20°F Temperature DB (B)	20°F Temperature Total (A+B)	100°F Temperature CT (C)	100°F Temperature DB (D)	100°F Temperature Total (C+D)	Florida No Threat Level ($\mu g/m^3$)
Antimony	2.15E-02	1.04E-03	1.67E-02	9.93E-04	8-hour	4.42E-03	1.11E-03	5.53E-03	5.33E-03	1.04E-03	6.37E-03	5
					24-hour	2.42E-03	6.43E-04	3.06E-03	3.25E-03	6.07E-04	3.86E-03	1.2
					Annual	4.26E-05	1.48E-05	5.74E-05	2.11E-05	4.30E-05	6.40E-05	0.3
Arsenic	4.13E-03	2.00E-04	3.21E-03	1.91E-04	8-hour	8.50E-04	2.14E-04	1.06E-03	1.02E-03	2.00E-04	1.22E-03	2
					24-hour	4.65E-04	1.24E-04	5.89E-04	6.25E-04	1.17E-04	7.42E-04	0.48
					Annual	8.20E-06	2.85E-06	1.10E-05	4.05E-06	8.27E-06	1.23E-05	0.00023
Barium	1.92E-02	9.28E-04	1.49E-02	8.88E-04	8-hour	3.95E-03	9.92E-04	4.94E-03	4.76E-03	9.30E-04	5.69E-03	5
					24-hour	2.16E-03	5.73E-04	2.74E-03	2.90E-03	5.43E-04	3.45E-03	1.2
					Annual	3.81E-05	1.32E-05	5.13E-05	1.88E-05	3.84E-05	5.72E-05	50
Beryllium	2.46E-03	1.19E-04	1.91E-03	1.14E-04	8-hour	5.06E-04	1.27E-04	6.33E-04	6.10E-04	1.19E-04	7.29E-04	0.02
					24-hour	2.77E-04	7.34E-05	3.50E-04	3.72E-04	6.95E-05	4.42E-04	0.0048
					Annual	4.88E-06	1.69E-06	6.57E-06	2.41E-06	4.92E-06	7.33E-06	0.00042
Cadmium	1.03E-02	4.99E-04	8.01E-03	4.77E-04	8-hour	2.13E-03	5.33E-04	2.66E-03	2.56E-03	5.00E-04	3.06E-03	0.5
					24-hour	1.16E-03	3.08E-04	1.47E-03	1.56E-03	2.92E-04	1.85E-03	0.12
					Annual	2.05E-05	7.10E-06	2.76E-05	1.01E-05	2.07E-05	3.08E-05	0.00056
Chlorine	2.65E-02	1.28E-03	2.06E-02	1.23E-03	8-hour	5.46E-03	1.37E-03	6.82E-03	6.58E-03	1.28E-03	7.86E-03	15
					24-hour	2.99E-03	7.91E-04	3.78E-03	4.01E-03	7.49E-04	4.76E-03	3.6
					Annual	5.26E-05	1.82E-05	7.08E-05	2.60E-05	5.30E-05	7.90E-05	0.4
Chromium III,IV	4.67E-02	2.26E-03	3.63E-02	2.16E-03	8-hour	9.61E-03	2.41E-03	1.20E-02	1.16E-02	2.26E-03	1.39E-02	5
					24-hour	5.26E-03	1.39E-03	6.66E-03	7.07E-03	1.32E-03	8.39E-03	1.2
					Annual	9.27E-05	3.21E-05	1.25E-04	4.58E-05	9.35E-05	1.39E-04	1000 ^a
Cobalt	8.92E-03	4.31E-04	6.92E-03	4.12E-04	8-hour	1.83E-03	4.60E-04	2.29E-03	2.21E-03	4.31E-04	2.64E-03	0.5
					24-hour	1.00E-03	2.66E-04	1.27E-03	1.35E-03	2.52E-04	1.60E-03	0.12
					Annual	1.77E-05	6.13E-06	2.38E-05	8.74E-06	1.78E-05	2.66E-05	NE

Table 4. Summary of Maximum Pollutant Emission Rates and Concentrations for the Air Toxic Modeling Analysis For Combustion Turbine and Duct Burner Stacks (Page 2 of 3)

Pollutant	Emission Rate (lb/hr) at 20°F Temperature CT	Emission Rate (lb/hr) at 20°F Temperature DB	Emission Rate (lb/hr) at 100°F Temperature CT	Emission Rate (lb/hr) at 100°F Temperature DB	Averaging Period	Maximum Predicted Concentration ($\mu g/m^3$) 20°F Temperature CT (A)	20°F Temperature DB (B)	20°F Temperature Total (A+B)	100°F Temperature CT (C)	100°F Temperature DB (D)	100°F Temperature Total (C+D)	Florida No Threat Level ($\mu g/m^3$)
Copper	2.76E-01	1.33E-02	2.14E-01	1.27E-02	8-hour	5.67E-02	1.42E-02	7.09E-02	6.83E-02	1.33E-02	8.16E-02	2
					24-hour	3.10E-02	8.22E-03	3.92E-02	4.17E-02	7.78E-03	4.94E-02	0.48
					Annual	5.47E-04	1.89E-04	7.36E-04	2.70E-04	5.51E-04	8.21E-04	NE
Fluoride	3.20E-02	1.54E-03	2.48E-02	1.48E-03	8-hour	6.58E-03	1.65E-03	8.23E-03	7.93E-03	1.55E-03	9.48E-03	25
					24-hour	3.60E-03	9.54E-04	4.56E-03	4.84E-03	9.03E-04	5.74E-03	6
					Annual	6.34E-05	2.20E-05	8.54E-05	3.13E-05	6.40E-05	9.53E-05	NE
Formaldehyde	3.98E-01	2.30E-02	3.09E-01	2.22E-02	8-hour	8.20E-02	2.46E-02	1.07E-01	9.88E-02	2.32E-02	1.22E-01	12
					24-hour	4.49E-02	1.42E-02	5.91E-02	6.03E-02	1.36E-02	7.38E-02	2.88
					Annual	7.91E-04	3.27E-04	1.12E-03	3.90E-04	9.60E-04	1.35E-03	0.077
Lead	8.76E-03	4.23E-04	6.79E-03	4.05E-04	8-hour	1.80E-03	4.52E-04	2.25E-03	2.17E-03	4.24E-04	2.60E-03	0.5
					24-hour	9.86E-04	2.61E-04	1.25E-03	1.32E-03	2.47E-04	1.57E-03	0.12
					Annual	1.74E-05	6.02E-06	2.34E-05	8.58E-06	1.75E-05	2.61E-05	0.09
Manganese	6.34E-03	3.06E-04	4.92E-03	2.93E-04	8-hour	1.30E-03	3.27E-04	1.63E-03	1.57E-03	3.07E-04	1.88E-03	50
					24-hour	7.14E-04	1.89E-04	9.03E-04	9.58E-04	1.79E-04	1.14E-03	12
					Annual	1.26E-05	4.35E-06	1.69E-05	6.21E-06	1.27E-05	1.89E-05	0.4
Mercury	2.95E-03	1.43E-04	2.29E-03	1.36E-04	8-hour	6.07E-04	1.52E-04	7.60E-04	7.32E-04	1.43E-04	8.75E-04	0.5
					24-hour	3.32E-04	8.81E-05	4.20E-04	4.46E-04	8.34E-05	5.30E-04	0.12
					Annual	5.86E-06	2.03E-06	7.88E-06	2.89E-06	5.90E-06	8.80E-06	0.3
Nickel	1.67E-01	8.08E-03	1.30E-01	7.73E-03	8-hour	3.44E-02	8.64E-03	4.30E-02	4.15E-02	8.09E-03	4.96E-02	10
					24-hour	1.88E-02	4.99E-03	2.38E-02	2.53E-02	4.73E-03	3.00E-02	2.4
					Annual	3.32E-04	1.15E-04	4.47E-04	1.64E-04	3.35E-04	4.98E-04	0.0042
Polycyclic Organic Matter	2.74E-04	1.24E-04	2.13E-04	1.23E-04	8-hour	5.64E-05	1.32E-04	1.89E-04	6.80E-05	1.29E-04	1.97E-04	NE
					24-hour	3.09E-05	7.64E-05	1.07E-04	4.15E-05	7.53E-05	1.17E-04	NE
					Annual	5.44E-07	1.76E-06	2.30E-06	2.69E-07	5.33E-06	5.60E-06	NE

Table 4. Summary of Maximum Pollutant Emission Rates and Concentrations for the Air Toxic Modeling Analysis For Combustion Turbine and Duct Burner Stacks (Page 3 of 3)

Pollutant	Emission Rate (lb/hr) at 20°F Temperature CT	Emission Rate (lb/hr) at 20°F Temperature DB	Emission Rate (lb/hr) at 100°F Temperature CT	Emission Rate (lb/hr) at 100°F Temperature DB	Averaging Period	Maximum Predicted Concentration ($\mu g/m^3$) 20°F Temperature CT (A)	20°F Temperature DB (B)	20°F Temperature Total (A+B)	100°F Temperature CT (C)	100°F Temperature DB (D)	100°F Temperature Total (C+D)	Florida No Threat Level ($\mu g/m^3$)
Selenium	2.31E-02	1.12E-03	1.79E-02	1.07E-03	8-hour	4.75E-03	1.19E-03	5.94E-03	5.73E-03	1.12E-03	6.84E-03	2
					24-hour	2.60E-03	6.89E-04	3.29E-03	3.49E-03	6.53E-04	4.15E-03	0.48
					Annual	4.58E-05	1.59E-05	6.17E-05	2.26E-05	4.62E-05	6.88E-05	NE
Sulfuric Acid Mist	8.12E+00	4.16E-01	6.30E+00	3.99E-01	8-hour	1.67E+00	4.44E-01	2.11E+00	2.02E+00	4.26E-01	2.44E+00	10
					24-hour	9.10E-01	2.56E-01	1.17E+00	1.23E+00	2.46E-01	1.48E+00	2.4
					Annual	1.61E-02	5.90E-03	2.20E-02	7.98E-03	1.77E-02	2.57E-02	NE
Vanadium	6.86E-02	3.31E-03	5.32E-02	3.17E-03	8-hour	1.41E-02	3.54E-03	1.77E-02	1.70E-02	3.32E-03	2.03E-02	0.5
					24-hour	7.72E-03	2.05E-03	9.77E-03	1.04E-02	1.94E-03	1.23E-02	0.12
					Annual	1.36E-04	4.71E-05	1.83E-04	6.72E-05	1.37E-04	2.04E-04	20
Zinc	6.72E-01	3.25E-02	5.21E-01	3.11E-02	8-hour	1.38E-01	3.47E-02	1.73E-01	1.67E-01	3.25E-02	1.99E-01	50
					24-hour	7.57E-02	2.01E-02	9.58E-02	1.02E-01	1.90E-02	1.21E-01	12
					Annual	1.33E-03	4.62E-04	1.80E-03	6.59E-04	1.34E-03	2.00E-03	NE

Note: Impacts for beryllium and sulfuric acid mist were predicted by modeling these pollutants at their actual emission rates. All other impacts presented were derived by using a ratio method based on the impacts predicted for beryllium.

NE = none established.

^a Based on 40 CFR 266, Subpart H, Hazardous Waste Burned in Boilers and Industrial Furnaces, Appendix IV, Reference Air Concentration.

~~John~~
~~Dustin~~
Path – permit file

Central and South West Services, Inc.

1616 Woodall Rodgers Freeway
P.O. Box 660164 • Dallas, Texas 75266-0164
214-754-1000

January 13, 1993

Mr. Richard D. Garrity, Director
Florida Department of Environmental Regulation
Southwest District
4520 Oak Fair Blvd.
Tampa, FL 33610-7347

Subject: DER File No. AC53-211670 and PSD-FL-187

Dear Richard:

On December 14, 1992, Polk Power Partners, L.P. commenced construction of the Mulberry Cogeneration Project located in Polk County. The EPC contractor will be CSW Development I, Inc., 2250 Hwy 555, Bartow, Florida, 33830, (214) 754-1451.

If you have questions regarding the commencement of construction activities at the site please contact me at (214) 754-1451 or Jim Ellis (Construction Site Manager) at (813) 533-6628.

Sincerely,

Jack Fox

JF/wcm

cc:Clair Fancy, FDER

RECEIVED
JAN 14 1993
Division of Air
Resources Management

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

DEC 16 1992

RECEIVED
DEC 21 1992
Division of Air
Resources Management

4APT-AEB

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: Polk Power Partners,
Mulberry Cogeneration Project (PSD-FL-187)

Dear Mr. Fancy:

This is to acknowledge receipt of the final determination and Prevention of Significant Deterioration (PSD) permit for the above referenced facility, by your letter dated November 24, 1992. The proposed facility will be an integrated cogeneration facility, producing approximately 120,000 kilowatts net power to the transmission system and approximately 150 tons per day of liquid CO_2. The cogeneration project consists of one General Electric PG 7111EA combustion turbine, with a primary heat recovery steam generator (HRSG), a secondary HRSG, and a steam turbine generator. The CO_2 equipment includes two, 75 ton per day CO_2 recovery units.

Your determination proposes to limit NO_x emissions from the combustion turbine through water injection and dry low-NO_x combustion technology (through 4/30/97), to limit NO_x emissions from the combustion turbine through advanced dry low-NO_x combustion technology, selective catalytic reduction, or an equivalent NO_x control system (after 4/30/97), to limit SO_2 and H_2SO_4 Mist emissions from the combustion turbine through limiting the sulfur content of the No. 2 distillate fuel oil, to limit CO emissions from the combustion turbine and duct burner through efficient combustion, to limit VOC emissions through efficient combustion for the combustion turbine and through a scrubber for CO_2 absorber exhausts, and to limit PM/PM_{10}, Be, and As emissions from the combustion turbine through combustion control and the use of clean fuels.

Printed on Recycled Paper

We have reviewed the package as submitted and have no adverse comments. Thank you for the opportunity to review and comment on this package. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 347-5014.

Sincerely yours,

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

cc: J. Reynolds
C. Holladay
B. Thomas, SWD/OKC.
J. Bunyak, NPS
D. Martin, Polk Co.
R. Hardy, KBN

AFFIDAVIT OF PUBLICATION

The Polk County Democrat

Published Semi-Weekly
Bartow, Polk County, Florida

Case No. _____

STATE OF FLORIDA
COUNTY OF POLK

Before the undersigned authority personally appeared _____ Mary G. Frisbie _____, who on oath says that (s)he is _____ Treasurer _____ of The Polk County Democrat, a newspaper published at Bartow, Polk County, Florida; that the attached copy of advertisement, being a _____ Notice of Intent to Reissue Permit _____ in the matter of _____ The Department of Environmental Protection permit to Polk Power Partners, (PSD) _____ in the _____ Court, was published in said newspaper in the issues of _____ Dec. 30, 1993 _____.

Affiant further says that The Polk County Democrat is a newspaper published at Bartow, in said Polk County, Florida, and that said newspaper has heretofore been continuously published in said Polk County, Florida, each Monday and Thursday, and has been entered as second class matter at the post office in Bartow, in said Polk County, Florida, for a period of one year next preceeding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm, or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

Signed Mary G. Frisbie

Sworn to and subscribed before me this 5th day of Jan., 1994,

by _____ Mary G. Frisbie _____,

who is personally known to me.

Teresa M Pacetti
(Signature of Notary Public)

Teresa M. Pacetti
(Printed or typed name of Notary Public)
Notary Public

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA

Notary Public, State of Florida
TERESA M. PACETTI
My Comm. Exp. Dec. 19, 1995
Comm. No. CC 169408

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION NOTICE OF INTENT TO REISSUE PERMIT

The Department of Environmental Protection gives notice of its intent to reissue a permit to Polk Power Partners, 23293 South Pointe Drive, Laguna Hills, California 92653, to construct a cogeneration facility 3.7 miles southwest of Bartow, Polk County, Florida. A determination of Best Available Control Technology is required. The proposed project is subject to Prevention of Significant Deterioration (PSD(regulations and federal new source performance standards. Modeling results show that increases in ground-level concentrations are less than PSD significant impact levels. The Department is issuing this Intent to Reissue for the reasons stated in the Technical Evaluation and Preliminary Determination.

The Department issued the permit initially on November 24, 1992. Since that time, the permittee submitted new information justifying revised gas turbine emission limits for carbon monoxide (CO) and a deletion of the carbon dioxide (CO2) recovery facility. Therefore, the Department is reissuing the permit to include these changes and provide additional time to accomplish the revised objectives.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within fourteen (14) days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be diffe-

rent from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within fourteen (14) days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application is available for public inspection during normal business hours, 8:00 a. m. to 5:00 p. m., Monday through Friday, except legal holidays, at: Department of Environmental Protection, Bureau of Air Regulation, 111 S. Magnolia Park Courtyard, Tallahassee, Florida 32301, Department of Environmental Protection, Southwest District, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.
Dec. 30, 1993—3293

AFFIDAVIT OF PUBLICATION

The Polk County Democrat

Published Semi-Weekly
Bartow, Polk County, Florida

Case No. _____

STATE OF FLORIDA
COUNTY OF POLK

Before the undersigned authority personally appeared _____ S. L. Frisbie, IV _____, who on oath says that (s)he is _____ Publisher _____ of The Polk County Democrat, a newspaper published at Bartow, Polk County, Florida; that the attached copy of advertisement, being a _____ Notice of Intenet to Issue Permit _____ in the matter of _____ POLK POWER PARTNERS _____

in the _____ Court, was published in said newspaper in the issues of _____ October 8, 1992 _____.

Affiant further says that The Polk County Democrat is a newspaper published at Bartow, in said Polk County, Florida, and that said newspaper has heretofore been continuously published in said Polk County, Florida, each Monday and Thursday, and has been entered as second class matter at the post office in Bartow, in said Polk County, Florida, for a period of one year next preceeding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm, or corporation any discount, rebate, commission, or refund for the purpose of securing this advertisement for publication in said newspaper.

Signed _____

The foregoing instrument was acknowledged before me this 9th day of Oct., 1992, by _____ S. L. Frisbie, IV _____,

who is personally known to me.

Teresa M Pacetti
(Signature of Notary Public)

Teresa M. Pacetti
(Printed or typed name of Notary Public)
Notary Public

My Commission Expires:

NOTARY PUBLIC STATE OF FLORIDA

Notary Public, State of Florida
TERESA M. PACETTI
My Comm. Exp. Dec. 19, 1995
Comm. No. CC 169408

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION NOTICE OF INTENT TO ISSUE PERMIT

The Department of Environmental Regulation gives notice of its intent to issue a permit to POLK POWER PARTNERS, 23293 South Pointe Drive, Laguna Hills, California 92653, to construct a cogeneration and CO2 recovery facility 3.7 miles southwest of Bartow, Polk County, Florida. A determination of Best Available Control Technology (BACT) is required. The proposed project is subject to Prevention of Significant Deterioration (PSD) regulations and federal new source performance standards. Modeling results show that increases in ground-level concentrations are less than PSD significant impact levels. The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within (14) days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received)

within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application is available for public inspection during normal business hours, 8:00 a. m. to 5:00 p. m., Monday through Friday, except legal holidays, at Department of Environmental Regulation, Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and Department of Environmental Regulation, Southwest District, 4520 Oak Fair Boulevard, Tampa, Florida 33610-7347.

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person. Such requests must be submitted within 30 days of this notice.

Oct. 8, 1992—2911

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23046 Avenida De La Carlota, Ste 400
Laguna Hills, CA 92653

4a. Article Number
P 872 562 596

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery 1-24-94

5. Signature (Addressee)

6. Signature (Agent)
D. Pangen

8. Addressee's Address (Only if requested and fee is paid)

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

P 872 562 596

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to: Mr. William R. Malenius	
Street and No.: 23046 Avenida De La Carlota Ste 400	
P.O., State and ZIP Code: Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 1-20-94 Permit: AC53-211670 PSD-FL-187	

PS Form **3800**, JUNE 1991

P 872 562 591

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to: Mr. William R. Malenius	
Street and No.: Polk Power Partners 23293 South Point Dr.	
P.O., State and ZIP Code: Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 12-30-93 Permit: AC 53-211670 PSD-FL-187	

PS Form **3800**, JUNE 1991

October 12, 1992

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

RE: Polk County--A.P.
Polk Power Partners, L.P.--Mulberry Cogeneration Project
Permit Application AC 53-211670 and PSD-FL-187

Dear Clair:

Enclosed please find a copy of the notice of intent to issue the air construction permit for this project which was published in The Polk County Democrat on October 8, 1992.

We have provided several minor clarifications to the draft permit to John Reynolds, which he indicated would be made in the final permit. These clarifications involved:

1. Presenting emission limits for NO_x, sulfur content for SO_2, and opacity limits using fuel oil as backup after the first 3 years of operation (Specific Condition No. 2).

2. Specifying that natural gas and fuel oil can be fired until December 31, 1997 (3 years after the construction permit expiration date). After that date, the primary fuel will be natural gas; fuel oil can be used as a backup for no more than 30 days (Specific Condition No. 3). Fuel consumption rates for natural gas and fuel oil will be based on a temperature of 59°F or the benchmark. The number of hours of operation for the turbine firing fuel oil is 6,833, or 78 percent of the year.

In addition, a few clarifications to the BACT determination were discussed which made it more consistent with the specific conditions.

I greatly appreciate your staff's efforts in completing the review and issuing the draft permit.

Sincerely,

Robert C. McCamish for

Kennard F. Kosky, P.E.
President

KFK/tyf

cc: Mr. William Malenius, Ark Energy, Inc.
Mr. Ward Marshall, Central and South West Services, Inc.
File (2)
J. Reynolds
C. Holladay
B. Thomas, SWD Dist
T. Harper, EPA
B. Mitchell, NPS
D. Martin, PCPD

RECEIVED
OCT 13 1992
Division of Air Resources Management

91193A1/13

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

Best Available Copy

FEDERAL EXPRESS

QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL PACKAGE TRACKING NUMBER 1028819643

1196M 1028819643

RECIPIENT'S COPY

Date 10/12/92

From (Your Name) Please Print	Your Phone Number (Very Important)	To (Recipient's Name) Please Print	Recipient's Phone Number (Very Important)
J.P. Kosky/VJP	(904) 331-9000	Clair H. Fancy	(904) 488-1384
Company	**Department/Floor No.**	**Company**	**Department/Floor No.**
JN ENG & APPLIED SCIENCES		Florida Dept. of Environmental Regulat	
Street Address		**Exact Street Address** (We Cannot Deliver to P.O. Boxes or P.O. Zip Codes.)	
334 NW 57TH ST		2600 Blair Stone Road	
City	**State** / **ZIP Required**	**City**	**State** / **ZIP Required**
GAINESVILLE	FL 32609	Tallahassee	FL 32399

YOUR INTERNAL BILLING REFERENCE INFORMATION (First 24 characters will appear on invoice.)
01193-0200

H IF HOLD FOR PICK-UP, Print FEDEX Address Here
Street Address
City State ZIP Required

3 PAYMENT 1 [X] Bill Sender 2 [ ] Bill Recipient's FedEx Acct. No. 3 [ ] Bill 3rd Party FedEx Acct. No. 4 [ ] Bill Credit Card
5 [ ] Cash/Check

4 SERVICES (Check only one box)

Priority Overnight (Delivery by next business morning†)		Standard Overnight (Delivery by next business afternoon†)	
11	YOUR PACKAGING	51	YOUR PACKAGING
16 [X]	FEDEX LETTER *	56	FEDEX LETTER *
12	FEDEX PAK *	52	FEDEX PAK *
13	FEDEX BOX	53	FEDEX BOX
14	FEDEX TUBE	54	FEDEX TUBE

Economy Two-Day (Delivery by second business day†)		Government Overnight (Restricted for authorized users only)	
30	ECONOMY	46	GOVT LETTER
		41	GOVT PACKAGE

Freight Service (for Extra Large or any package over 150 lbs.)
70 OVERNIGHT FREIGHT ** (Confirmed reservation required)
80 TWO-DAY FREIGHT **
†Delivery commitment may be later in some areas. *Declared Value Limit $100. **Call for delivery schedule.

5 DELIVERY AND SPECIAL HANDLING (Check services required)

1	[ ]	HOLD FOR PICK-UP (Fill in Box H)
2	[X]	DELIVER WEEKDAY
3	[ ]	DELIVER SATURDAY (Extra charge) (Not available to all locations)
4	[ ]	DANGEROUS GOODS (Extra charge)
5	[ ]	
6	[ ]	DRY ICE ____ Lbs
7	[ ]	OTHER SPECIAL SERVICE
8	[ ]	
9	[ ]	SATURDAY PICK-UP (Extra charge)
10	[ ]	
11	[ ]	DESCRIPTION
12	[ ]	HOLIDAY DELIVERY (If offered) (Extra charge)

6 PACKAGES / WEIGHT In Pounds Only
Total / Total

DIM SHIPMENT (Chargeable Weight)
[ ] ____ lbs.
____ X ____ X ____ = ____

7 Received At
1 [ ] Regular Stop 3 [ ] Drop Box
2 [ ] On-Call Stop 4 [ ] B.S.C. 5 [ ] Station

Emp. No. Date
[ ] Cash Received
[ ] Return Shipment
[ ] Third Party [ ] Chg. To Del. [ ] Chg. To Hold
Street Address
City State Zip
Received By: X
Date/Time Received FedEx Employee Number
Release Signature:
FedEx Emp. No. Date/Time

Federal Express Use
Base Charges
Declared Value Charge
Other 1
Other 2
Total Charges

REVISION DATE 4/91
PART #137204 FXEM 6/91
FORMAT #082
082

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PRINTED IN U.S.A.

0102473

139

POLK POWER PARTNERS, L.P.
1125 US 98 SOUTH, SUITE 100
LAKELAND, FL 33801
PH. (813) 682-6338

CITRUS & CHEMICAL BANK
LAKELAND, FL 33801

63-597/631

FIFTY DOLLARS AND NO/100----------

DATE 4/11/95

AMOUNT $50.00

PAY TO THE ORDER OF
FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR REGULATION
2600 BLAIR STONE ROAD
TALLAHASSEE, FL 32399

Timothy L Burke
AUTHORIZED SIGNATURE

[redacted]

POLK POWER PARTNERS, L.P.

1394

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF AIR REGULATION
2600 BLAIR STONE ROAD
TALLAHASSEE, FL 32399

CONSTRUCTION PERMIT EXTENSION FOR MULBERRY COGEN
PERMIT # AC53-211670 PSD-FL-187

$50.00

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ms. Nancy Henning Jones
Vice President & General Manager
Polk Power Partners
1125 U.S. 98 South ◯ Suite 100
Lakeland, Florida 33801

4a. Article Number
P 872 562 689

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
9-30-94

5. Signature (Addressee)
Janet Wynodick

6. Signature (Agent)

8. Addressee's Address (Only if requested and fee is paid)

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 689

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Ms. Nancy Henning Jones	
Street and No. 1125 U.S. 98 South -	
P.O., State and ZIP Code Lakeland, FL 33801	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 9/27/94 AC53-211670, PSD-FL-187	

PS Form **3800**, JUNE 1991

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. William R. Malenius
Polk Power Partners
23406 Avenida De La Carlota,
Suite 400
Laguna Hills, CA 92653

4a. Article Number
P 872 562 605

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
2-25-94

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 605

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. William R. Malenius	
Street and No. 23406 Avenida De La Carlota Ste 400	
P.O., State and ZIP Code Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 2-21-94 Permit: AC53-211670 PSD-FL-187	

PS Form **3800**, JUNE 1991

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. William R. Malenius
Polk Power Partners
23046 Avenida De La Carlota
Suite 400
Laguna Hills, California 92650

4a. Article Number
P 872 562 709

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)
Cindy Seare

PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 712

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to: Mr. Willam R. Malenius	
Street and No.: 23293 South Pointe Drive	
P.O., State and ZIP Code: Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 8/4/94 AC53-211670 (PSD-FL-187)	

PS Form 3800, JUNE 1991

P 872 562 709

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to: Mr. William R. Malenius	
Street and No.: 23046 Avenida De La Carlota	
P.O., State and ZIP Code: Laguna Hills, CA 92650	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 8/16/94 AC53-211670(PSD-FL-187)	

PS Form 3800, JUNE 1991

KBN Engineering and Applied Sciences, Inc.
GENERAL DISBURSEMENT ACCOUNT
PH. 904-331-9000
1034 N.W. 57TH STREET
GAINESVILLE, FL 32605

First Union National Bank of Florida
Gainesville, Florida 32605
63-2/630
Branch 311

0004928 012830

28 June 1994

PAY **********250*** DOLLARS AND 00 CENTS $ ******250.00

TO THE ORDER OF
Florida Department of Environmental Regulation
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee FL 32399-2400

KBN ENGINEERING AND APPLIED SCIENCES, INC.

AUTHORIZED SIGNATURE

[redacted]

KBN ENGINEERING AND APPLIED SCIENCES, INC.
GAINESVILLE, FL 32605

V-3922 012830

PLEASE DETACH AND RETAIN FOR YOUR RECORDS

INVOICE NUMBER	DATE		VOUCHER NO.	AMOUNT
	06/28/94	Mulberry Cogeneration Project NSPS Custom Fuel Monitoring Permit No. AC53-211670, PSD-FL-187		250.00

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

RECEIVED
JUN 28 1994
Bureau of
Air Regulation

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Kennard F. Kosky, P.E.
President
KBN ENgineering and Applied
Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605

4a. Article Number
P 872 562 716

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
6/27/94

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)
J.O. Kosky

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 716

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to: Mr. Kennard F. Kosky, P.E.	
Street and No.: 1034 NW 57th Street	
P.O., State and ZIP Code: Gainesville, FL 32605	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 6/23/94 AC 53-211670, PSD-FL-187	

PS Form **3800**, JUNE 1991

POWER OPERATIONS DIVISION
C · S · W
ENERGY
A CENTRAL AND SOUTH WEST COMPANY
Mulberry Cogen
P.O. Box 824 • 3600 Hwy. 555
Bartow, FL 33830
813-533-9073 • Fax 813-533-4092

RECEIVED
NOV 18 1994
Bureau of
Air Regulation

October 28, 1994

State of Florida
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Polk Power Partners, L.P.
Permit Number: AC 53-211670
PSD-FL-187

Dear Sir or Madam:

In compliance with Paragraph 5 of the above-referenced permit, please consider this our 30 days notification of compliance testing at the Mulberry Cogeneration Facility. If you require additional information, please feel free to contact me at (813) 533-9073.

Sincerely,

John Paul Jones
Manager of Cogeneration

/pcp
xc: Nancy Jones, Polk Power Partners
J. Reynolds
M. Harley
B. Thomas, SW Dist
J. Harper, EPA

POWER OPERATIONS DIVISION

C · S · W

ENERGY

A CENTRAL AND SOUTH WEST COMPANY

Mulberry Cogen
P.O. Box 824
Bartow, FL 33830

BARTOW OCT 28'94 FLA.

U.S. POSTAGE .29

PB METER 1696542

Bureau of Air MS# 5505

~~HQ~~

State of Florida
Department of ~~Environmental~~ Protection
Twin Towers Office Building
2600 ~~Blair Stone~~ Road
~~Tallahassee~~, FL 32399-2400

~~This does not belong to~~

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Farzie Shelton
McIntosh Power Plant
3030 E. Lake Parker Drive
Lakeland, Florida 33805

4a. Article Number
Z 751 860 000

4b. Service Type
☐ Registered ☐ Insured
XX Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
11-23-94

5. Signature (Addressee)

6. Signature (Agent)

8. Addressee's Address (Only if requested and fee is paid)

Thank you for using Return Receipt Service.

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Z 751 860 000

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to: Mr. Farzie Shelton	
Street and No: 3030 E. Lake Parker Drive	
P.O., State and ZIP Code: Lakeland, FL 33805	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 11/21/94	

PS Form **3800**, March 1993

Is your RETURN ADDRESS completed on the reverse side?

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Mr. Kennard F. Kosky, P.E.
President
KBN Engineering & Applied Sciences
1034 Northwest 57th Street
Gainesville, Florida 32605

4a. Article Number: P 230 524 385

4b. Service Type
☐ Registered ☐ Insured
XX Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

5. Signature (Addressee): Alyce Lancaster

6. Signature (Agent)

7. Date of Delivery: 8-23-93

8. Addressee's Address (Only if requested and fee is paid)

Thank you for using Return Receipt Service.

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

P 230 524 385

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to: Mr. Kennard F. Kosky, P.E.	
Street and No.: 1034 Northwest 57th Street	
P.O., State and ZIP Code: Gainesville, FL 32605	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 8/20/93 AC53-211670	

PS Form **3800**, June 1991

Best Available Copy

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Ken Kosky, PE
KBN Engineering + App. Sc.
1034 NW 57th St.
Gainesville, Fl 32605

4a. Article Number
P 062 921 977

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
3-22-93

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)
R Mitchell

PS Form 3811, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 062 921 977

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to: Ken Kosky	
Street and No. KBN	
P.O., State and ZIP Code Gainesville, Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 3-19-93	

PS Form 3800, June 1991

PS Form 3811, July 1983 447-845

SENDER: Complete items 1, 2, 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 service(s) requested.

1. ☐ Show to whom, date and address of delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to:
William R. Malenius
Polk Power Partners
23293 S Pointe Dr.
Laguna Hills, CA 92653

4. Type of Service:
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail

Article Number
P062921 927

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature – Addressee
X

6. Signature – Agent
X

7. Date of Delivery
12-1-92

8. Addressee's Address *(ONLY if requested and fee paid)*

DOMESTIC RETURN RECEIPT

P 062 921 927

Receipt for Certified Mail

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to
William Malenius
Street and No.
Polk Power Partners
P.O. State and ZIP Code
Laguna Hills, CA

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$

Postmark or Date 11-24-92

AC 53-211670
PSD-FI-187

PS Form 3800, June 1991

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece next to the article number.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Dirve
Laguna Hills, CA 92653

4a. Article Number
P 710 058 531

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
5/14/92

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)
Amy Kitmitto

PS Form 3811, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

P 710 058 531

Certified Mail Receipt
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to: Mr. William R. Malenius, Polk	
Street & No. Power Partners 23293 South Pointe Drive	
P.O., State & ZIP Code: Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date: Mailed: 5-5-92 Pemrit: AC 53-211670 PSD-FL-187	

PS Form 3800, June 1990

SENDER:

- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt Fee will provide you the signature of the person delivered to and the date of delivery.

I also wish to receive the following services (for an extra fee):

1. ☒ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, California 92653

4a. Article Number
P 062 921 986

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
8-19-92

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)
C. Coll

PS Form **3811**, November 1990 ☆U.S. GPO: 1991—287-066 **DOMESTIC RETURN RECEIPT**

P 062 921 986

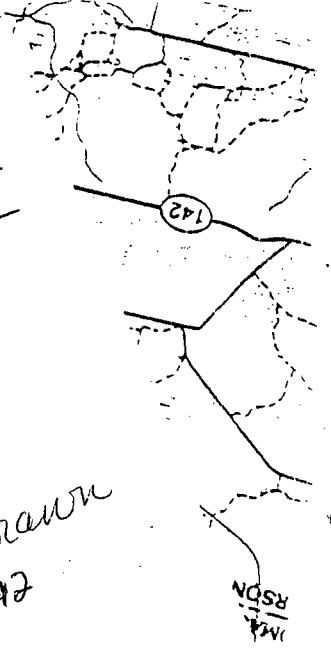
Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. William R. Malenius	
Street and No. Senior Program Manager	
P.O., State and ZIP Code Polk Power Partners 23293 South Pointe Drive Laguna Hills, CA 92653	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date mailed: 8/14/92 AC 53-211670 PSD-FL 187	

PS Form **3800**, June 1991

BEST AVAILABLE COPY



Check Sheet

Company Name: Polk Power Partners, L.P.
Permit Number: AC53-211669 AC53-211670
PSD Number: PSD-FL-187
Permit Engineer:

Cross References:
- ☑ AC53 - 242805
- ☐
- ☐ AC 53-211669 - Withdrawn 9/25/97

Application:
- ☑ Initial Application
- ☐ Incompleteness Letters
- ☑ Responses
- ☐ Waiver of Department Action
- ☐ Department Response
- ☐ Other

Intent:
- ☑ Intent to Issue
- ☑ Notice of Intent to Issue
- ☑ Technical Evaluation
- ☑ BACT or LAER Determination
- ☑ Unsigned Permit
- ☑ Correspondence with:
  - ☐ EPA
  - ☐ Park Services
  - ☐ Other
- ☑ Proof of Publication
- ☐ Petitions - (Related to extensions, hearings, etc.)
- ☐ Waiver of Department Action
- ☐ Other

Final Determination:
- ☑ Final Determination
- ☐ Signed Permit
- ☑ BACT or LAER Determination
- ☐ Other

Post Permit Correspondence:
- ☑ Extensions/Amendments/Modifications Reissue under AC53-242805
- ☐ Other

Revision #5

Best Available Copy

R. File

Department of Environmental Protection

Lawton Chiles
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Virginia B. Wetherell
Secretary

April 28, 1995

Mr. Wade Smith, Director
Business Operations Director
Polk Power GP, Inc.
1125 U.S. 98 South
Lakeland, Florida 33801

Dear Mr. Smith:

Re: Mulberry Cogeneration Facility PSD-FL-187
Permit Number AC 53-211670

The Department has reviewed your request of April 11, 1995 and determined that a renewal of the referenced permit, which expires on December 31, 1995, will be necessary.

According to F.A.C. 62-213(1)(a) "Timely Application", a Title V application must be submitted on behalf of your facility by April 2, 1995 (being revised to November 15, 1995). According to F.A.C. 62-213(1)(b), "Complete Application", an applicant submitting a timely and complete Title V application may continue to operate under the authority and provisions of any existing valid permit or site certification. Since your construction permit will expire during the 60 day Title V permit application completeness review period, your permit will be extended through January 15, 1996.

If for any reason the due date of your Title V application is deferred beyond November 15, 1995, we will extend your construction permit beyond January 15, 1996. If you have any questions about this matter, please call me at (904)488-1344.

Sincerely,

A. A. Linero, P.E.
Administrator
New Source Review

cc: John Brown
Bruce Mitchell
Jerry Kissel
David Zell

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

Mr. William R. Malenius
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, CA 92653

DER File No. AC53-211670
PSD-FL-187
Polk County

Enclosed is Permit Number AC53-211670 to construct a cogeneration and CO_2 recovery facility at County Road 555 approximately 3.7 miles southwest of Bartow, Polk County, Florida, issued pursuant to Section(s) 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 11-24-92 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED,
on this date, pursuant to
§120.52(11), Florida Statutes,
with the designated Department
Clerk, receipt of which is hereby
acknowledged.

(Clerk) 11-24-92 (Date)

Copies furnished to:
W. Thomas, SWD
D. Martin, Polk Co.
J. Harper, EPA
C. Shaver, NPS
K. Kosky, KBN

Final Determination

Polk Power Partners
Cogeneration/CO_2 Recovery Project
Polk County, Florida

Permit No. AC 53-211670
PSD-FL-187

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

November 19, 1992

Final Determination

The Technical Evaluation and Preliminary Determination for the permit to construct a cogeneration and CO_2 recovery facility approximately 3.7 miles southwest of Bartow in Polk County, Florida, was distributed on September 22, 1992. The Notice of Intent to Issue was published in the Polk County Democrat on October 8, 1992. Copies of the evaluation were available for public inspection at the Department's Tallahassee and Tampa offices.

On October 26, 1992, a letter was received from the EPA concurring with the Department's proposed action. Comments were received from the applicant on October 13 and November 4, 1992, requesting minor modifications of certain specific conditions. The Department made the following changes in response to those comments:

Specific Condition No. 2 - The emission limits were modified to show fuel oil use as backup after the first three years of operation. Oil use is limited to 30 days per year after December 31, 1997.

Specific Condition No. 3 - Fuel consumption rates and hours of operation were modified to show fuel oil use as backup after the first three years of operation and limited use (30 days per year) after December 31, 1997.

BACT Determination - Minor revisions were made to the last paragraph of the NO_x section to clarify that SCR may be required if the emission limits are not achieved by April 30, 1997.

The final action of the Department will be to issue construction permit AC53-211670 (PSD-FL-187) as modified.

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:
Polk Power Partners, L.P.
23293 South Pointe Drive
Laguna Hills, CA 92653

Permit Number: AC 53-211670
PSD-FL-187
Expiration Date: December 31, 1994
County: Polk
Latitude/Longitude: 27°50'56"N
81°52'39"W
Project: Mulberry 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 construction of a 126 Megawatt cogeneration unit along with a 150 ton per day CO_2 recovery plant. The facility will be located off County Road 555 approximately 3.7 miles southwest of Bartow in Polk County, Florida. UTM coordinates of the site are: Zone 17, 413.6 km E and 3080.6 km N.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be controlled by proper combustion techniques. NO_X emissions shall be initially controlled by water injection and Low NO_X Burners. Future control technology for NOx (SCR) will depend on whether the Low NO_X Burners can achieve the levels specified by this permit.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. DER letter dated May 5, 1992.
2. KBN letter dated April 15, 1992.
3. KBN letter dated June 2, 1992.
4. EPA letter dated July 1, 1992.
5. KBN submittal dated July 8, 1992.
6. KBN letter dated July 29, 1992.
7. KBN letter dated August 12, 1992.
8. DER letter dated August 13, 1992.
9. KBN letter dated August 26, 1992.
10. KBN letter dated October 12, 1992.
11. KBN letter dated November 2, 1992.

Recycled Paper
Printed with Soy Based Inks

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 prescribed 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.

GENERAL CONDITIONS:

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

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;

GENERAL CONDITIONS:

- 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.

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. Unless otherwise indicated, the construction and operation of the subject facilities shall be in accordance with the capacities and specifications stated in the application.

2. Emissions from these facilities shall not exceed the limits listed below (based on operation at 59°F):

Pollu-tant	Source	Fuel	Through 12/31/97 lbs/hr	Through 12/31/97 tons/yr	After 12/31/87 (See notes) lbs/hr	After 12/31/87 (See notes) tons/yr
NOx	HRSG Stack	Gas	87.8	384.5	52.7	230.7
	CO_2 Plant Stack	Gas	19.9	87.1	18.3	80.0
	HRSG Stack	Oil	164.0	718.2	164.0	59.0
	CO_2 Plant Stack	Oil	23.4	102.4	23.4	8.4
SO2	HRSG Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	CO_2 Plant Stack	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack	Gas	10% Opacity		10% Opacity	
	CO_2 Plant Stack	Gas	10% Opacity		10% Opacity	
	HRSG Stack	Oil	20% Opacity		20% Opacity	
	CO_2 Plant Stack	Oil	20% Opacity		20% Opacity	
VOC	CO_2 Plant Stack	--	18.2	79.6	17.7	77.6
CO	HRSG Stack	Gas	42.9	187.8	42.9	187.8
	CO_2 Plant Stack	Gas	11.9	52.0	11.9	52.0
	HRSG Stack	Oil	75.3	329.9	75.3	27.1
	CO_2 Plant Stack	Oil	13.4	58.5	13.4	4.8

Notes: (1) Oil may be used as backup fuel for up to 30 days per year.
(2) NO_x limits after 12/31/97 based on 15 ppmvd.
(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.

SPECIFIC CONDITIONS:

3. The cogeneration facility shall be permitted to fire natural gas and No. 2 fuel oil until December 31, 1997, after which the primary fuel will be natural gas. Fuel consumption rates (based on operation at 20°F) and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr	MM ft3/yr	hrs/yr	M lb/hr	M lb/yr	hrs/yr
Turbine	1013.4	8877.4	8760	55.6	379.9	6833(1)
Duct Burner	104.2	912.8	8760	0	0	0

(1) After December 31, 1997, fuel oil can be used permanently as backup fuel for no more than 720 hours per year.

4. Before this construction permit expires, the cogeneration facility and CO_2 Recovery Plant stacks shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96% to 100% of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_X: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10
VOC: EPA Method 25A

5. The DER Southwest District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the DER Southwest District office in Tampa and the DER Bureau of Air Regulation office in Tallahassee (third annual compliance test only) within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and water injection flows to the cogeneration turbine along with the power output of the generators shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DER upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions

SPECIFIC CONDITIONS:

necessary for future installation of state-of-the-art catalytic abatement or equivalent NOx control systems. Within 90 days of receipt of the third annual compliance test results, the Bureau of Air Regulation shall, if NO_x emission limits are not met, review the need for making a revised determination of Best Available Control Technology. If test results show that it is unlikely that NO_x limits can be met, a revised BACT determination shall be made. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. The retrofit costs associated with not making provisions for such technology initially shall not be considered by the Department in the retrofit cost analysis.

8. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

9. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this 20th day
of November, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Carol M. Browner, Secretary

Best Available Control Technology (BACT) Determination
Mulberry Cogeneration Project
Polk County

The applicant proposes to install a 126 MW combined cycle cogeneration unit along with a 150 TPD carbon dioxide plant that will recover CO_2 from the power plant flue gas. The Polk County facility will consist of a General Electric PG7111EA Gas Turbine Generator exhausting through a primary heat recovery steam generator which will produce steam for the steam-electric cycle. Initially, the turbine will be fired by natural gas and No. 2 fuel oil, with natural gas becoming the permanent fuel after the first three years of operation. A secondary heat recovery steam generator will be auxiliary-fired by natural gas to provide a CO_2-enriched flue gas feed to the CO_2 recovery plant.

Date of Receipt of a Complete Application

August 14, 1992

BACT Determination Requested by Applicant

NO_x - Dry Low NO_x Combustion
CO - Combustion Design
H_2SO_4/SO_2 - Low Sulfur Fuel Oil (0.1%S)
VOC - Combustion Design for CT
Scrubber for CO_2 Absorber Exhaust
PM/PM_{10} - Combustion Design/Clean Fuel

BACT Determination by the Department

NO_x - Dry Low NO_x Combustion with potential future SCR capability
CO - Combustion Design
H_2SO_4/SO_2 - Low Sulfur Fuel Oil (0.1%S)
VOC - Combustion Design for CT
Scrubber for CO_2 Absorber Exhaust
PM/PM_{10} - Combustion Design/Clean Fuel

Proposed Emission Limits (tons per year)

	First 3 yrs (22% Gas/78% Oil)			After First 3 yrs (100% Gas)			PSD
	HRSG	CO_2 Plant	Total	HRSG	CO_2 Plant	Total	
NO_x	644.8	99.1	743.9	230.7	80.0	310.7	40.0
SO_2	327.4	16.4	343.8	11.4	1.8	13.2	40.0
PM/PM_{10}	58.0	28.9	86.9	30.7	27.7	58.4	25/15
CO	298.6	57.1	355.7	187.8	52.0	239.8	100.0
VOC	37.7	79.3	117.0	28.2	78.8	107.0	40.0
H_2SO_4	26.4	1.3	27.7	0.9	0.1	1.0	7.0
Be	.008	--	.008	--	--	--	0.0004
As	.013	--	.013	--	--	--	0.0

These limits assume that 4.6% of the turbine exhaust mass flow is diverted to the CO_2 plant. Emissions for the first three years are based on firing 22% gas - 78% oil in the turbine for 8,760 hours/yr at 1016 MMBtu/hr and natural gas in the duct burner for 8,760 hours/yr at 99 MMBtu/hr. Emissions after the first three years are based on firing only natural gas at 868.8 MMBtu/hr. Turbine performance under natural gas firing is based on NO_x emissions of 25 ppm (corrected to 15 percent O_2) for the first three years and 15 ppm thereafter. Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O_2). SO_2 emissions are based on 0.1 percent sulfur.

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, than 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.

BACT Determination Rationale

Particulate Matter (PM/PM_{10})

Particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not cause visible emissions to exceed 10% and 20% opacity, respectively.

Arsenic and Berylium (As, Be)

The Department agrees that there are no feasible methods to control beryllium and arsenic except by specifying the quality of the fuel.

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The majority of BACT emissions limitations have been based on controlling carbon monoxide and volatile organic compounds through efficient combustion. Advanced control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalyst systems are not considered to be technically feasible for gas turbines fired with fuel oil. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for a natural gas-fired unit; however, the cost effectiveness of over $6,000 per ton of CO removed will have a significant economic impact on this project. Therefore, efficient combustion will be the control method for CO and VOC.

Nitrogen Oxides (NO_X)

The applicant requested that BACT for nitrogen oxides during the first three years be water injection and Low NO_X Burners. This would limit emissions to 25 ppmvd when burning natural gas and 42 ppmvd when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_X emission limit established to date for a combustion turbine is 4.5 ppmvd (corrected to 15% O_2). This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_X emissions. The SCR process combines vaporized ammonia with NO_X in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_X with a new catalyst. As the catalyst ages, the maximum NO_X reduction will decrease to approximately 86 percent.

Although feasible, the applicant rejected using SCR because of economic, energy, and environmental impacts. The following factors were considered in the decision not to propose SCR:

a) Disposal of hazardous waste generated (spent catalyst).
b) An energy penalty of $0.05/KWH due to back pressure from the catalyst bed.
c) A power loss penalty based on lost capacity.
d) Potential for public exposure to high concentrations from ammonia storage and handling leaks and ammonia slip.
e) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
f) Cost effectiveness for SCR technology was determined to be in the range of $6,000 per ton of NO_X removed.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate which can be formed by reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. The latest information available indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_X injection ratio. For natural gas firing, NO_X emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_X can be controlled with efficiencies ranging from 60 to 75 percent. When the injection

ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. SCR has been established as BACT for oil fired combined cycle facilities with NO_X emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control.

The applicant determined that the total annual cost of SCR for this project is $1,957,700 with an average cost effectiveness in the range of $6,000 to $7,000 per ton of NO_X removed. The maximum annual NO_X emissions using water injection and Low NO_X combustor design will be 744 tons/year for the first three years. Assuming that SCR would reduce the NO_X emissions by 65%, about 484 tons/year of NO_X would be removed initially followed by 200 tons/year thereafter. When this reduction is factored into the total annual cost, the cost per ton of controlling NO_X is in the range of $6,000 to $6,500. This calculated cost is higher than has previously been approved as BACT.

The latest DER BACT determinations have a NO_X limit of 15 ppmvd (natural gas) using Low-NO_X burner technology. Although the turbine manufacturer does not presently guarantee this limit, they have agreed to lower NO_X to 15 ppm by 4/30/97. This lower NO_X limit will be achieved by application of low-NO_X burners or SCR. Therefore, the Department accepts water injection and Low NO_X Burner design as BACT for a limited time (up to 4/30/97).

The calculations that the applicant presented and Department findings indicate that the cost of controlling NO_X is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_X control is not justifiable as BACT at this time.

The Department will revise the allowable BACT limit for this project if necessary no later than 4/30/97. It is the Department's understanding that the turbine manufacturer will be able to achieve 15 ppmvd NO_X emission limits within this period. If the 15 (gas)/42 (oil) ppmvd emission rates cannot be met, SCR or another technology will be required no later than December 31, 1997.

Sulfur Dioxide(SO_2) and Sulfuric Acid Mist (H_2SO_4)

In accordance with "top down" BACT review, only two alternatives exist that would result in stringent SO_2 emissions; using low sulfur content fuel oil or flue gas desulfurization (FGD). EPA has recognized that FGD technology is inappropriate to apply to these combustion units due to negative environmental, economic and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and

water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

This leaves the use of low sulfur fuel oil as the best option. The Department accepts the use of No. 2 fuel oil with a 0.1% sulfur by weight as BACT for this project.

Details of the Analysis May be Obtained by Contacting:

Preston Lewis, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

November 18, 1992
Date

Approved by:

Carol M. Browner, Secretary
Dept. of Environmental Regulation

November 20, 1992
Date

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

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

Interoffice Memorandum

TO: Carol M. Browner

FROM: Howard L. Rhodes

DATE: November 19, 1992

SUBJ: Approval of Construction Permit AC53-211670 (PSD-FL-187)
Polk Power Partners

Attached for your approval and signature is a permit prepared by the Bureau of Air Regulation for the above mentioned company to construct a cogeneration and CO_2 recovery facility near Bartow.

This facility is not controversial and consists of a 126 MW combined cycle cogeneration power plant along with a 150 ton per day carbon dioxide (CO_2) plant that will recover CO_2 from the power plant flue gas. The permanent fuel for the power plant will be natural gas although the plant will not have a firm contract for natural gas until the fourth year of operation. During the first three years, natural gas will provide a minimum of 22 percent of fuel requirements with the balance supplied by distillate fuel oil.

The facility is required to meet Best Available Control Technology for NO_x using low NO_x burner and water injection. If this technique does not meet the necessary emission limits, then DER is requiring the use of Selective Catalytic Reduction (SCR).

Comments were received from the applicant requesting minor clarification to indicate use of fuel oil as backup after the first three years of operation.

I recommend your approval and signature.

8-5

HLR/JR/plm

Attachments

PATTY:

ALTHOUGH WE DID NOT SEND THIS 2nd INCOMPLETENESS LETTER, CAN WE CLAIM THE CLOCK WAS TOLLED BECAUSE THE APPLICANT WAS AWARE OF THE INCOMPLETENESS ?

PS Form 3811, July 1983 447-845

DOMESTIC RETURN RECEIPT

SENDER: Complete items 1, 2, 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 service(s) requested.

1. ☐ Show to whom, date and address of delivery.
2. ☐ Restricted Delivery.

3. Article Addressed to:
William R. Malenius
Polk Power Partners
23293 S Pointe Dr.
Laguna Hills, CA 92653

4. Type of Service:
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail

Article Number
P062921927

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature – Addressee
X

6. Signature – Agent
X

7. Date of Delivery
12-1-92

8. Addressee's Address *(ONLY if requested and fee paid)*

P 062 921 927

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to William Malenius	
Street and No. Polk Power Partners	
P.O. State and ZIP Code Laguna Hills, CA	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 11-24-92	
AC 53-211670 PSD-FI-187	

PS Form 3800, June 1991

November 2, 1992

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

Subject: Polk County - A.P.
Polk Power Partners, L.P. - Mulberry Cogeneration Project
Permit Application AC 53-211670 and PSD-FL-187

Dear Clair:

We appreciate the efforts that your staff made to issue the draft permit for the Mulberry Cogeneration Project. After receipt of the draft permit, Bob McCann and I suggested to John Reynolds several minor clarifications which he indicated would be made in the final permit. These clarifications involved:

1. Specific Condition No. 2

After the first three years of operation, the emissions for the facilities shall not exceed the following limits:

			Emission Limits	
Pollutant	Source	Fuel	lbs/hr	tons/yr
NOx	HRSG Stack	Oil	164.0	59.0
	CO_2 Plant Stack	Oil	23.4	8.4
SO_2	HRSG Stack	Oil	0.1 % Sulfur Max.	
	CO_2 Plant Stack	Oil	0.1 % Sulfur Max.	
VE	HRSG Stack	Oil	20 % Opacity*	
	CO_2 Plant Stack	Oil	20 % Opacity*	

* Except for one 6-minute period per hour of not more than 27% opacity.

RECEIVED
NOV 0 3 1992
Division of Air
Resources Management

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

KBN

2. Specific Condition No. 3

The cogeneration facility shall be permitted to fire natural gas permanently and No. 2 fuel until December 31, 1997. After which time the primary fuel will be natural gas and No. 2 fuel oil can be used as backup for no more than 30 days per year. Fuel consumption rates and hours of operation for the turbine and duct burner shall not exceed those listed below (based on operation at 20 °F ambient temperature):

	Natural Gas			No. 2 Fuel Oil		
	M ft^3/hr	MM ft^3/yr	hrs/yr	M lb/hr	M lb/yr	hrs/yr
Turbine	1013.4	8877.4	8760	55.6	379.9	6833
Duct Burner	104.2	912.8	8760	0	0	0

3. Best Available Control Technology (BACT) Determination

a. On page 1 under the heading, BACT Determination by the Department, the BACT for NO_x emissions will be changed to: Dry Low NO_x Combustion with future potential SCR capability

b. Under the heading, BACT Determination Rationale for NO_x on page 5 of 6, the last paragraph will be changed to:

First sentence- The Department will revise the allowable BACT limit for this project, if necessary, no later than 4/30/97.

Last sentence- If the 15 (gas)/ 42 (oil) ppmvd emission rates cannot be met, SCR may be required no later than December 31, 1997.

I appreciate the opportunity to provide these comments to you and your staff in preparing the final permit conditions for this project.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

cc: Mr. William Malenius, Ark Energy, Inc.
Mr. Ward Marshall, Central and South West Services, Inc.
John Reynolds, FDER
C. Holladay
RCM/mlb
B. Thomas, SW Dist.
G. Harper, EPA
B. Mitchell, NPS
D. Martin, Polk Co.
91193A1/14
JCB/PL

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

OCT 23 1992

4APT-AEB

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: Polk Power Partners,
Mulberry Cogeneration Project (PSD-FL-187)

Dear Mr. Fancy:

This is to acknowledge receipt of the preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility, by your letter dated September 22, 1992. The proposed facility will be an integrated cogeneration facility, producing approximately 120,000 kilowatts net power to the transmission system and approximately 150 tons per day of liquid CO_2. The cogeneration project consists of one General Electric PG 7111EA combustion turbine, with a primary heat recovery steam generator (HRSG), a secondary HRSG, and a steam turbine generator. The CO_2 equipment includes two, 75 ton per day CO_2 recovery units.

Your determination proposes to limit NO_x emissions from the combustion turbine through water injection and dry low-NO_x combustion technology (through 4/30/97), to limit NO_x emissions from the combustion turbine through advanced dry low-NO_x combustion technology or selective catalytic reduction (after 4/30/97), to limit SO_2 and H_2SO_4 Mist emissions from the combustion turbine through limiting the sulfur content of the No. 2 distillate fuel oil, to limit CO emissions from the combustion turbine and duct burner through efficient combustion, to limit VOC emissions through efficient combustion for the combustion turbine and through a scrubber for CO_2 absorber exhausts, and to limit PM/PM_{10}, Be, and As emissions from the combustion turbine through combustion control and the use of clean fuels.

RECEIVED

OCT 26 1992

Division of Air
Resources Management

Printed on Recycled Paper

We have reviewed the package as submitted and have no adverse comments. Thank you for the opportunity to review and comment on this package. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 347-5014.

Sincerely yours,

for Gregg M. Worley

Brian D. Beals, Chief
Source Evaluation Unit
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

CC: J. Reynolds
C. Holladay
B. Thomas, SW Dist
B. Mitchell, NPS
O. Martin, Polk Co.
K. Kosky, KBN
JB/PL

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

September 22, 1992

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, California 92653

Dear Mr. Malenius:

Attached is one copy of the Technical Evaluation and Preliminary Determination and proposed permit for Polk Power Partners to construct a cogeneration and CO_2 recovery facility in Polk County.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Mr. Preston Lewis of the Bureau of Air Regulation.

Sincerely,

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

CHF/JR/plm

Attachments

c: B. Thomas, SWD
J. Harper, EPA
C. Shaver, NPS
K. Kosky, KBN
D. Martin, Polk Co.

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STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DER File No. AC 53-211670
PSD-FL-187

Polk Power Partners
23293 South Pointe Drive
Laguna Hills, California 92653

_____/

INTENT TO ISSUE

The Department of Environmental Regulation gives notice of its intent to issue a permit (copy attached) for the proposed project as detailed in the application specified above, for the reasons stated in the attached Technical Evaluation and Preliminary Determination.

The applicant, Polk Power Partners, applied on April 6, 1992, to the Department of Environmental Regulation for a permit to construct a cogeneration and CO_2 recovery facility 3.7 miles southwest of Bartow in Polk County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes and Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4. The project is not exempt from permitting procedures. The Department has determined that a construction permit is required for the proposed work.

Pursuant to Section 403.815, Florida Statutes and Rule 17-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permit. The notice shall be published one time only within 30 days in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permits. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed on the fourth page. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within seven days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

The Department will issue the permit with the attached conditions unless a petition for an administrative proceeding (hearing) is filed pursuant to the provisions of Section 120.57, F.S.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department.

Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE and all copies were mailed by certified mail before the close of business on 9-25-92 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Clerk

9-25-92
Date

Copies furnished to:
B. Thomas, SWD
J. Harper, EPA
C. Shaver, NPS
K. Kosky, KBN

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF INTENT TO ISSUE PERMIT

The Department of Environmental Regulation gives notice of its intent to issue a permit to Polk Power Partners, 23293 South Pointe Drive, Laguna Hills, California 92653, to construct a cogeneration and CO_2 recovery facility 3.7 miles southwest of Bartow, Polk County, Florida. A determination of Best Available Control Technology (BACT) is required. The proposed project is subject to Prevention of Significant Deterioration (PSD) regulations and federal new source performance standards. Modeling results show that increases in ground-level concentrations are less than PSD significant impact levels. The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this

Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

The application is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

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

Department of Environmental Regulation
Southwest District
4520 Oak Fair Blvd.
Tampa, Florida 33610-7347

Any person may send written comments on the proposed action to Mr. Preston Lewis at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person. Such requests must be submitted within 30 days of this notice.

Technical Evaluation
and
Preliminary Determination

Polk Power Partners
Cogeneration/CO_2 Recovery Project
Polk County, Florida

Permit No. AC 53-211670
PSD-FL-187

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

September 22, 1992

I. Application Information

A. Applicant

Polk Power Partners
23293 South Pointe Drive
Laguna Hills, Florida 92653

B. Request

The applicant submitted an application on April 6, 1992, for a permit to construct a 126 megawatt (MW) combined cycle cogeneration/CO_2 recovery facility near Bartow, Florida. The Department received incompleteness items which made the application complete on July 9, 1992. However, on August 14, 1992, the applicant submitted a letter proposing new NO_x emission limits. This had the effect of moving up the completion date to August 14, 1992.

C. Classification/Location

The proposed facility (SIC Codes 4911 and 2813) will be located on County Road 555 approximately 3.7 miles southwest of Bartow, Polk County, Florida. Latitude and longitude are 27°50'56"N and 81°52'38.9"W, respectively. The UTM coordinates of the site are: Zone 17, 413.6 km E and 3,080.6 km N.

II. Project Description/Emissions

The applicant proposes to construct a 126 MW combined cycle cogeneration power plant along with a 150 ton per day carbon dioxide (CO_2) plant that will recover CO_2 from the power plant flue gas. Cogeneration equipment will include a General Electric combustion turbine (CT), a non-auxiliary fired primary and an auxiliary-fired secondary heat recovery steam generator (HRSG), and a steam turbine generator. CO_2 plant equipment consists of two identical 75 TPD recovery units, each including a CO_2 absorber using monoethanclamine (MEA) solvent, MEA stripper, potassium permanganate ($KMnO_4$) scrubber, carbon adsorption tower, CO_2 compression and refrigeration equipment.

The permanent fuel for the power plant will be natural gas, although the plant will not have a firm contact for natural gas until the fourth year of operation. During the first three years, natural gas will provide a minimum of 22% of fuel requirements with the balance supplied by distillate fuel oil. About two-thirds of the facility's power output will come from the gas turbine generator. Steam from the primary and secondary HRSG will drive a steam turbine to generate the other third of the power output.

Combustion gases from the turbine will be routed to the primary HRSG which provides steam for additional power generation. Part of the turbine exhaust will go to the secondary HRSG to be burned with natural gas forming CO_2-rich feed gas for the CO_2 recovery plant.

The CO_2-enriched flue gas is compressed and scrubbed with MEA solvent to absorb most of the CO_2. MEA is then stripped off the absorbed CO_2 in a steam-heated reboiler with the CO_2 being released through the stripper tower overhead. Purification of the stripped CO_2 is accomplished by scrubbing first with recirculating $KMnO_4$ to remove remaining MEA, then with water to remove soluble impurities. Activated carbon provides the final purification step. The purified CO_2 is compressed, cooled and dried before being liquified in an ammonia refrigeration system. Final products include liquid, solid and gaseous CO_2.

Emission estimates below are based on the initial three-year operation using a 22% gas/78% oil fuel mix followed by natural gas as the permanent fuel. Annual estimates are based on full load operation at 59°F and 0.1% sulfur content of the fuel oil.

	Projected Emissions (TPY)					
	First 3 yrs (22% Gas/78% Oil)(1)			After First 3 yrs (100% Gas)(2)		
	HRSG Stack	CO_2 Plant Stack	Total	HRSG Stack	CO_2 Plant Stack	Total
NO_x	644.8	99.1	743.9	230.7	80.0	310.7
SO_2	327.4	16.4	343.8	11.4	1.8	13.2
PM/PM_{10}	58.0	28.9	86.9	30.7	27.7	58.4
CO	298.6	57.1	355.7	187.8	52.0	239.8
VOC	37.7	79.3	117.0	28.2	78.8	107.0
H_2SO_4	26.4	1.3	27.7	0.9	0.1	1.0
Be	.008	--	.008	--	--	--
As	.013	--	.013	--	--	--

(1) Based on 25 ppm NO_x (gas) and 42 ppm NO_x (oil).
(2) Based on 15 ppm NO_x (gas).

III. Rule Applicability

The construction permit application is subject to review under Chapter 403, Florida Statutes, and Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4. The proposed facility is subject to the provisions of F.A.C. Rule 17-2.500, Prevention of Significant Deterioration (PSD). The facility is located in an area classified as attainment for all regulated air pollutants. The proposed emissions exceed the significant levels set forth in Table 500-2 of F.A.C. Rule 17-2.500. Preconstruction review must include a determination of Best Available Control Technology (BACT), good-engineering practice stack height, ambient impact

analysis, impact on soils, vegetation and visibility. Applicable emission limit rules are F.A.C. Rules 17-2.660, Table 660-1, Section 60.330, New Source Performance Standards (NSPS) for Stationary Gas Turbines, Subpart GG, and F.A.C. Rule 17-2.600(b), Fossil Fuel Steam Generators with Less than 250 Million Btu per Hour Heat Input. Contrary to the applicant's analysis, the emission limits under Subpart Dc of the federal NSPS do not apply to the duct burner since this rule requires only recordkeeping and reporting for natural gas applications. BACT limits will be based on the turbine manufacturer's performance guarantees since they are more stringent than the NSPS limits.

IV. Air Quality Analysis

a. Introduction

The operation of the proposed facility will result in emissions increases which are projected to be greater than the PSD significant emission rates for the following pollutants: NO_X, SO_2, PM, PM_{10}, Be, CO, VOC, inorganic arsenic, and H_2SO_4 mist. Therefore, the project is subject to the PSD NSR requirements contained in F.A.C. Rule 17-2.500(5) for these pollutants. Part of these requirements is an air quality impact analysis for these pollutants, which includes:

- An analysis of existing air quality;
- A PSD increment analysis (for SO_2, PM, PM_{10}, and NO_2);
- An ambient Air Quality Standards analysis (AAQS);
- An analysis of impacts on soils, vegetation, visibility a growth-related air quality impacts; and,
- A Good Engineering Practice (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The PSD increment and AAQS analyses are based on air quality dispersion modeling completed in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the proposed project, 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. A brief description of the modeling methods used and results of the required analyses follow. A more complete description is contained in the permit application on file.

b. Analysis of the Existing Air Quality

Preconstruction ambient air quality monitoring may be required for pollutants subject to PSD review. However, an exemption to the monitoring requirement can be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined through air quality modeling, is less than a pollutant-specific de minimus concentration. The predicted maximum concentration increase for each pollutant subject to PSD (NSR) is given below:

	SO_2	TSP & PM_{10}	NO_2	CO	Be
PSD de minimus Concentra. (ug/m^3)	13	10	14	575	.001
Averaging Time	24-hr	24-hr	Annual	8-hr	24-hr
Maximum Predicted Impact (ug/m^3)	15.5	2.8	0.85	23.6	0.00038

There are no monitoring de minumus concentrations for H_2SO_4 mist and inorganic arsenic. Preconstruction monitoring may be required for ozone concentrations when the maximum potential VOC emissions from a proposed source are projected to be greater than 100 tons per year. The applicant projected emissions from VOCs to be greater than 100 tons per year based on 100% fuel oil firing. The Department is limiting VOC emissions to 79.6 TPY; therefore, no preconstruction monitoring is required. As shown above, the predicted impacts for TSP/PM_{10}, NO_2, CO, and Be are all less than the corresponding de minimus concentrations; therefore, no preconstruction monitoring is required for these pollutants. However, since the predicted SO_2 impact is greater than the de minimus concentration, a preconstruction ambient monitoring analysis is required for SO_2. The Department determined that the use of existing FDER air quality monitoring data collected in 1991 from the Mulberry SO_2 monitoring site in Polk County would be appropriate to satisfy the ambient monitoring analysis requirement. Background SO_2 values of 176 ug/m^3, 3-hr average; 40 ug/m^3, 24-hr average; and 12 ug/m^3, annual average, were based on these data. This site is located 9.7 km away from the project.

c. Modeling Method

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used by the applicant to predict the impact of the proposed project on the surrounding ambient air. All recommended EPA default options were used. Downwash parameters were used because the stacks were less than the good engineering practice (GEP) stack height. Five years of sequential hourly surface and mixing depth data from the Tampa, Florida National

Weather Service (NWS) station collected during 1982 through 1986 were used in the model. Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations are compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards.

d. Modeling Results

The applicant first evaluated the potential increase in ambient ground-level concentrations associated with the project to determine if these predicted ambient concentration increases would be greater than specified PSD significant impact levels for SO_2, CO, NO_x, PM and PM_{10}. This evaluation was based on the proposed facility operating at maximum load conditions and 20°F and 100°F design temperatures. Maximum load conditions along with these two design temperatures were used because the highest emissions and flow rate occur at the 20°F design condition while the lowest emissions and flow rate occur at the 100°F design condition. This approach ensured that the maximum impacts from the proposed facility were obtained either for the maximum emission condition or minimum flow rate condition. The applicant modeled emissions based on the use of fuel oil with a maximum sulfur content of 0.1%. Dispersion modeling was performed with receptors placed along the 36 standard radial directions (10 degrees apart) surrounding the proposed units at the following downwind distances: (1) the first 36 receptors were located at the plant property boundaries; (2) subsequent receptors were located at distances of 0.3, 0.5, 0.7, 1.0, 1.5, 2.0, 3.0, 4.0 and 5.0 km from the facility, all of which are off plant property. The results of this modeling presented below show that the increases in ambient ground-level concentrations for all averaging times are less than the PSD significant impact levels for CO, NO_x, PM and PM_{10}.

	SO_2			NO_2	CO		PM and PM_{10}	
Avg. Time	Annual	3-hr	24-hr	Annual	1-hr	8-hr	Ann.	24-hr
PSD Signifi. Level (ug/m^3)	1.0	25.0	5.0	1.0	2000	800	1.0	5.0
Ambient Concen. Increase (ug/m^3)	0.3	42.5	15.5	0.9	58.9	23.6	0.2	2.8

Therefore, further dispersion modeling for comparison with AAQS and PSD increment consumption were not required for CO, NOx, PM and PM_{10}. However, the results also show that the increases in maximum ambient ground level concentrations for the 3-hr and 24-hr averaging times for SO_2 were greater than the PSD significant impact levels, thus requiring the applicant to do a full impact analysis for SO_2. The significant impact area for the facility was determined to be 0.7 km; therefore, all sources within 51 km of the

facility were evaluated by the applicant. Screening analyses were performed to predict maximum SO_2 concentrations for comparison to the PSD Class II increments and the AAQS using the same receptor grid described above. Refined AAQS and PSD Class II analyses were based on modeling the years during which the overall HSH 3-hour and HSH 24-hour concentrations were predicted in the screening analyses. The refined 3-hr and 24-hr modeling was conducted using a receptor grid centered on the receptor which had the HSH 3-hr or 24-hr concentration determined from the screening analysis. These receptors were located at intervals of 200m between the distances considered in the screening phase, along 9 radials spaced at 2-degree increments centered on the radial along which the maximum concentration was predicted. The results of these analyses for SO_2 and their comparison with the appropriate standards and increments are summarized in the following tables. The tables show that the maximum predicted SO_2 concentrations are all less than the appropriate AAQS and PSD increments.

AAQS Analysis (all values in ug/m^3)

Avg. Time	Annual	3-hr	24-hr
Maximum Predicted Concentration	42	837	234
Includes Background Value	12	176	40
AAQS	60	1300	260

Cumulative PSD Class II
Increment Analysis (all values in ug/m^3)

Avg. Time	Annual	3-hr	24-hr
Max. Predicted Consumption Concen.	-0.42	139	39
Increment	20	512	91

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area located 120 km from the facility. The predicted impact of the proposed project on this area was evaluated by first using the ISCST model to predict maximum increment consumptions by the source alone and by comparing these predicted values to the appropriate recommended significance levels to determine whether further modeling was necessary. The significance levels used by the Department were the more stringent National Park Service (NPS) recommended levels. The predicted maximum PM/PM_{10} and NO_2 increment consumptions for all applicable averaging times were less

than these significance levels. Therefore, no further modeling for PM/PM_{10} and NO_2 was required. In addition, the predicted maximum SO_2 annual average increment consumption by the source alone was also below the NPS significance level. However, the predicted maximum SO_2 24-hour and 3-hour concentrations were predicted to be greater than the NPS levels. The Department and the NPS directed the applicant to further evaluate the SO_2 short term impacts on the Class I area. The applicant used ISCST and modeled the inventory of all PSD increment consuming and expanding sources using 1982-1986 Tampa meteorological data. The applicant also modeled the proposed facility's impacts during this time period and compared the results to the NPS significance levels. Results of this evaluation show that on the days and at the location of significant impacts due to the proposed facility, total 3-hour and 24-hour SO_2 impacts at Chassahowitzka were predicted to be less than the allowable 3-hour and 24-hour PSD Class I increments except for one case. In that case, the total 24-hour concentration was predicted to be 5.22 ug/m^3 with the proposed source contributing 0.09 ug/m^3. The allowable 24-hour Class I increment is 5.0 ug/m^3 and the NPS significance level is 0.07 ug/m^3. However, the NPS has stated by verbal communication that they do not expect the proposed facility to adversely impact the Class I area since the maximum predicted impacts were based on the use of fuel oil and the applicant is committed to using and will be limited by the Department to using natural gas as the permanent fuel after the first three years.

Sulfuric acid mist, beryllium and inorganic arsenic are noncriteria pollutants, which means that neither national AAQS nor PSD Significant Impacts have been defined for these pollutants. However, the Department does have a draft Air Toxics Permitting Strategy, which defines no threat levels for these pollutants. The Department and the applicant have used the same modeling procedure described above for the screening analysis to evaluate the maximum increase in ground level concentration of these pollutants for comparison with the no-threat levels. The results of this analysis are shown below:

Avg. Time	H_2SO_4 Mist 24-hr	Be Annual	As Annual
No Threat-Level (ug/m^3)	2.38	0.00042	0.00023
Max. Concen. Increase	1.24	0.00001	0.00001

All of these values are less than their respective no-threat levels.

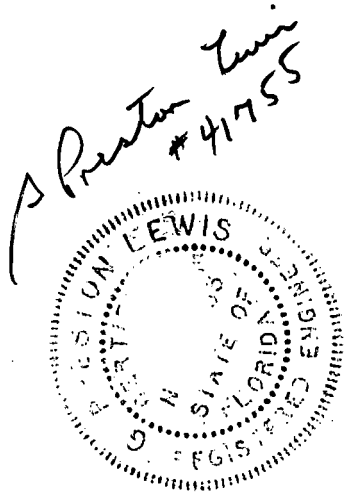
e. Additional Impacts Analysis

A Level-1 screening analysis using the EPA model, VISCREEN was used to determine any potential adverse visibility impacts on the Class I Chassahowitzka National Wilderness Area located about 120 km away. Based on this analysis, the maximum predicted visual impacts due to the proposed project are less than the screening criteria both inside and outside the Class I area. A comprehensive air quality related values (AQRV) analysis for this Class I area was performed by the applicant.

In addition, the maximum predicted concentrations from NOx, CO, SO_2, PM and PM_{10} are predicted to be less than the AAQS, including the national secondary standards designed to protect public welfare-related values. As such, no harmful effects on soil and vegetation are expected in the area of the project. Also, the proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

VI. Conclusion

Based on the information provided by Polk Power Partners, L.P., the Department has reasonable assurance that the proposed installation, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapter 17-2 of the Florida Administrative Code.



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:
Polk Power Partners, L.P.
23293 South Pointe Drive
Laguna Hills, CA 92653

Permit Number: AC 53-211670
PSD-FL-187
Expiration Date: December 31, 1994
County: Polk
Latitude/Longitude: 27°50'56"N
81°52'39"W
Project: Mulberry 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 construction of a 126 Megawatt cogeneration unit along with a 150 ton per day CO_2 recovery plant. The facility will be located off County Road 555 approximately 3.7 miles southwest of Bartow in Polk County, Florida. UTM coordinates of the site are: Zone 17, 413.6 km E and 3080.6 km N.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be controlled by proper combustion techniques. NO_X emissions shall be initially controlled by water injection and Low NO_X Burners. Future control technology for NOx (SCR) will depend on whether the Low NO_X Burners can achieve the levels specified by this permit.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. DER letter dated May 5, 1992.
2. KBN letter dated April 15, 1992.
3. KBN letter dated June 2, 1992.
4. EPA letter dated July 1, 1992.
5. KBN submittal dated July 8, 1992.
6. KBN letter dated July 29, 1992.
7. KBN letter dated August 12, 1992.
8. DER letter dated August 13, 1992.
9. KBN letter dated August 26, 1992.

Printed with Soy Based Inks

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 prescribed 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.

GENERAL CONDITIONS:

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

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;

GENERAL CONDITIONS:

- 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.

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. Unless otherwise indicated, the construction and operation of the subject facilities shall be in accordance with the capacities and specifications stated in the application.

2. Emissions from these facilities shall not exceed the limits listed below (based on operation at 59°F):

Pollutant	Source	Fuel	1st Three Years lbs/hr	1st Three Years tons/yr	After 1st Three Years** lbs/hr	After 1st Three Years** tons/yr
NOx	HRSG Stack	Gas	87.8	384.5	52.7	230.7
	CO_2 Plant Stack	Gas	19.9	87.1	18.3	80.0
	HRSG Stack	Oil	164.0	718.2	--	--
	CO_2 Plant Stack	Oil	23.4	102.4	--	--
SO2	HRSG Stack	Oil	0.1% Sulfur Max.		--	--
	CO_2 Plant Stack	Oil	0.1% Sulfur Max.		--	--
VE	HRSG Stack	Gas	10% Opacity*		10% Opacity*	
	CO_2 Plant Stack	Gas	10% Opacity*		10% Opacity*	
	HRSG Stack	Oil	20% Opacity*		--	
	CO_2 Plant Stack	Oil	20% Opacity*		--	
VOC	CO_2 Plant Stack	--	18.2	79.6	17.7	77.6
CO	HRSG Stack	Gas	42.9	187.8	42.9	187.8
	CO_2 Plant Stack	Gas	11.9	52.0	11.9	52.0
	HRSG Stack	Oil	75.3	329.9	75.3	329.9
	CO_2 Plant Stack	Oil	13.4	58.5	13.4	58.5

*Except for one 6-minute period per hour of not more than 27% opacity.
**Based on 15 ppmvd NO_x.

SPECIFIC CONDITIONS:

3. The cogeneration facility shall be permitted to fire natural gas permanently and No. 2 fuel oil for the first three years of operation. Fuel consumption rates and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr	MM ft3/yr	hrs/yr	M lb/hr	M lb/yr	hrs/yr
Turbine	914.5	8011.0	8760	55.6	372.6	6701
Duct Burner	104.2	912.8	8760	0	0	0

4. Before this construction permit expires, the cogeneration facility and CO_2 Recovery Plant stacks shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96% to 100% of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_X: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10
VOC: EPA Method 25A

5. The DER Southwest District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the DER Southwest District office in Tampa and the DER Bureau of Air Regulation office in Tallahassee (third annual compliance test only) within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and water injection flows to the cogeneration turbine along with the power output of the generators shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DER upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions

SPECIFIC CONDITIONS:

necessary for future installation of state-of-the-art catalytic abatement or equivalent NOx control systems. Within 90 days of receipt of the third annual compliance test results, the Bureau of Air Regulation shall, if NO_x emission limits are not met, review the need for making a revised determination of Best Available Control Technology. If test results show that it is unlikely that NO_x limits can be met, a revised BACT determination shall be made. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. The retrofit costs associated with not making provisions for such technology initially shall not be considered by the Department in the retrofit cost analysis.

8. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

9. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this _____ day
of _____, 1992

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

_____
Carol M. Browner, Secretary

Best Available Control Technology (BACT) Determination
Mulberry Cogeneration Project
Polk County

The applicant proposes to install a 126 MW combined cycle cogeneration unit along with a 150 TPD carbon dioxide plant that will recover CO_2 from the power plant flue gas. The Polk County facility will consist of a General Electric PG7111EA Gas Turbine Generator exhausting through a primary heat recovery steam generator which will produce steam for the steam-electric cycle. Initially, the turbine will be fired by natural gas and No. 2 fuel oil, with natural gas becoming the permanent fuel after the first three years of operation. A secondary heat recovery steam generator will be auxiliary-fired by natural gas to provide a CO_2-enriched flue gas feed to the CO_2 recovery plant.

Date of Receipt of a Complete Application

August 14, 1992

BACT Determination Requested by Applicant

NO_x - Dry Low NO_x Combustion
CO - Combustion Design
H_2SO_4/SO_2 - Low Sulfur Fuel Oil (0.1%S)
VOC - Combustion Design for CT
Scrubber for CO_2 Absorber Exhaust
PM/PM_{10} - Combustion Design/Clean Fuel

BACT Determination by the Department

NO_x - Dry Low NO_x Combustion with future SCR capability
CO - Combustion Design
H_2SO_4/SO_2 - Low Sulfur Fuel Oil (0.1%S)
VOC - Combustion Design for CT
Scrubber for CO_2 Absorber Exhaust
PM/PM_{10} - Combustion Design/Clean Fuel

Proposed Emission Limits (tons per year)

	First 3 yrs (22% Gas/78% Oil)			After First 3 yrs (100% Gas)			PSD
	HRSG	CO_2 Plant	Total	HRSG	CO_2 Plant	Total	
NO_x	644.8	99.1	743.9	230.7	80.0	310.7	40.0
SO_2	327.4	16.4	343.8	11.4	1.8	13.2	40.0
PM/PM_{10}	58.0	28.9	86.9	30.7	27.7	58.4	25/15
CO	298.6	57.1	355.7	187.8	52.0	239.8	100.0
VOC	37.7	79.3	117.0	28.2	78.8	107.0	40.0
H_2SO_4	26.4	1.3	27.7	0.9	0.1	1.0	7.0
Be	.008	--	.008	--	--	--	0.0004
As	.013	--	.013	--	--	--	0.0

These limits assume that 4.6% of the turbine exhaust mass flow is diverted to the CO_2 plant. Emissions for the first three years are based on firing 22% gas - 78% oil in the turbine for 8,760 hours/yr at 1016 MMBtu/hr and natural gas in the duct burner for 8,760 hours/yr at 99 MMBtu/hr. Emissions after the first three years are based on firing only natural gas at 868.8 MMBtu/hr. Turbine performance under natural gas firing is based on NO_x emissions of 25 ppm (corrected to 15 percent O_2) for the first three years and 15 ppm thereafter. Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O_2). SO_2 emissions are based on 0.1 percent sulfur.

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, than 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.

BACT Determination Rationale

Particulate Matter (PM/PM_{10})

Particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not cause visible emissions to exceed 10% and 20% opacity, respectively.

Arsenic and Berylium (As, Be)

The Department agrees that there are no feasible methods to control beryllium and arsenic except by specifying the quality of the fuel.

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The majority of BACT emissions limitations have been based on controlling carbon monoxide and volatile organic compounds through efficient combustion. Advanced control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalyst systems are not considered to be technically feasible for gas turbines fired with fuel oil. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for a natural gas-fired unit; however, the cost effectiveness of over $6,000 per ton of CO removed will have a significant economic impact on this project. Therefore, efficient combustion will be the control method for CO and VOC.

Nitrogen Oxides (NO_X)

The applicant requested that BACT for nitrogen oxides during the first three years be water injection and Low NO_X Burners. This would limit emissions to 25 ppmvd when burning natural gas and 42 ppmvd when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_X emission limit established to date for a combustion turbine is 4.5 ppmvd (corrected to 15% O_2). This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_X emissions. The SCR process combines vaporized ammonia with NO_X in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_X with a new catalyst. As the catalyst ages, the maximum NO_X reduction will decrease to approximately 86 percent.

Although feasible, the applicant rejected using SCR because of economic, energy, and environmental impacts. The following factors were considered in the decision not to propose SCR:

a) Disposal of hazardous waste generated (spend catalyst).
b) An energy penalty of $0.05/KWH due to back pressure from the catalyst bed.
c) A power loss penalty based on lost capacity.
d) Potential for public exposure to high concentrations from ammonia storage and handling leaks and ammonia slip.
e) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
f) Cost effectiveness for SCR technology was determined to be in the range of $6,000 per ton of NO_X removed.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate which can be formed by reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. The latest information available indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_X injection ratio. For natural gas firing, NO_X emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_X can be controlled with efficiencies ranging from 60 to 75 percent. When the injection

ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. SCR has been established as BACT for oil fired combined cycle facilities with NO_X emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control.

The applicant determined that the total annual cost of SCR for this project is $1,957,700 with an average cost effectiveness in the range of $6,000 to $7,000 per ton of NO_X removed. The maximum annual NO_X emissions using water injection and Low NO_X combustor design will be 744 tons/year for the first three years. Assuming that SCR would reduce the NO_X emissions by 65%, about 484 tons/year of NO_X would be removed initially followed by 200 tons/year thereafter. When this reduction is factored into the total annual cost, the cost per ton of controlling NO_X is in the range of $6,000 to $6,500. This calculated cost is higher than has previously been approved as BACT.

The latest DER BACT determinations have a NO_X limit of 15 ppmvd (natural gas) using Low-NO_X burner technology. Although the turbine manufacturer does not presently guarantee this limit, they have agreed to lower NO_X to 15 ppm by 4/30/97. This lower NO_X limit will be achieved by application of low-NO_X burners or SCR. Therefore, the Department accepts water injection and Low NO_X Burner design as BACT for a limited time (up to 4/30/97).

The calculations that the applicant presented and Department findings indicate that the cost of controlling NO_X is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_X control is not justifiable as BACT at this time.

The Department will revise and lower the allowable BACT limit for this project no later than 4/30/97. It is the Department's understanding that the turbine manufacturer will be able to achieve 15 ppmvd NO_X emission limits within this period. If the 15 (gas)/42 (oil) ppmvd emission rates cannot be met by April 30, 1997, SCR will be installed.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

In accordance with "top down" BACT review, only two alternatives exist that would result in stringent SO_2 emissions; using low sulfur content fuel oil or flue gas desulfurization (FGD). EPA has recognized that FGD technology is inappropriate to apply to these combustion units due to negative environmental, economic and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and

water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

This leaves the use of low sulfur fuel oil as the best option. The Department accepts the use of No. 2 fuel oil with a 0.1% sulfur by weight as BACT for this project.

Details of the Analysis May be Obtained by Contacting:

Preston Lewis, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

Date 1992

Approved by:

Carol M. Browner, Secretary
Dept. of Environmental Regulation

Date 1992

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:
Polk Power Partners, L.P.
23293 South Pointe Drive
Laguna Hills, CA 92653

Permit Number: AC 53-211670
PSD-FL-187
Expiration Date: December 31, 1994
County: Polk
Latitude/Longitude: 27°50'56"N
81°52'39"W
Project: Mulberry 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 construction of a 126 Megawatt cogeneration unit along with a 150 ton per day CO_2 recovery plant. The facility will be located off County Road 555 approximately 3.7 miles southwest of Bartow in Polk County, Florida. UTM coordinates of the site are: Zone 17, 413.6 km E and 3080.6 km N.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be controlled by proper combustion techniques. NO_X emissions shall be initially controlled by water injection and Low NO_X Burners. Future control technology for NOx (SCR) will depend on whether the Low NO_X Burners can achieve the levels specified by this permit.

The source shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. DER letter dated May 5, 1992.
2. KBN letter dated April 15, 1992.
3. KBN letter dated June 2, 1992.
4. EPA letter dated July 1, 1992.
5. KBN submittal dated July 8, 1992.
6. KBN letter dated July 29, 1992.
7. KBN letter dated August 12, 1992.
8. DER letter dated August 13, 1992.
9. KBN letter dated August 26, 1992.

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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 prescribed 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.

GENERAL CONDITIONS:

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

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;

GENERAL CONDITIONS:

- 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.

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. Unless otherwise indicated, the construction and operation of the subject facilities shall be in accordance with the capacities and specifications stated in the application.

2. Emissions from these facilities shall not exceed the limits listed below (based on operation at 59°F):

Pollutant	Source	Fuel	1st Three Years		After 1st Three Years**	
			lbs/hr	tons/yr	lbs/hr	tons/yr
NOx	HRSG Stack	Gas	87.8	384.5	52.7	230.7
	CO_2 Plant Stack	Gas	19.9	87.1	18.3	80.0
	HRSG Stack	Oil	164.0	718.2	--	--
	CO_2 Plant Stack	Oil	23.4	102.4	--	--
SO2	HRSG Stack	Oil	0.1% Sulfur Max.		--	--
	CO_2 Plant Stack	Oil	0.1% Sulfur Max.		--	--
VE	HRSG Stack	Gas	10% Opacity*		10% Opacity*	
	CO_2 Plant Stack	Gas	10% Opacity*		10% Opacity*	
	HRSG Stack	Oil	20% Opacity*		--	
	CO_2 Plant Stack	Oil	20% Opacity*		--	
VOC	CO_2 Plant Stack	--	18.2	79.6	17.7	77.6
CO	HRSG Stack	Gas	42.9	187.8	42.9	187.8
	CO_2 Plant Stack	Gas	11.9	52.0	11.9	52.0
	HRSG Stack	Oil	75.3	329.9	75.3	329.9
	CO_2 Plant Stack	Oil	13.4	58.5	13.4	58.5

*Except for one 6-minute period per hour of not more than 27% opacity.
**Based on 15 ppmvd NO_x.

SPECIFIC CONDITIONS:

3. The cogeneration facility shall be permitted to fire natural gas permanently and No. 2 fuel oil for the first three years of operation. Fuel consumption rates and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr	MM ft3/yr	hrs/yr	M lb/hr	M lb/yr	hrs/yr
Turbine	914.5	8011.0	8760	55.6	372.6	6701
Duct Burner	104.2	912.8	8760	0	0	0

4. Before this construction permit expires, the cogeneration facility and CO_2 Recovery Plant stacks shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96% to 100% of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_x: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10
VOC: EPA Method 25A

5. The DER Southwest District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the DER Southwest District office in Tampa and the DER Bureau of Air Regulation office in Tallahassee (third annual compliance test only) within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and water injection flows to the cogeneration turbine along with the power output of the generators shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DER upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions

SPECIFIC CONDITIONS:

necessary for future installation of state-of-the-art catalytic abatement or equivalent NOx control systems. Within 90 days of receipt of the third annual compliance test results, the Bureau of Air Regulation shall, if NO_x emission limits are not met, review the need for making a revised determination of Best Available Control Technology. If test results show that it is unlikely that NO_x limits can be met, a revised BACT determination shall be made. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. The retrofit costs associated with not making provisions for such technology initially shall not be considered by the Department in the retrofit cost analysis.

8. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

9. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this _____ day
of _____, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

_____
Carol M. Browner, Secretary

Best Available Control Technology (BACT) Determination
Mulberry Cogeneration Project
Polk County

The applicant proposes to install a 126 MW combined cycle cogeneration unit along with a 150 TPD carbon dioxide plant that will recover CO_2 from the power plant flue gas. The Polk County facility will consist of a General Electric PG7111EA Gas Turbine Generator exhausting through a primary heat recovery steam generator which will produce steam for the steam-electric cycle. Initially, the turbine will be fired by natural gas and No. 2 fuel oil, with natural gas becoming the permanent fuel after the first three years of operation. A secondary heat recovery steam generator will be auxiliary-fired by natural gas to provide a CO_2-enriched flue gas feed to the CO_2 recovery plant.

Date of Receipt of a Complete Application

August 14, 1992

BACT Determination Requested by Applicant

NO_x - Dry Low NO_x Combustion
CO - Combustion Design
H_2SO_4/SO_2 - Low Sulfur Fuel Oil (0.1%S)
VOC - Combustion Design for CT
Scrubber for CO_2 Absorber Exhaust
PM/PM_{10} - Combustion Design/Clean Fuel

BACT Determination by the Department

NO_x - Dry Low NO_x Combustion with future SCR capability
CO - Combustion Design
H_2SO_4/SO_2 - Low Sulfur Fuel Oil (0.1%S)
VOC - Combustion Design for CT
Scrubber for CO_2 Absorber Exhaust
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Proposed Emission Limits (tons per year)

	First 3 yrs (22% Gas/78% Oil)			After First 3 yrs (100% Gas)			PSD
	HRSG	CO_2 Plant	Total	HRSG	CO_2 Plant	Total	
NO_x	644.8	99.1	743.9	230.7	80.0	310.7	40.0
SO_2	327.4	16.4	343.8	11.4	1.8	13.2	40.0
PM/PM_{10}	58.0	28.9	86.9	30.7	27.7	58.4	25/15
CO	298.6	57.1	355.7	187.8	52.0	239.8	100.0
VOC	37.7	79.3	117.0	28.2	78.8	107.0	40.0
H_2SO_4	26.4	1.3	27.7	0.9	0.1	1.0	7.0
Be	.008	--	.008	--	--	--	0.0004
As	.013	--	.013	--	--	--	0.0

These limits assume that 4.6% of the turbine exhaust mass flow is diverted to the CO_2 plant. Emissions for the first three years are based on firing 22% gas - 78% oil in the turbine for 8,760 hours/yr at 1016 MMBtu/hr and natural gas in the duct burner for 8,760 hours/yr at 99 MMBtu/hr. Emissions after the first three years are based on firing only natural gas at 868.8 MMBtu/hr. Turbine performance under natural gas firing is based on NO_x emissions of 25 ppm (corrected to 15 percent O_2) for the first three years and 15 ppm thereafter. Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O_2). SO_2 emissions are based on 0.1 percent sulfur.

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, than 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.

BACT Determination Rationale

Particulate Matter (PM/PM_{10})

Particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not cause visible emissions to exceed 10% and 20% opacity, respectively.

Arsenic and Berylium (As, Be)

The Department agrees that there are no feasible methods to control beryllium and arsenic except by specifying the quality of the fuel.

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The majority of BACT emissions limitations have been based on controlling carbon monoxide and volatile organic compounds through efficient combustion. Advanced control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions).

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ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. SCR has been established as BACT for oil fired combined cycle facilities with NO_X emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control.

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The Department will revise and lower the allowable BACT limit for this project no later than 4/30/97. It is the Department's understanding that the turbine manufacturer will be able to achieve 15 ppmvd NO_X emission limits within this period. If the 15 (gas)/42 (oil) ppmvd emission rates cannot be met by April 30, 1997, SCR will be installed.

Sulfur Dioxide(SO_2) and Sulfuric Acid Mist (H_2SO_4)

In accordance with "top down" BACT review, only two alternatives exist that would result in stringent SO_2 emissions; using low sulfur content fuel oil or flue gas desulfurization (FGD). EPA has recognized that FGD technology is inappropriate to apply to these combustion units due to negative environmental, economic and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and

water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

This leaves the use of low sulfur fuel oil as the best option. The Department accepts the use of No. 2 fuel oil with a 0.1% sulfur by weight as BACT for this project.

Details of the Analysis May be Obtained by Contacting:

Preston Lewis, BACT Coordinator
Department of Environmental Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

_____ 1992
Date

Approved by:

Carol M. Browner, Secretary
Dept. of Environmental Regulation

_____ 1992
Date

KBN

August 12, 1992

RECEIVED

AUG 14 1992

Bureau of
Air Regulation

Mr. John Reynolds
Bureau of Air Regulation
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Mulberry Cogeneration Project

Dear John:

The developers of the Mulberry Cogeneration Project and I appreciate the time you spent last week concerning the dry low-nitrogen oxide (NO_x) combustion technology being developed by General Electric (GE). As discussed, the developers of the project and GE have reviewed the development schedule for this technology and have reached agreement to offer lower NO_x emissions for the Department's consideration. In addition, as suggested by Preston Lewis, the proposed permit for the Auburndale Power Partners project was reviewed. Elements of this permit are directly applicable to the Mulberry Project and should be of assistance in drafting the permit for our project. Based on these efforts, I am transmitting on behalf of the project developers of the Mulberry Cogeneration Project the following emission and fuel limiting standards for your consideration. These proposed limitations are applicable as best available control technology (BACT) and are consistent with those proposed for the Auburndale Project.

1. First 3 Years of Operation: The full load equivalent capacity factor on fuel oil will be no more than 78 percent; the capacity factor for natural gas will be 22 percent. The NO_x emission limits will be limited to no more than 25 parts per million by volume dry (ppmvd) (corrected to 15 percent oxygen) when firing natural gas and 42 ppmvd (corrected) when firing fuel oil.

2. After the First 3 Years of Operation: The emissions limits for NO_x will not exceed 15 ppmvd (corrected) when firing natural gas and 42 ppmvd (corrected) when firing fuel oil. Natural gas will be used as the primary fuel when available from the Florida Gas Transmission Phase III pipeline expansion. When available from the expansion, fuel oil would be limited to no more than 30 days of full load operation per year, and the NO_x emissions would not exceed 42 ppmvd (corrected). The limit for natural gas firing (i.e., 15 ppmvd corrected to 15 percent O_2) would apply no later than April 30, 1997.

Please be advised that our discussion of higher heat input for the secondary heat recovery steam generator (HRSG) has been evaluated, and it has been concluded that an increase will not be requested. Therefore, the heat input as proposed in the application of 99 million British thermal units per hour (MMBtu/hr) will not change.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

KBN

As we discussed at the meeting, the timing of receipt of the proposed permit is not only important to the project developers but to the State of Florida. This project has been approved by the Public Service Commission, and power from this facility is needed to meet future power requirements in the state. The proposed permit for the Auburndale project should be helpful in drafting the proposed permit for our project. Your expeditious issuance of the proposed permit would be greatly appreciated.

If you have any questions please call me or Ward Marshall of Central & Southwest Services (214) 754-1374.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

KFK/abb

cc: William Malenius
File (2)
C. Holladay
B. Thomas, SW Dist
J. Harper, EPA
C. Shaver, NPS
CHP/PL

91193A1/11

August 12, 1992

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

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Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

KFK/abb

cc: William Malenius
File (2)

91193A1/11

Best Available Copy

KBN

FACSIMILE COVERSHEET

DATE: 08/12/92

TO: Toba Reynolds

ORGANIZATION: FDEP - Air

FAX NUMBER: 904-922-6979 TELEPHONE NUMBER: 904-488-1344

FROM: Ken Kosky

TOTAL NUMBER OF PAGES: 3 (including cover page)

MESSAGE/INSTRUCTIONS:

PROJECT NUMBER: 9193-0100 FAX OPERATOR: _____

( ) This is the ONLY form of delivery of the transmitted document.

(✓) The original of the transmitted document will be sent by:

(✓) US Mail
( ) Overnight delivery
( ) Other: _____

Return original to KK

cc: Project File ✓ yes _____ no

KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street, Gainesville, FL 32605
Phone (904) 331-9900 FAX (904) 332-6189

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

4APT-AEB

JUL 11 1992

RECEIVED

JUL 08 1992

Division of Air Resources Management

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: Polk Power Partners,
Mulberry Cogeneration Project (PSD-FL-187)

Dear Mr. Fancy:

This is to acknowledge receipt of the Prevention of Significant Deterioration (PSD) permit application and additional information packages for the above referenced facility. The proposed facility will be an integrated cogeneration facility, producing approximately 120,000 kilowatts net power to the transmission system and approximately 150 tons per day of liquid CO_2. The project consists of one General Electric PG 7111EA combustion turbine, with a primary heat recovery steam generator (HRSG), a secondary HRSG, and a steam turbine generator.

The applicant proposes to limit NO_x emissions from the combustion turbine through water injection and dry low-NO_x combustion technology, to limit NO_x emissions from the duct burner through combustion control, to limit SO_2 and H_2SO_4 Mist emissions from the combustion turbine through limiting the sulfur content of the No. 2 distillate fuel oil, to limit CO emissions from the combustion turbine and duct burner through combustion control, to limit VOC emissions through combustion control for the combustion turbine and through a scrubber for CO_2 absorber exhausts, and to limit PM/PM_{10}, Be, and As emissions from the combustion turbine through combustion control and the use of clean fuels.

Printed on Recycled Paper

We have reviewed the package as submitted and have no adverse comments. Thank you for the opportunity to review and comment on the package. If you have any questions or comments, please contact Mr. Scott Davis of my staff at (404) 347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: J. Reynolds
C. Holladay
B. Thomas, SLO Dist.
C. Shaver, NPS
T. Tooby, KBN
CHF/PL

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

June 30, 1992

NOTE: It was agreed that the completeness date would be extended until calculations were received!

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, California 92653

Dear Mr. Malenius:

Re: Permit Application AC 53-211670, PSD-FL-187
Mulberry Cogeneration Project

This is the second incompleteness letter for the subject application. On June 8, the Department received KBN's response to the May 5 incompleteness letter which requested that the application show all emission calculations. KBN enclosed a computer disk containing matrixed Lotus 1-2-3 spreadsheets to present the emission calculations and stated that this was the only feasible way to perform the calculations. While that method may work best for the consultant performing the calculations, it is not the best method of presenting the calculations. It requires more time for permit review because the review engineer must search through the row/column matrix to find the raw numbers used in the formulas. The emission calculations and formulas should be submitted in hard copy and in raw, non-matrix form. This facilitates review and thus speeds up processing of the application. We generally accept modeling data submitted on computer disks. However, the modeling formulas are part of the software and do not have to be checked in the same manner as the emission calculations.

Enclosed are some example calculations from other applications to illustrate preferred formats for emission calculations. Please resubmit the requested calculations in hard copy using a similar format.

Sincerely,

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

1304

CHF/JR/plm

Enclosure

c: W. Thomas, SED (w/o enclosure)
C. Shaver, NPS (" ")
D. Martin, Planner (" ")
J. Harper, EPA (w/o enclosure)
K. Kosky, P.E. (w/ enclosure)

6/30/92

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KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street
Gainesville, Florida 32605
FAX: 904/332-4189
Telephone: 904/331-9000

Letter of Transmittal

Date: 7-8-92

Project No.: 9119 3-0200

To: JOHN REYNOLDS
FLORIDA DEPT. ENV. REG.
2600 BLAIR STONE RD
TALLAHASSEE, FL 32399-2400

RECEIVED
JUL 9 1992
Bureau of Air Regulation

Re: MULBERRY COGENERATION PROJECT
PERMIT APPLICATION AC 53-211670
PSD-FL-187

The following items are being sent to you: ☑ with this letter ☐ under separate cover

Copies	Description
1	APPENDIX A TABLES FROM REPORT
	REVISED TO SHOW CALCULATIONS WITH FORMULAS
	AND INPUT PARAMETERS
	INFORMATION PROVIDED FOR DISTILLATE OIL AND
	NATURAL GAS. PROPANE IS NO LONGER CONSIDERED
	FOR THIS PROJECT

These are transmitted:

- ☑ As requested
- ☐ For review
- ☐ For review and comment
- ☑ For approval
- ☐ For your information
- ☐ _____

Remarks: PLEASE CALL ME WHEN YOU HAVE REVIEWED THIS MATERIAL

Signed: Robert C McCamy

Copy to: KF KOSKY

KBN6/LOT.1-P
04/06/90

Table A-1. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Data		Gas Turbine Fuel Oil 20of	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F	G
General						
Power (kW)		95,860.0	90,080.0	84,470.0	77,930.0	71,250.0
Heat Rate (Btu/kwh)		10,760.0	10,870.0	10,990.0	11,150.0	11,350.0
CT Exhaust Flow						
Mass Flow (lb/hr)		2,605,000	2,492,000	2,384,000	2,261,000	2,134,000
Temperature (oF)		957	971	984	999	1,015
Moisture (% Vol.)		7.53	7.70	8.03	8.72	9.93
Oxygen (% Vol.)		13.22	13.23	13.23	13.18	13.04
Molecular Weight		28.59	28.57	28.53	28.44	28.30
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu						
Power (kW)		95,860.0	90,080.0	84,470.0	77,930.0	71,250.0
Heat Rate (Btu/kwh)		10,760.0	10,870.0	10,990.0	11,150.0	11,350.0
Heat Input (MMBtu/hr)		1,031.5	979.2	928.3	868.9	808.7
Fuel Oil Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)						
Heat Input (MMBtu/hr)		1,031.5	979.2	928.3	868.9	808.7
Heat Content,LHV (Btu/lb)		18,550	18,550	18,550	18,550	18,550
Fuel Oil (lb/hr)		55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
Mass Flow (lb/hr)		2,605,000	2,492,000	2,384,000	2,261,000	2,134,000
Temperature (°F)		957	971	984	999	1,015
Molecular Weight		28.59	28.57	28.53	28.44	28.30
Volume Flow (acfm)		1,570,662	1,518,533	1,468,004	1,410,850	1,352,891
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
Mass Flow (lb/hr)		2,605,000	2,492,000	2,384,000	2,261,000	2,134,000
Temperature (°F)		68	68	68	68	68
Molecular Weight		28.59	28.57	28.53	28.44	28.30
Volume Flow (scfm)		585,257	560,297	536,777	510,575	484,289
HRSG Stack Data						
Stack Height (ft)		125	125	125	125	125
Diameter (ft)		15.0	15.0	15.0	15.0	15.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]						
Volume Flow (acfm) from CT		1,570,662	1,518,533	1,468,004	1,410,850	1,352,891
CT Temperature (°F)		957	971	984	999	1,015
HRSG Temperature (°F)		220	220	220	220	220
Volume Flow (acfm) from HRSG		753,740	721,595	691,304	657,559	623,705
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min						
Volume Flow (acfm) from HRSG		753,740	721,595	691,304	657,559	623,705
Diameter (ft)		15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)		71.1	68.1	65.2	62.0	58.8

Source: General Electric, 1991.

Table A-2. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant		Gas Turbine Fuel Oil 20oF	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F	G
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
PM, lb/hr (manufacturer)		15.0	15.0	15.0	15.0	15.0
TPY		65.7	65.7	65.7	65.7	65.7
Sulfur Dioxide (lb/hr)= Fuel oil (lb/hr) x sulfur content(fraction) x (lb SO2/lb S) x fraction emitted as SO2						
Fuel Oil (lb/hr)		55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
Sulfur content (%)		0.10	0.10	0.10	0.10	0.10
lb SO2/lb S (64/32)		2.0	2.0	2.0	2.0	2.0
SO2 Fraction emitted		0.95	0.95	0.95	0.95	0.95
SO2, lb/hr		105.65	100.29	95.08	89.00	82.83
TPY		462.7	439.3	416.5	389.8	362.8
Nitrogen Oxides (lb/hr)= NOx(ppm) x [20.9 x (1 - Moisture(%)/100) - Oxygen(%)] x 2116.8 lb/ft2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]						
Basis, ppm*		42.0	42.0	42.0	42.0	42.0
Moisture (%)		7.53	7.7	8.03	8.72	9.93
Oxygen (%)		13.22	13.23	13.23	13.18	13.04
Volume Flow (acfm)		1,570,662	1,518,533	1,468,004	1,410,850	1,352,891
Temperature (°F)		957	971	984	999	1015
NOx, lb/hr		182.2	173.1	164.0	153.5	142.8
TPY		798.0	758.3	718.2	672.4	625.6
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+		35.0	35.0	35.0	35.0	35.0
Moisture (%)		7.53	7.7	8.03	8.72	9.93
Volume Flow (acfm)		1,570,662	1,518,533	1,468,004	1,410,850	1,352,891
Temperature (°F)		957	971	984	999	1015
lb/hr		82.6	78.9	75.3	71.1	66.6
TPY		361.7	345.6	329.9	311.5	291.5
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 12 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+		10.0	10.0	10.0	10.0	10.0
Moisture (%)		7.53	7.7	8.03	8.72	9.93
Volume Flow (acfm)		1,570,662	1,518,533	1,468,004	1,410,850	1,352,891
Temperature (°F)		957	971	984	999	1015
lb/hr		10.11	9.66	9.22	8.71	8.15
TPY		44.3	42.3	40.4	38.1	35.7
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
Basis, lb/10E+12 Btu		8.9	8.9	8.9	8.9	8.9
HIR (MMBtu/hr)		1,031.5	979.2	928.3	868.9	808.7
lb/hr		9.18E-03	8.71E-03	8.26E-03	7.73E-03	7.20E-03
TPY		0.040	0.038	0.036	0.034	0.032

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Table A-3. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A	B	C	D	E	F	G
Arsenic (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	4.2	4.2	4.2	4.2	4.2
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	4.33E-03	4.11E-03	3.90E-03	3.65E-03	3.40E-03
	TPY	1.90E-02	1.80E-02	1.71E-02	1.60E-02	1.49E-02
Beryllium (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	2.5	2.5	2.5	2.5	2.5
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.58E-03	2.45E-03	2.32E-03	2.17E-03	2.02E-03
	TPY	1.13E-02	1.07E-02	1.02E-02	9.51E-03	8.86E-03
Mercury (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	3	3	3	3	3
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	3.09E-03	2.94E-03	2.78E-03	2.61E-03	2.43E-03
	TPY	1.36E-02	1.29E-02	1.22E-02	1.14E-02	1.06E-02
Fluoride (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	32.5	32.5	32.5	32.5	32.5
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	3.35E-02	3.18E-02	3.02E-02	2.82E-02	2.63E-02
	TPY	1.47E-01	1.39E-01	1.32E-01	1.24E-01	1.15E-01
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)						
	Fraction SO2 (%)	5	5	5	5	5
	SO2 (lb/hr)/0.95	111.2	105.6	100.1	93.7	87.2
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53
	lb/hr	8.51E+00	8.08E+00	7.66E+00	7.17E+00	6.68E+00
	TPY	3.73E+01	3.54E+01	3.36E+01	3.14E+01	2.92E+01

Sources: (1) EPA, 1990; (2) EPA, 1980

Table A-4. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A	B	C	D	E	F	G
Manganese (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	6.44	6.44	6.44	6.44	6.44
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	6.64E-03	6.31E-03	5.98E-03	5.60E-03	5.21E-03
	TPY	2.91E-02	2.76E-02	2.62E-02	2.45E-02	2.28E-02
Nickel (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	170	170	170	170	170
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	1.75E-01	1.66E-01	1.58E-01	1.48E-01	1.37E-01
	TPY	7.68E-01	7.29E-01	6.91E-01	6.47E-01	6.02E-01
Cadmium (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	10.5	10.5	10.5	10.5	10.5
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	1.08E-02	1.03E-02	9.75E-03	9.12E-03	8.49E-03
	TPY	4.74E-02	4.50E-02	4.27E-02	4.00E-02	3.72E-02
Chromium (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	47.5	47.5	47.5	47.5	47.5
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	4.90E-02	4.65E-02	4.41E-02	4.13E-02	3.84E-02
	TPY	2.15E-01	2.04E-01	1.93E-01	1.81E-01	1.68E-01
Copper (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	280	280	280	280	280
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.89E-01	2.74E-01	2.60E-01	2.43E-01	2.26E-01
	TPY	1.26E+00	1.20E+00	1.14E+00	1.07E+00	9.92E-01
Vanadium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	30	30	30	30	30
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	7.19E-02	6.83E-02	6.47E-02	6.06E-02	5.64E-02
	TPY	3.15E-01	2.99E-01	2.83E-01	2.65E-01	2.47E-01
Selenium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	10.1	10.1	10.1	10.1	10.1
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.42E-02	2.30E-02	2.18E-02	2.04E-02	1.90E-02
	TPY	1.06E-01	1.01E-01	9.54E-02	8.93E-02	8.31E-02
Polycyclic Organic Matter (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	0.12	0.12	0.12	0.12	0.12
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.88E-04	2.73E-04	2.59E-04	2.42E-04	2.26E-04
	TPY	1.26E-03	1.20E-03	1.13E-03	1.06E-03	9.88E-04
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	405	405	405	405	405
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	4.18E-01	3.97E-01	3.76E-01	3.52E-01	3.28E-01
	TPY	1.83E+00	1.74E+00	1.65E+00	1.54E+00	1.43E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant
Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A	B	C	D	E	F	G
Antimony (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	9.4	9.4	9.4	9.4	9.4
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.25E-02	2.14E-02	2.03E-02	1.90E-02	1.77E-02
	TPY	9.87E-02	9.37E-02	8.88E-02	8.31E-02	7.74E-02
Barium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	8.4	8.4	8.4	8.4	8.4
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.01E-02	1.91E-02	1.81E-02	1.70E-02	1.58E-02
	TPY	8.82E-02	8.37E-02	7.94E-02	7.43E-02	6.91E-02
Cobalt (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	3.9	3.9	3.9	3.9	3.9
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	9.35E-03	8.87E-03	8.41E-03	7.88E-03	7.33E-03
	TPY	4.09E-02	3.89E-02	3.69E-02	3.45E-02	3.21E-02
Zinc (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	294	294	294	294	294
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	7.05E-01	6.69E-01	6.34E-01	5.94E-01	5.53E-01
	TPY	3.09E+00	2.93E+00	2.78E+00	2.60E+00	2.42E+00
Chlorine (lb/hr)= Basis (ppm) x Fuel oil (lb/hr) ÷ 1,000,000						
	ppm	0.5	0.5	0.5	0.5	0.5
	Fuel Oil (lb/hr)	55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
	lb/hr	2.78E-02	2.64E-02	2.50E-02	2.34E-02	2.18E-02
	TPY	1.22E-01	1.16E-01	1.10E-01	1.03E-01	9.55E-02

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-6. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Data	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A B	C	D	E	F	G
General					
Power (kW)	93,110.0	87,470.0	82,040.0	75,880.0	69,900.0
Heat Rate (Btu/kwh)	10,340.0	10,450.0	10,590.0	10,790.0	11,050.0
CT Exhaust Flow					
Mass Flow (lb/hr)	2,558,000	2,448,000	2,343,000	2,226,000	2,108,000
Temperature (oF)	962	976	988	1,003	1,017
Moisture (% Vol.)	6.10	6.32	6.77	7.75	9.46
Oxygen (% Vol.)	14.03	14.04	14.00	13.85	13.55
Molecular Weight	28.61	28.58	28.53	28.42	28.23
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu					
Power (kW)	93,110.0	87,470.0	82,040.0	75,880.0	69,900.0
Heat Rate (Btu/kwh)	10,340.0	10,450.0	10,590.0	10,790.0	11,050.0
Heat Input (MMBtu/hr)	962.8	914.1	868.8	818.7	772.4
Natural Gas Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)					
(cf/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/cf)					
Heat Input (MMBtu/hr)	962.8	914.1	868.8	818.7	772.4
Heat Content,LHV (Btu/lb)	19,303	19,303	19,303	19,303	19,303
Natural Gas (lb/hr)	49,876.1	47,353.3	45,008.7	42,415.4	40,014.2
Heat Content,LHV (Btu/cf)	950	950	950	950	950
Natural Gas (cf/hr)	1,013,429	962,170	914,530	861,837	813,047
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)	2,558,000	2,448,000	2,343,000	2,226,000	2,108,000
Temperature (°F)	962	976	988	1,003	1,017
Molecular Weight	28.61	28.58	28.53	28.42	28.23
Volume Flow (acfm)	1,546,476	1,495,987	1,446,407	1,393,785	1,341,523
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)	2,558,000	2,448,000	2,343,000	2,226,000	2,108,000
Temperature (°F)	68	68	68	68	68
Molecular Weight	28.61	28.58	28.53	28.42	28.23
Volume Flow (scfm)	574,219	550,057	527,419	503,020	479,569
HRSG Stack Data					
Stack Height (ft)	125	125	125	125	125
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]					
Volume Flow (acfm) from CT	1,546,476	1,495,987	1,446,407	1,393,785	1,341,523
CT Temperature (°F)	962	976	988	1,003	1,017
HRSG Temperature (°F)	220	220	220	220	220
Volume Flow (acfm) from HRSG	739,524	708,406	679,252	647,829	617,627
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min					
Volume Flow (acfm) from HRSG	739,524	708,406	679,252	647,829	617,627
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	69.7	66.8	64.1	61.1	58.3

Source: General Electric, 1991.

Table A-7. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Pollutant		Gas Turbine Natural Gas 20of	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A	B	C	D	E	F	G
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer						
PM, lb/hr (manufacturer)		7.0	7.0	7.0	7.0	7.0
TPY		30.66	30.66	30.66	30.66	30.66
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2/lb S) ÷ 100						
Natural Gas (cf/hr)		1,013,429	962,170	914,530	861,837	813,047
Basis, gr/100 cf		1.0	1.0	1.0	1.0	1.0
lb SO2/lb S (64/32)		2.0	2.0	2.0	2.0	2.0
SO2, lb/hr		2.90	2.75	2.61	2.46	2.32
TPY		12.68	12.04	11.44	10.79	10.17
Nitrogen Oxides (lb/hr)= NOx(ppm) x [20.9 x (1 - Moisture(%)/100) - Oxygen(%)] x 2116.8 lb/ft2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]						
Basis, ppm*		25.0	25.0	25.0	25.0	25.0
Moisture (%)		6.1	6.32	6.77	7.75	9.46
Oxygen (%)		14.03	14.04	14	13.85	13.55
Volume Flow (acfm)		1,546,476	1,495,987	1,446,407	1,393,785	1,341,523
Temperature (°F)		962	976	988	1003	1017
NOx, lb/hr		97.5	92.5	87.8	82.9	78.2
TPY		427.05	404.98	384.53	363.07	342.49
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+		20.0	20.0	20.0	20.0	20.0
Moisture (%)		6.1	6.32	6.77	7.75	9.46
Volume Flow (acfm)		1,546,476	1,495,987	1,446,407	1,393,785	1,341,523
Temperature (°F)		962	976	988	1003	1017
lb/hr		47.0	44.9	42.9	40.5	37.9
TPY		205.91	196.78	187.78	177.21	165.81
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 12 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+		7.0	7.0	7.0	7.0	7.0
Moisture (%)		6.1	6.32	6.77	7.75	9.46
Volume Flow (acfm)		1,546,476	1,495,987	1,446,407	1,393,785	1,341,523
Temperature (°F)		962	976	988	1003	1017
lb/hr		7.05	6.74	6.43	6.07	5.68
TPY		30.9	29.5	28.2	26.6	24.9
Lead (lb/hr)= Negligible						
Basis, lb/10E+12 Btu		NA	NA	NA	NA	NA
HIR (MMBtu/hr)		NA	NA	NA	NA	NA
lb/hr		NA	NA	NA	NA	NA
TPY		NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Table A-8. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A	B	C	D	E	F	G
Arsenic (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Beryllium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Mercury (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Fluoride (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)						
	Fraction SO2 (%)	5	5	5	5	5
	SO2 (lb/hr)/0.95	3.0	2.9	2.8	2.6	2.4
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53
	lb/hr	2.33E-01	2.22E-01	2.11E-01	1.98E-01	1.87E-01
	TPY	1.02E+00	9.70E-01	9.22E-01	8.69E-01	8.20E-01

Sources: (1) EPA, 1990; (2) EPA, 1980

Table A-9. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A	B	C	D	E	F	G
Manganese (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Nickel (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Cadmium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Chromium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Copper (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Vanadium (lb/hr)= Negligible						
	pg/J (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Selenium (lb/hr)= Negligible						
	pg/J (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Polycyclic Organic Matter (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	0.48	0.48	0.48	0.48	0.48
	HIR (MMBtu/hr)	962.8	914.1	868.8	818.7	772.4
	lb/hr	1.07E-03	1.02E-03	9.69E-04	9.13E-04	8.62E-04
	TPY	4.70E-03	4.47E-03	4.24E-03	4.00E-03	3.77E-03
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	38	38	38	38	38
	HIR (MMBtu/hr)	962.8	914.1	868.8	818.7	772.4
	lb/hr	8.50E-02	8.07E-02	7.67E-02	7.23E-02	6.82E-02
	TPY	3.72E-01	3.54E-01	3.36E-01	3.17E-01	2.99E-01

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

Table A-14. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjusted Flow for CO2 Plant)

Data	Gas Turbine Fuel Oil 20of	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A B	C	D	E	F	G
General					
Power (kW)	95,860.0	90,080.0	84,470.0	77,930.0	71,250.0
Heat Rate (Btu/kwh)	10,760.0	10,870.0	10,990.0	11,150.0	11,350.0
CT Exhaust Flow (Design Mass Flow - 120,000 lb/hr to CO2 Plant)					
Design Mass Flow (lb/hr)	2,605,000	2,492,000	2,384,000	2,261,000	2,134,000
Mass Flow, CT (lb/hr)	2,485,000	2,372,000	2,264,000	2,141,000	2,014,000
Mass Flow, CO2 plant (lb/hr)	120,000	120,000	120,000	120,000	120,000
Ratio Mass Flow, CT/Design	0.954	0.952	0.950	0.947	0.944
Temperature (oF)	957	971	984	999	1,015
Moisture (% Vol.)	7.53	7.70	8.03	8.72	9.93
Oxygen (% Vol.)	13.22	13.23	13.23	13.18	13.04
Molecular Weight	28.59	28.57	28.53	28.44	28.30
Heat Input (MMBtu/hr)= Power (kW) x Heat Rate (Btu/kwh) ÷ 1,000,000 Btu/MMBtu					
Power (kW)	95,860.0	90,080.0	84,470.0	77,930.0	71,250.0
Heat Rate (Btu/kwh)	10,760.0	10,870.0	10,990.0	11,150.0	11,350.0
Heat Input (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
Fuel Oil Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)					
Heat Input (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
Heat Content,LHV (Btu/lb)	18,550	18,550	18,550	18,550	18,550
Fuel Oil (lb/hr)	55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)- CT Adjusted	2,485,000	2,372,000	2,264,000	2,141,000	2,014,000
Temperature (°F)	957	971	984	999	1,015
Molecular Weight	28.59	28.57	28.53	28.44	28.30
Volume Flow (acfm)	1,498,309	1,445,409	1,394,112	1,335,971	1,276,814
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr					
Mass Flow (lb/hr)- CT Adjusted	2,485,000	2,372,000	2,264,000	2,141,000	2,014,000
Temperature (°F)	68	68	68	68	68
Molecular Weight	28.59	28.57	28.53	28.44	28.30
Volume Flow (scfm)	558,297	533,317	509,758	483,477	457,056
HRSG Stack Data					
Stack Height (ft)	125	125	125	125	125
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Volume Flow (acfm) from HRSG= [Volume flow (acfm) x (HRSG temp.(°F)+ 460°F)] ÷ [CT temp.(°F)+ 460°F]					
Volume Flow (acfm) from CT	1,498,309	1,445,409	1,394,112	1,335,971	1,276,814
CT Temperature (°F)	957	971	984	999	1,015
HRSG Temperature (°F)	220	220	220	220	220
Volume Flow (acfm) from HRSG	719,019	686,847	656,507	622,659	588,633
Velocity (ft/sec)= Volume flow (acfm) from HRSG ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min					
Volume Flow (acfm) from HRSG	719,019	686,847	656,507	622,659	588,633
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	67.8	64.8	61.9	58.7	55.5

Source: General Electric, 1991.

Table A-15. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjusted Flow for CO2 Plant)

Pollutant		Gas Turbine Fuel Oil 20oF	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F	G
Particulate (lb/hr)= Emission rate (lb/hr) from manufacturer x Ratio CT Adjusted/Design Mass Flow						
PM, lb/hr (manufacturer)		15.0	15.0	15.0	15.0	15.0
Ratio Mass Flow, CT/Design		0.954	0.952	0.950	0.947	0.944
PM, lb/hr		14.3	14.3	14.2	14.2	14.2
TPY		62.7	62.5	62.4	62.2	62.0
Sulfur Dioxide (lb/hr)= Fuel oil (lb/hr) x sulfur content(fraction) x (lb SO2/lb S) x fraction emitted as SO2 x Ratio CT Adjusted/Design Mass Flow						
Fuel Oil (lb/hr)		55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
Sulfur content (%)		0.10	0.10	0.10	0.10	0.10
lb SO2/lb S (64/32)		2.0	2.0	2.0	2.0	2.0
SO2 Fraction emitted		0.95	0.95	0.95	0.95	0.95
Ratio Mass Flow, CT/Design		0.954	0.952	0.950	0.947	0.944
SO2, lb/hr		100.78	95.46	90.30	84.28	78.17
TPY		441.4	418.1	395.5	369.1	342.4
Nitrogen Oxides (lb/hr)= NOx(ppm) x [20.9 x (1 - Moisture(%)/100) - Oxygen(%)] x 2116.8 lb/ft2 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]						
Basis, ppm*		42.0	42.0	42.0	42.0	42.0
Moisture (%)		7.53	7.7	8.03	8.72	9.93
Oxygen (%)		13.22	13.23	13.23	13.18	13.04
Volume Flow (acfm)		1,498,309	1,445,409	1,394,112	1,335,971	1,276,814
Temperature (°F)		957	971	984	999	1015
NOx, lb/hr		173.8	164.8	155.7	145.4	134.8
TPY		761.3	721.8	682.0	636.7	590.4
Carbon Monoxide (lb/hr)= CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt NOx) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+		35.0	35.0	35.0	35.0	35.0
Moisture (%)		7.53	7.7	8.03	8.72	9.93
Volume Flow (acfm)		1,498,309	1,445,409	1,394,112	1,335,971	1,276,814
Temperature (°F)		957	971	984	999	1015
lb/hr		78.8	75.1	71.5	67.3	62.8
TPY		345.0	329.0	313.3	294.9	275.1
VOCs (lb/hr)= VOC(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 12 (mole. wgt as methane) x 60 min/hr ÷ [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]						
Basis, ppm+		10.0	10.0	10.0	10.0	10.0
Moisture (%)		7.53	7.7	8.03	8.72	9.93
Volume Flow (acfm)		1,498,309	1,445,409	1,394,112	1,335,971	1,276,814
Temperature (°F)		957	971	984	999	1015
lb/hr		9.65	9.20	8.76	8.25	7.69
TPY		42.2	40.3	38.4	36.1	33.7
Lead (lb/hr)= Lead (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr)x Ratio CT Adjusted/Design Mass Flow ÷ 1,000,000 Btu/MMBtu						
Basis, lb/10E+12 Btu		8.9	8.9	8.9	8.9	8.9
HIR (MMBtu/hr)		1,031.5	979.2	928.3	868.9	808.7
Ratio Mass Flow, CT/Design		0.954	0.952	0.950	0.947	0.944
lb/hr		8.76E-03	8.29E-03	7.85E-03	7.32E-03	6.79E-03
TPY		0.038	0.036	0.034	0.032	0.030

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Table A-16. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjusted Flow for CO2 Plant)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A	B	C	D	E	F	G
Ratio Mass Flow, CT/Design		0.954	0.952	0.950	0.947	0.944
Arsenic (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	4.2	4.2	4.2	4.2	4.2
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	4.13E-03	3.91E-03	3.70E-03	3.46E-03	3.21E-03
	TPY	1.81E-02	1.71E-02	1.62E-02	1.51E-02	1.40E-02
Beryllium (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	2.5	2.5	2.5	2.5	2.5
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.46E-03	2.33E-03	2.20E-03	2.06E-03	1.91E-03
	TPY	1.08E-02	1.02E-02	9.65E-03	9.01E-03	8.36E-03
Mercury (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	3	3	3	3	3
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.95E-03	2.80E-03	2.64E-03	2.47E-03	2.29E-03
	TPY	1.29E-02	1.22E-02	1.16E-02	1.08E-02	1.00E-02
Fluoride (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	32.5	32.5	32.5	32.5	32.5
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	3.20E-02	3.03E-02	2.87E-02	2.67E-02	2.48E-02
	TPY	1.40E-01	1.33E-01	1.25E-01	1.17E-01	1.09E-01
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)						
	Fraction SO2 (%)	5	5	5	5	5
	SO2 (lb/hr)/0.95	106.1	100.5	95.1	88.7	82.3
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53
	lb/hr	8.12E+00	7.69E+00	7.28E+00	6.79E+00	6.30E+00
	TPY	3.56E+01	3.37E+01	3.19E+01	2.97E+01	2.76E+01

Sources: (1) EPA, 1990; (2) EPA, 1980

Table A-17. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjusted Flow for CO2 Plant)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A	B	C	D	E	F	G
Ratio Mass Flow, CT/Design		0.954	0.952	0.950	0.947	0.944
Manganese (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	6.44	6.44	6.44	6.44	6.44
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	6.34E-03	6.00E-03	5.68E-03	5.30E-03	4.92E-03
	TPY	2.78E-02	2.63E-02	2.49E-02	2.32E-02	2.15E-02
Nickel (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	170	170	170	170	170
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	1.67E-01	1.58E-01	1.50E-01	1.40E-01	1.30E-01
	TPY	7.33E-01	6.94E-01	6.56E-01	6.13E-01	5.68E-01
Cadmium (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	10.5	10.5	10.5	10.5	10.5
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	1.03E-02	9.79E-03	9.26E-03	8.64E-03	8.01E-03
	TPY	4.53E-02	4.29E-02	4.05E-02	3.78E-02	3.51E-02
Chromium (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	47.5	47.5	47.5	47.5	47.5
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	4.67E-02	4.43E-02	4.19E-02	3.91E-02	3.63E-02
	TPY	2.05E-01	1.94E-01	1.83E-01	1.71E-01	1.59E-01
Copper (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	280	280	280	280	280
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.76E-01	2.61E-01	2.47E-01	2.30E-01	2.14E-01
	TPY	1.21E+00	1.14E+00	1.08E+00	1.01E+00	9.36E-01
Vanadium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	30	30	30	30	30
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	6.86E-02	6.50E-02	6.15E-02	5.74E-02	5.32E-02
	TPY	3.00E-01	2.85E-01	2.69E-01	2.51E-01	2.33E-01
Selenium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	10.1	10.1	10.1	10.1	10.1
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.31E-02	2.19E-02	2.07E-02	1.93E-02	1.79E-02
	TPY	1.01E-01	9.58E-02	9.06E-02	8.46E-02	7.85E-02
Polycyclic Organic Matter (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMB						
	pg/J (1)	0.12	0.12	0.12	0.12	0.12
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.74E-04	2.60E-04	2.46E-04	2.29E-04	2.13E-04
	TPY	1.20E-03	1.14E-03	1.08E-03	1.01E-03	9.32E-04
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	lb/10E+12 Btu (1)	405	405	405	405	405
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	3.98E-01	3.77E-01	3.57E-01	3.33E-01	3.09E-01
	TPY	1.75E+00	1.65E+00	1.56E+00	1.46E+00	1.35E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

Table A-18. Maximum Emissions for Additional Non-Regulated Pollutant
Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjusted Flow for CO2 Plant)

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A	B	C	D	E	F	G
Ratio Mass Flow, CT/Design		0.954	0.952	0.950	0.947	0.944
Antimony (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	9.4	9.4	9.4	9.4	9.4
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	2.15E-02	2.04E-02	1.93E-02	1.80E-02	1.67E-02
	TPY	9.41E-02	8.92E-02	8.44E-02	7.87E-02	7.30E-02
Barium (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) x Ratio mass Flow ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	8.4	8.4	8.4	8.4	8.4
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	1.92E-02	1.82E-02	1.72E-02	1.61E-02	1.49E-02
	TPY	8.41E-02	7.97E-02	7.54E-02	7.04E-02	6.53E-02
Cobalt (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	3.9	3.9	3.9	3.9	3.9
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	8.92E-03	8.45E-03	7.99E-03	7.46E-03	6.92E-03
	TPY	3.91E-02	3.70E-02	3.50E-02	3.27E-02	3.03E-02
Zinc (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (MMBtu/hr) x Ratio Mass Flow ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	294	294	294	294	294
	HIR (MMBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
	lb/hr	6.72E-01	6.37E-01	6.02E-01	5.62E-01	5.21E-01
	TPY	2.94E+00	2.79E+00	2.64E+00	2.46E+00	2.28E+00
Chlorine (lb/hr)= Basis (ppm) x Fuel oil (lb/hr) x Ratio Mass Flow ÷ 1,000,000						
	ppm	0.5	0.5	0.5	0.5	0.5
	Fuel Oil (lb/hr)	55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
	lb/hr	2.65E-02	2.51E-02	2.38E-02	2.22E-02	2.06E-02
	TPY	1.16E-01	1.10E-01	1.04E-01	9.71E-02	9.01E-02

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

Table A-23. Stack Parameters for CO2 Facility (Includes Duct Burner on Natural Gas)

Data		Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
		20of	40oF	59oF	80oF	100oF
A	B	C	D	E	F	G
General						
	Power (kW)	NA	NA	NA	NA	NA
	Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
	CT Exhaust Flow					
	Mass Flow (lb/hr)*	112,500	112,500	112,500	112,500	112,500
	Temperature (oF)	220	220	220	220	220
	Moisture (% Vol.)	6.10	6.32	6.77	7.75	9.46
	Oxygen (% Vol.)	14.03	14.04	14.00	13.85	13.55
	Molecular Weight	28.00	28.00	28.00	28.00	28.00
Heat Input (MMBtu/hr)= Provided						
	Power (kW)	NA	NA	NA	NA	NA
	Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
	Heat Input (MMBtu/hr)	99.0	99.0	99.0	99.0	99.0
Natural Gas Consumption (lb/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/lb)						
(cf/hr)= Heat Input (MMBtu/hr) x 1,000,000 Btu/MMBtu ÷ Fuel Heat Content, LHV (Btu/cf)						
	Heat Input (MMBtu/hr)	99.0	99.0	99.0	99.0	99.0
	Heat Content,LHV (Btu/lb)	19,303	19,303	19,303	19,303	19,303
	Natural Gas (lb/hr)	5,128.7	5,128.7	5,128.7	5,128.7	5,128.7
	Heat Content,LHV (Btu/cf)	950	950	950	950	950
	Natural Gas (cf/hr)	104,211	104,211	104,211	104,211	104,211
Volume Flow (acfm)= [(Mass Flow (lb/hr) x 1,545 x (Temp. (°F)+ 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
	Mass Flow (lb/hr); from CT,DB*	112,500	112,500	112,500	112,500	112,500
	Temperature (°F); from CT, DB	220	220	220	220	220
	Molecular Weight	28.00	28.00	28.00	28.00	28.00
	Volume Flow (acfm)	33,235	33,235	33,235	33,235	33,235
Volume Flow (scfm)= [(Mass Flow (lb/hr) x 1,545 x (68°F + 460°F)] ÷ [Molecular weight x 2116.8] ÷ 60 min/hr						
	Mass Flow (lb/hr)*	112,500	112,500	112,500	112,500	112,500
	Temperature (°F)	68	68	68	68	68
	Molecular Weight	28.00	28.00	28.00	28.00	28.00
	Volume Flow (scfm)	25,806	25,806	25,806	25,806	25,806
CO2 Stack Data						
	Stack Height (ft)	170	170	170	170	170
	Diameter (ft)	3.0	3.0	3.0	3.0	3.0
Volume Flow (acfm)= [Volume flow (acfm) x (CO2 temp.(°F)+ 460°F)] ÷ [DB temp.(°F)+ 460°F]						
	Volume Flow (acfm); CT, DB	33,235	33,235	33,235	33,235	33,235
	DB Temperature (°F)	220	220	220	220	220
	CO2 Temperature (°F)	117	117	117	117	117
	Volume Flow (acfm)	28,201	28,201	28,201	28,201	28,201
Velocity (ft/sec)= Volume flow (acfm) ÷ [((diameter)²÷ 4) x 3.14159] ÷ 60 sec/min						
	Volume Flow (acfm)	28,201	28,201	28,201	28,201	28,201
	Diameter (ft)	3.0	3.0	3.0	3.0	3.0
	Velocity (ft/sec)	66.5	66.5	66.5	66.5	66.5

* Based on 120,000 lb/hr from CT; 5,000 lb/hr from duct burner; less 12,500 lb/hr (10 %) due to CO2 removal.

Table A-24. Maximum Criteria Pollutant Emissions for CO2 Plant (Without Contribution from CT)

Pollutant		Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
		20of	40oF	59oF	80oF	100oF
A	B	C	D	E	F	G
Particulate (lb/hr)= Basis (lb/MMBtu) x Heat Input Rate (MMBtu/hr)						
Basis (lb/MMBtu)		0.01	0.01	0.01	0.01	0.01
HIR (MMBtu/hr)		99.0	99.0	99.0	99.0	99.0
PM, lb/hr		0.99	0.99	0.99	0.99	0.99
TPY		4.34	4.34	4.34	4.34	4.34
Sulfur Dioxide (lb/hr)= Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO2/lb S) ÷ 100						
Natural Gas (cf/hr)		104,211	104,211	104,211	104,211	104,211
Basis, gr/100 cf		1.0	1.0	1.0	1.0	1.0
lb SO2/lb S (64/32)		2.0	2.0	2.0	2.0	2.0
SO2, lb/hr		0.30	0.30	0.30	0.30	0.30
TPY		1.30	1.30	1.30	1.30	1.30
Nitrogen Oxides (lb/hr)= Basis (lb/MMBtu) x Heat Input Rate (MMBtu/hr)						
Basis (lb/MMBtu)		0.16	0.16	0.16	0.16	0.16
HIR (MMBtu/hr)		99.0	99.0	99.0	99.0	99.0
NOx, lb/hr		15.84	15.84	15.84	15.84	15.84
TPY		69.38	69.38	69.38	69.38	69.38
Carbon Monoxide (lb/hr)= Basis (lb/MMBtu) x Heat Input Rate (MMBtu/hr)						
Basis (lb/MMBtu)		0.1	0.1	0.1	0.1	0.1
HIR (MMBtu/hr)		99.0	99.0	99.0	99.0	99.0
NOx, lb/hr		9.90	9.90	9.90	9.90	9.90
TPY		43.36	43.36	43.36	43.36	43.36
VOCs (lb/hr)= Basis (lb/MMBtu) x Heat Input Rate (MMBtu/hr)						
Basis (lb/MMBtu)		0.03	0.03	0.03	0.03	0.03
HIR (MMBtu/hr)		99.0	99.0	99.0	99.0	99.0
NOx, lb/hr		2.97	2.97	2.97	2.97	2.97
TPY		13.01	13.01	13.01	13.01	13.01
Lead (lb/hr)= Negligible						
Basis, lb/10E+12 Btu		NA	NA	NA	NA	NA
HIR (MMBtu/hr)		NA	NA	NA	NA	NA
lb/hr		NA	NA	NA	NA	NA
TPY		NA	NA	NA	NA	NA

Note: Additional 5 lb/hr of PM are emitted due to heat stable salts from amine absorber.
Additional 14.7 lb/hr of VOCs are emitted due to monoethanolamine (as carbon) from amine absorber.

Table A-25. Maximum Other Regulated Pollutant Emissions for CO2 Plant (Without Contribution from CT)

Pollutant	Units	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
		20oF	40oF	59oF	80oF	100oF
A	B	C	D	E	F	G
Arsenic (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Beryllium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Mercury (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Fluoride (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Sulfuric Acid Mist (lb/hr) = Fraction of SO2 Emission Rate x SO2 Emission Rate x lb H2SO4/lb SO2 (98/64)						
	Fraction SO2 (%)	5	5	5	5	5
	SO2 (lb/hr)/0.95	0.3	0.3	0.3	0.3	0.3
	lb H2SO4/lb SO2	1.53	1.53	1.53	1.53	1.53
	lb/hr	2.40E-02	2.40E-02	2.40E-02	2.40E-02	2.40E-02
	TPY	1.05E-01	1.05E-01	1.05E-01	1.05E-01	1.05E-01

Source: (1) EPA, 1990

Table A-26. Maximum Non-Regulated Pollutant Emissions for CO2 Plant (Without Contribution from CT)

Pollutant	Units	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
		20oF	40oF	59oF	80oF	100oF
A	B	C	D	E	F	G
Manganese (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Nickel (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Cadmium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Chromium (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Copper (lb/hr)= Negligible						
	lb/10E+12 Btu (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Vanadium (lb/hr)= Negligible						
	pg/J (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Selenium (lb/hr)= Negligible						
	pg/J (1)	NA	NA	NA	NA	NA
	HIR (MMBtu/hr)	NA	NA	NA	NA	NA
	lb/hr	NA	NA	NA	NA	NA
	TPY	NA	NA	NA	NA	NA
Polycyclic Organic Matter (lb/hr)= Basis (pg/J) x 2.324 x Heat Input Rate (mmBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	0.48	0.48	0.48	0.48	0.48
	HIR (MMBtu/hr)	99.0	99.0	99.0	99.0	99.0
	lb/hr	1.10E-04	1.10E-04	1.10E-04	1.10E-04	1.10E-04
	TPY	4.84E-04	4.84E-04	4.84E-04	4.84E-04	4.84E-04
Formaldehyde (lb/hr)= Basis (lb/10E+12 Btu) x Heat Input Rate (MMBtu/hr) ÷ 1,000,000 Btu/MMBtu						
	pg/J (1)	38	38	38	38	38
	HIR (MMBtu/hr)	99.0	99.0	99.0	99.0	99.0
	lb/hr	8.74E-03	8.74E-03	8.74E-03	8.74E-03	8.74E-03
	TPY	3.83E-02	3.83E-02	3.83E-02	3.83E-02	3.83E-02

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

United States Department of the Interior

FISH AND WILDLIFE SERVICE
75 Spring Street, S.W.
Atlanta, Georgia
30303

TAKE PRIDE IN AMERICA

RECEIVED
JUN 22 1992
Division of Air
Resources Management

June 15, 1992

Mr. C. 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

Dear Mr. Fancy:

We have reviewed Florida Power Corporation's (FPC) May 14, 1992, letter that clarifies the modeling protocol for their proposed power plant facility in Polk County, Florida. The proposed facility would be located approximately 110 km southeast of the Chassahowitzka Wilderness Area (WA), a Fish and Wildlife Service (Service) Prevention of Significant Deterioration (PSD) Class I area.

It is our understanding that FPC will initially model the proposed Polk County facility and all other increment-consuming sources in the Florida Department of Environmental Regulation (FDER) supplied inventory with the EPA ISCST model using 1982-86 National Weather Service data from Tampa, Florida. If a Class I increment violation is predicted in the cumulative ISCST analysis, and the proposed FPC source does not significantly contribute to the modeled increment violation, then no additional analysis for that averaging period or receptor is necessary. During the averaging periods when modeled violations occur, and the proposed FPC source has a predicted significant impact, additional air quality modeling will be performed with the EPA MESOPUFF II model.

In the MESOPUFF II Step 1 analysis, FPC will model the proposed Polk County facility emissions alone. FPC will then add their MESOPUFF II concentrations to the ISCST cumulative PSD impacts (minus the FPC ISCST predicted impacts). If this substitution of FPC MESOPUFF concentrations results in receptor concentrations below the Class I increments, then the analysis is complete for that averaging period and receptor.

If the Class I increment violation persists after MESOPUFF II Step 1, FPC will model all sources in the inventory which are greater than 50 km from the Chassahowitzka WA with MESOPUFF II for the cumulative PSD increment analysis for the respective

averaging periods and receptors which still exceed the Class I increment. This analysis constitutes MESOPUFF II Step 2. All source(s) which are 50 km or less from the Chassahowitzka WA will be modeled with the EPA ISCST model during all steps of this analysis. These "near" source(s) will have their impact added to the respective ISCST or MESOPUFF II cumulative analysis. To allow the MESOPUFF II model to be initialized, a 3-day period before the event in question and 2 days afterward will be modeled to allow the MESOPUFF II model to reach stabilization. These initial MESOPUFF II calculations will be performed by adhering to the EPA guidance of modeling sulfur dioxide (SO_2) as inert. Upon Service review of these inert SO_2 results, we may accept MESOPUFF II calculations with some or all of the chemical transformation and deposition options available in the MESOPUFF II model.

All other issues of this modeling protocol have been agreed to in our May 13, 1992, letter. The "fine tuning" portions of this protocol were decided on a case-by-case basis for this specific air quality analysis. From our standpoint, the acceptance of the protocol should allow FPC to proceed with the air quality modeling analysis.

With regards to the issue of PSD Class I increment significant levels which FPC discussed in their May 14, 1992, letter, we believe they should be as conservative as possible and consistent with the methodology originally used to establish the significant impact levels for the National Ambient Air Quality Standards (NAAQS). In other words, the Class I significant impact levels should be established by ratioing the NAAQS significant levels to the NAAQS, and then multiplying by the respective Class I increments. For example, the ratio of the 24-hour significance level (5 ug/m^3) to the 24-hour NAAQS (365 ug/m^3), is 0.014. Multiplying this ratio by the Class I SO_2 increment, 24-hour average, yields a significance level of 0.07 ug/m^3 (rounded to the nearest hundredth). Similarly, the annual and 3-hour significant levels would be 0.025 and 0.48 ug/m^3, respectively. The resulting significant levels are more conservative than the State of Virginia's proposal because they are proportional to the NAAQS rather than the Class II increments.

As proposed, the significant impact levels would not be applied to determine whether a source or modification might have an adverse impact on an Air Quality Related Value (AQRV) at a Class I area, or whether a source has to conduct a cumulative modeling analysis to assess the total ambient concentrations used in such an analysis. The proposed significant levels are for the purpose of assessing whether a source causes or contributes to Class I increment violations, but <u>not</u> for determining whether a source needs to conduct an AQRV analysis. FPC acknowledged this distinction, and will be performing an AQRV analysis.

Regarding the AQRV analysis, we have received a second letter dated May 22, 1992, from FPC asking us to provide them with a list of sensitive resources in the Chassahowitzka WA that may potentially be affected by increased concentrations of pollutants. We will send the following information to both you and FPC under separate cover within the next week: a map of the Chassahowitzka National Wildlife Refuge that outlines the boundaries of the WA; the most recent plant, amphibian, reptile, bird, and mammal lists for the refuge; and selected pages from the 1991 Annual Narrative of the Chassahowitzka National Wildlife Refuge that list endangered and threatened species found on the refuge, in addition to discussing habitat types and associated dominant plant species.

We would like FPC to address the effects of increased concentrations of primary pollutants, such as sulfur dioxide and nitrogen oxides, on resources, in addition to addressing the effects of secondary pollutants such as ozone, nitrates, and sulfates. Although we are of course concerned about impacts on resources throughout the refuge, FPC can limit their AQRVs analysis to those resources located in the WA. FPC should do a literature survey to help them assess the effects of pollutants on vegetation in the hardwood swamplands and the mangrove forest, since these habitat types are found exclusively in the WA. They should focus particular attention to assessing the effects on lichens because some of these species are known to be sensitive to SO_2. As far as the wetlands species are concerned, we do not expect the rushes and marsh grasses to be sensitive to air pollutants; however, the effects of pollutants on the species found on the tree islands--the cabbage palms and Eastern red cedars--should be addressed.

Although SO_2 modeling is important for the increment analysis, we do not anticipate that wildlife on the refuge will be directly affected by gaseous pollutant emissions. However, we are concerned about the effects on wildlife resulting from acid deposition (i.e., loss of invertebrate food base, death of fish and amphibian eggs and larvae). Freshwater creeks flowing into the WA provide important feeding areas for the Federally-endangered peregrine falcon and bald eagle; and therefore, their integrity is essential to support these species in the WA. FPC should assess the effects of increased acid deposition on the invertebrates, fish, and amphibians that inhabit these freshwater creeks in addition to addressing any indirect effects on other wildlife species. A literature review should help them with this assessment as well.

Visibility is another AQRV of concern at Chassahowitzka WA. In addition to plume impacts, regional haze is a pervasive problem in the area that can detract from the experience of visitors to the WA. We would like FPC to address the visibility issue also.

If you have any concerns regarding the modeling protocol for the FPC Polk County facility, please contact Mr. John Notar of our Air Quality Branch in Denver at 303/969-2071. Any questions regarding the AQRV analysis should be directed to Ms. Tonnie Maniero at the same phone number.

Sincerely yours,

for James W. Pulliam, Jr.
Regional Director

cc:
Ms. Jewell Harper, Chief
Air Enforcement Branch
Air, Pesticides and Toxic Management Division
U.S. EPA, Region 4
345 Courtland Street, NE.
Atlanta, Georgia 30365

Mr. Scott Osborne
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Mr. Robert McCann
KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605

cc: J. Reynolds
C. Holladay, SO Dist
B. Thomas,
CHF/PL

KBN

June 2, 1992

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

RECEIVED
JUN 3 1992
Division of Air
Resources Management

RE: Polk County--A.P.
Polk Power Partners, L.P.--Mulberry Cogeneration Project
Permit Application AC 53-211670 and PSD-FL-187

Dear Clair:

This correspondence and attachments present the information requested by the Department's May 5, 1992 letter.

1. A computer disk containing the Lotus 1-2-3 spreadsheets used to calculate emissions and presented in Tables A-1 through A-27 of the application is included with this correspondence. The spreadsheets are contained in files named TABA0105.WK3 through TABA2327.WK3. Because of the number and repetition of the calculations, a computerized spreadsheet is the only feasible way to perform the calculations. The computerized spreadsheet shows all calculations used to generate all the numerical quantities involving emissions.

   Please note that these spreadsheets are work products of KBN Engineering and Applied Sciences Inc., (KBN), and must be considered as confidential business information.

2. During the first 3 years of operation, the cogeneration facility will use only natural gas and fuel oil. Current project design does not include propane and therefore it should not be considered further in the application. The amount of natural gas under firm contract for the project during the first 3 years is sufficient to operate the facility at 22 percent of full load in any 24 hour period. The remainder of the fuel will be oil, i.e. 78 percent of full load in any 24-hour period.

   After the first 3 years of operation, the primary fuel will be natural gas. Fuel oil will only be used as backup (maximum of 30 days of operation).

3. Attachment 1 contains additional analyses to address the prevention of significant deterioration (PSD) Class I increment consumption and potential impacts on the air quality related values (AQRVs) of the Chassahowitska National Wilderness Area. As discussed, the proposed project's impacts are expected to be less than the National Park Service's proposed significant impact levels when potential violations of the Class I increment are predicted. Also, the proposed project's impacts are not expected to have an adverse effect on AQRVs. A disk copy and paper copy of the air dispersion modeling printouts are included with this letter.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

Submittal of this information should clarify all questions raised by the Department in the completeness determination for the above-referenced project. Please call if there are any further questions on the material submitted herein.

Sincerely,

Robert E. McLean Jr.
for

Kennard F. Kosky, P.E.
President

KFK/dmpm

Enclosure

cc: William Malenius, Ark Energy, Inc.
Ward Marshall, Central and South West Services, Inc.
File (2)
J. Reynolds
C. Holladay
B. Thomas, SW Dist
J. Harper, EPA
C. Shaver, UPS
D. Martin, Polk Co. Planning Dir.

ATTACHMENT 1

Prevention of Significant Deterioration (PSD) Class I Increment Consumption and Air Quality Related Values (AQRV) Analyses of the Proposed Mulberry Cogeneration Facility

1.0 INTRODUCTION

KBN Engineering and Applied Sciences, Inc. (KBN) has performed air quality analyses to determine the prevention of significant deterioration (PSD) Class I increment consumption and air quality related values (AQRVs) analyses for the Chassahowitzka National Wilderness Area (NWA) due to emissions from the integrated cogeneration facility proposed by Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd. The facility, which is referred to as the Mulberry Cogeneration Facility, is located approximately 120 km from the closest part of the Chassahowitzka NWA, a PSD Class I area. Because the proposed facility alone had predicted 3-hour and 24-hour sulfur dioxide (SO_2) impacts greater than the National Park Service's (NPS's) proposed significant impact levels of 0.07 and 0.48 $\mu g/m^3$, respectively, the Florida Department of Environmental Regulation (FDER) has requested that a cumulative PSD Class I increment consumption analysis be performed for the 3-hour and 24-hour averaging periods. Based on verbal communications between FDER and NPS's, the AQRV analyses need only address the impacts of increased emissions of SO_2, nitrogen dioxide (NO_2), and volatile organic compounds for this project.

The following sections present the approaches, methods, and results of the respective PSD Class I increment consumption and AQRV analyses.

2.0 PREVENTION OF SIGNIFICANT DETERIORATION CLASS I INCREMENT ANALYSIS

An air quality modeling analysis was performed to determine the maximum SO_2 PSD Class I increment consumption at the Chassahowitzka PSD Class I area. This analysis included modeling with the Industrial Source Complex Short-Term (ISCST) model using the SO_2 emissions from the proposed project for the maximum emission case (i.e., 20 °F) with an inventory of other increment-consuming major and minor sources. The inventory for other sources, presented in Table 1, was based on data submitted in recent permit applications to FDER. The SO_2 impacts were predicted using the ISCST model at 13 discrete receptors surrounding the PSD Class I area which have also been included in recent permit applications. The impacts were predicted using a

5-year meteorological record (1982 through 1986) of surface and mixing height data from the National Weather Service (NWS) stations in Tampa and Ruskin, respectively.

Maximum predicted impacts for the 5 years of meteorological data are presented in Table 2. The overall highest, second-highest 3- and 24-hour impacts due to all sources are predicted to be 38.0 micrograms per cubic meter ($\mu g/m^3$) and 7.7 $\mu g/m^3$, respectively. The 3-hour and 24-hour impacts are above the SO_2 PSD Class I increment values. An additional modeling analysis was performed to determine the proposed project's contribution to the predicted violations. This analysis involved identifying the receptors and time periods for which the proposed source's impacts were greater than the NPS's proposed significant impact levels and then calculating the cumulative impacts from PSD sources for those periods and receptors. A summary of these results is presented in Table 3.

As shown in Table 3, when the proposed source's impacts are greater than the NPS's proposed significant impact levels, there were no predicted violations of the PSD Class I increment, except for one 24-hour event in 1986. For that event, the predicted 24-hour concentration was 5.22 $\mu g/m^3$ with the proposed source contributing approximately 0.09 $\mu g/m^3$. An investigation of the meteorological conditions which occurred on the day during which the proposed source had a predicted "significant" impact (see Table 4) revealed that the wind speeds were generally low (i.e., average of approximately 2.6 m/s) for the entire 24-hour period, including 2 hours of calm conditions, with wind direction change of about 130 degrees between the first and last hours of predicted source impacts. Because the proposed source's plume is not likely to be transported to the Class I area under those meteorological conditions, the proposed source's contribution is a conservative and unrealistic impact associated with the predicted violation. Also, with 2 hours of calm, the calculated 24-hour concentration of 5.22 $\mu g/m^3$ was based on 22 hours of impact (the 2 hours of calm were excluded from calculating the 24-hour concentration), instead of 24 hours. By considering only 22 hours of potential impacts, the 24-hour concentration is artificially increased by a factor of 1.09 (i.e., 24 hours/22 hours), or approximately 9 percent. Therefore, if a more realistic assessment of the proposed source's 24-hour impact was performed (i.e., long-range transport modeling) and all hours were used in the calculation, the predicted impact is expected to be less than the NPS's proposed significant impact levels. As a result, the total cumulative impact is also expected to be less than the PSD Class I increment.

3.0 AIR QUALITY RELATED VALUE ANALYSIS

3.1 POTENTIAL IMPACTS ON VEGETATION

The Chassahowitzka NWA is characterized by vegetation that includes flatwoods and brackish-water, marine, and halophytic terrestrial species. Predominant tree species are slash pine, laurel oak, sweetgum, and palm. Other plants in the preserve include needlegrass rush, seashore saltgrass, marsh hay, and red mangrove.

SO_2 concentrations at elevated levels have long been known to cause injury to plants. Acute SO_2 injury usually develops within a few hours or days of exposure, and symptoms include marginal, flecked, and/or intercoastal necrotic areas which appear water-soaked and dullish green initially. This injury generally occurs to younger leaves. Chronic injury usually is evident by signs of chlorosis, bronzing, premature senescence, reduced growth, and possible tissue necrosis (EPA, 1982). Phytotoxic symptoms demonstrated by plants can occur as low as 88 $\mu g/m^3$ (USDHEW, 1971). However, this occurs with the more primitive plants (i.e., mosses, ferns, lichens).

Many studies have been conducted to determine the effects of high-concentration, short-term SO_2 exposure on natural community vegetation. Sensitive plants include ragweed, legumes, blackberry, southern pine, and red and black oak. These species are injured by exposure to 3-hour SO_2 concentrations from 790 to 1,570 $\mu g/m^3$. Intermediate plants include locust and sweetgum. These species are injured by exposure to 3-hour SO_2 concentrations from 1,570 to 2,100 $\mu g/m^3$. Resistant species (injured at concentrations above 2,100 $\mu g/m^3$ for 3 hours) include white oak and dogwood (EPA, 1982).

A study of native Floridian species (Woltz and Howe, 1981) demonstrated that cypress, slash pine, live oak, and mangrove exposed to 1,300 $\mu g/m^3$ SO_2 for 8 hours were not visibly damaged. This supports the levels cited by other researchers on the effects of SO_2 on vegetation. A corroborative study (McLaughlin and Lee, 1974) demonstrated that approximately 20 percent of a cross-section of plants ranging from sensitive to tolerant were visibly injured at 3-hour SO_2 concentrations of 920 $\mu g/m^3$.

In order to assess the total air quality impacts at the Class I area that can be compared to the reported effects levels, the predicted impacts due to the PSD increment-affecting sources were added to background concentrations applicable to the 3-hour, 24-hour, and annual averaging periods. The background concentrations are assumed to be representative of impacts from sources

not modeled and available from existing ambient monitoring data. In this analysis, ambient data collected in 1990 from a monitoring station (Station No. 0580-005-J02) located about 20 kilometers (km) from the Class I area were used to represent background concentrations. The annual concentration of 7 $\mu g/m^3$ and second-highest 3-hour and 24-hour concentrations of 248 and 53 $\mu g/m^3$, respectively, were assumed to represent background concentrations.

By adding the maximum predicted 3-hour SO_2 concentration of 38.0 $\mu g/m^3$ to the assumed background SO_2 concentration of 248 $\mu g/m^3$, a maximum total SO_2 concentration of 286 $\mu g/m^3$ would be expected in the Class I area. By comparing this concentration to those causing injury to native species, the SO_2-sensitive species (as well as more tolerant species) would not be damaged by the maximum predicted concentrations. By comparison with concentrations that cause plant injury, the maximum predicted SO_2 concentration of 286 $\mu g/m^3$ is approximately 36 percent of the most conservative concentration (i.e., 790 $\mu g/m^3$) that causes injury to SO_2-sensitive species.

The maximum total 24-hour and annual SO_2 concentrations of 60.7 and 8.2 $\mu g/m^3$, respectively, that would be predicted within the Class I area represent levels which are lower than those known to cause damage to test species. Jack pine seedlings exposed to SO_2 concentrations of 470 to 520 $\mu g/m^3$ for 24 hours demonstrated inhibition of foliar lipid synthesis; however, this inhibition was reversible (Malhotra and Kahn, 1978). Black oak exposed to 1,310 $\mu g/m^3$ SO_2 for 24 hours a day for 1 week demonstrated a 48 percent reduction in photosynthesis (Carlson, 1979). By comparison of these levels, it is apparent that the maximum predicted 24-hour concentrations are well below the concentrations that cause damage in SO_2-sensitive plants. The maximum annual concentration of 1.2 $\mu g/m^3$ due to the PSD sources adds slightly to the background levels and poses a minimal threat to area vegetation.

Nitrogen dioxide (NO_2) can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO_2 can be absorbed by plants, enzymatically transformed into ammonia, and incorporated into plant constituents such as amino acids (Matsumaru et al., 1979).

Plant damage can occur through either acute (short-term, high-concentration) or chronic (long-term, relatively low-concentration) exposure. For plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused 5 percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 $\mu g/m^3$ (Heck and Tingey, 1979).

Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 $\mu g/m^3$ for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975).

By comparison of published toxicity values for NO_2 exposure to short-term (i.e., 1-, 3-, and 8-hour averaging times) and long-term (annual averaging time) modeled concentrations, the possibility of plant damage in the preserve can be examined for both acute and chronic exposure situations, respectively. The 1-, 3-, and 8-hour estimated NO_2 concentrations at the point of maximum impact are 3.8, 2.3, and 1.1 $\mu g/m^3$, respectively. These concentrations are approximately $7x10^{-5}$ to $1x10^{-3}$ of the levels that could potentially injure 5 percent of the plant foliage. For a chronic exposure, the annual estimated NO_2 concentration at the point of maximum impact in the preserve (0.020 $\mu g/m^3$) is $0.5x10^{-6}$ to $1.0x10^{-5}$ of the levels that caused minimal yield loss and chlorosis in plant tissue.

With the exception of ethylene, little information exists that examines the effects of gaseous organic compounds on plant growth. Ethylene is produced naturally by plants and is responsible for many of the responses a plant produces as it ages and enters the reproductive stage of development. Ethylene is also produced by the combustion of organic material such as agricultural and industrial waste. Losses due to ethylene have been documented in a cotton field when levels of ethylene rose above 7,500 $\mu g/m^3$. Lemons are affected by ethylene concentrations as low as 62 to 125 $\mu g/m^3$, at which point epinastic symptoms are observed (U.S. Department of Health, Education, and Welfare, 1969)

By assuming a threshold concentration of 62 $\mu g/m^3$ as a basis for risk assessment for the group of organic gases, an estimate of the impact of this group of compounds can be constructed. The maximum 1-hour concentrations of polycyclic organic matter and formaldehyde of 0.00001 and 0.0078 $\mu g/m^3$, respectively, are in the range of $1.6x10^{-7}$ to $1.3x10^{-4}$ of the values causing injury.

3.2 POTENTIAL IMPACTS ON SOILS

The majority of the soil in the Class I area is classified as Weekiwachee-Durbin muck. This is an euic, hyperthermic typic sufihemist that is characterized by high levels of sulfur and organic matter. This soil is flooded daily with the advent of high tide, and the pH ranges between 6.1 and 7.8. The upper level of this soil may contain as much as 4 percent sulfur (USDA, 1991).

The greatest threat to soils from increased SO_2 deposition is a decrease in pH or an increase of sulfur to levels considered unnatural or potentially toxic. Although ground deposition was not calculated, it is evident that the amount of SO_2 deposited would be inconsequential in light of the inherent sulfur content. The regular flooding of these soils by the Gulf of Mexico regulates the pH, and any rise in acidity in the soil would be buffered by this activity.

3.3 POTENTIAL IMPACTS ON WILDLIFE

The predicted SO_2 and NO_2 concentrations are well below the lowest observed effect levels in animals (Newman and Schreiber, 1988). Given these conditions, the proposed source's emissions poses no risk to wildlife. Because predicted levels are below those known to cause effect to vegetation, there is also no risk.

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Table 1. Summary of SO2 Emission Source Stack and Operating Data Used in the Modeling Analysis (Metric Units)
(Page 1 of 2)

Modeled Source ID	Source Description	UTM Coordinates (m)		Stack Data (m)		Operating Data		Modeled SO2 Emissions (g/sec)
		East	North	Height	Diameter	Temperature (K)	Velocity (m/sec)	
99002	FPC Debary	467500	3197200	15.24	4.21	819.8	56.21	466.40
99005	FPC Int City/7EA	446300	3126000	15.24	4.21	819.8	56.21	310.90
99008	FPC Int City/7FA	446300	3126000	15.24	7.04	880.8	32.07	276.10
1	FL Crushed Stone Kiln 1	360000	3162398	97.60	4.88	442.0	23.23	98.40
6	CF Ind. Baseline C	388000	3116000	60.35	2.44	353.0	16.40	-50.40
7	CF Ind. Proposed C	388000	3116000	60.35	2.44	353.0	17.77	54.60
9	CF Ind. Baseline D	388000	3116000	60.35	2.44	353.0	16.40	-50.40
10	CF Ind. Proposed D	388000	3116000	60.35	2.44	353.0	17.77	54.60
22	FL Mining and Mtls Kiln	356200	3169900	27.40	4.88	470.2	7.48	1.45
30	TECO Big Bend - Unit 4	361900	3075000	149.40	7.32	342.2	19.81	654.70
31	TECO Big Bend - Units 1,2 (24-hr)	361900	3075000	149.40	7.32	422.0	28.65	-2436.00
33	TECO Big Bend - Unit 3 (24-hr)	361900	3075000	149.40	7.32	418.0	14.33	-1218.00
40	Pasco Cty RRF	347100	3139200	83.82	3.05	394.3	15.70	14.10
46	Crystal River 4	334200	3204500	182.90	6.90	398.0	21.00	1008.80
47	Crystal River 5	334200	3204500	182.90	6.90	398.0	21.00	1008.00
48	Crystal River 1	334200	3204500	152.00	4.57	422.0	42.00	-314.00
49	Crystal River 2	334200	3204500	153.00	4.86	422.0	42.00	-1859.00
50	OUC Stanton 1	334200	3204500	167.60	5.80	325.7	21.60	105.40
51	OUC Stanton 2 (24-hr)	483500	3150600	167.60	5.80	324.2	23.50	359.00
52	Kissimmee Util Exist	460100	3129300	18.30	3.66	422.0	38.00	32.10
53	Hardee	404800	3057400	22.90	4.88	389.0	23.90	277.60
54	Stauffer Shutdown	325600	3116700	49.00	1.20	293.0	3.60	-52.07
55	Lakeland McIntosh 3	408500	3105800	76.20	4.88	350.0	19.70	500.10
56	Hillsborough Cty RRF	368200	3092700	50.00	1.80	491.0	18.30	21.40
57	Pinellas	335300	3084400	49.10	2.74	522.0	27.72	62.24
61	Evans Packing	383300	3135800	12.30	0.40	466.2	9.20	0.20
70	Asphalt Pavers 4	361400	3168400	8.50	1.08	357.4	10.95	2.25
71	Asphalt Pavers 3	359900	3162400	12.20	1.37	377.0	10.58	2.25
90	Lakeland Util CT	409185	3102754	30.48	5.79	783.2	28.22	29.11
91	IMC SAP 1,2,3 Baseline	396600	3078900	61.00	2.60	350.0	14.28	-170.10
92	IMC SAP 1,2,3 Projected	396600	3078900	61.00	2.60	350.0	15.31	182.85
93	IMC SAP 4,5 Projected	396600	3078900	60.70	2.60	350.0	15.31	121.90
94	IMC DAP	396600	3078900	36.60	1.83	319.1	20.15	5.54
101	Prop Pasco Cogen	385600	3139000	30.48	3.35	384.3	17.13	5.04
102	Prop Lake Cogen	434000	3198800	30.48	3.35	384.3	17.13	5.04
111	CF Bartow Retired H2SO4	408500	3083000	30.50	1.68	350.0	14.60	-110.60
112	CF Bartow DAP	408500	3083000	9.10	0.70	450.0	22.50	4.30
113	CF Bartow #7 H2SO4	408500	3083000	67.10	2.40	351.0	9.80	52.90
114	CLM Chl	361800	3088300	30.00	0.61	375.0	20.00	21.02
115	Conserve	398400	3084200	30.50	1.80	308.0	18.90	-15.20
116	Conserve #1 H2SO4	398400	3084200	45.70	2.30	352.0	10.30	42.00
117	Farmland 1,2 H2SO4	409500	3079500	30.48	1.37	311.0	20.18	-54.56
118	Farmland 3,4 H2SO4	409500	3079500	30.48	2.29	355.0	9.27	67.16
119	Farmland 5 H2SO4	409500	3079500	45.72	2.44	355.0	9.65	41.96
120	IMC Lonesome Mine Dryer 1	389550	3067930	38.10	2.90	339.0	10.13	18.40

Table 1. Summary of SO2 Emission Source Stack and Operating Data Used in the Modeling Analysis (Metric Units) (Page 2 of 2)

Modeled Source ID	Source Description	UTM Coordinates (m)		Stack Data (m)		Operating Data		Modeled SO2 Emissions (g/sec)
		East	North	Height	Diameter	Temperature (K)	Velocity (m/sec)	
121	IMC Lonesome Mine Dryer 2	389550	3067930	38.10	2.44	346.0	18.40	21.17
136	Royster #1	406700	3085200	51.00	2.13	356.0	9.90	-257.60
137	Royster #2	406700	3085200	61.00	2.13	360.0	12.20	35.70
140	USSAC Ft Meade H2SO4 1	416120	3068620	53.40	2.59	355.0	15.91	63.00
141	USSAC Ft Meade H2SO4 2	416120	3068620	53.40	2.59	355.0	15.91	63.00
142	USSAC Ft Meade H2SO4 X	416210	3068740	29.00	3.02	314.0	6.77	-78.80
143	WR Grace Retired H2SO4	409700	3086000	45.70	1.40	352.0	16.50	-216.00
144	WR Grace 2 46 16	409700	3086000	61.00	2.80	346.0	7.30	73.60
145	WR Grace 2 46 17	409500	3086500	61.00	1.52	347.0	28.40	72.00
147	Gardinier SAP 4,5,6	363400	3082400	22.60	1.52	322.0	19.50	-196.30
148	Gardinier SAP 7 Exist	363400	3082400	45.70	2.29	355.0	9.20	-50.71
149	Gardinier SAP 7 Mod	363400	3082400	45.70	2.29	355.0	9.20	36.75
150	AMAX	394800	3067720	8.20	0.41	505.0	7.57	0.60
151	AMAX	394850	3069770	30.50	1.82	334.0	7.26	16.35
154	Mobil-Nichols	398290	3084290	25.90	2.29	339.0	15.20	2.44
250	FDOC Boiler #3	382200	3166100	9.14	0.61	478.0	4.57	2.99
260	E R Jahna (Lime Dryer)	386700	3155800	10.67	1.83	327.0	8.99	0.82
270	Oman Const (Asphalt)	359800	3164900	7.62	1.83	347.0	6.29	2.09
280	Dris Paving (Asphalt)	340600	3119200	12.20	3.05	339.0	6.47	0.23
290	Overstreet Paving (Asphalt)	355900	3143700	9.14	1.30	408.0	16.00	3.67
300	New Pt Richey Hosp Blr#1	331200	3124500	10.98	0.31	544.0	3.88	0.06
310	New Pt Richey Hosp Blr#2	331200	3124500	10.98	0.31	544.0	3.88	0.03
320	Hosp Corp of Am Boiler #1	333400	3141000	10.98	0.31	533.0	4.00	0.08
330	Hosp Corp of Am Boiler #2	333400	3141000	10.98	0.31	533.0	4.00	0.08
340	Couch Const-Odessa (Asphalt)	340700	3119500	9.14	1.40	436.0	22.30	7.25
350	Couch Const-Zephyrhills (Asphalt)	390300	3129400	6.10	1.38	422.0	21.00	3.54
400	Agrico Baseline	407500	3071300	45.73	1.60	350.0	26.40	-75.60
410	Agrico Proposed	407500	3071300	45.73	1.60	350.0	39.06	113.50
88020	Ark Energy - CO2 Plant	413600	3080600	51.82	0.91	320.0	20.27	0.65
99020	Ark Energy - Combustion Turbine	413600	3080600	38.10	4.57	378.0	20.67	12.70

Note: Ark Energy modeled at 20°F design temperature.

Table 2. Maximum Predicted SO2 Concentrations from the Screening Analysis for Comparison to PSD Class I Increments

Averaging Period	Maximum Concentration (µg/m)	Receptor Location (UTM) East (km)	Receptor Location (UTM) North (km)	Period Julian Day	Period Hour Ending	Period Year
3-Hour*	35.5	331.5	3183.4	161	3	1982
	27.2	336.5	3183.4	136	6	1983
	37.9	331.5	3183.4	156	12	1984
	38.0	331.5	3183.4	29	12	1985
	33.9	331.5	3183.4	108	12	1986
24-Hour*	7.40	340.3	3169.8	335	24	1982
	7.06	340.3	3165.7	211	24	1983
	7.24	331.5	3183.4	156	24	1984
	7.22	340.3	3169.8	334	24	1985
	7.71	343.0	3176.2	193	24	1986
Annual	1.03	340.3	3165.7	-	-	1982
	0.84	340.3	3165.7	-	-	1983
	1.06	340.3	3165.7	-	-	1984
	0.96	340.3	3165.7	-	-	1985
	1.18	342.0	3174.0	-	-	1986

Note: - = Not applicable.
µg/m = micrograms per cubic meter.
km = kilometers.

* Highest, second-highest concentrations predicted for this averaging period.

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 1 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1982	3	232	3	343.7	3178.3	5.58	0.49
1982	3	240	6	339.0	3183.4	3.42	0.51
1982	3	240	6	343.7	3178.3	3.31	0.50
1982	3	240	6	343.0	3176.2	2.49	0.49
1982	3	248	3	343.7	3178.3	0.82	0.49
1982	3	248	3	339.0	3183.4	0.30	0.51
1982	3	355	3	340.3	3165.7	-1.18	0.51
1982	3	22	24	336.5	3183.4	-2.47	0.49
1982	3	345	6	342.0	3174.0	-2.59	0.49
1982	3	232	3	339.0	3183.4	-3.43	0.50
1982	3	232	3	343.0	3176.2	-3.66	0.49
1982	3	345	6	343.0	3176.2	-3.93	0.49
1982	3	22	24	342.0	3174.0	-6.75	0.48
1982	3	199	6	343.7	3178.3	-8.29	0.49
1982	3	240	3	342.0	3174.0	-8.88	0.49
1982	3	49	6	340.3	3169.8	-9.74	0.48
1982	3	240	3	334.0	3183.4	-10.50	0.49
1982	3	210	3	342.0	3174.0	-10.85	0.79
1982	3	248	3	343.0	3176.2	-11.82	0.49
1982	3	145	3	343.0	3176.2	-12.00	0.56
1982	3	354	24	340.3	3167.7	-12.19	0.52
1982	3	49	6	340.3	3167.7	-12.35	0.52
1982	3	79	24	336.5	3183.4	-12.57	0.49
1982	3	199	6	339.0	3183.4	-12.68	0.50
1982	3	80	6	340.3	3165.7	-12.91	0.52
1982	3	264	3	340.3	3165.7	-13.37	0.54
1982	3	363	6	331.5	3183.4	-15.62	0.73
1982	3	199	6	343.0	3176.2	-16.20	0.49
1982	3	145	3	336.5	3183.4	-16.60	0.59
1982	3	210	3	334.0	3183.4	-16.89	0.85
1982	3	363	6	340.7	3171.9	-17.22	0.80
1982	3	176	24	342.0	3174.0	-17.35	0.84
1982	3	79	24	342.0	3174.0	-17.97	0.48
1982	3	263	9	340.3	3165.7	-18.17	0.64
1982	3	210	24	341.1	3183.4	-18.49	0.60
1982	3	210	24	342.4	3180.6	-21.19	0.57
1982	3	176	24	334.0	3183.4	-21.75	0.90
1982	3	210	24	343.7	3178.3	-22.49	0.55
1982	3	145	3	342.0	3174.0	-23.52	0.58
1982	3	210	3	340.7	3171.9	-23.81	1.07
1982	3	210	3	331.5	3183.4	-27.06	0.97
1982	3	363	6	340.3	3169.8	-27.19	0.81
1982	3	363	6	340.3	3167.7	-29.77	0.55
1982	3	210	3	340.3	3169.8	-32.94	0.81

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 2 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1982	3	176	24	331.5	3183.4	-38.35	1.07
1982	3	176	24	340.7	3171.9	-40.87	1.17
1982	3	176	24	340.3	3167.7	-44.95	0.54
1982	3	176	24	340.3	3169.8	-49.80	0.91
1982	24	205	24	340.3	3169.8	3.89	0.09
1982	24	49	24	340.3	3169.8	2.88	0.08
1982	24	205	24	340.3	3167.7	2.45	0.10
1982	24	204	24	343.7	3178.3	2.37	0.08
1982	24	263	24	340.3	3165.7	2.34	0.11
1982	24	204	24	342.4	3180.6	2.27	0.08
1982	24	155	24	340.3	3165.7	2.24	0.07
1982	24	49	24	340.3	3167.7	2.16	0.09
1982	24	364	24	334.0	3183.4	2.07	0.07
1982	24	339	24	342.4	3180.6	2.04	0.10
1982	24	339	24	343.7	3178.3	2.02	0.10
1982	24	339	24	341.1	3183.4	2.01	0.09
1982	24	204	24	341.1	3183.4	1.98	0.07
1982	24	22	24	343.0	3176.2	1.93	0.07
1982	24	155	24	340.3	3167.7	1.89	0.07
1982	24	339	24	343.0	3176.2	1.62	0.10
1982	24	49	24	340.3	3165.7	1.62	0.08
1982	24	362	24	343.0	3176.2	1.55	0.07
1982	24	339	24	339.0	3183.4	1.50	0.09
1982	24	263	24	340.3	3167.7	1.46	0.09
1982	24	364	24	336.5	3183.4	1.39	0.09
1982	24	145	24	343.0	3176.2	1.35	0.07
1982	24	116	24	340.3	3165.7	1.30	0.08
1982	24	205	24	340.3	3165.7	1.15	0.09
1982	24	339	24	336.5	3183.4	1.12	0.09
1982	24	204	24	339.0	3183.4	1.06	0.08
1982	24	191	24	342.0	3174.0	0.88	0.07
1982	24	345	24	343.0	3176.2	0.88	0.07
1982	24	339	24	342.0	3174.0	0.86	0.09
1982	24	204	24	336.5	3183.4	0.83	0.08
1982	24	232	24	340.3	3165.7	0.80	0.07
1982	24	364	24	339.0	3183.4	0.78	0.10
1982	24	204	24	343.0	3176.2	0.65	0.09
1982	24	248	24	339.0	3183.4	0.62	0.07
1982	24	22	24	336.5	3183.4	0.60	0.08
1982	24	145	24	336.5	3183.4	0.38	0.07
1982	24	339	24	334.0	3183.4	0.38	0.08
1982	24	364	24	341.1	3183.4	0.28	0.11
1982	24	364	24	340.7	3171.9	0.28	0.07

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 3 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1982	24	22	24	342.0	3174.0	0.17	0.08
1982	24	364	24	340.3	3169.8	0.10	0.07
1982	24	364	24	343.0	3176.2	0.05	0.10
1982	24	364	24	342.4	3180.6	0.03	0.11
1982	24	204	24	342.0	3174.0	-0.04	0.08
1982	24	191	24	334.0	3183.4	-0.05	0.08
1982	24	364	24	343.7	3178.3	-0.25	0.11
1982	24	145	24	342.0	3174.0	-0.28	0.07
1982	24	199	24	343.7	3178.3	-0.39	0.07
1982	24	364	24	342.0	3174.0	-0.45	0.09
1982	24	307	24	340.7	3171.9	-0.47	0.07
1982	24	363	24	340.7	3171.9	-0.47	0.10
1982	24	240	24	336.5	3183.4	-0.50	0.09
1982	24	210	24	341.1	3183.4	-0.64	0.09
1982	24	191	24	340.7	3171.9	-0.77	0.10
1982	24	80	24	340.3	3167.7	-0.78	0.07
1982	24	199	24	343.0	3176.2	-0.88	0.07
1982	24	199	24	339.0	3183.4	-0.89	0.07
1982	24	240	24	334.0	3183.4	-0.99	0.08
1982	24	240	24	339.0	3183.4	-1.03	0.09
1982	24	65	24	340.3	3167.7	-1.16	0.08
1982	24	240	24	343.0	3176.2	-1.22	0.10
1982	24	144	24	340.7	3171.9	-1.23	0.07
1982	24	176	24	342.0	3174.0	-1.28	0.11
1982	24	307	24	340.3	3169.8	-1.31	0.07
1982	24	240	24	341.1	3183.4	-1.36	0.08
1982	24	240	24	342.4	3180.6	-1.51	0.09
1982	24	240	24	342.0	3174.0	-1.51	0.09
1982	24	210	24	342.4	3180.6	-1.54	0.09
1982	24	65	24	340.3	3165.7	-1.59	0.08
1982	24	80	24	340.3	3165.7	-1.67	0.09
1982	24	191	24	340.3	3169.8	-1.73	0.08
1982	24	176	24	334.0	3183.4	-1.74	0.12
1982	24	191	24	331.5	3183.4	-1.75	0.09
1982	24	240	24	343.7	3178.3	-1.85	0.09
1982	24	173	24	334.0	3183.4	-2.04	0.07
1982	24	210	24	334.0	3183.4	-2.15	0.13
1982	24	210	24	343.7	3178.3	-2.19	0.09
1982	24	210	24	339.0	3183.4	-2.21	0.08
1982	24	264	24	340.3	3167.7	-2.39	0.09
1982	24	210	24	336.5	3183.4	-2.48	0.09
1982	24	363	24	331.5	3183.4	-2.53	0.09
1982	24	144	24	340.3	3169.8	-2.57	0.08
1982	24	210	24	331.5	3183.4	-2.76	0.14

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 4 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1982	24	363	24	340.3	3169.8	-2.97	0.10
1982	24	153	24	343.0	3176.2	-3.49	0.07
1982	24	173	24	342.0	3174.0	-3.54	0.08
1982	24	176	24	331.5	3183.4	-3.91	0.14
1982	24	264	24	340.3	3165.7	-4.25	0.12
1982	24	210	24	343.0	3176.2	-4.34	0.09
1982	24	355	24	340.3	3165.7	-4.36	0.09
1982	24	153	24	342.0	3174.0	-4.45	0.08
1982	24	153	24	334.0	3183.4	-4.49	0.07
1982	24	210	24	342.0	3174.0	-4.84	0.13
1982	24	176	24	340.7	3171.9	-4.88	0.15
1982	24	153	24	340.7	3171.9	-5.05	0.08
1982	24	176	24	340.3	3167.7	-5.11	0.07
1982	24	153	24	340.3	3169.8	-5.24	0.07
1982	24	153	24	331.5	3183.4	-5.44	0.07
1982	24	210	24	340.3	3167.7	-5.47	0.07
1982	24	210	24	340.7	3171.9	-5.60	0.16
1982	24	176	24	340.3	3169.8	-6.08	0.12
1982	24	210	24	340.3	3169.8	-6.52	0.12
1983	3	225	3	342.0	3174.0	-2.83	0.58
1983	3	264	6	334.0	3183.4	-4.60	0.48
1983	3	224	6	340.3	3165.7	-5.74	0.54
1983	3	135	6	342.0	3174.0	-8.63	0.51
1983	3	225	3	334.0	3183.4	-8.77	0.59
1983	3	336	24	343.0	3176.2	-9.02	0.60
1983	3	135	6	334.0	3183.4	-9.36	0.51
1983	3	30	3	341.1	3183.4	-10.17	0.51
1983	3	225	3	340.7	3171.9	-10.38	0.56
1983	3	30	3	334.0	3183.4	-10.58	0.49
1983	3	247	3	342.0	3174.0	-10.98	0.72
1983	3	30	3	342.4	3180.6	-11.24	0.50
1983	3	186	21	340.7	3171.9	-11.83	0.51
1983	3	225	3	331.5	3183.4	-11.90	0.51
1983	3	129	24	343.0	3176.2	-12.01	0.56
1983	3	174	6	343.0	3176.2	-12.06	0.57
1983	3	30	3	343.7	3178.3	-12.19	0.50
1983	3	39	24	342.0	3174.0	-12.87	0.54
1983	3	122	3	341.1	3183.4	-14.01	0.49
1983	3	279	3	341.1	3183.4	-14.55	0.50
1983	3	135	6	331.5	3183.4	-14.56	0.66
1983	3	242	6	340.3	3165.7	-14.61	0.54
1983	3	336	24	336.5	3183.4	-14.67	0.73
1983	3	285	21	331.5	3183.4	-14.90	0.56

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 5 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1983	3	30	3	342.0	3174.0	-15.01	0.51
1983	3	39	24	334.0	3183.4	-15.56	0.55
1983	3	247	3	334.0	3183.4	-16.03	0.73
1983	3	285	21	340.7	3171.9	-16.11	0.61
1983	3	135	6	340.7	3171.9	-16.44	0.74
1983	3	129	24	336.5	3183.4	-16.60	0.59
1983	3	174	6	336.5	3183.4	-16.68	0.60
1983	3	258	24	340.3	3167.7	-16.97	0.55
1983	3	186	21	340.3	3169.8	-18.80	0.51
1983	3	135	6	340.3	3169.8	-22.02	0.84
1983	3	39	24	331.5	3183.4	-22.87	0.48
1983	3	247	3	331.5	3183.4	-22.96	0.63
1983	3	135	6	340.3	3165.7	-23.52	0.59
1983	3	129	24	342.0	3174.0	-23.63	0.58
1983	3	174	6	342.0	3174.0	-23.78	0.59
1983	3	39	24	340.7	3171.9	-24.62	0.53
1983	3	135	6	340.3	3167.7	-24.79	0.78
1983	3	336	24	342.0	3174.0	-25.17	0.94
1983	3	285	21	340.3	3169.8	-25.32	0.62
1983	3	247	3	340.7	3171.9	-26.55	0.70
1983	3	244	3	339.0	3183.4	-26.71	0.61
1983	3	336	24	334.0	3183.4	-26.83	0.87
1983	3	244	3	342.4	3180.6	-27.92	0.56
1983	3	244	3	343.7	3178.3	-28.38	0.59
1983	3	336	24	331.5	3183.4	-31.92	0.64
1983	3	336	24	340.7	3171.9	-37.16	0.70
1983	3	244	3	343.0	3176.2	-39.79	0.59
1983	24	247	24	342.0	3174.0	3.82	0.13
1983	24	247	24	336.5	3183.4	3.03	0.09
1983	24	285	24	342.4	3180.6	2.83	0.09
1983	24	285	24	341.1	3183.4	2.82	0.09
1983	24	336	24	343.0	3176.2	2.69	0.09
1983	24	285	24	343.7	3178.3	2.55	0.09
1983	24	174	24	343.0	3176.2	2.41	0.09
1983	24	285	24	339.0	3183.4	2.22	0.07
1983	24	122	24	343.7	3178.3	2.06	0.07
1983	24	135	24	336.5	3183.4	1.85	0.07
1983	24	99	24	343.7	3178.3	1.55	0.07
1983	24	247	24	334.0	3183.4	1.54	0.13
1983	24	285	24	334.0	3183.4	1.51	0.08
1983	24	122	24	342.4	3180.6	1.46	0.08
1983	24	247	24	340.7	3171.9	1.34	0.13
1983	24	285	24	342.0	3174.0	1.26	0.07

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 6 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1983	24	135	24	342.0	3174.0	1.19	0.09
1983	24	174	24	336.5	3183.4	1.06	0.09
1983	24	122	24	341.1	3183.4	1.04	0.08
1983	24	99	24	339.0	3183.4	1.02	0.08
1983	24	174	24	342.0	3174.0	0.81	0.09
1983	24	135	24	334.0	3183.4	0.68	0.09
1983	24	247	24	340.3	3169.8	0.56	0.08
1983	24	258	24	340.3	3169.8	0.54	0.09
1983	24	336	24	336.5	3183.4	0.36	0.10
1983	24	135	24	340.7	3171.9	0.30	0.12
1983	24	99	24	343.0	3176.2	0.26	0.09
1983	24	36	24	341.1	3183.4	0.23	0.07
1983	24	135	24	340.3	3165.7	0.18	0.09
1983	24	285	24	331.5	3183.4	0.06	0.11
1983	24	135	24	340.3	3167.7	-0.10	0.11
1983	24	135	24	340.3	3169.8	-0.27	0.12
1983	24	135	24	331.5	3183.4	-0.29	0.10
1983	24	36	24	342.4	3180.6	-0.37	0.07
1983	24	285	24	340.7	3171.9	-0.50	0.12
1983	24	99	24	336.5	3183.4	-0.50	0.08
1983	24	247	24	331.5	3183.4	-0.54	0.12
1983	24	244	24	341.1	3183.4	-0.62	0.08
1983	24	258	24	340.3	3167.7	-0.69	0.10
1983	24	174	24	334.0	3183.4	-0.73	0.08
1983	24	244	24	343.7	3178.3	-0.77	0.10
1983	24	36	24	343.7	3178.3	-0.80	0.08
1983	24	225	24	342.0	3174.0	-0.88	0.08
1983	24	244	24	339.0	3183.4	-0.98	0.10
1983	24	244	24	342.4	3180.6	-0.99	0.09
1983	24	285	24	340.3	3165.7	-1.01	0.08
1983	24	99	24	342.0	3174.0	-1.03	0.09
1983	24	264	24	342.0	3174.0	-1.12	0.08
1983	24	336	24	342.0	3174.0	-1.13	0.13
1983	24	264	24	334.0	3183.4	-1.14	0.08
1983	24	224	24	340.3	3165.7	-1.19	0.08
1983	24	99	24	340.3	3165.7	-1.20	0.07
1983	24	99	24	340.3	3167.7	-1.30	0.07
1983	24	336	24	334.0	3183.4	-1.30	0.12
1983	24	258	24	340.3	3165.7	-1.35	0.09
1983	24	256	24	340.3	3165.7	-1.41	0.07
1983	24	99	24	340.3	3169.8	-1.45	0.08
1983	24	249	24	336.5	3183.4	-1.47	0.07
1983	24	39	24	342.0	3174.0	-1.51	0.07
1983	24	99	24	340.7	3171.9	-1.52	0.09

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 7 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1983	24	244	24	336.5	3183.4	-1.56	0.08
1983	24	98	24	340.3	3167.7	-1.59	0.08
1983	24	99	24	334.0	3183.4	-1.83	0.08
1983	24	285	24	340.3	3169.8	-1.83	0.12
1983	24	285	24	340.3	3167.7	-1.94	0.10
1983	24	186	24	340.7	3171.9	-2.01	0.08
1983	24	129	24	343.0	3176.2	-2.03	0.09
1983	24	186	24	331.5	3183.4	-2.20	0.08
1983	24	39	24	334.0	3183.4	-2.28	0.08
1983	24	279	24	341.1	3183.4	-2.37	0.08
1983	24	244	24	343.0	3176.2	-2.39	0.10
1983	24	279	24	342.4	3180.6	-2.40	0.08
1983	24	99	24	331.5	3183.4	-2.45	0.08
1983	24	279	24	343.7	3178.3	-2.53	0.08
1983	24	336	24	331.5	3183.4	-2.68	0.10
1983	24	129	24	336.5	3183.4	-2.78	0.10
1983	24	336	24	340.7	3171.9	-2.92	0.11
1983	24	98	24	340.3	3165.7	-2.94	0.12
1983	24	186	24	340.3	3169.8	-3.19	0.08
1983	24	39	24	340.7	3171.9	-3.20	0.07
1983	24	264	24	340.7	3171.9	-3.27	0.07
1983	24	225	24	340.7	3171.9	-3.45	0.07
1983	24	129	24	342.0	3174.0	-3.97	0.10
1983	24	129	24	334.0	3183.4	-4.04	0.08
1983	24	225	24	334.0	3183.4	-4.07	0.08
1983	24	242	24	340.3	3165.7	-4.34	0.08
1984	3	145	6	342.4	3180.6	-9.17	0.55
1984	3	110	9	340.3	3165.7	-9.33	0.53
1984	3	145	6	343.7	3178.3	-10.77	0.59
1984	3	110	24	331.5	3183.4	-11.78	0.55
1984	3	193	24	334.0	3183.4	-12.04	0.48
1984	3	357	9	340.3	3165.7	-14.16	0.53
1984	3	123	6	331.5	3183.4	-14.22	0.55
1984	3	246	24	340.3	3167.7	-14.68	0.52
1984	3	110	24	341.1	3183.4	-15.11	0.60
1984	3	145	6	339.0	3183.4	-15.13	0.61
1984	3	123	6	340.7	3171.9	-15.52	0.60
1984	3	110	24	340.7	3171.9	-15.92	0.60
1984	3	194	3	340.3	3165.7	-19.11	0.65
1984	3	145	6	343.0	3176.2	-20.10	0.59
1984	3	110	24	342.4	3180.6	-20.11	0.57
1984	3	110	24	340.3	3169.8	-20.72	0.60
1984	3	110	24	343.7	3178.3	-22.06	0.55

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 8 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1984	3	123	6	340.3	3169.8	-24.48	0.61
1984	24	145	24	341.1	3183.4	1.87	0.08
1984	24	145	24	342.4	3180.6	1.32	0.10
1984	24	145	24	343.7	3178.3	1.08	0.10
1984	24	246	24	340.3	3167.7	0.96	0.07
1984	24	145	24	339.0	3183.4	0.72	0.11
1984	24	145	24	342.0	3174.0	0.25	0.08
1984	24	141	24	342.0	3174.0	0.19	0.07
1984	24	145	24	343.0	3176.2	0.16	0.11
1984	24	110	24	340.7	3171.9	0.09	0.11
1984	24	110	24	341.1	3183.4	0.07	0.15
1984	24	110	24	331.5	3183.4	-0.06	0.10
1984	24	55	24	334.0	3183.4	-0.13	0.08
1984	24	110	24	340.3	3169.8	-0.35	0.13
1984	24	55	24	342.0	3174.0	-0.38	0.08
1984	24	145	24	336.5	3183.4	-0.84	0.09
1984	24	110	24	342.4	3180.6	-1.13	0.14
1984	24	110	24	340.3	3167.7	-1.53	0.12
1984	24	110	24	339.0	3183.4	-1.58	0.10
1984	24	110	24	340.3	3165.7	-1.74	0.11
1984	24	194	24	340.3	3165.7	-1.80	0.09
1984	24	110	24	343.7	3178.3	-1.81	0.13
1984	24	193	24	334.0	3183.4	-1.93	0.08
1984	24	193	24	342.0	3174.0	-2.13	0.08
1984	24	193	24	331.5	3183.4	-2.75	0.07
1984	24	55	24	340.7	3171.9	-2.91	0.07
1984	24	193	24	340.7	3171.9	-3.25	0.08
1984	24	110	24	343.0	3176.2	-3.53	0.08
1984	24	123	24	331.5	3183.4	-4.83	0.08
1984	24	123	24	340.7	3171.9	-5.47	0.09
1984	24	123	24	340.3	3169.8	-7.05	0.09
1985	3	234	6	342.0	3174.0	10.29	0.48
1985	3	234	6	334.0	3183.4	9.51	0.48
1985	3	302	3	340.3	3165.7	-4.07	0.54
1985	3	206	6	342.0	3174.0	-4.38	0.49
1985	3	231	9	340.7	3171.9	-4.98	0.50
1985	3	233	24	342.0	3174.0	-5.46	0.49
1985	3	140	3	340.3	3167.7	-5.85	0.48
1985	3	206	6	336.5	3183.4	-6.78	0.50
1985	3	168	6	334.0	3183.4	-7.32	0.48
1985	3	288	6	340.7	3171.9	-7.58	0.50
1985	3	231	9	340.3	3169.8	-9.24	0.51

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 9 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1985	3	87	6	342.0	3174.0	-9.48	0.56
1985	3	88	24	341.1	3183.4	-10.76	0.49
1985	3	64	3	340.3	3169.8	-11.12	0.57
1985	3	233	24	331.5	3183.4	-11.21	0.57
1985	3	198	6	340.7	3171.9	-11.34	0.51
1985	3	198	24	336.5	3183.4	-11.44	0.50
1985	3	303	3	343.0	3176.2	-11.51	0.53
1985	3	87	6	334.0	3183.4	-11.59	0.57
1985	3	24	6	340.7	3171.9	-12.20	0.52
1985	3	288	6	340.3	3169.8	-12.48	0.51
1985	3	303	3	336.5	3183.4	-12.67	0.50
1985	3	24	6	340.3	3165.7	-13.55	0.52
1985	3	27	24	340.7	3171.9	-14.22	0.58
1985	3	24	6	340.3	3169.8	-14.44	0.54
1985	3	27	24	331.5	3183.4	-14.62	0.53
1985	3	24	6	340.3	3167.7	-14.81	0.54
1985	3	168	6	342.0	3174.0	-16.00	0.48
1985	3	303	3	342.0	3174.0	-16.56	0.49
1985	3	140	3	340.3	3165.7	-16.66	0.66
1985	3	233	24	340.7	3171.9	-16.73	0.63
1985	3	198	24	342.0	3174.0	-16.81	0.49
1985	3	198	6	340.3	3169.8	-17.64	0.51
1985	3	233	24	340.3	3169.8	-20.69	0.57
1985	3	64	3	340.3	3167.7	-20.95	0.67
1985	3	87	6	331.5	3183.4	-21.29	0.50
1985	3	27	24	340.3	3169.8	-21.79	0.58
1985	3	3	3	339.0	3183.4	-21.99	0.48
1985	3	3	3	343.7	3178.3	-22.91	0.56
1985	3	3	3	341.1	3183.4	-22.94	0.58
1985	3	3	3	342.4	3180.6	-23.59	0.57
1985	3	87	6	340.7	3171.9	-23.73	0.55
1985	3	64	3	340.3	3165.7	-26.78	0.58
1985	24	335	24	341.1	3183.4	2.42	0.11
1985	24	335	24	342.4	3180.6	1.73	0.11
1985	24	335	24	343.7	3178.3	1.45	0.12
1985	24	303	24	340.3	3169.8	1.09	0.07
1985	24	335	24	339.0	3183.4	1.04	0.10
1985	24	303	24	340.3	3167.7	1.01	0.08
1985	24	206	24	334.0	3183.4	0.83	0.07
1985	24	335	24	336.5	3183.4	0.82	0.08
1985	24	303	24	340.3	3165.7	0.80	0.07
1985	24	233	24	331.5	3183.4	0.76	0.08
1985	24	233	24	334.0	3183.4	0.57	0.07

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 10 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1985	24	303	24	343.0	3176.2	0.22	0.07
1985	24	206	24	336.5	3183.4	0.14	0.09
1985	24	335	24	343.0	3176.2	0.02	0.10
1985	24	233	24	342.0	3174.0	-0.07	0.07
1985	24	168	24	334.0	3183.4	-0.08	0.07
1985	24	87	24	342.0	3174.0	-0.12	0.09
1985	24	24	24	334.0	3183.4	-0.29	0.07
1985	24	302	24	340.3	3165.7	-0.51	0.08
1985	24	24	24	342.0	3174.0	-0.52	0.08
1985	24	27	24	340.7	3171.9	-0.58	0.08
1985	24	206	24	342.0	3174.0	-0.65	0.09
1985	24	87	24	334.0	3183.4	-0.70	0.09
1985	24	24	24	331.5	3183.4	-0.76	0.08
1985	24	140	24	340.3	3167.7	-0.89	0.08
1985	24	24	24	340.3	3165.7	-1.07	0.08
1985	24	24	24	340.7	3171.9	-1.12	0.09
1985	24	206	24	343.0	3176.2	-1.24	0.09
1985	24	233	24	340.7	3171.9	-1.33	0.09
1985	24	27	24	331.5	3183.4	-1.36	0.08
1985	24	24	24	340.3	3169.8	-1.39	0.09
1985	24	24	24	340.3	3167.7	-1.40	0.08
1985	24	233	24	341.1	3183.4	-1.41	0.08
1985	24	198	24	340.3	3169.8	-1.50	0.07
1985	24	233	24	342.4	3180.6	-1.64	0.08
1985	24	87	24	340.7	3171.9	-1.69	0.09
1985	24	198	24	336.5	3183.4	-1.69	0.08
1985	24	168	24	342.0	3174.0	-1.77	0.07
1985	24	198	24	331.5	3183.4	-1.91	0.08
1985	24	27	24	340.3	3169.8	-1.93	0.08
1985	24	87	24	331.5	3183.4	-1.98	0.08
1985	24	140	24	340.3	3165.7	-2.00	0.10
1985	24	64	24	340.3	3169.8	-2.13	0.07
1985	24	88	24	343.7	3178.3	-2.23	0.09
1985	24	198	24	334.0	3183.4	-2.29	0.09
1985	24	233	24	343.7	3178.3	-2.35	0.08
1985	24	233	24	340.3	3169.8	-2.38	0.08
1985	24	88	24	341.1	3183.4	-2.63	0.10
1985	24	198	24	342.0	3174.0	-2.67	0.09
1985	24	198	24	340.7	3171.9	-2.85	0.09
1985	24	88	24	342.4	3180.6	-3.05	0.09
1985	24	64	24	340.3	3167.7	-3.18	0.08
1985	24	64	24	340.3	3165.7	-3.83	0.07
1985	24	19	24	341.1	3183.4	-4.32	0.08
1985	24	3	24	343.7	3178.3	-5.34	0.07

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 11 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1985	24	3	24	342.4	3180.6	-5.81	0.07
1985	24	3	24	341.1	3183.4	-6.00	0.08
1986	3	215	6	340.3	3167.7	1.06	0.55
1986	3	344	24	341.1	3183.4	-3.52	0.57
1986	3	344	24	342.4	3180.6	-3.59	0.65
1986	3	139	6	340.3	3169.8	-4.73	0.56
1986	3	344	24	343.7	3178.3	-4.74	0.69
1986	3	139	6	340.3	3167.7	-7.17	0.60
1986	3	163	3	334.0	3183.4	-7.21	0.59
1986	3	163	3	342.0	3174.0	-7.55	0.58
1986	3	344	24	339.0	3183.4	-7.84	0.69
1986	3	299	3	340.3	3167.7	-9.70	0.57
1986	3	139	6	340.3	3165.7	-10.20	0.59
1986	3	335	3	342.0	3174.0	-10.47	0.48
1986	3	344	24	343.0	3176.2	-11.22	0.69
1986	3	321	6	340.3	3165.7	-11.24	0.53
1986	3	345	3	331.5	3183.4	-11.30	0.60
1986	3	75	6	340.7	3171.9	-11.41	0.52
1986	3	227	6	341.1	3183.4	-11.60	0.50
1986	3	344	24	336.5	3183.4	-12.53	0.54
1986	3	70	24	336.5	3183.4	-12.59	0.49
1986	3	150	6	340.3	3165.7	-12.94	0.53
1986	3	345	3	340.7	3171.9	-13.87	0.66
1986	3	163	3	331.5	3183.4	-14.09	0.52
1986	3	150	3	340.3	3167.7	-14.10	0.54
1986	3	225	24	340.3	3165.7	-14.62	0.54
1986	3	299	3	340.3	3165.7	-14.80	0.68
1986	3	75	6	340.3	3169.8	-15.10	0.54
1986	3	335	3	340.7	3171.9	-15.11	0.48
1986	3	75	6	340.3	3167.7	-15.94	0.49
1986	3	47	24	340.7	3171.9	-17.40	0.52
1986	3	70	24	342.0	3174.0	-18.00	0.48
1986	3	47	24	340.3	3169.8	-19.65	0.50
1986	3	163	3	340.7	3171.9	-20.27	0.57
1986	3	345	3	340.3	3169.8	-22.41	0.71
1986	3	345	3	340.3	3167.7	-25.12	0.57
1986	3	168	3	340.3	3165.7	-25.22	0.65
1986	3	217	3	342.0	3174.0	-34.66	0.58
1986	3	217	3	334.0	3183.4	-40.09	0.58
1986	3	217	3	340.7	3171.9	-43.82	0.56
1986	3	217	3	331.5	3183.4	-51.02	0.51
1986	24	215	24	331.5	3183.4	5.22	0.09

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 12 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location UTM East (km)	Receptor Location UTM North (km)	Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
1986	24	215	24	340.7	3171.9	4.52	0.11
1986	24	344	24	331.5	3183.4	2.97	0.08
1986	24	344	24	341.1	3183.4	2.87	0.13
1986	24	344	24	342.4	3180.6	2.57	0.14
1986	24	344	24	343.7	3178.3	2.23	0.15
1986	24	215	24	340.3	3169.8	2.03	0.15
1986	24	344	24	340.7	3171.9	1.74	0.09
1986	24	163	24	342.0	3174.0	1.72	0.09
1986	24	168	24	340.3	3167.7	1.68	0.07
1986	24	344	24	339.0	3183.4	1.52	0.15
1986	24	163	24	334.0	3183.4	1.34	0.09
1986	24	335	24	343.0	3176.2	0.90	0.07
1986	24	344	24	342.0	3174.0	0.82	0.13
1986	24	335	24	342.0	3174.0	0.61	0.12
1986	24	344	24	343.0	3176.2	0.54	0.16
1986	24	215	24	340.3	3167.7	0.50	0.16
1986	24	168	24	340.3	3165.7	0.49	0.10
1986	24	344	24	334.0	3183.4	0.09	0.10
1986	24	205	24	341.1	3183.4	0.07	0.10
1986	24	335	24	340.7	3171.9	-0.10	0.14
1986	24	150	24	340.3	3169.8	-0.20	0.11
1986	24	205	24	343.7	3178.3	-0.38	0.09
1986	24	335	24	331.5	3183.4	-0.39	0.12
1986	24	335	24	336.5	3183.4	-0.39	0.09
1986	24	205	24	342.4	3180.6	-0.42	0.10
1986	24	335	24	334.0	3183.4	-0.44	0.11
1986	24	163	24	331.5	3183.4	-0.55	0.08
1986	24	344	24	336.5	3183.4	-0.69	0.14
1986	24	215	24	340.3	3165.7	-0.69	0.14
1986	24	299	24	340.3	3169.8	-0.87	0.09
1986	24	205	24	339.0	3183.4	-0.95	0.08
1986	24	335	24	340.3	3167.7	-1.30	0.09
1986	24	70	24	342.4	3180.6	-1.37	0.08
1986	24	227	24	341.1	3183.4	-1.43	0.08
1986	24	239	24	340.3	3169.8	-1.57	0.08
1986	24	335	24	340.3	3169.8	-1.62	0.12
1986	24	239	24	340.7	3171.9	-1.65	0.08
1986	24	139	24	340.3	3169.8	-1.72	0.09
1986	24	239	24	340.3	3167.7	-1.72	0.07
1986	24	70	24	343.7	3178.3	-1.77	0.09
1986	24	227	24	342.4	3180.6	-1.86	0.08
1986	24	299	24	340.3	3167.7	-1.88	0.11
1986	24	70	24	339.0	3183.4	-1.90	0.10
1986	24	163	24	340.7	3171.9	-2.14	0.09

Table 3. Summary of PSD Class I Impacts for which the Proposed Project Has a Significant Contribution Based on the Proposed National Park Service Significant Impact Levels (Page 13 of 13)

Year	Averaging Period	Julian Day	Hour Ending	Receptor Location		Total Class I Impact (ug/m3)	Proposed Source Contribution (ug/m3)*
				UTM East (km)	UTM North (km)		
1986	24	75	24	340.3	3169.8	-2.16	0.07
1986	24	139	24	340.3	3167.7	-2.17	0.11
1986	24	227	24	343.7	3178.3	-2.19	0.07
1986	24	225	24	343.0	3176.2	-2.22	0.08
1986	24	150	24	340.3	3167.7	-2.40	0.14
1986	24	139	24	340.3	3165.7	-2.48	0.12
1986	24	299	24	340.3	3165.7	-2.59	0.12
1986	24	217	24	342.0	3174.0	-2.87	0.08
1986	24	70	24	343.0	3176.2	-3.12	0.13
1986	24	70	24	336.5	3183.4	-3.27	0.13
1986	24	225	24	342.0	3174.0	-3.41	0.09
1986	24	345	24	340.7	3171.9	-3.50	0.11
1986	24	141	24	341.1	3183.4	-3.75	0.07
1986	24	345	24	331.5	3183.4	-3.80	0.10
1986	24	225	24	336.5	3183.4	-3.83	0.08
1986	24	225	24	334.0	3183.4	-3.84	0.07
1986	24	208	24	343.7	3178.3	-3.87	0.07
1986	24	70	24	334.0	3183.4	-4.23	0.11
1986	24	225	24	340.7	3171.9	-4.42	0.08
1986	24	150	24	340.3	3165.7	-4.43	0.15
1986	24	208	24	342.4	3180.6	-4.46	0.08
1986	24	70	24	340.7	3171.9	-4.52	0.08
1986	24	70	24	342.0	3174.0	-4.68	0.13
1986	24	208	24	341.1	3183.4	-4.85	0.09
1986	24	225	24	340.3	3169.8	-4.96	0.09
1986	24	217	24	334.0	3183.4	-4.97	0.08
1986	24	217	24	340.7	3171.9	-5.17	0.08
1986	24	225	24	340.3	3167.7	-5.53	0.11
1986	24	345	24	340.3	3169.8	-5.78	0.12
1986	24	225	24	340.3	3165.7	-6.09	0.13
1986	24	345	24	340.3	3167.7	-6.97	0.11
1986	24	345	24	340.3	3165.7	-7.13	0.08

* Ark Energy modeled at 20°F design temperature.

Table 4. Detail of Hourly Meteorological Data Used in the Modeling Analysis - Tampa 1986, Julian Day 215

Hour	Flow Vector (degrees)	Random Flow Vector (degrees)	Wind Speed (m/sec)	Mixing Height (m)		Temperature (°K)	Input Stability Category	Proposed Project Impact (µg/m)
				Rural	Urban			
1	330	330	2.06	1312	925	298.2	5	0.0
2	340	337	2.06	1299	925	298.7	5	0.0
3	320	320	2.06	1285	925	298.7	5	0.767
4	320	320	2.06	1272	925	298.2	6	0.681
5	330	329	2.57	1259	925	298.2	6	0.0
6	330	331	3.60	7	926	298.2	5	0.0
7	340	339	2.57	148	953	299.3	4	0.0
8	320	317	2.57	289	979	300.9	3	0.016
9	320	325	2.57	431	1006	302.6	2	0.299
10	40	39	4.12	572	1032	303.7	3	0.0
11	10	6	4.63	714	1059	304.8	2	0.0
12	360	4	4.12	855	1085	304.3	2	0.0
13	40	40	3.60	997	1112	303.7	2	0.0
14	80	79	4.12	1138	1138	304.3	2	0.0
15	90	90	4.12	1138	1138	303.7	3	0.0
16	290	293	2.06	1138	1138	303.7	4	0.0
17	320	322	1.54	1138	1138	299.8	3	0.324
18	320	325	1.00	1138	1138	302.0	2	0.0
19	320	324	1.00	1138	1138	301.5	3	0.0
20	270	271	1.54	1153	1153	300.4	4	0.0
21	300	297	2.06	1172	1068	299.8	5	0.0
22	300	297	2.57	1192	1028	299.3	5	0.0
23	280	277	1.54	1212	987	299.3	6	0.0
24	300	300	2.57	1232	947	298.7	6	0.0

United States Department of the Interior

FISH AND WILDLIFE SERVICE
75 Spring Street, S.W.
Atlanta, Georgia
30303

May 13, 1992

RECEIVED
MAY 15 1992
Bureau of
Air Regulation

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

Dear Mr. Fancy:

We have reviewed the March 5, 1992, modeling protocol for Florida Power Corporation's (FPC) proposed power plant facility located in Polk County, Florida. The proposed facility would be located approximately 110 km southeast of the Chassahowitzka Wilderness Area (WA), a Fish and Wildlife Service class I area.

The MESOPUFF II model (an EPA Appendix B model) will be used to calculate class I sulfur dioxide (SO_2) increment consumption at Chassahowitzka WA from the proposed FPC facility as well as all other increment consuming sources in the area as defined by the Florida Department of Environmental Regulation (FDER). The U.S. Environmental Protection Agency (EPA) has recently determined that sources located within 50.0 km of a class I area should be modeled with an EPA guideline model as defined in the EPA "Guidelines on Air Quality Models." FPC's proposal to apply the EPA, Industrial Source Complex Short Term Model (ISCST) for these near field sources is acceptable to us.

The following material will discuss the technical acceptability of the proposed FPC modeling protocol. The proposed modeling grid domain of 225 cells, each 20 x 20 km, is acceptable for the scale of the total analysis. We accept the proposed use of 5 years of National Weather Service (NWS) upper air rawinsonde data (1982-1986) from the Ruskin, Florida, the West Palm Beach, Florida, and the Waycross, Georgia, stations. Missing data replacement from the previous day's sounding of the same time period is acceptable, and missing data at certain levels within the sounding may be substituted by persistence from a lower level. The 5 years (1982-1986) of NWS surface data from Tampa and Orlando will be input to the MESOPAC II program. Also the NWS surface data for 1984-1986 from Gainesville will be used. Surface NWS data from Jacksonville will be used for 1982 and 1983 since digitized data from Gainesville is not available. If a refined MESOPUFF II analysis is required after the initial inert pollutant model run, then hourly precipitation data from the

above surface stations will be employed. Land use data from the proposed Argonne National Laboratory data base will be applied to each grid cell based on the land use category covering the greatest percent of each grid cell. The time dependent dispersion coefficients in MESOPUFF II will be applied at distances of greater than 50 km. The FDER has developed 13 discrete receptor locations in the class I area at which concentration calculations will be made. We have reviewed and agree with the proposed "selected values" for the variables in the Read 56 program, the MESOPAC II program, and the MESOPUFF II model.

Presently, there are no specified significant impact levels for the class I increments. We have proposed to EPA's Office of Air Quality and Planning Standards the following class I SO_2 significant levels: 0.48 ug/m^3, 3-hour average; 0.07 ug/m^3, 24-hour average; and 0.025 ug/m^3, annual average. If the proposed FPC's source impact is less than these values, then the proposed source does not significantly contribute to a predicted increment violation.

Initially, the ISCST model will be run for the 5-year period with the Tampa surface and mixing height data, to calculate averaging periods when the class I SO_2 concentration is exceeded in the cumulative analysis. During the 5-year period, if FPC's proposed source has an impact of less than the above described significant levels, on periods when the class I increment is exceeded, then no additional modeling for that time period is required. For time periods when the cumulative impact exceeds the class I increment and the FPC's source impact is greater than the above significant levels, a cumulative MESOPUFF II analysis will be performed for that averaging time period for all 13 receptor locations.

To initialize the MESOPUFF II model, the model must be run for 4 days before and 3 days after the short term averaging period which is being analyzed. This MESOPUFF II cumulative analysis will be performed without deposition or chemical transformation. This follows the EPA guidance that SO_2 be modeled as an inert pollutant. We recognize that some deposition and chemical transformation processes occur in long-range transport and will entertain a request to employ some of these options after the inert model run, if the analysis reaches a critical junction. If modeling is performed with some of the deposition or chemical transformation options, sources with a negative emission rate (i.e., increment expanding sources) must be modeled separately. The MESOPUFF II model does not internally calculate a negative deposition rate or chemical transformation. The negative emission rate sources will have their contribution subtracted from that of the increment consuming sources on a receptor-by-receptor and hour-by-hour basis, in the MESOPUFF II

postprocessing step of the analysis. Therefore, the total concentration for a particular time period can be either positive or negative, depending on the relative contribution of the various sources.

Results from the MESOPUFF II analysis will report the highest annual, and the highest and high second-high short term concentrations. The FPC source's contribution to these concentrations will also be reported.

We are awaiting concurrence on the specifics and totality of this protocol. We will provide response on any agreed to modification of this protocol.

If you have any concerns regarding the protocol or any other Prevention of Significant Deterioration issue regarding FPC Polk County facility, please contact John Notar of our Air Quality Branch in Denver at 303/969-2071.

Sincerely yours,

for James W. Pulliam, Jr.
Regional Director

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

Mr. Scott Osborne
Florida Power Corporation
3201 34th Street South
St. Petersburg, Florida 33733

Mr. Robert McCann
KBN Engineering and Applied Sciences, Inc.
1034 N.W. 57th Street
Gainesville, Florida 32605

J. Reynolds
C. Holladay
B. Thomas, SW Dist
D. Martin, Polk Co. Planning Div.
CHF/BA/PL

May 5, 1992

Memorandum

To: Regional Director, Refuges and Wildlife, Fish and Wildlife Service, Region 4

From: Chief, Air Quality Branch

Subject: Florida Power Corporation

We have reviewed the material that the Florida Department of Environmental Regulation (FDER) forwarded to us regarding Florida Power Corporation's (FPC) proposed Polk County Generating Station. They request to apply the EPA long-range transport model MESOPUFF II to access increment consumption to the PSD class I Chasshowitzka Wilderness Area (CHAS). The proposed 900 megawatts FPC facility would be located some 110 km southeast of CHAS.

The FPC will first access the impact of its Polk County facility with the EPA guideline air quality model Industrial Source Complex Short Term (ISCST). If there are periods when the conservative ISCST modeling indicates an exceedance of the class I increment, and the proposed FPC facility significantly contributes to that exceedance, then a long-range transport analysis with the MESOPUFF II model will be performed.

We are working closely with the State of Florida Department of Environmental Regulations, FPC, and EPA Region IV to ensure that this analysis conforms with State and federal methodology and policy.

We ask that you finalize and sign the attached letter. If you have any questions regarding this matter, please contact me or John Notar at (303) 969-2071.

Sandra V. Silva

Attachment

bcc:
AQD-DEN: Bunyak, Rolofson, Ross, Shaver, Silva, Reading File
AQD-DEN:JNOTAR:jn:5/4/92:x2071:POLK-M1.MEM

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

May 5, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, California 92653

Dear Mr. Malenius:

Re: Permit Application AC 53-211670, PSD-FL-187
Mulberry Cogeneration Project

In order to complete the subject application received on April 6, 1992, the following additional information and revisions are required:

1. The subject application should be revised to show all emission calculations. It should clearly show the calculation of all numerical quantities involving emissions instead of just sample calculations for fuel oil firing.

2. The application states that natural gas will be the permanent primary fuel. Please provide further clarification as to why no primary fuel is specified during the first three years of operation. The application should be revised to show total emissions from the projected actual annual use of each fuel.

3. The predicted maximum SO_2 24-hour and 3-hour concentrations in the Chassahowitzka PSD Class I area due to the proposed project's emissions are greater than the National Park Service proposed 24-hour and 3-hour significant impact levels of 0.07 and 0.48 ug/m^3, respectively. Please perform a cumulative 24-hour and 3-hour SO_2 Class I increment analysis as required by the National Park Service. An air quality related values (AQRVs) analysis should also be done since there are presently no significant impact levels that exempt a proposed PSD project from performing this analysis. The AQRVs analysis includes impacts to soils, vegetation, and wildlife. The National Park Service has indicated through verbal communication that the AQRVs analysis needs only to address the impacts of increased SO_2, NO_x, and VOC emissions for this project.

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If further clarification is needed on any of the above, please contact John Reynolds or Cleve Holladay at 904-488-1344.

Sincerely,

Barry D. Andrews

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

CHF/JR/plm

c: W. Thomas, SWD
J. Harper, EPA
C. Shaver, NPS
D. Martin, Planner
K. Kosky, P.E.

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- Complete items 3, and 4a & b.
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3. Article Addressed to:

Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Dirve
Laguna Hills, CA 92653

4a. Article Number
P 710 058 531

4b. Service Type
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☒ Certified ☐ COD
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5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)
Amy Kitmitto

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PS Form 3800, June 1990

KBN

April 15, 1992

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Division of Air
Resources Management

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

RE: Polk County - A.P.
Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd.
Mulberry Cogeneration Project
Computer Modeling Printouts

Dear Clair:

As a followup to the air construction permit application and prevention of significant deterioration analysis for the above-referenced project (submitted to FDER April 3, 1992), please find enclosed a portion of the ISCST modeling computer printouts for the air dispersion analysis. A diskette copy of **all** air modeling input and output files was submitted with the application. The computer printouts provided include those for the SO_2 AAQS, PSD Class I, and PSD Class II analysis. However, due to the voluminous amount of output, only a portion of the proposed facility significance analysis printouts have been enclosed. This portion includes only one year of output at one operating scenario (i.e., 1982 meteorological data and CT operating at a 100-degree ambient temperature). The hard copies provided account for approximately 15 percent of the total output for this project.

For your convenience, summary reports have been included for all pollutants and operating scenarios included on the diskette. This computer-generated listing, developed by KBN, summarizes five years of modeling output runs and shows highest and second-highest concentrations along with location and time period. The output is grouped by source group and averaging period.

Please refer to the output files on diskette if you find it necessary to reference those analyses not provided on hard copy. Please feel free to contact me at 904-331-9000 if you have any questions concerning this submittal.

Sincerely,

Gail C. Rampersaud

Gail C. Rampersaud
Associate Engineer

CC: J. Rumaldo
L. Holladay
B. Thomas, SW Dist
J. Harper, EPA
C. Shaver, NPS

91193A1/1

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

April 10, 1992

Ms. Jewell A. Harper, Chief
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30308

Dear Ms. Harper:

RE: Polk Power Partners, LP, d/b/a Polk Power Partners, LP, Ltd
Mulberry Cogen/CO_2 Recovery Facilities
Polk County, PSD-FL-187

The Department has received the above referenced PSD application package. Please review this package and forward your comments to the Department's Bureau of Air Regulation by May 4, 1992. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact John Reynolds or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

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

CHF/rbm

Enclosures

Recycled Paper
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Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

April 10, 1992

Mr. Bill Thomas
District Air Program Administrator
Southwest District
4520 Oak Fair Blvd.
Tampa, Florida 33610-7347

Dear Mr. Thomas:

RE: Polk Power Partners, LP, d/b/a Polk Power Partners, LP, Ltd
Mulberry Cogen/CO_2 Recovery Facilities
Polk County, AC 53-211669 & AC 53-211670; PSD-FL-187

The Department has received the above referenced PSD application package. Please review this package and forward your comments to the Department's Bureau of Air Regulation by May 4, 1992. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact John Reynolds or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

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

CHF/rbm

Enclosures

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Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

April 10, 1992

Mrs. Chris Shaver, Chief
Permit Review and Technical Support Branch
National Park Service-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Dear Mrs. Shaver:

RE: Polk Power Partners, LP, d/b/a Polk Power Partners, LP, Ltd
Mulberry Cogen/CO_2 Recovery Facilities
Polk County, PSD-FL-187

The Department has received the above referenced PSD application. Please review this package for completeness and forward your comments to the Bureau of Air Regulation by May 4, 1992. The Bureau's FAX number is (904)922-6979.

If you have any questions, please call John Reynolds or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

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

CHF/rbm

Enclosures

Recycled Paper
Printed with Soy Based Inks

Imperial

Polk County

Board of County Commissioners

Planning Division

P.O. Box 1969
330 W. Church St.
Bartow, FL 33830
(813) 534-6084
SUNCOM 569-6084
FAX (813) 534-6055

RECEIVED
DER - MAIL ROOM
1992 APR -6 AM 8:28

Florida Department of Env. Reg.
Div. of Air Resources Mgmt.
4520 Oak Fair Blvd.
Tampa, Fl 33610

March 12, 1992

Dr. Richard Garrity:

This letter is to inform you that Polk County is an interested party in the permitting process for the following project:

Applicant: Polk Power Partners LP
Project: Non-certified Electric-Power Generating Facility at the Noralyn Commerce Park

Plant Location: Section 26 Township 30 Range 24

Please notify us of all meetings as we would like the opportunity to participate in the conditioning of the permit for the purposes of compliance with the Polk County Comprehensive Plan and site specific parameters. If this permit has already been granted or if an intent to issue has been noticed, please contact Celeste Deardorf of my staff immediately. Under provisions of Florida Statutes, we would like the opportunity to comment as it relates to local issues.

Thank you for your cooperation in this matter.

Sincerely,

Robert Anders, AICP
Planning Director

Donald Martin
Principal Planner
Planning Division
P.O. Box 1969
Bartow, Florida 33830

RE: Polk Power Partners/Noralyn Commerce Park

I have received the permit application pursuant to the above referenced project as well as Polk County's Notice of Interested Party and Notice of Participation. We will keep you informed of all proceedings and decisions in regards to this project.

AGENCY:
Florida Department of Env. Reg.
Div. of Air Resources Mgmt.

John Reynolds
(signature of permit reviewer)

4-20-92
(date)

JOHN REYNOLDS
(print name)

DER BUREAU OF AIR REGULATION
2600 BLAIRSTONE RD
TALLAHASSEE, FL 32399-2400
(address)

904-488-1344
(phone)

ARK ENERGY INC.

March 13, 1992

To Whom It May Concern:

Polk Power Partners, L.P. d/b/a Polk Power Partners, L.P., Ltd. hereby designates Black & Veatch (B&V) and KBN Engineering and Applied Sciences, Incorporated (KBN) as authorized agent for permitting activities associated with the Mulberry Cogeneration Facility located within the Noralyn Commerce Park, Polk County, Florida.

Sincerely,

Arnold R. Klann
Vice President and Secretary
Polk Power G.P. Inc.

wrm:TW031392.LTR
cc: Will Stratton - CSW Energy, Inc.
Bill Malenius - ARK Energy, Inc.
David Brown - CSW Services
Karen Wong - Millbank, Tweed, Hadley & McCloy
Michael Craig - Peterson, Myers, Craig, Crews, Brandon & Puterbaugh, P.A.
Roger Anderson - KBN Engineering and Applied Sciences, Inc.
Don Gray - Black & Veatch

23293 South Pointe Drive • Laguna Hills, California 92653 • Tel (714) 588-3767 • Fax (714) 588-3972

Summary of Computer Modeling Printouts Supplied to FDER for the Mulberry Cogeneration Facility 4/3/92

Output File Name	Description
<< PROPOSED FACILITY ONLY >>	
ARK<ppp><tt>.O<yy>	Proposed Facility Screening Impacts for Regulated Pollutants
ARKSREF.O<yy>	SO2 Refinements - 3-hour and 24-hour
ARKPRF<tt>.O<yy>	PM Refinements, 24-hour
ARKCRF<hh>.O<yy>	CO Refinements, 20 and 100 degrees
ARKMRF<hh>.O<yy>	Sulfuric Acid Mist Refinements, 20 and 100 degrees
ARKBRF<hh>.O<yy>	Be Refinements, 20 and 100 degrees
ARKASRF8.O<yy>	Arsenic Refinements, 20 and 100 degrees, 8-hour
ARKASRF2.O<yy>	Arsenic Refinements, 20 and 100 degrees, 24-hour
ARKAMINE.O<yy>	Ethanolamine Screening Impacts (CO2 Plant Only)
ARKARF<hh>.O<yy>	Amine Refinements
<< CLASS I >>	
ARKSCL1.O<yy>	SO2 PSD Class I Impacts, 20 and 100 degrees
ARKNCL1.O<yy>	NO2 PSD Class I Impacts, 20 and 100 degrees
ARKPCL1.O<yy>	PM PSD Class I Impacts, 20 and 100 degrees
<< CLASS II and AAQS >>	
ARKCLSII.O<yy>	SO2 PSD Class II Screeening
ARKSAAQS.O<yy>	SO2 AAQS Screening
AR<rr>RF<hh>.O<yy>	AAQS and Class II Refinements
AR<rr>SC<hh>.O<yy>	AAQS and Class II Source Contributions

Note:
ppp = pollutant (SO2,NOX,PM,BE,CO,AS,SA(sulfuric acid mist)
tt = temperature (20=20 degrees; 10=100 degrees)
yy = meteorological year (82,83,84,85,86)
rr = run type (AQ=AAQS; C2=Class II)
hh = averaging period (03=3-hour;08=8-hour;24=24-hour;AN=annual;32=3,24-hour)

May 13, 1991

ENVIRONMENTAL
ENGINEERING
CONSULTANTS, INC.

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, FL 32399-2400

RECEIVED
MAY 15 1991
Bureau of
Air Regulation

Re: Westford Resources, Inc.
Mulberry Power Plant

Dear Mr. Fancy:

On February 4, 1991 an informal pre-application meeting was held with you regarding Westford Resources, Inc's plan on constructing a 74.9 MW power plant in Polk County, fired on Orilmulsion. Part of the discussions dealt with the pre-construction monitoring requirements of the PSD regulations. Attached is a discussion of our evaluation of the requirements and subsequent request to use the data from two of FDER's SO_2 monitoring stations located close to the proposed site.

Please review this request as quickly as possible. We plan on submitting the PSD application within a month and therefore, your prompt consideration of this request will be appreciated.

Should you or your staff have any questions, please call Jim Estler at 1-800-229-3311.

Sincerely,

ENVIRONMENTAL ENGINEERING CONSULTANTS, INC.

Robert E. Wallace III, P.E.
President

REW/dege

Enclosure

cc: Arch Ford, Westford Resources (With Attachments)

5119 NORTH FLORIDA AVENUE
P.O. BOX 7854
TAMPA, FLORIDA 33673
813/237-3781
TELEFAX 813/238-0036

WESTFORD RESOURCES, INC.

MULBERRY POWER PLANT

PSD APPLICABILITY:

Project Location:

The proposed 74.9 MW power plant will be located south of Bartow on Highway 555 at the Noralyn Commerce Park, Polk County. The area has been designated attainment for all criteria pollutants and a PSD Class II area for SO_2, TSP and NO_2. The site is located more than 100 Km from the nearest Class I area (Chassahowitka National Wilderness Area) and thus will not be addressed in any modeling analysis (Location Map attached).

Potential Emissions:

The potential emissions from the proposed source are projected to exceed 100 TPY cut-off specified in Subsection 17-2.500(2)(d)2., b., F.A.C. and therefore the proposed source would be considered a new major facility. The proposed potential emission rates are presented in Table 1 and will exceed the applicable PSD significant emission rates for SO_2, TSP, PM10, NO_x, and CO. Therefore, the proposed source is subject to PSD review for those pollutants.

PRE-CONSTRUCTION AMBIENT MONITORING:

Overview:

As stated in EPA's "Ambient Monitoring Guidelines For Prevention of Significant Deterioration (PSD)", it is the "intent not to require extensive and costly monitoring programs by sources unless it is absolutely necessary. If preliminary

modeling or other data indicates that a new source would not pose a threat to a NAAQS, the source may not need to conduct pre-construction monitoring".

For any criteria pollutant that the applicant proposes to emit in significant amounts, continuous ambient monitoring data may be required as part of the air quality analysis. If, however, either (1) the predicted ambient impact, i.e., the highest modeled concentration for the applicable averaging time, caused by the proposed source or (2) the existing ambient pollutant concentrations are less than the prescribed significant monitoring value (see Table 1), the permitting agency has discretionary authority to exempt an applicant from this data requirement.

From the applicability determination, a review of pre-construction monitoring must be evaluated for TSP, PM_{10}, SO_2, NO_2, and CO. However, pre-construction monitoring generally would not be required if the maximum predicted ambient impact of the source is less than de mimimis air quality impact levels list in Table 1.

Project Modeling Impacts:

The determination of the proposed project's effects on air quality is based on the results of the dispersion modeling used to establish if the maximum air quality impact is less than the pollutant specified "de minimus" concentration.

Air quality modeling has been preformed on the proposed source and will be formally submitted as part of the PSD application. The predicted maximum air quality impacts of the

proposed facility for those pollutants subject to PSD review are listed in Table 1.

TABLE 1: Potential Emissions and Predicted Impacts of Mulberry Power Plant Project Compared to PSD Significant Emission Rates and De Minimis Air Quality Impacts Levels

Pollutant	Emissions (TPY) Potential From Proposed Source	Signif-incant Emission Rate	Impacts (ug/m3) Predicted Impacts	De Minimus Air Quality Impact Level
Sulfur Dioxide	1437.69	40	17	13, 24-hour
Particulate Matter (TSP)	107.83	25	1.3	10, 24-hour
Particulate Matter (PM10)	107.83	15	1.3	10, 24-hour
Nitrogen Dioxide	1078.27	40	1.1	14, Annual
Carbon Monoxide	431.31	100	<575	575, 8-hour
Volatile Organic Compounds	7.19	40	NA	Emissions Increase
Lead	0.0001	0.6	**	0.1,Calendar quarter
Sulfuric Acid Mist	19.4	7	**	*
Total Fluorides	0.125	3	**	0.25, 24-hour
Total Reduced Sulfur	NEG	10	**	10, 1-hour
Reduced Sulfur Compounds	NEG	10	**	10, 1-hour
Hydrogen Sulfide	NEG	10	**	0.2, 1-hour
Asbestos	NEG	0.007	**	*
Beryllium	0.0001	0.0004	**	0.001, 24-hour
Mercury	0.0001	0.1	**	0.25, 24-hour
Vinyl Chloride	NEG	1	**	15, 24-hour

Pollutant	Emissions (TPY) Potential From Proposed Source	Signif-incant Emission Rate	Impacts (ug/m3) Predicted Impacts	Impacts (ug/m3) De Minimus Air Quality Impact Level
Benzene	NEG	0	**	*
Radionuclides	NEG	0	**	*
Inorganic Arsenic	1.0×10^{-4}	0	+	*

Note: NA = Not Applicable.
NEG = Negligible.

* No acceptable ambient measurement method has been developed and, therefore, de minimis levels have not been established by EPA.

\+ Predicted impacts will be assessed on soils and vegetation in the PSD application.

** Predicted impacts are not required because emissions are less than significant emission rates.

Existing Ambient Data:

The predicted maximum impact of SO_2 is greater than its defined "de minimus" value. Under certain conditions the guidelines allow for the use of existing ambient data. In order to be acceptable, the data must be judged by FDER to be representative of the air quality for the area in which the proposed project is located. In determining the representativeness of the data, the following critical items as discussed in the PSD Monitoring Guidelines must be considered:

1. Monitor location
2. Quality of data
3. Currentness of data

FDER currently operates two continuous SO_2 monitors in the Polk County area. Existing air quality data were obtained from these monitoring stations which are the closest monitoring stations to the proposed project site. The closest ambient air monitoring station to the proposed project site that measures SO_2 concentrations are located in Nichols, about 14 km west of the site and a former site in Lakeland, about 21 km north, northwest of the site. FDER has recently moved the Lakeland site to an east Mulberry location about 9 km west, northwest from the proposed site. This relocated continuous SO2 monitor has been in operation for a few months. All sites are located in industrial areas dominated by phosphate fertilizer chemical plants and power plants. Because they are located in industrial areas and in proximity of major sources, the observed concentrations are considered slightly higher than those expected to occur at the proposed site. Therefore the existing background concentrations are considered to be conservative (i.e. higher than expected than at the proposed site). A summary of the maximum concentration measured at the closest monitors are presented in Table 2. The SO2 data collected at the monitoring station in Nichols and Lakeland were reviewed and used in estimating background concentrations. The data from the new Mulberry site is not yet available. Therefore the nearest station to the proposed site is located in Nichols approximately 14 km to the west. During 1987, the second highest 3-hour and 24-hour and annual average concentrations were (267, 51, and 11 ug/m3, respectively. These concentrations are assumed to represent background concentrations.

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3hr 24hr Ann

TABLE 2 Summary of maximum SO2, TSP, and NO2 Concentrations Measured at the Closest Monitoring Site

---

Pollutant: SO2

Location: Lakeland

Site No.: 2160-001-F01

UTM Coordinates (km) East: 407.5,

UTM Coordinates (km) North: 3107.5

Year: 1987/1986

Observations Number: 8444/6520

Observations %: 96.4 / 74.4

Concentration (ug/m3) - 3-hour	1st: 200/267	2nd: 162/178
Concentration (ug/m3) - 24-hour	1st: 86/81	2nd: 55/71
Concentration (ug/m3) - Annual:	10/13	

Pollutant: SO2

Location: Nichols

Site No.: 3680-010-F02

UTM Coordinates (km) East: 399.5

UTM Coordinates (km) North: 3081.3

Year: 1987/1986

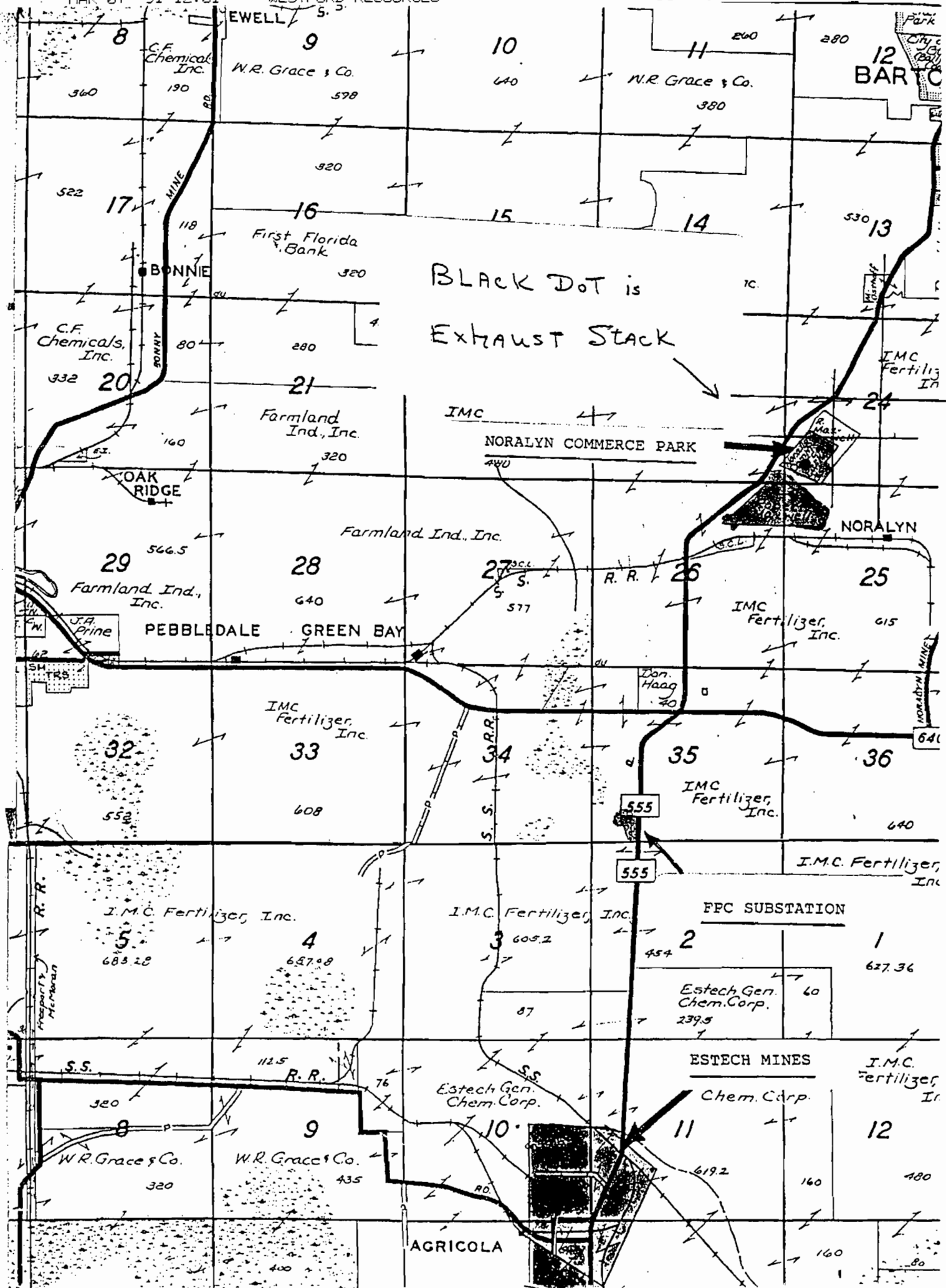
Observations Number: 8571/4994

Observations %: 97.8/57.0

Concentration (ug/m3) - 3-hour	1st: 697/203	2nd: 267/162
Concentration (ug/m3) - 24-hour	1st: 115/38	2nd: 51/35
Concentration (ug/m3) - Annual:	11/7	

Pre-construction Exemption Request:

It is therefore proposed, that the data from these sites be judged acceptable by FDER to satisfy the pre-construction monitoring requirements for the proposed Mulberry Power Plant. This data has been considered acceptable by both FDER and EPA Region IV in the past in PSD application submitted for TECO Power Services Corporation, Hardee Power Station (PSD-FL-140). See the attached copy of EPA's August 17, 1990 letter to Mr. Clair Fancy, P.E., paragraph 2 and EPA's letter of December 21, 1990 to Mr. Steve Smallwood, P.E., paragraph 2 and 3 (copies attached).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C.F. Chemicals Inc.
W.R. Grace & Co.
W.R. Grace & Co.
BAR C
MINE
First Florida Bank
BONNIE
BLACK DOT is
Exhaust Stack
C.F. Chemicals, Inc.
BONNY
IMC Fertiliz In
Farmland Ind., Inc.
IMC
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Don Haag
NORALYN MINE
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Chem. Corp.
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R. R.

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

AUG 17 1990

4APT-AEB

RECEIVED
AUG 20 1990
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: TECO Power Services Corp. Hardee Power Station (PSD-FL-140)

Dear Mr. Fancy:

This is to acknowledge receipt of the preliminary determination for the above referenced facility by letter dated August 2, 1990. We have reviewed the package as submitted and have the following comments.

MODELING/MONITORING

As noted in our comments on the permit application dated August 11, 1989, we indicated that preconstruction monitoring based on regional monitors was acceptable if such monitors could be found to be representative. For SO_2, the monitors located north of the site fall into the representative category and we will accept one of those monitors as fullfilling the PSD requirement for SO_2.

For ozone, we believe the Tampa monitoring site is the most representative site based on the prevailing winds and distance to the Hardee County site. Also, since maximum ozone concentrations will occur downwind from an urban area in the range of 30 or more kilometers, it is possible that the background levels at the site are higher than at sites that are not downwind of the Tampa area. The purpose of PSD monitoring is to quantify the background levels in the impact area.

BACT ANALYSIS

The BACT determination requires the use of wet injection and limits the hours of operation of the combined cycle units to 2190 hours per year. This is equivalent to 25% of capacity which is typical of a "peaking" unit. The simple cycle turbine of Phase IA, however, is not limited on hours of operation. In addition, the combined cycle units have the capacity to use by-pass vents and thus function as simple cycle units. It would appear, then, that the combined cycle units could operate continuously provided the hours of operation in the combined phase did not exceed 2190.

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If the units are "peaking" units as the applicant claims, then the combined capacity of all the units (both combined cycle and simple cycle) should be limited to 25% of facility capacity. This is in keeping with the precedent set with Key West and facilities in North and South Carolina. Otherwise, the BACT analysis would indicate the need for add-on NO_x controls.

In addition, the burner design should be evaluated for BACT. The applicant proposes to use General Electric turbines. GE manufactures a "quiet combustor" which achieves NO_x levels of 25 ppm using wet injection when firing natural gas. Other burner designs are available which are capable of achieving equal or better emission levels. For example, the South Bay Power Plant in Chula Vista, CA, has recently proposed a 140 MW combined cycle turbine with emission limits of 9 ppm NO_x and 8 ppm CO firing natural gas, using steam injection. The technology proposed is currently in practice at the Delmarva Power and Light, Hay Road Station, Delaware. NO_x emissions at this facility have been tested at lower than 25 ppm.

In any case, it does not seem appropriate to allow a simple cycle "peaking" unit to operate 8760 hours per year without a lower emission rate. Also, clarification should be given as to whether the combined cycle units will be allowed to operate in simple cycle mode.

As with the Key West permit, the permit should contain provisions to require that the facility must reevaluate BACT, with SCR as a minimum, in the event that the 25% capacity factor is exceeded or the source wishes to operate as other than a peaking unit.

Thank you for the opportunity to review and comment on this package. If you have any questions on these comments, please do not hesitate to contact Mr. Gregg Worley of my staff at (404) 347-2904.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: Mr. Barry Andrews, FDER
TECO Hardee

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

RECEIVED
DEC 21 1990
DEC 24 1990
DER - BAQM
D. E. R.
SOUTHWEST DISTRICT

4APT-AEB

Mr. Steve Smallwood, P.E., Director
Air Resources Management Division
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: TECO Power Services Corp. Hardee Power Station (PSD-FL-140)

Dear Mr. Smallwood:

This is to acknowledge receipt of the revised preliminary determination for the above referenced facility by letter dated December 5, 1990. We have reviewed the package as submitted and have significant comments as outlined in the following paragraphs. The issues raised in this letter are sufficient to preclude the issuance of a construction permit to TECO Power Services Corp. In order to prevent additional action by EPA, we strongly advise that you not issue this construction permit until the following issues are resolved.

MODELING/MONITORING

As noted in our comments on the permit application dated August 11, 1989, and in our comments on the preliminary determination of August 2, 1990, we indicated that preconstruction monitoring based on regional monitors was acceptable if such monitors could be found to be representative. As you know, the requirement for preconstruction monitoring under PSD regulations is not discretionary. A source may be exempted from preconstruction monitoring only if its impacts are predicted to be de minimis as defined in PSD regulations. Once the predicted impacts are determined to be greater than de minimis, a reviewing agency may allow the use of representative data in place of on-site monitoring. Such decision is made on a case-by-case basis and is not discretionary; the basis for such decision must conform to the "Ambient Monitoring Guidelines for Prevention of Significant Deterioration."

For SO_2, the monitors located north of the site fall into the representative category and we will accept one of those monitors as fulfilling the PSD requirement for SO_2.

For ozone however, we believe the Tampa monitoring site is the most representative site based on the prevailing winds and distance to the Hardee County site. Also, since maximum ozone concentrations will occur downwind from an urban area in the range of 30 or more kilometers, it is possible that the background levels at the site are higher than at sites that are not downwind of the Tampa area. The purpose of PSD monitoring is to quantify the background levels in the impact area. Therefore, we do not concur that the identified monitoring sites are representative and we recommend actual preconstruction monitoring at the Hardee site or use of data from the Tampa monitoring site.

BACT ANALYSIS

In light of Region IV's previous comments on the application and preliminary determination for this source along with the permitting history for combustion turbines both in the Region and nationwide, Region IV cannot condone the BACT determination presented in the revised preliminary determination. The applicant has continually based the rejection of SCR as a NO_x control on the fact that the projected use of the facility is 25% of capacity, thereby rendering the application of SCR to be technically infeasible (when firing in the simple cycle mode) and economically unreasonable (when firing in the combined cycle mode). This is consistent with recent BACT determinations in Florida and Region IV; however, the sources in previous cases (Key West, Panda Energy, and South Carolina Electric and Gas) each accepted permit limits on hours of operation to roughly 25% of capacity.

The NESCAUM Stationary Source Committee published a recommendation in June of 1990 concerning the permitting of simple cycle turbines. This recommendation stated: "Historically, simple cycle gas turbines used in peaking service have operated, on the average, less than fifteen hundred hours per year. However, actual hours of operation in any given year can vary substantially and could easily exceed fifteen hundred hours per year." 1500 hours per year is roughly 18% of full capacity (8760 hours per year). The recommendation suggested that regulatory agencies limit the hours of operation of "peaking units" and proposed emission guidelines for sources which included limiting the hours of operation to 2500 hours per year (28.5%).

Correspondence from the applicant indicates that in addition to the predicted capacity utilization of 25%, a maximum capacity utilization of 55% is expected. In other words, the applicant proposes to utilize the facility in a cycling manner, going from peak load to

mid-range to base load according to need. The August 2, 1990, preliminary determination is consistent with recent BACT determinations in that it proposed to limit the hours of operation of the source to 25% with the condition that if this capacity would be exceeded, the source would install SCR. However, the December 5, 1990, preliminary determination proposes to allow the source to operate at 60% lifetime capacity before having to install SCR. It is not acceptable to limit capacity on a 60% lifetime average such that the source could operate at 20% capacity one year and 100% capacity the next year and still not be required to apply SCR. In essence, the revised preliminary determination allows the source to operate as a base load unit without requiring add-on controls or even dry low-NO_x combustors. Furthermore, a lifetime average is not an enforceable entity.

The August 2, 1990 BACT determination for TECO required the use of wet injection and limited the hours of operation of the combined cycle units to 2190 hours per year. This is equivalent to 25% of capacity which is typical of a "peaking" unit. The simple cycle turbine of Phase IA, however, was not limited on hours of operation. In addition, the combined cycle units have the capacity to use by-pass vents and thus function as simple cycle units. It would appear, then, that the combined cycle units could operate continuously provided the hours of operation in the combined phase did not exceed 2190.

If the units are "peaking" units as the applicant previously claimed, then the combined capacity of all the units (both combined cycle and simple cycle) should be limited to 25% of facility capacity. This is in keeping with the precedent set with Key West and facilities in North and South Carolina. Otherwise, the BACT analysis would indicate the need for add-on NO_x controls.

In addition, the burner design should be evaluated for BACT. The applicant proposes to use General Electric Frame 7EA turbines. General Electric manufactures a "quiet combustor" which achieves NO_x levels of 25 ppm using wet injection when firing natural gas. Other burner designs are available which are capable of achieving equal or better emission levels with and without wet injection. For example, the South Bay Power Plant in Chula Vista, CA, has recently proposed a 140 MW combined cycle turbine with emission limits of 9 ppm NO_x and 8 ppm CO firing natural gas, using steam injection. The technology proposed is currently in practice at the Delmarva Power and Light, Hay Road Station, Delaware. NO_x emissions at this facility have been tested at lower than 25 ppm.

BEST AVAILABLE COPY

In any case, it does not seem appropriate to allow a simple cycle "peaking" unit to operate 8760 hours per year without a lower emission rate. Also, clarification should be given as to whether the combined cycle units will be allowed to operate in simple cycle mode.

The applicant has continually pointed to the firing of fuel oil as another drawback to implementing the use of SCR; however, as seen in publications such as the "White Paper Selective Catalytic Reduction Controls to Abate NO_x Emissions" by the Industrial Gas Cleaning Institute (November, 1989), SCR manufacturers are confident with performance on "high sulfur" fuels, and especially low sulfur distillate fuels such as proposed by the applicant.

As with the Key West permit, the permit for TECO should contain provisions to require the facility reevaluate BACT, with SCR as a minimum, in the event that the 25% capacity factor is exceeded or the source wishes to operate as other than a peaking unit. The determination made by DER staff in the August 2, 1990, document is justified and consistent with previous BACT determinations.

Thank you for the opportunity to review and comment on this package. If you have any questions on these comments, please do not hesitate to contact me at (404) 347-3043.

Sincerely yours,

Richard D. Green, Deputy/for

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

cc: TECO Hardee

August 26, 1992

RECEIVED
AUG 28 1992
Division of Air
Resources Management

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

Dear Clair:

I have been out of the country so I was unaware of your August 13, 1992, letter indicating that the Mulberry Cogeneration was complete as of my letter dated August 12, 1992. I find this conclusion to be not only disturbing but completely inconsistent with the facts in this case. I believe you will find the facts support the conclusion that no additional or new information was submitted to justify an additional review of 90 days.

On July 30, representatives of the project, General Electric (GE), and I met with Preston Lewis and John Reynolds to present GE's low-NO_x combustion technology. This was done in light of the recent decision on the Orlando CoGen Project which required 15 ppm NO_x (corrected to 15 percent oxygen) when firing natural gas. The GE representatives presented their program which included achieving 15 ppm NO_x levels in the near future (1994-96 timeframe). At the meeting, it was expressly mentioned by Preston Lewis that the draft permit for the Auburndale Cogeneration was being issued with conditions that would be of interest to the Mulberry project. That is, Auburndale Project was allowed to operate an interim period on oil with the imposition of 15 ppm NO_x emissions when firing gas at a date 3 years after initial operation.

You should be aware that the interim use of oil (up to 3 years) for the Mulberry project was previously known to the Department since the original application. Indeed, in June 1992, in response to an incompleteness letter from the Department, information was transmitted that indicated that oil would only be used up to a 78 percent capacity rather than a 100 percent capacity factor as indicated in the original application.

Also discussed at the meeting was a possible change in the heat input for the secondary HRSG duct burners. In fact, I expressly stated that there would be no requested increase in heat input for the HRSG.

After the meeting I reviewed the Auburndale Cogeneration Project's draft permit. After discussions with the proponents for the Mulberry project, I submitted on behalf of the project sponsors their desire to have permit conditions similar to those drafted for the Auburndale project. No new additional information was submitted! Furthermore, the interim use of oil was previously known to the Department and no questions were raised from our June submittal.

I also understand that a conversation was held among Ward Marshall (Central and South West Services), Robert McCann (KBN), and John Reynolds on August 25, 1992. Mr. Reynolds committed to providing

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

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a preliminary determination within 1 to 2 weeks. I am concerned with the restart of the 90-day clock, particularly when the application was assumed to be complete in June.

I would hope that this project is treated in a manner similar to the other two most recent cogeneration projects, i.e., the Auburndale project and the Orlando CoGen project. Your previous handling of issues has always been fair and consistent on similar projects. I would therefore request that the permit be considered complete as of the date of our June 1992 submittal and a draft permit be issued.

Your assistance is always appreciated.

Sincerely,

Kennard F. Kosky, P.E.
Principal Scientist

KFK/dmm

cc: John Reynolds, FDER
Bill Malenius (Ark Energy)
Ward Marshall (CSW)
File (2)

HOPPING BOYD GREEN & SAMS
ATTORNEYS AND COUNSELORS
123 SOUTH CALHOUN STREET
POST OFFICE BOX 6526
TALLAHASSEE, FLORIDA 32314
(904) 222-7500
FAX (904) 224-8551
FAX (904) 681-2964

CARLOS ALVAREZ
JAMES S. ALVES
BRIAN H. BIBEAU
KATHLEEN BLIZZARD
ELIZABETH C. BOWMAN
WILLIAM L. BOYD, IV
RICHARD S. BRIGHTMAN
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RALPH A. DEMEO
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JAMES C. GOODLETT
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DALANA W. JOHNSON
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ANGELA R. MORRISON
MARIBEL N. NICHOLSON
GARY V. PERKO
MICHAEL P. PETROVICH
DOUGLAS S. ROBERTS
KRISTIN C. RUBIN
JULIE ROME STEINMEYER

OF COUNSEL
W. ROBERT FOKES

December 20, 1993

RECEIVED
DEC 20 1993
Division of Air
Resources Management

BY HAND DELIVERY

Clair Fancy, Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, Fla. 32399

RE: Mulberry Cogeneration Project;
PSD-FL-187

Dear Clair:

Pursuant to the attached correspondence, GE Capital Corporation has indicated it will be unable to close the planned financing of the Mulberry Cogeneration Project with the current carbon monoxide emissions limits contained in the project's PSD permit. The concern involves the future CO emission limits after January 1, 1998 when the nitrogen oxides emissions limit is reduced from a basis of 25 ppm to 15 ppm. As previously indicated to the Department, a reduction in the NOx emissions will result in an increase in CO emissions. However, the present PSD permit does not allow this increase.

On behalf of Polk Power Partners, I would request the opportunity to meet with you and others on your staff as quickly as possible to discuss what actions the Department can undertake to revise the permit. It appears that a revised PSD permit to establish a CO emission rate based upon 25 ppm at such time as the project reaches 15 ppm NOx will be needed to obtain financing.

We prefer to arrange a meeting sometime during the day, Tuesday, December 21st to allow time for the client to attend. I will contact you later today to identify a time when we could meet for an hour or so to discuss this matter.

Sincerely,

Douglas S. Roberts

Encls.
cc: John Reynolds w/encls.

MULBERRY
COGENERATION FACILITY
POLK POWER PARTNERS, L.P.

VIA FACSIMILE (904) 224-8551

December 17, 1993

Gary P. Sams, Esq.
HOPPING BOYD GREEN & SAMS
123 South Calhoun Street
P.O. Box 6526
Tallahassee, Florida 32314

SUBJECT: Attached Correspondence from General Electric Capital Corporation

Dear Gary:

Attached is a letter from Andrew Beaton of General Electric Capital Corporation regarding the correspondence from the Florida Department of Environmental Protection concerning the raising of the carbon monoxide (CO) emission rate at the Mulberry Project from 20 ppm to 25 ppm. As you will note, GECC is unwilling to close the transaction on the basis of the DEP letter. Since this delays our currently scheduled December 31, 1993 closing, we need to take all possible action to try to address this matter. Accordingly, I would appreciate it if you could try to arrange a meeting with the appropriate individuals at the Department of Environmental Protection so that we can discuss possible solutions to the problem.

If you have any questions, please do not hesitate to contact me.

Yours very truly,

Davis G. (Jeff) Reese
Legal & Public Affairs

Attachment

cc: Arnold R. Klann
William Malenius

123NW641.JR

3753 Howard Hughes Parkway • Suite 200 • Las Vegas, Nevada 89109 • Tel (800) 772-5146 • Fax (702) 892-3950
Mailing Address: 23046 Avenida de la Carlota, Suite 400 • Laguna Hills, California 92653 • Tel (714) 588-3767 • Fax (714) 588-3972

GE Capital

Transportation & Industrial Funding Corporation
A unit of General Electric Capital Corporation
1600 Summer Street, Stamford, CT 06927-4000
203 357-4499

December 16, 1993

Polk Power Partners, L.P.
c/o ARK Energy Inc.
23046 Avenida de la Carlota
Suite 400
Laguna Hills, CA 02653

Attn: Bill Malenius

RE: Mulberry Cogeneration Project

Gentlemen:

We have reviewed the correspondence by representatives of the Mulberry Cogeneration Project with the State of Florida Department of Environmental Protection concerning the raising of the carbon monoxide (CO) emission rate from 20 ppm to 25 ppm in conjunction with the ultimate lowering of the NOx emission rate to 15 ppm. We recognize that the Department has written that it will "adjust the CO limits higher if necessary based on the results of the compliance test...so that the Mulberry Cogeneration Facility can be operated and in a manner that is environmentally responsible." We have no reason to doubt the Department's sincerity.

Unfortunately, the existing permit allows emissions based only on a CO emission rate of 20 ppm, notwithstanding the inability of GE, the equipment vendor, to guarantee performance at that CO emission level with a NOx emission rate of 15 ppm. We further understand, on advice of counsel, that as a matter of law the Department's letter agreement may not constitute a strictly enforceable undertaking to later revise Permit PSD-FL-187, without regard for potential intervening circumstances, which could include challenges by third parties and changes of applicable BACT policies of the State or U.S. EPA.

Accordingly, our lending guidelines do not permit us to accept the risk of not obtaining the appropriately modified permit despite obviously well-intended agency assurances of future official action such as that of the State of Florida Department of Environmental Protection.

Based on these circumstances, we regretfully inform you that the financial closing now tentatively scheduled to occur by December 31, 1993, cannot take place until Polk Power Partners obtains an appropriate modification of the CO emission limit in Permit PSD-FL-187. We hope that you can remedy this deficiency as soon as possible

Sincerely,

Andrew Beaton

Andrew Beaton
Vice President

AB/ss

KBN

August 12, 1992

Mr. John Reynolds
Bureau of Air Regulation
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Mulberry Cogeneration Project

Dear John:

The developers of the Mulberry Cogeneration Project and I appreciate the time you spent last week concerning the dry low-nitrogen oxide (NO_x) combustion technology being developed by General Electric (GE). As discussed, the developers of the project and GE have reviewed the development schedule for this technology and have reached agreement to offer lower NO_x emissions for the Department's consideration. In addition, as suggested by Preston Lewis, the proposed permit for the Auburndale Power Partners project was reviewed. Elements of this permit are directly applicable to the Mulberry Project and should be of assistance in drafting the permit for our project. Based on these efforts, I am transmitting on behalf of the project developers of the Mulberry Cogeneration Project the following emission and fuel limiting standards for your consideration. These proposed limitations are applicable as best available control technology (BACT) and are consistent with those proposed for the Auburndale Project.

1. First 3 Years of Operation: The full load equivalent capacity factor on fuel oil will be no more than 78 percent; the capacity factor for natural gas will be 22 percent. The NO_x emission limits will be limited to no more than 25 parts per million by volume dry (ppmvd) (corrected to 15 percent oxygen) when firing natural gas and 42 ppmvd (corrected) when firing fuel oil.

2. After the First 3 Years of Operation: The emissions limits for NO_x will not exceed 15 ppmvd (corrected) when firing natural gas and 42 ppmvd (corrected) when firing fuel oil. Natural gas will be used as the primary fuel when available from the Florida Gas Transmission Phase III pipeline expansion. When available from the expansion, fuel oil would be limited to no more than 30 days of full load operation per year, and the NO_x emissions would not exceed 42 ppmvd (corrected). The limit for natural gas firing (i.e., 15 ppmvd corrected to 15 percent O_2) would apply no later than April 30, 1997.

Please be advised that our discussion of higher heat input for the secondary heat recovery steam generator (HRSG) has been evaluated, and it has been concluded that an increase will not be requested. Therefore, the heat input as proposed in the application of 99 million British thermal units per hour (MMBtu/hr) will not change.

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

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Best Available Copy

KBN

As we discussed at the meeting, the timing of receipt of the proposed permit is not only important to the project developers but to the State of Florida. This project has been approved by the Public Service Commission, and power from this facility is needed to meet future power requirements in the state. The proposed permit for the Auburndale project should be helpful in drafting the proposed permit for our project. Your expeditious issuance of the proposed permit would be greatly appreciated.

If you have any questions please call me or Ward Marshall of Central & Southwest Services (214) 754-1374.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

KFK/abb

cc: William Malenius
File (2)

91193A1/11

File Copy

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

August 13, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, California 92653

Dear Mr. Malenius:

Re: Permit Application AC 53-211670, PSD-FL-187
Mulberry Cogeneration Project

This letter is in response to KBN's August 12, 1992, revision of the proposed emission and fuel limits for the subject project. Although the effect of this application revision will be to restart the 90-day permitting clock, the Department will make every effort to process the revised application as expeditiously as possible.

Sincerely,

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

CHF/JR/plm

cc: W. Thomas, SWD
J. Harper, EPA
C. Shaver, NPS
D. Martin, Planner
K. Kosky, P.E.
Buddy File
John Reynolds } 8/14/92 AA

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- Complete items 3, and 4a & b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write "Return Receipt Requested" on the mailpiece below the article number.
- The Return Receipt Fee will provide you the signature of the person delivered to and the date of delivery.

I also wish to receive the following services (for an extra fee):

1. ☒ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. William R. Malenius
Senior Program Manager
Polk Power Partners
23293 South Pointe Drive
Laguna Hills, California 92653

4a. Article Number
P 062 921 986

4b. Service Type
☐ Registered ☐ Insured
☒ Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery
8-19-92

5. Signature (Addressee)

8. Addressee's Address (Only if requested and fee is paid)

6. Signature (Agent)
C. Cole

PS Form **3811**, November 1990 ☆U.S. GPO: 1991—287-066 **DOMESTIC RETURN RECEIPT**

P 062 921 986

Receipt for Certified Mail
No Insurance Coverage Provided
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(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. William R. Malenius	
Street and No. Senior Program Manager	
P.O., State and ZIP Code Polk Power Partners 23293 South Pointe Drive	
Postage Laguna Hills, CA	$ 92653
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date mailed: 8/14/92 AC 53-211670 PSD-FL 187	

PS Form **3800**, June 1991

POLK POWER
PARTNERS

1125 U.S. 98 SOUTH
SUITE 100
LAKELAND, FLORIDA 33801
813-682-6338
FAX 813-683-8257

December 6, 1994

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

RECEIVED
DEC 7 1994
Bureau of
Air Regulation

RE: Mulberry Cogeneration Project, PSD-FL-187 (AC53-211670)
New Source Performance Standards (NSPS) - Compliance Test
FDEP Air Permit - Compliance Test

Dear Mr. Fancy:

This correspondence is submitted on behalf of the Polk Power Partners to notify you that the Mulberry Cogeneration Facility began NSPS and state air permit compliance testing the week of November 28, 1994. The testing should be completed by December 19. If you have any questions regarding the testing schedule, I may be contacted at (813) 682-6338.

Sincerely,

Nancy Henning Jones
Vice President & General Manager
Polk Power GP, Inc.

cc: John Paul Jones, CSW-Mulberry
Ms. Jewell A. Harper, Chief Air Enforcement Branch
Dr. Richard D. Garrity, Director, Southeast District Fla Dept of Env. Prot.

KBN

April 3, 1992

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

RE: Polk County - A.P.
Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd.
Mulberry Cogeneration Project

Dear Clair:

Please find enclosed five copies of air construction permit application and prevention of significant deterioration analysis for an integrated congeneration facility. The facility will consist of a cogeneration power plant and a carbon dioxide (CO_2) recovery plant. A fee of $15,000 is enclosed to cover the appropriate permit fees for both facilities. The computer printouts of the air quality modeling results are being sent under separate cover.

I will be contacting you in a few weeks to review the initial comments your staff my have. In the meantime please call if you have any questions.

Sincerely,

Kennard F. Kosky, P.E.
President

KFK/tyf

cc: William Malenius, Ark Energy, Inc.
Ward Marshall, Central and South West Services, Inc.
Barry Andrews, FDER
File (2)

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

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FEDERAL EXPRESS

QUESTIONS? CALL 800-238-5355 TOLL FREE.

AIRBILL PACKAGE TRACKING NUMBER 1028818405

1028818405

RECIPIENT'S COPY

1 Date: 4-3-92

From (Your Name) Please Print	Your Phone Number (Very Important)	2 To (Recipient's Name) Please Print	Recipient's Phone Number (Very Important)
Robert C. McCann, Jr.	(904) 331-9000	Clair Fancy	(904) 488-1344
Company	**Department/Floor No.**	**Company**	**Department/Floor No.**
KBN ENG & APPLIED SCIENCES		FL Dept. of Environmental Regulation	
Street Address		**Exact Street Address** (We Cannot Deliver to P.O. Boxes or P.O. Zip Codes.)	
1034 NW 57TH ST		2600 Blair Stone Road Room 238	
City	**State** / **ZIP Required**	**City**	**State** / **ZIP Required**
GAINESVILLE	FL 32605	Tallahassee	FL 32399-2400

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Project 91193-0200

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5 [ ] Cash/Check

4 SERVICES (Check only one box)

Priority Overnight (Delivery by next business morning†)	Standard Overnight (Delivery by next business afternoon)
11 [ ] YOUR PACKAGING	51 [ ] YOUR PACKAGING
16 [ ] FEDEX LETTER *	56 [ ] FEDEX LETTER *
12 [ ] FEDEX PAK *	52 [ ] FEDEX PAK *
13 [X] FEDEX BOX	53 [ ] FEDEX BOX
14 [ ] FEDEX TUBE	54 [ ] FEDEX TUBE
Economy Two-Day (Delivery by second business day†)	**Government Overnight** (Restricted to authorized users only)
30 [ ] ECONOMY	46 [ ] GOVT LETTER
	41 [ ] GOVT PACKAGE

Freight Service (for Extra Large or any package over 150 lbs.)
70 [ ] OVERNIGHT FREIGHT ** (Confirmed reservation required)
80 [ ] TWO-DAY FREIGHT **
† Delivery commitment may be later in some areas.
*Declared Value Limit $100.
**Call for delivery schedule.

5 DELIVERY AND SPECIAL HANDLING (Check services required)

1 [ ] HOLD FOR PICK-UP (Fill in Box H)
2 [ ] DELIVER WEEKDAY
[ ] DELIVER SATURDAY (Extra charge) (Not available to all locations)
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[ ] DRY ICE ____ lbs.
[ ] OTHER SPECIAL SERVICE
[ ] SATURDAY PICK-UP (Extra charge)
10 [ ]
11 [ ] DESCRIPTION
12 [ ] HOLIDAY DELIVERY (If offered) (Extra charge)

6 PACKAGES	WEIGHT In Pounds Only
1	
Total 1	Total 16

DIM SHIPMENT (Chargeable Weight)
[ ] ____ lbs.
____ x ____ x ____ = ____

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2 ☐ On-Call Stop 4 ☐ B.S.C. 5 ☐ Station

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Division of Waste Management
Resource Management

Emp. No. Date
[ ] Cash Received
[ ] Return Shipment
[ ] Third Party [ ] Chg. To Del. [ ] Chg. To Hold
Street Address
City State Zip
Received By: X
Date/Time Received FedEx Employee Number

7 Release Signature:
FedEx Emp. No. Date/Time

Federal Express Use
Base Charges
Declared Value Charge
Other 1
Other 2
Total Charges

REVISION DATE 4/91
PART #137204 FXEM 6/91
FORMAT #082

082

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ARK/CSW DEVELOPMENT PARTNERSHIP

1036

VENDOR NO.	DATE	AMOUNT
288	3/16/92	$7500.00

FLORIDA DEPT. OF ENVIRONMENTAL REGULATIONS
(APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES)

ARK/CSW DEVELOPMENT PARTNERSHIP
PH. 714-588-3767
23293 S. POINTE DRIVE
LAGUNA HILLS, CA 92653

SECURITY PACIFIC BANK
IRVINE COMMERCIAL CENTER OFFICE 0732
NEWPORT BEACH, CA 92660
16-4-1220

1036

**********SEVEN THOUSAND FIVE HUNDRED AND NO/100**********

DATE	AMOUNT
3/16/92	$7,500.00

PAY TO THE ORDER OF FLORIDA DEPT. OF ENVIRONMENTAL REGULATIONS

[redacted]

ARK/CSW DEVELOPMENT PARTNERSHIP

1048

VENDOR NO.	DATE	AMOUNT
288	3/24/92	$7,500.00

FLORIDA DEPT. OF ENVIRONMENTAL REGULATION

"APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES"

900631

ARK/CSW DEVELOPMENT PARTNERSHIP
PH. 714-588-3767
23293 S. POINTE DRIVE
LAGUNA HILLS, CA 92653

SECURITY PACIFIC BANK
IRVINE COMMERCIAL CENTER OFFICE 0732
NEWPORT BEACH, CA 92660
16-4-1220

1048

**********SEVEN THOUSAND FIVE HUNDRED DOLLARS AND NO/100**********

DATE	AMOUNT
3/24/92	$7,500.00

PAY TO THE ORDER OF FLORIDA DEPT. OF ENVIRONMENTAL REGULATION

[redacted] Anthony J. Williams

RH 180758
#750000
AC53-~~211669~~ 211670
PSD-FL-187

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *Cogeneration Power Plant* [x] New[1] [ ] Existing[1]

APPLICATION TYPE: [x] Construction [ ] Operation [ ] Modification

COMPANY NAME: *Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd.* COUNTY: *Polk*

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) *Cogen Power Plant*

SOURCE LOCATION: Street *County Road 555* City *3.7 miles SW of Bartow*

UTM: East *413.6 km Zone 17* North *3080.6 km*

Latitude *27* ° *50* ' *56.0*"N Longitude *81* ° *52* ' *38.9*"W

APPLICANT NAME AND TITLE: *William R. Malenius, Senior Program Manager*

APPLICANT ADDRESS: *23293 South Pointe Drive, Laguna Hills, California 92653*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Polk Power Partners, L.P.*

I certify that the statements made in this application for *an air construction* permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: *W. Malenius*

William R. Malenius, Senior Program Manager
Name and Title (Please Type)

Date: *4/2/92* Telephone No. *(714) 588-3767*

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)
This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

[1]See Florida Administration Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed _____

Kennard F. Kosky

Name (Please Type)

KBN Engineering and Applied Sciences, Inc.

Company Name (Please Type)

1034 N.W. 57th Street, Gainesville, FL 32605

Mailing Address (Please Type)

Florida Registration No. *14996* Date: *4/2/92* Telephone No. *(904) 331-9000*

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Construction and operation of integrated cogeneration facility. The power plant consists of one combustion turbine, an associated heat recovery steam generator (HRSG), and a secondary HRSG with duct burner. See Sections 1.0 and 2.0 in PSD Application.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction *10/1/92* Completion of Construction *9/1/94*

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

The cost of control is integral to the overall design of the project. Dry low-NO_x combustion technology and water injection will be used to reduce air pollutant emissions.

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

No previous DER permits.

E. Requested permitted equipment operating time: hrs/day *24* ; days/wk *7* ; wks/yr *52* ;
If power plant, hrs/yr _____; if seasonal, describe: _____

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? *No*
   a. If yes, has "offset" been applied? _____
   b. If yes, has "Lowest Achievable Emission Rate" been applied? _____
   c. If yes, list non-attainment pollutants. _____
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. *Yes*[a]
3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. *Yes*[b]
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? *Yes*[c]
5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? *No*

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? *No*
   a. If yes, for what pollutants? _____
   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable. ***PSD permit application attached. Full responses can be found as follows:***

[a] ***Section 4.0***
[b] ***Section 3.0***
[c] ***Section 4.0***

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
	Not Applicable			

B. Process Rate, if applicable: (See Section V, Item 1)

1. Total Process Input Rate (lbs/hr): _____

2. Product Weight (lbs/hr): _____

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) ***See Tables 2-1 and 2-2 in PSD Application***

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO_2	*105.7(0.3)*	*416.5(1.3)*	*0.8% Sulfur*	*845.6*	*105.7(0.3)*	*416.5(1.3)*	*See*
PM	*15.0(1.0)*	*65.7(4.3)*	*NA*	*NA*	*15.0(1.0)*	*65.7(4.3)*	*Figure 2-1*
NO_x	*182.2(15.8)*	*718.2(69.4)*	*93 ppmvd*	*403.4*	*182.2(15.8)*	*718.2(69.4)*	*in PSD*
CO	*82.6(9.9)*	*329.9(43.4)*	*NA*	*NA*	*82.6(9.9)*	*329.9(43.4)*	*Application*
VOC	*10.11(3.0)*	*40.4(13.0)*	*NA*	*NA*	*10.11(3.0)*	*40.4(13.0)*	

[1]See Section V, Item 2. ***Maximum at 20°F; Actual at 59°F; Secondary HRSG Duct Burner Emissions shown in parentheses.***

[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)***NSPS - 0.8% Sulfur Fuel Oil and 75 ppmvd NO_x corrected to 15% O_2 and heat rate at ISO conditions. FDER Rule 17-2.660 40 CFR Part 60 Subpart GG.***

[3]Calculated from operating rate and applicable standard.

[4]Emission, if source operated with~~out~~ control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4) *See Section 4.0 in PSD application*

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas--CT	*914.5 MCF/hr*	*1,013.4 MCF/hr*	*962.8*
Distillate Oil--CT	*50,044.5 lb/hr*	*55,604 lb/hr*	*1,031.5*
Propane--CT	*997.7 MCF/hr*	*1,104.2 MCF/hr*	*1,049.0*
Natural Gas--DB	*104.2 MCF/hr*	*104.2 MCF/hr*	*99*

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.

Fuel Analysis:

Percent Sulfur: *Natural gas & propane--1 grain/100 CF; Oil--0.1%* Percent Ash: *<0.01% WGT*

Density: *7.1* lbs/gal Typical Percent Nitrogen: *0.03% WGT*

Heat Capacity: *Gas--19,303; propane--19,910; oil--18,550* BTU/lb *131,700* BTU/gal

Other Fuel Contaminants (which may cause air pollution): *See Appendix A in PSD application*

F. If applicable, indicate the percent of fuel used for space heating. *Not applicable*

Annual Average *N.A.* Maximum *N.A.*

G. Indicate liquid or solid wastes generated and method of disposal.

Plant will be designed for zero wastewater discharge. Solid wastes will be disposed of in an approved manner.

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: *125* ft. Stack Diameter: *15.0* ft.

Gas Flow Rate: *753,740* ACFM *532,987* DSCFM Gas Exit Temperature: *220* °F.

Water Vapor Content: *7.3* % Velocity: *71.1* FPS

See Tables A-1, A-6 and A-11 in Appendix A of PSD application. Data for distillate oil at 20°F shown above (maximum emission case). Does not include flow reduction with diversion to CO_2 recovery plant.

SECTION IV: INCINERATOR INFORMATION

Not Applicable

Type of Waste	Type 0 (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Pathological)	Type V (Liq. & Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste _____

Total Weight Incinerated (lbs/hr) _____ Design Capacity (lbs/hr) _____

Approximate Number of Hours of Operation per day _____ day/wk _____ wks/yr. _____

Manufacturer _____

Date Constructed _____ Model No. _____

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: _____ ft. Stack Diameter: _____ Stack Temp. _____

Gas Flow Rate: _____ ACFM _____ DSCFM* Velocity: _____ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control devices: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) _____

Brief description of operating characteristics of control devices: _____

_____

_____

_____

_____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

_____

_____

_____

_____

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   Not Applicable
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See Tables A-1 through A-15 in PSD application.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Tables A-1 through A-15 in PSD application.
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)
   See Sections 2.0 and 4.0 in PSD application and Tables A-6 and A-11.
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   Manufacturers' guarantees form the basis of emission estimates (see Tables A-1 through A-15 in PSD application).
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Figure 2-1 in PSD application.
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in PSD application.
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figure 1-2 in PSD application.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.
Applicable fee is attached.

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit. *Not Applicable*

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[X] Yes [ ] No

Contaminant	Rate or Concentration
NO_x - oil firing	*93 ppmvd corrected to 15% O_2 heat rate & nitrogen content*
- natural gas firing	*96 ppmvd corrected to 15% O_2 and heat rate*
SO_2	*0.8% sulfur fuel*

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[X] Yes [ ] No

Contaminant	Rate or Concentration
See Section 4.0 in PSD application	

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
See Sections 2.0 and 4.0 in PSD application	

D. Describe the existing control and treatment technology (if any).

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected:

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1]Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See Section 5.0 in PSD application

A. Company Monitored Data

1. _____ no. sites _____ TSP _____( )_____ SO^{2*} _____ Wind spd/dir

Period of Monitoring _____/_____/_____ to _____/_____/_____
month day year month day year

Other data recorded _____

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling *See Section 6.1 in PSD application*

1. _____ Year(s) of data from _____/_____/_____ to _____/_____/_____
month day year month day year

2. Surface data obtained from (location)_____

3. Upper air (mixing height) data obtained from (location) _____

4. Stability wind rose (STAR) data obtained from (location) _____

C. Computer Models Used *See Section 6.1 in PSD application*

1. _____ Modified? If yes, attach description.

2. _____ Modified? If yes, attach description.

3. _____ Modified? If yes, attach description.

4. _____ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data *See Section 6.1 in PSD application*

Pollutant	Emission Rate	
TSP	_____	grams/sec
SO^2	_____	grams/sec

E. Emission Data Used in Modeling *See Section 6.0 in PSD application*

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review. *See PSD application*

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e, jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. *See Section 4.0 in PSD application*

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. *See Section 4.0 in PSD application*

R# 180758
#7500.00

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

AC53-211670
PSD-FL-187

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *CO_2 Recovery Plant* [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: *Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd.* COUNTY: *Polk*

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) *CO_2 Recovery Vents (2)*

SOURCE LOCATION: Street *County Road 555* City *3.7 miles SW of Bartow*

UTM: East *413.6 km; zone 17* North *3080.6 km*

Latitude *27* ° *50* ' *56.0* "N Longitude *81* ° *52* ' *38.9*"W

APPLICANT NAME AND TITLE: *William R. Malenius, Senior Program Manager*

APPLICANT ADDRESS: *23293 South Pointe Drive, Laguna Hills, California 92653*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Polk Power Partners, L.P.*

I certify that the statements made in this application for an *air construction* permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: Bill Malenius

William R. Malenius, Senior Program Manager
Name and Title (Please Type)

Date: *04/02/92* Telephone No. *(714) 588-3767*

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)
This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

[1]See Florida Administration Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will discharge an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed _____

Kennard F. Kosky

Name (Please Type)

KBN Engineering and Applied Sciences, Inc.

Company Name (Please Type)

1034 N.W. 57th Street, Gainesville, FL 32605

Mailing Address (Please Type)

Florida Registration No. *14996* Date: *04/02/92* Telephone No. *(904) 331-9000*

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Construction and operation of an integrated cogeneration facility. The CO_2 recovery plant consists of CO_2 absorption and processing. Liquid CO_2 of beverage and food quality and dry ice will be produced; 150 tons per day will be the maximum CO_2 produced. See Sections 1.0 and 2.0 in PSD application.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction *10/01/92* Completion of Construction *09/01/94*

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

Scrubber for amine solvent is estimated at $240,600.

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

No previous DER permits.

E. Requested permitted equipment operating time: hrs/day *24*; days/wk *7*; wks/yr *52*;
If power plant, hrs/yr _____; if seasonal, describe: _____

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? *No*
   a. If yes, has "offset" been applied? _____
   b. If yes, has "Lowest Achievable Emission Rate" been applied? _____
   c. If yes, list non-attainment pollutants. _____
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. *Yes*[a]
3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. *Yes*[b]
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? *Yes*[c]
5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? *No*

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? *No*
   a. If yes, for what pollutants? _____
   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

PSD permit application attached. Full responses can be found as follows:

[a] *Section 4.0.*
[b] *Section 3.0.*
[c] *Section 4.0.*

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable:

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
FS-1 Solvent	*VOC*	*85*	*Recirculating scrubber*	*See Figure 2-2*

B. Process Rate, if applicable: (See Section V, Item 1) *Not Applicable*

1. Total Process Input Rate (lbs/hr): _____

2. Product Weight (lbs/hr): _____

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

See Table 2-2 in PSD application

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO_2	*5.17*	*22.27*	*NA*	*NA*	*5.17*	*22.27*	*see*
PM	*6.68*	*29.54*	*NA*	*NA*	*6.68*	*29.54*	*Figure*
NO_x	*24.23*	*105.53*	*NA*	*NA*	*24.23*	*105.53*	*2-2 in*
CO	*13.70*	*59.97*	*NA*	*NA*	*13.70*	*59.97*	*PSD*
VOC	*18.17*	*79.58*	*NA*	*NA*	*18.17*	*79.58*	*App.*

[1]See Section V, Item 2. *Emissions from combustion turbine (CT) and duct burner (DB) included.*

[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3]Calculated from operating rate and applicable standard.

[4]Emission, if source operated with~~out~~ control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Packed tower	*VOC*	*90%*	*N.A.*	*Manufacturer*
(scrubber)				*estimate*

E. Fuels *All energy used in CO_2 recovery plant is derived from cogeneration power plant.*

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.

Fuel Analysis:

Percent Sulfur:_____ Percent Ash:_____

Density: _____ lbs/gal Typical Percent Nitrogen:_____

Heat Capacity:_____ BTU/lb _____ BTU/gal

Other Fuel Contaminants (which may cause air pollution):_____

F. If applicable, indicate the percent of fuel used for space heating. ***Not Applicable***

Annual Average _____ Maximum _____

G. Indicate liquid or solid wastes generated and method of disposal.

Plant will be designed for zero wastewater discharge. Solid wastes will be disposed of in an approved manner.

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: 170 ft. Stack Diameter: 3.0 ft.

Gas Flow Rate: 28,202 ACFM 22,620 DSCFM Gas Exit Temperature: 117 °F.

Water Vapor Content: approximately 11 % Velocity: 66.5 FPS

SECTION IV: INCINERATOR INFORMATION

Not Applicable

Type of Waste	Type 0 (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Pathological)	Type V (Liq. & Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste _____

Total Weight Incinerated (lbs/hr) _____ Design Capacity (lbs/hr) _____

Approximate Number of Hours of Operation per day _____ day/wk _____ wks/yr. _____

Manufacturer _____

Date Constructed _____ Model No. _____

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: _____ ft. Stack Diameter: _____ Stack Temp. _____

Gas Flow Rate: _____ ACFM _____ DSCFM* Velocity: _____ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control devices: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) _____

Brief description of operating characteristics of control devices: _____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   Not applicable
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See Section 2.0 in PSD application.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Section 2.0 in PSD application.
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)
   See Section 4.0 in PSD application.
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   See Section 4.0 in PSD application.
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Figure 2-2 in PSD application.
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in PSD application.
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figure 1-2 in PSD application.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation. ***Applicable fee is attached.***

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[ ] Yes [X] No

Contaminant	Rate or Concentration

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[X] Yes[a] [ ] No [a]*In general*

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
VOC	*90% removal*
See Section 4.0 in PSD application	

D. Describe the existing control and treatment technology (if any).

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected: ***See Section 4.0 in PSD application.***

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

[1]Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See Section 5.0 in PSD application

A. Company Monitored Data

1. _____ no. sites _____ TSP _____ ( ) SO^{2*} _____ Wind spd/dir

Period of Monitoring ____/____/____ to ____/____/____
month day year month day year

Other data recorded _____

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling *See Section 6.0 in PSD application*

1. _____ Year(s) of data from _____/____/_____ to _____/____/_____
month day year month day year

2. Surface data obtained from (location)_____

3. Upper air (mixing height) data obtained from (location) _____

4. Stability wind rose (STAR) data obtained from (location) _____

C. Computer Models Used *See Section 6.0 in PSD application*

1. _____ Modified? If yes, attach description.

2. _____ Modified? If yes, attach description.

3. _____ Modified? If yes, attach description.

4. _____ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables.

D. Applicants Maximum Allowable Emission Data *See Section 6.0 in PSD application*

Pollutant	Emission Rate	
TSP	_____	grams/sec
SO^2	_____	grams/sec

E. Emission Data Used in Modeling *See Section 6.0 in PSD application*

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review. *See PSD application*

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e, jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. *See Section 4.0 in PSD application*

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. *See Section 4.0 in PSD application*

1.0 INTRODUCTION

Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd., is proposing to construct and operate an integrated cogeneration facility at a 54.7-acre site. The facility is referred to as the Mulberry Cogeneration Facility. The Mulberry Cogeneration Facility is a combined cycle cogeneration power plant located approximately 3.7 miles southwest of the community of Bartow, Florida, on County Road 555 (see Figure 1-1).

The plant consists of one General Electric (GE) PG 7111EA combustion turbine, with a primary heat recovery steam generator (HRSG), a secondary HRSG, and one steam turbine generator. The facility will generate approximately 120,000 kilowatts (kW) net power to the transmission system at average ambient conditions. The primary fuel for the plant is natural gas; the plant is also capable of burning fuel oil or propane as the backup fuel. The combustion turbine (CT) uses specially designed combustors to limit nitrogen oxide (NO_x) emissions. Exhaust gas from the CT is ducted to the primary HRSG to produce steam which is used in the steam turbine to generate electrical power and to provide steam to the host carbon dioxide (CO_2) plant. The secondary HRSG takes a slipstream from the discharge of the primary HRSG. The slipstream is duct fired with natural gas to create additional high-pressure steam for the steam turbine. The exhaust gas of the secondary HRSG is rich in CO_2 and is ducted to the CO_2 plant thermal host as feed gas to the CO_2 stripping process. Approximately 150 tons per day (TPD) of liquid CO_2 is produced by the thermal host. Steam is provided to the CO_2 plant thermal host at a rate of 25,000 pounds per hour (lb/hr) at 105 pounds per square inch absolute (psia) and 341 degrees Fahrenheit (°F). Liquid CO_2 storage, handling, and dry ice production facilities are also on-site. General characteristics of the facility are presented in Table 1-1.

KBN Engineering and Applied Sciences, Inc. (KBN), has been contracted to provide air permitting services for the facility. Initially, preliminary analyses were performed to determine compliance with prevention of significant deterioration (PSD) increments and preconstruction de minimis

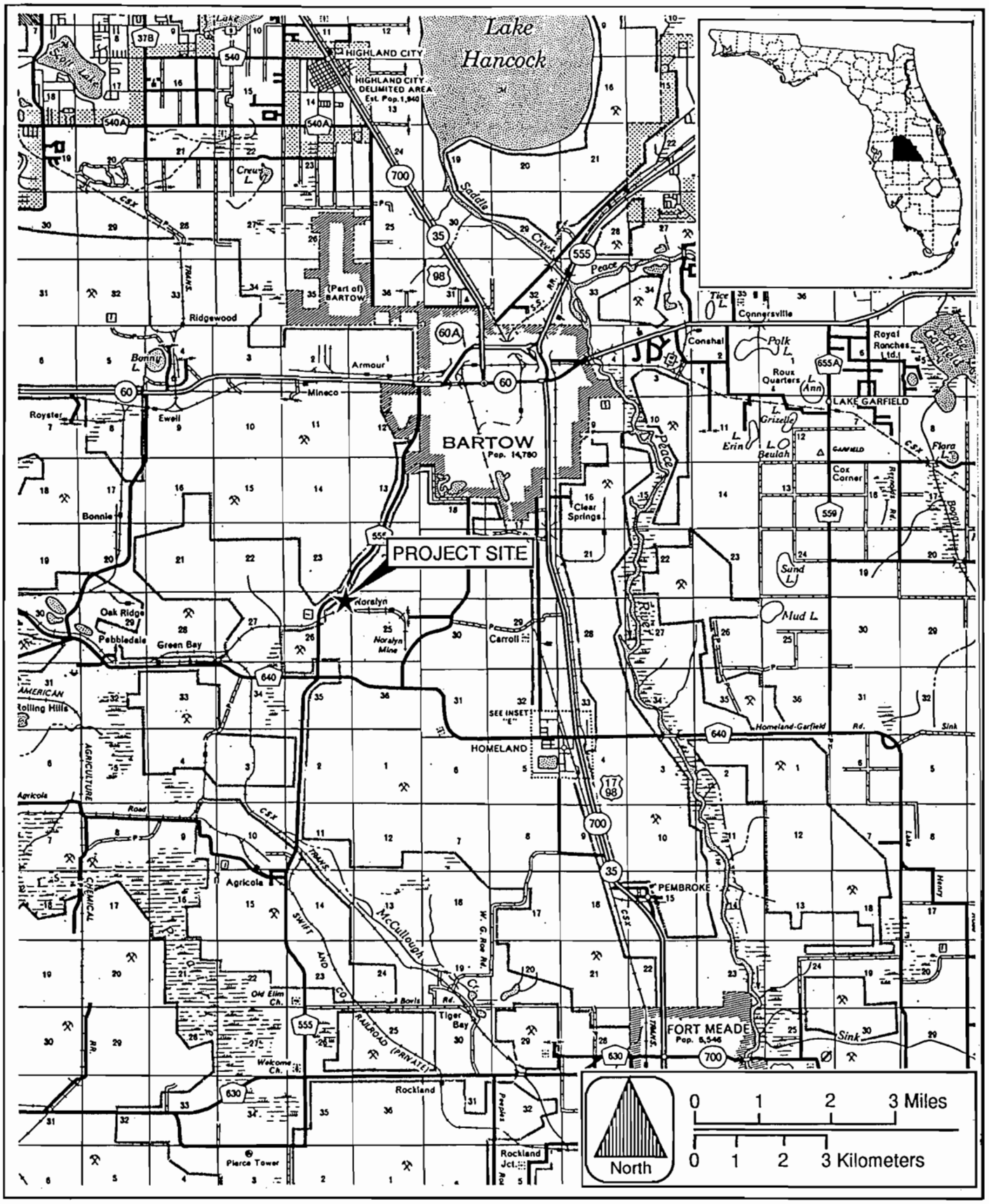


Figure 1-1 PROJECT LOCATION MAP

SOURCES: FDOT, 1988; KBN, 1992.

KBN

Table 1-1. Characteristics of the Mulberry Cogeneration Facility

Characteristic	Data
Nominal Capacity (MW)	
Combustion Turbine	81
Steam Cycle	45
Total	126
Auxiliary Loads	-3.5
Net Output	122.5
Equipment Characteristics	
Type of CT	GE PG 7111EA
Heat Input (MMBtu/hr)	859.3[a]
Number of HRSGs[b]	2
Number of Steam Turbines	1
Fuels	
Initial Operation (first 3 years)	Natural gas, distillate oil, and propane
Permanent Operation	Natural gas with distillate oil as backup
CO_2 Plant	
Capacity (TPD)	150
Solvent	Economic FS[c]-1
Trains	2
Process Steam Requirements (lb/hr)	25,000

Note: CT = combustion turbine
GE = General Electric
HRSG = heat recovery steam generator

[a] Represents ISO conditions and firing natural gas.
[b] Main HRSG does not have supplemental firing; secondary HRSG will have a maximum firing rate of 99 MM Btu/hour and utilize only natural gas.
[c] Monoethanolamine (MEA) proprietary solution.

monitoring levels for the proposed plant only. A full PSD review was then performed to determine whether significant air quality deterioration will result from the proposed facility and other PSD increment-consuming sources and to determine compliance with ambient air quality standards (AAQS). The PSD review included control technology review, source impact analysis, air quality analysis (monitoring), and additional impact analyses.

The proposed project will be a major facility because emissions of at least one regulated pollutant exceeds 250 tons per year (TPY). PSD review is required for these emissions and for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates. The potential emissions from the proposed project will exceed the PSD significant emission rates for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 micrometers (PM10), volatile organic compounds (VOCs), sulfuric acid mist, beryllium (Be), and arsenic (As). Therefore, the project is subject to PSD review for these pollutants.

This report is presented in seven sections. A general description of the proposed operation is given in Section 2.0. The air quality review requirements and applicability of the project to the PSD and nonattainment regulations are presented in Section 3.0. The control technology review for the project applicable under the U.S. Environmental Protection Agency's (EPA's) current top-down approach is discussed in Section 4.0. A discussion of the need for air quality monitoring data to satisfy the PSD preconstruction monitoring requirements is presented in Section 5.0. The air source impact analysis approach is presented in Section 6.0. The results of the air quality analyses and additional impact analyses associated with the project's impacts on vegetation, soils, and associated growth are discussed in Section 7.0.

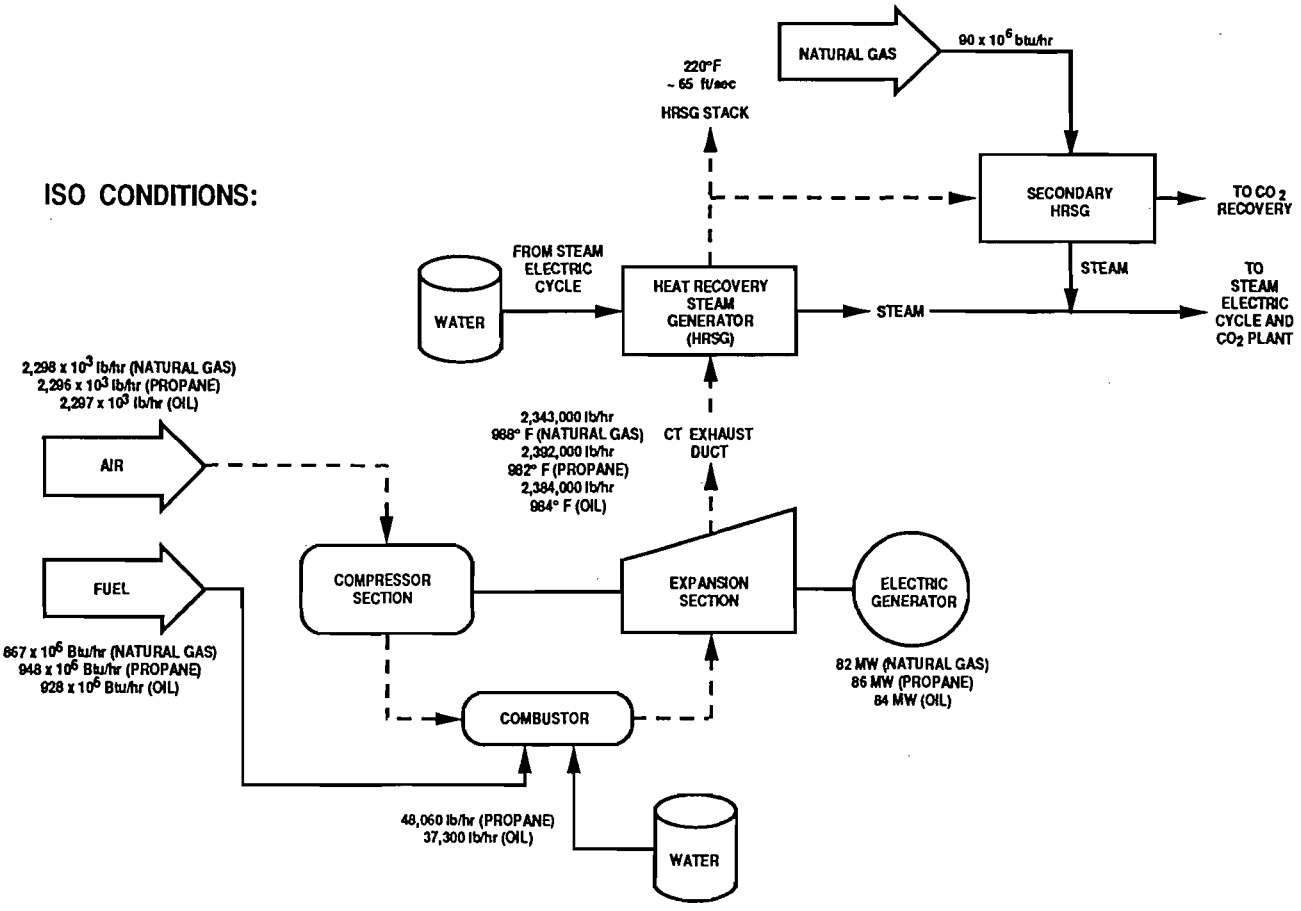
2.0 PROJECT DESCRIPTION

2.1 POWER PLANT DESCRIPTION

The proposed power plant will consist of one GE PG 7111EA combustion turbine. This CT is a heavy-frame industrial gas turbine that will use dry low-NOx combustion technology and water injection to control NO_x emissions. The CT combustion gases will exhaust through a HRSG and into a single stack. There will be no bypass for simple cycle operation. A flow diagram is presented in Figure 2-1. Stack, operating, and emission data for the proposed combustion turbines are presented in Table 2-1.

For the first 3 years of operation, the CT will be fired with natural gas, propane, and distillate oil. The amount of generation for each fuel will depend upon availability. After this period, natural gas will be the primary fuel with distillate use as backup (maximum of 30 days operation). The distillate oil will have a sulfur content of 0.1 percent or less. The main HRSG will not be supplementary fired.

The steam turbine is a single casing, condensing machine with an induction port to accept a portion of the steam. The steam turbine exhausts to a surface condenser served by a multicell cooling tower and circulating water pumps. Plant water for makeup to the cooling tower and steam cycle is obtained from two wells located on the site. The raw water is processed in a pretreatment system upstream of the demineralizer. A demineralizer system is used to treat the incoming water for makeup to the HRSG steam cycle. Wastewater from the plant is disposed of in a wastewater treatment system to meet the zero discharge requirements of the environmental permits. The wastewater treatment system consumes 5,300 lb/hr of steam (105 psia, 341°F). Natural gas is provided at the facility boundary and is pressurized in a fuel gas compressor to the pressure required by the combustion turbine generator. All systems in the plant are controlled from a central control room via a digital control system. The plant control room and office space are located adjacent to the steam turbine area. Figure 2-2 presents a plot plan of the facility.



NOTE: SEE TABLE A-1 FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

Figure 2-1 SIMPLIFIED FLOW DIAGRAM OF PROPOSED MULBERRY COGENERATION POWER PLANT

Table 2-1. Stack, Operating, and Emission Data for the Proposed Combustion Turbine [GE PG7111(EA)]

Parameter	Fuel Type[a]		
	Natural Gas	Fuel Oil	Propane
Stack Data (ft)			
Height	125	125	125
Diameter	15	15	15
Operating Data (ISO Conditions, i.e. 59°F)[b]			
Temperature (°F)	220	220	220
Velocity (ft/sec)	64.1	65.2	65.9
Maximum Hourly Emission Data (lb/hr) for Each Emission Unit/Fuel Type (20°F)[c]			
SO_2	2.9	105.7	3.2
PM	7.0	15.0	6.0
NO_x	97.5	182.2	177.8
CO	47.0	82.6	23.5
VOC	7.05	10.11	7.1
Pb	Neg.	0.0092	Neg.
Sulfuric Acid Mist	0.23	8.5	0.25
F	Neg.	0.0335	Neg.
Be	Neg.	0.00258	Neg.
Hg	Neg.	0.00309	Neg.
As	Neg.	0.00433	Neg.
Annual Potential Emission Data (TPY) for Each Emission Unit/Fuel Type (59°F)[c]			
SO_2	11.4	416.5	12.5
PM	30.7	65.7	26.8
NO_x	384.5	718.2	703.3
CO	187.8	329.9	94.0
VOC	28.2	40.4	28.2
Pb	Neg.	0.036	Neg.
Sulfuric Acid Mist	0.9	33.6	1.0
F	Neg.	0.132	Neg.
Be	Neg.	0.0102	Neg.
Hg	Neg.	0.0122	Neg.
As	Neg.	0.0171	Neg.

Note: Neg. = negligible emissions for applicable pollutant.

[a] Refer to Appendix A for detailed information on each fuel.
[b] Does not account for exhaust flow diverted to the CO_2 plant.
[c] Other regulated pollutants are assumed to have negligible emissions. These pollutants include reduced sulfur compounds, hydrogen sulfide, asbestos, vinyl chloride, and radionuclides.

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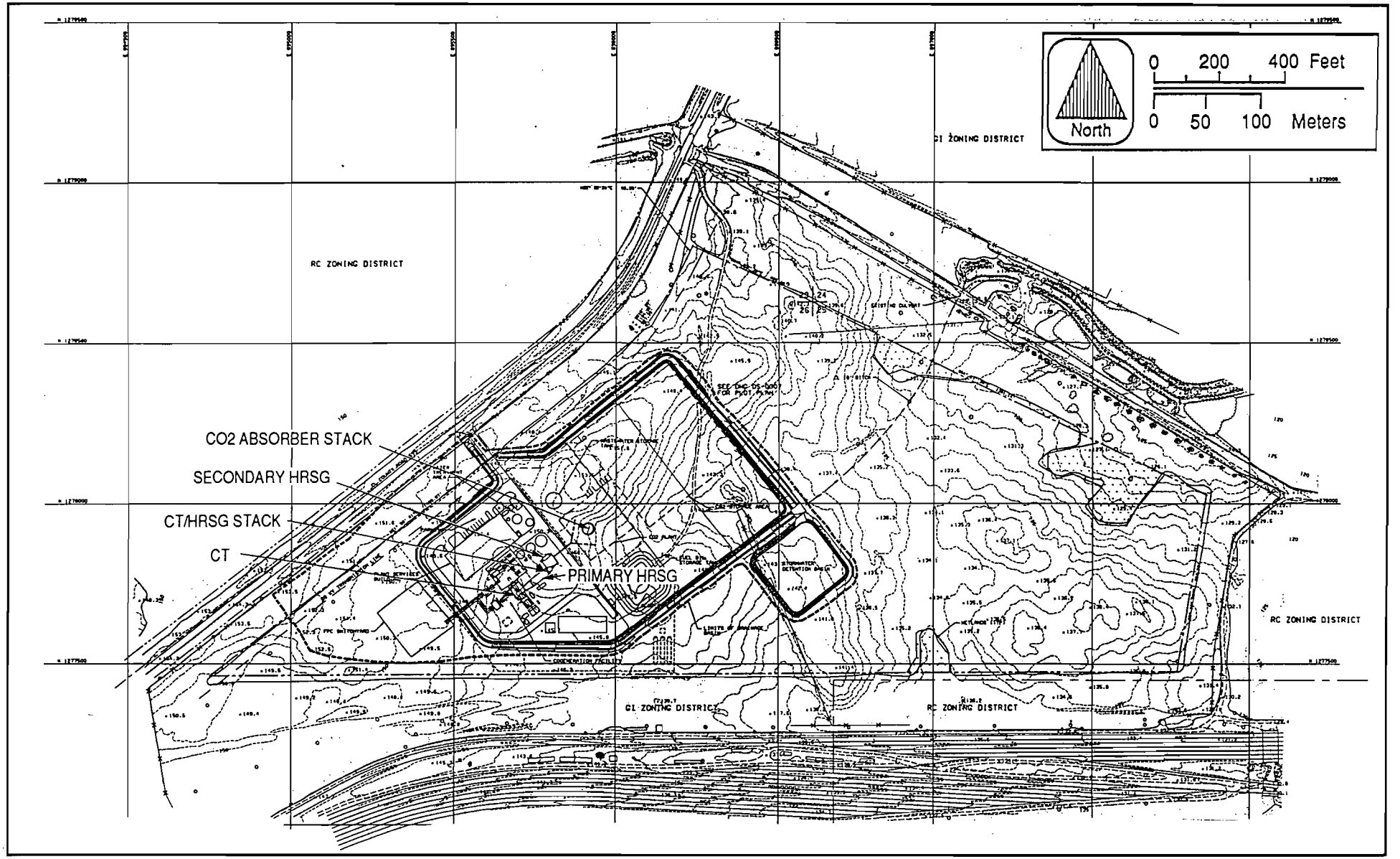

Figure 2-2 PROPOSED SITE ARRANGEMENT
MULBERRY COGEN

SOURCES: C& SW SERVICES, INC., 1/14/92; KBN, 1992.

KBN

2.2 CO_2 PLANT DESCRIPTION

A simplified flow diagram of the CO_2 plant is shown in Figure 2-3. Stack, operating, and emission data for the CO_2 plant are presented in Table 2-2.

A slip stream of cooled gas turbine exhaust (flue gas) from the primary HRSG will feed the CO_2 recovery plant. To enrich the CO_2 content, and simultaneously reduce the O_2 content, the flue gas is first fired in a secondary HRSG with natural gas. The maximum firing rate for the secondary HRSG will be 99 MM Btu/hour.

The enriched flue gas then will feed a pair of CO_2 recovery units. The following description is typical for each of two 75 TPD CO_2 recovery trains. Both units operate simultaneously for a combined output of 150 TPD CO_2.

A flue gas compressor will boost the pressure of the enriched flue gas to about 2.5 pounds per square inch gauge (psig). The gas is then cooled to about 115°F with cooling water which condenses a portion of the contained water vapor. The condensed water is returned to the plant cooling tower basin. The remaining flue gas enters the amine absorber where it is contacted in a countercurrent fashion with a circulating amine solvent. The amine solvent employed is a proprietary solvent (known as FS solvent). The FS solvent is an aqueous monoethanolamine (MEA) solution with proprietary corrosion inhibitors which offer increased oxygen tolerance. The solvent absorbs a majority of the CO_2 contained in the flue gas. The balance of the gas is washed with a circulating water stream to reduce the entrainment of the amine solvent in the treated gas. The treated gas then will exit the top of the absorber, venting to the atmosphere.

The rich amine solvent, loaded with the absorbed CO_2, is pumped to the amine stripper where it is regenerated by steam stripping. The stripping section is generated indirectly by heating the solvent in a steam heated reboiler. The stripping vapors release the absorbed CO_2 which exits overhead in the stripper tower. Low pressure steam is provided for heating

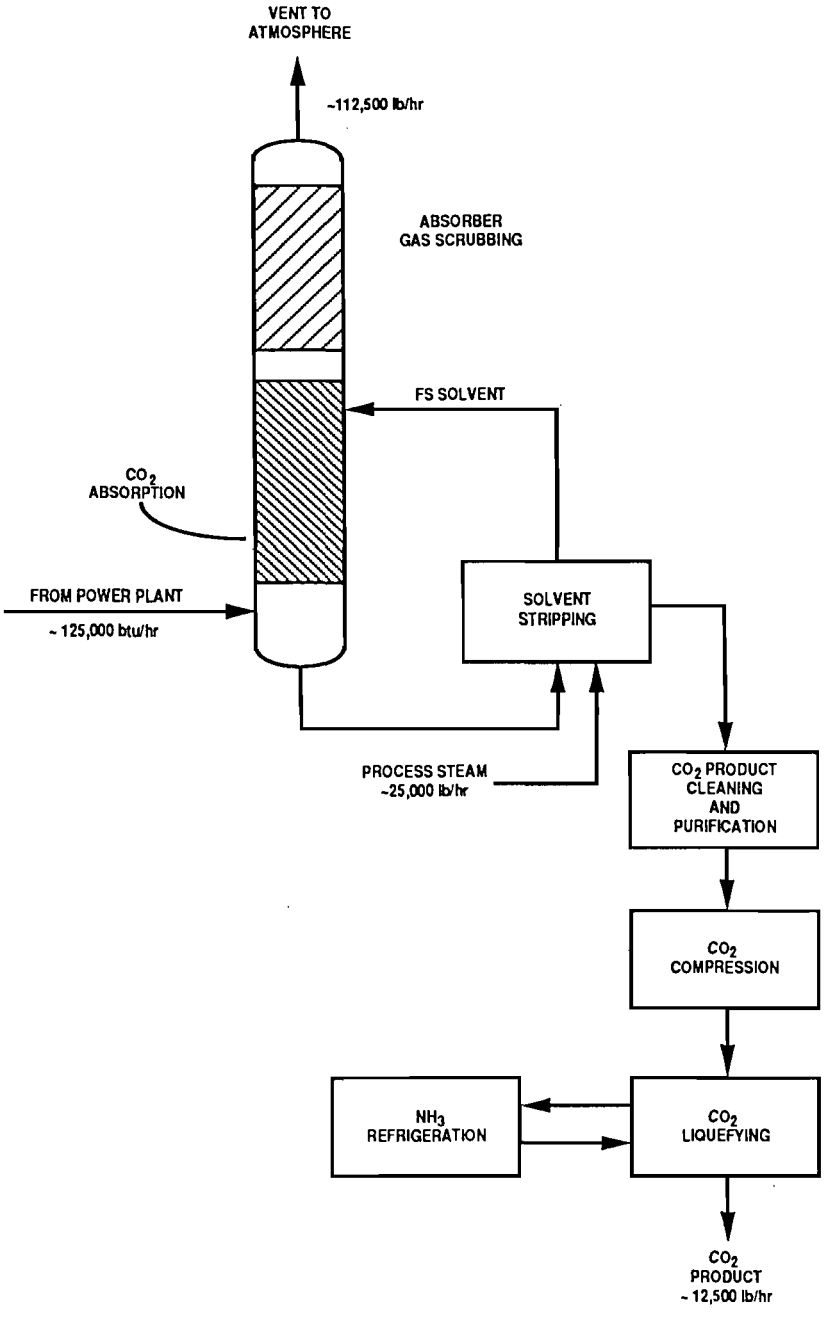

Figure 2-3 SIMPLIFIED FLOW DIAGRAM OF CO_2 RECOVERY PLANT

Table 2-2. Stack, Operating, and Emission Data for the Proposed Carbon Dioxide Recovery Plant Emissions and Stack Parameters

	Source			Total Maximum Emissions
	CT[a]	Duct Burner[b]	CO_2 Absorber[c]	
Stack Parameters:				
Height (ft)				170.0
Velocity (ft/sec)				66.5
Temperature (°F)				117.0
Flow (acfm)				28,201.7
Diameter (ft)				3.0
Maximum Hourly Emissions (lb/hr)[d]:				
SO_2	4.87	0.30	0.00	5.17
PM	0.69	0.99	5.00	6.68
NO_x	8.39	15.84	0.00	24.23
CO	3.80	9.90	0.00	13.70
VOC	0.47	2.97	14.73	18.17
Pb	0.0005	Neg.	0.00	0.00
Sulfuric Acid Mist	0.39	0.02	0.00	0.41
F	0.0015	Neg.	0.00	0.0015
Be	0.00012	Neg.	0.00	0.00012
Hg	0.00014	Neg.	0.00	0.00014
As	0.00020	Neg.	0.00	0.00020
Maximum Annual Emissions (TPY)[d]:				
SO_2	20.96	1.30	0.00	22.27
PM	3.31	4.34	21.90	29.54
NO_x	36.15	69.38	0.00	105.53
CO	16.61	43.36	0.00	59.97
VOC	2.03	13.01	64.54	79.58
Pb	0.0018	Neg.	0.00	0.00
Sulfuric Acid Mist	1.69	0.10	0.00	1.79
F	0.0067	Neg.	0.00	0.0067
Be	0.00051	Neg.	0.00	0.00051
Hg	0.00061	Neg.	0.00	0.00061
As	0.00086	Neg.	0.00	0.00086

Note: Neg. = negligible emissions for applicable pollutant.

[a] Based on diverting 120,000 lb/hr of mass flow. Hourly emissions are based on distillate oil firing at 20°F; annual emissions are based on 59°F. Calculated based on the percentage of mass flow to the CO_2 plant.

[b] Based on 99 MM Btu per hour and the following emission factors: PM = 0.01 lb/MM Btu; SO_2 = 1 grain/100 cf of natural gas; NO_x = 0.16 lb/MM Btu; CO = 0.1 lb/MM Btu; VOC = 0.03 lb/MM Btu, and H_2SO_4 = 5% of SO_2

[c] VOC emissions based on 6 lb FS solvent/ton of CO_2; VOC as carbon.

[d] Other regulated pollutants are assumed to have negligible or no emissions.

the stripping reboiler. A total of 25,000 lb/hr of steam is used to generate the CO_2 production of 150 TPD.

A solvent reclaimer is operated intermittently to reduce degradation products and heat stable salts in the circulating amine solution which result from side reactions and thermal/chemical degradation of the solvent. The reclaimed solution is vaporized by indirect steam heating and returned to the stripper. The balance of the reclaimer "bottoms" represents a liquid waste product for disposal off-site.

The regenerated amine solvent from the stripper is cooled, filtered, and pumped back to the absorber.

The water saturated CO_2 stream exiting the stripper overhead is cooled with condensed water returned to the stripper as reflux. The remaining CO_2 vapor stream proceeds to the CO_2 purification and liquefaction section.

The CO_2 vapor is first contacted with a recirculating potassium permanganate solution for removal of amine solvent traces as well as any trace levels of NO_x and SO_2. The gas is then water washed with a recirculating water stream and feeds an activated carbon tower for final purification. The scrubbing operation produces a small aqueous permanganate stream for disposal off-site. The water wash operation produces a water effluent which is sent to wastewater storage for zero discharge treating.

The purified CO_2 vapor is then compressed from near atmospheric pressure to about 250 psig. The compressor discharge is cooled with cooling water which condenses a portion of the contained water vapor. This water is recycled back to the amine unit. The CO_2 vapor is then dried in a CO_2 dryer to prevent subsequent freezing of the remaining water vapor.

The dry CO_2 is then liquified by condensing with a closed loop ammonia refrigeration system. Liquid CO_2 of beverage and food grade quality is then pressured to intermediate storage before being trucked from the site.

Dry ice will be produced on-site. A portion of the liquid CO_2 produced will be converted to solid and gaseous CO_2. Of the portion of liquid CO_2 used in dry ice production, about 40 percent is converted to solid CO_2, 40 percent is reliquefied, and 20 percent is lost as a gas.

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the proposed project. These regulations must be satisfied before the proposed facility (combined cycle turbine and CO_2 processing plant) can begin operation.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a preconstruction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA, and therefore PSD approval authority has been granted to the Florida Department of Environmental Regulation (FDER).

A "major facility" is defined as any one of 28 named source categories that has the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels ($\mu g/m^3$)

Pollutant	Averaging Time	AAQS[a] National Primary Standard	AAQS[a] National Secondary Standard	AAQS[a] State of Florida	PSD Increments[a] Class I	PSD Increments[a] Class II	Significant Impact Levels[b]
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	4[c]	17[c]	1
	24-Hour Maximum	150	150	150	8[c]	30[c]	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	1-Hour Maximum[d]	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	15	NA	NA	NA

[a]Short-term maximum concentrations are not to be exceeded more than once per year.
[b]Maximum concentrations are not to be exceeded.
[c]Proposed October 5, 1989.
[d]Achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

Note: Particulate matter (TSP) = total suspended particulate matter.
Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

NA = Not applicable, i.e., no standard exists.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50.
40 CFR 52.21.
Chapter 17-2.400, F.A.C.

A "major modification" is defined under PSD regulations as a change at an existing major facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations that are essentially identical to federal regulations [Chapter 17-2.510, Florida Administrative Code (F.A.C.)]. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level of SO_2 and total suspended particulate matter [PM(TSP)] concentrations would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated, based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks,

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	[c]	NM
Radionuclides	NESHAP	[c]	NM
Inorganic Arsenic	NESHAP	[c]	NM

[a] Short-term concentrations are not be be exceeded.
[b] No de minimis concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.
[c] Any emission rate of these pollutants.

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below de minimis monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = micrograms per cubic meter.

Sources: 40 CFR 52.21.
Chapter 17-2, F.A.C.

national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. EPA then promulgated as regulations the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated regulations to prevent significant deterioration as a result of emissions of NO_x and established PSD increments for NO_2 concentrations. The EPA class designations and allowable PSD increments are presented in Table 3-1. FDER has adopted the EPA class designations and allowable PSD increments for SO_2, PM(TSP), and NO_2 increments.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations, or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP) concentrations, and after February 8, 1988, for NO_2 concentrations; and

2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP), and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP), and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Chapter 17-2.450, F.A.C.).

3.2.3 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission-limiting standards be met, and that Best Available Control Technology (BACT) be applied to control emissions from the source [Chapter 17-2.500(5)(c), F.A.C]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Chapter 17-2.100(25), F.A.C., as:

> An emissions limitation, including a visible emission standard, 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 (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining Best Available Control Technology (BACT), (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decisionmaking.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limit that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between

the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990).

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Chapter 17-2.500(f), F.A.C, any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDER may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the de minimis levels presented in Table 3-2 [Chapter 17-2.500(3)(e), F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (Revised). The source impact analysis for criteria pollutants to address compliance with AAQS and PSD Class II increments may be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is below significance levels, as presented in Table 3-1.

EPA has recently recommended significant impact levels for PSD Class I areas. The levels are as follows:

Pollutant	Averaging Time	Maximum Significance Level ($\mu g/m^3$)
SO_2	3-hour	1.23
	24-hour	0.275
	Annual	0.1
PM(TSP)	24-hour	1.35
	Annual	0.27
NO_2	Annual	0.1

Although these levels were proposed for use in Virginia and may not be binding in other states, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. EPA's Office of Air Quality Planning and Standards has initiated a motion that will lead to rulemaking

to address the general need for Class I significant impact levels. The action is part of EPA's efforts to incorporate new source review provisions of the 1990 Clean Air Act Amendments. Because the process of developing the regulations will be lengthy, EPA believes that immediate guidance concerning the significant impact levels is appropriate in order to assist states in implementing the PSD permit process.

Various lengths of record for meteorological data can be used for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21; Chapter 17-2.500(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical

regulations have been adopted by FDER [Chapter 17-2.270, F.A.C.]. GEP stack height is defined as the highest of:

1. 65 meters (m), or
2. A height established by applying the formula:

$$Hg = H + 1.5L$$

where: Hg = GEP stack height,
H = Height of the structure or nearby structure, and
L = Lesser dimension (height or projected width) of nearby structure(s), or

3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometer (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Chapter 17-2.510, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. A major modification at a major facility is required to undergo review if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or if the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all VOC sources that are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 AREA CLASSIFICATION

The project site is located in Polk County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants. Polk County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_x. The site is located approximately 120 km from the closest part of the Chassahowitzka National Wilderness Area.

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The proposed project is considered to be a major facility because emissions of any regulated pollutant will exceed 250 TPY (refer to Table 2-2); therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., major modification). As shown, potential emissions from the proposed project will exceed the PSD significant emission rates for SO_2, PM(TSP), PM(PM10), NO_2, CO, VOCs, sulfuric acid mist, Be, and inorganic As. Therefore, the project is subject to PSD review for these pollutants.

3.4.2.2 Ambient Monitoring

Based on the net increase in emissions from the proposed project, presented in Table 3-3, a PSD preconstruction ambient monitoring analysis is required for SO_2, PM(TSP), PM(PM10), NO_2, CO, VOCs, sulfuric acid mist, Be, and As. However, if the net increase in impact of a pollutant is less than the de minimis monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement is provided for in the FDER regulations [FDER Rule 17-2.500(3)(e)]. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

If preconstruction monitoring data are required to be submitted, data collected at or near the project site can be submitted, based on existing air quality data (e.g., FDER) or the collection of on-site data.

Maximum predicted impacts as a result of the net increase associated with the proposed project are presented in Table 3-4 for pollutants requiring PSD review. The methodology used to predict maximum impacts and the impact analysis results are presented in Sections 6.0 and 7.0. As shown in Table 3-4, the maximum net increase in impact is below the respective de minimis monitoring concentration for all pollutants except SO_2. For VOCs, the maximum emissions from the proposed facility exceeds the de minimis emission rate of 100 TPY. There are no acceptable ambient monitoring methods for sulfuric acid mist, radionuclides, or As; therefore, monitoring is not required for these pollutants.

For SO_2 and ozone concentrations, the monitoring data collected in Polk County are proposed for use in satisfying the preconstruction monitoring requirements (see Section 5.2).

3.4.2.3 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m high. The stacks for the proposed turbine and CO_2 plant will be 125 feet (ft) (38.1 m) and 170 ft (51.8 m), respectively. These stack heights do not

Table 3-3. Net Increase in Emissions Due To the Proposed Mulberry Cogeneration Facility Compared to the PSD Significant Emission Rates

Pollutant	Emissions (TPY) Potential Emissions From Proposed Facility	Significant Emission Rate	PSD Review
Sulfur Dioxide	418[a]	40	Yes
Particulate Matter (TSP)	92	25	Yes
Particulate Matter (PM10)	92	15	Yes
Nitrogen Dioxide	788	40	Yes
Carbon Monoxide	373	100	Yes
Volatile Organic Compounds	118	40	Yes
Lead	0.036	0.6	No
Sulfuric Acid Mist	34	7	Yes
Total Fluorides	0.13	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Asbestos	NEG	0.007	No
Beryllium	0.010	0.0004	Yes
Mercury	0.012	0.1	No
Vinyl Chloride	NEG	1	No
Benzene	NEG	0	No
Radionuclides	NEG	0	No
Inorganic Arsenic	0.017	0	Yes

Note: NEG = Negligible.
All calculations based on 59°F peak load condition.

[a]Based on a maximum sulfur content specification of 0.1 percent in fuel oil.

Table 3-4. Predicted Net Increase in Impacts Due To the Proposed Mulberry Cogeneration Facility Compared to PSD De Minimis Monitoring Concentrations

Pollutant	Concentration ($\mu g/m^3$) Predicted Net Increase in Impacts	Concentration ($\mu g/m^3$) De Minimis Monitoring Concentration
Sulfur Dioxide	15.5	13, 24-hour
Particulate Matter (TSP)	2.8	10, 24-hour
Particulate Matter (PM10)	2.8	10, 24-hour
Nitrogen Dioxide	0.85	14, annual
Carbon Monoxide	23.6	575, 8-hour
Volatile Organic Compounds	118 TPY	100 TPY[a]
Sulfuric Acid Mist	NA	NM
Beryllium	0.0004	0.001, 24-hour
Inorganic Arsenic	NA	NM

Note: NA = Not applicable.
NM = No acceptable ambient measurement method has been developed and, therefore, de minimis levels have not been established by EPA.

[a] No de minimis concentration; an increase in emissions of 100 TPY or more will require a monitoring analysis for ozone.

exceed the GEP stack height. The potential for downwash of the units' emissions caused by nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.4.3 NONATTAINMENT REVIEW

The project site is located in Polk County, which is classified as an attainment area for all criteria pollutants. The plant is also located more than 50 km from any nonattainment area. Therefore, nonattainment requirements are not applicable.

3.4.4 HAZARDOUS POLLUTANT REVIEW

The FDER has promulgated guidelines (FDER, 1991) to determine whether any emission of a hazardous or toxic pollutant can pose a possible health risk to the public. All regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants are to be compared to no threat levels (NTL) for each applicable pollutant. If the maximum predicted concentration for any hazardous pollutant is less than the corresponding NTL for each applicable averaging time, that emission is considered not to pose a significant health risk. The NTLs for pollutants applicable to the proposed project are presented in Table 3-5. Emissions for these pollutants are presented in Appendix A.

Table 3-5. Summary of Florida No Threat Levels for Toxic Air Pollutants Applicable to the Proposed Facility Analysis

Pollutant	No Threat Level (μg/m) 8-Hour	24-Hour	Annual
Antimony	5	1.2	0.3
Arsenic	2	0.48	0.00023
Barium	5	1.2	50
Beryllium	0.02	0.0048	0.00042
Cadmium	0.5	0.12	0.00056
Chlorine	15	3.6	NE
Chromium	5	1.2	1000
Colbalt	0.5	0.12	NE
Copper	1	0.24	NE
Ethanolamine	80	19.2	NE
Fluorine	2	0.48	50
Formaldehyde	4.5	1.08	0.077
Lead	1.5	0.36	0.09
Manganese	50	12	NE
Mercury	0.5	0.12	0.3
Nickel	0.5	0.12	0.0042
Polyorganic Matter	NE	NE	NE
Selenium	2	0.48	NE
Sulfuric Acid Mist	10	2.38	NE
Vanadium	0.5	0.12	20
Zinc[a]	50	12	NE

Note: NE = none established.

[a] As zinc oxide.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of PM10, SO_2, NO_x, CO, VOC, H_2SO_4 mist, Be, and inorganic As (see Section 3.0). This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring the top-down approach.

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas turbines are codified in 40 CFR 60, Subpart GG. These regulations apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100 x 10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of their potential electric output capacity for sale to any utility power distribution system [40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the project and are the most stringent provision of the NSPS. These requirements are summarized in Table 4-1 and were considered in the BACT analysis.

As noted from Table 4-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.06 percent, the NSPS is increased by 0.0024 percent or 24 parts per million (ppm).

Table 4-1. Federal NSPS for Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr.

[b] Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-bound nitrogen (percent by weight)	Allowed Increase NO_x percent by volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60 Subpart GG.

For the proposed CTs, the NSPS emission limit would be 93 ppm on oil and 96 ppm on gas (corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent). The applicable NSPS for the secondary duct burner will be 40 CFR 60, Subpart Dc. The applicable requirements are presented in Table 4-2.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 NITROGEN OXIDES

4.3.1.1 Identification of NO_x Control Technologies

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table 4-3 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions made by state environmental agencies and EPA regional offices for gas turbines. This table was developed from the information contained in the LAER/BACT clearinghouse documents (EPA, 1985b, 1986, 1987c, 1988c, 1989) and by contacting state agencies, such as the California Air Control Board, the South Coast Air Quality Management District, the New Jersey Department of Environmental Protection, and the Rhode Island Department of Environmental Management.

The most stringent NO_x controls for CTs established as LAER/BACT by state agencies are selective catalytic reduction (SCR) with wet injection and wet injection alone. When SCR has been employed, wet injection is used initially to reduce NO_x emissions. SCR has been installed or permitted in about 132 projects. The majority of these projects (more than 90 percent) are cogeneration facilities with capacities of 50 MW or less. About

Table 4-2

Summary of NSPS For Small Industrial-Commercial-Institutional Steam Generating Units

Unit Size (heat input)	Fuel	Annual Capacity Factor	Emission Standard
		PARTICULATE MATTER	
30-100 MMBtu/hr	Coal; Coal w/other fuels	>90% on coal	0.05 lb/MMBtu
		<90% on coal	0.10 lb/MMBtu
	Wood; Wood w/other fuels (except coal)	>30% on wood	0.10 lb/MMBtu
		<30% on wood	0.30 lb/MMBtu
	Oil	No limitation	No emission limit
		OPACITY	
30-100 MMBtu/hr	All fuels	No limitation	20% opacity
		SULFUR DIOXIDE	
>75 MMBtu/hr	Coal	>55% on coal	1.2 lb/MMBtu; 90% reduction
	Coal	<55% on coal	1.2 lb/MMBtu
	Coal w/emerging SO2 control technology	>55% on coal	0.6 lb/MMBtu; 50% reduction
	Coal in duct burner of combined cycle system	No limitation	1.2 lb/MMBtu
	Oil	No limitation	0.5 lb/MMBtu or 0.5% S fuel
	Coal refuse in fluidized bed combustor	No limitation	1.2 lb/MMBtu; 80% reduction
30-75 MMBtu/hr	Coal	No limitation	1.2 lb/MMBtu
	Coal w/emerging SO2 control technology	No limitation	0.6 lb/MMBtu
	Coal in duct burner of combined cycle system	No limitation	0.6 lb/MMBtu
	Oil	No limitation	0.5 lb/MMBtu or 0.5% S fuel
	Coal refuse in fluidized bed combustor	No limitation	1.2 lb/MMBtu

Source: 40 CFR Part 60 Subpart Dc

SUBDCREG
10/23/90

Table 4-3. Summary of BACT Determinations for NOx from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	pmvd basis)	Control Method	Eff. (%)
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	25 @ 15% O2	Steam Injection	—
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	25 @ 15% O2	Steam Injection	—
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	—	—	—	42 @ 15% O2	Dry Low NOx Combustor	—
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	—	6.3	—	40 ppmv @ 15% O2	Water Inject 0.67 lb/lb	71.00%
City of Lakeland	FL	Jul-91	Combined Cycle	120 MW	—	—	—	25 @ 15% O2	Dry Low NOx Combustor	—
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	—	—	—	6 @ 15% O2	SCR	90.00%
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	—	—	—	25 @ 15% O2	Dry Low NOx Combustor	—
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	—	139	—	25 ppmvd	H2o Injection & Low NOx Comb.	—
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	—	—	1032	42 ppmvd	Water Injection	—
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	—	—	—	42 @ 15% O2	Steam Injection	—
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	—	—	—	42 @ 15% O2	Wet Injection	—
Salinas River Cogen	CA	Nov-90	Gas Turbine	43.2 MW	—	10	—	6 @ 15% O2	Dry Low NOx Comb. & SCR	—
Sargent Canyon Cogen Co	CA	Nov-90	Gas Turbine	42.5 MW	—	10	—	6 @ 15% O2	Dry Low NOx Comb. & SCR	—
March Point Cogen	WA	Oct-90	Turbine	80 MW	—	—	—	25 @ 15% O2	Massive Steam Injection	80.00%
Las Vegas Cogen	NV	Oct-90	Turbine, Peaking	397 MMBtu/hr	—	—	—	10 ppm	Water Injection & SCR	—
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	0.10	—	—	25 @ 15% O2	Dry Low NOx Combustor	—
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	—	—	—	9 ppmvd	Dry Comb. to 25 ppm, SCR to 9 pp	—
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	—	—	—	36	Water Injection	—
O'Brian California Cogen II	CA	Jan-90	Gas Turbine	49.50 MW	—	114.6	—	—	SCR	—
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	—	—	—	9 @ 15% O2, 1H Av	Water Injection & SCR	80.00%
Richmond Power Enterprise Partn.	VA	Dec-89	Gas Turbine	1,163.5 MMBtu/hr	—	—	—	8.2 @ 15% O2	Steam Inj. & SCR	—
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	—	—	—	25 ppm	Steam Injection	—
Badger Creek Limited	CA	Oct-89	GT-Cogen	457.8 MMBtu/hr	0.0135	—	—	—	Steam Injection & SCR	—
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	—	—	—	42 @ 15% O2	Steam Injection	—
City of Anaheim GT Proj.	CA	Sep-89	Gas Turbine	442 MMBtu/hr	—	3.75	—	--	Steam Injection & SCR	69.60%
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.17	83	—	—	Water Injection	—
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	—	—	—	36 ppm	Water Injection	—
Cimarron Chemical Co.	CO	Aug-89	Turbines (2)	271.0 MMBtu/hr	—	—	—	65 ppmv @ 15% O2	Steam Injection	—
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	—	—	—	42 @ 15% O2	Steam Injection	—
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	—	—	—	42 ppm	Steam Injection	—
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	—	—	—	42 ppm	Water Injection	—
Potomac Electric Power Company	MD	Mar-89	Combined Cycle	860 MW	—	—	—	42 @ 15% O2	Steam Injection	—
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	—	—	—	42 @ 15% O2	Water Injection	—

Table 4-3. Summary of BACT Determinations for NOx from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	pmvd	basis)	Control Method	Eff. (%)
Pawtucket Power	RI	Jan-89	Turbine	58 MW	—	—	—	9	@ 15% O2	SCR	—
L&J Energy System Cogen	NY	Jan-89	GE LM 5000	40 MW	—	—	—	42	ppm	Steam Injection	—
Mojave Cogen	CA	Jan-89	Turbine	490 MMBtu/hr	0.031	—	—	—		—	—
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	—	—	—	9	@ 15% O2	Water Injection & SCR	—
Mojave Cogen	CA	Dec-88	Turbine	45 MW	—	—	—	10	ppm	Steam Injection & SCR	—
Champion International	AL	Nov-88	Gas Turbine	35 MW	—	—	—	42	@ 15% O2	Steam Injection	70.00%
Indeck-Yerks Energy Services	NY	Nov-88	GE Frame 6	40 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	—	—	—	55	ppm	Water Injection	—
Amtrak	PA	Oct-88	Turbine (2)	20 MW	—	—	—	42	@ 15% O2	H2O Injection	—
Mobile Oil	CA	Sep-88	Turbine (2)	81.40 MMBtu/hr	0.047	3.78	—	—		Water Inj. & SCR	—
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	—	—	—	42	ppm	Steam Injection	—
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	—	—	—	42	ppm	Low NOx Burners & Water Inj.	—
O'Brien Cogen	CT	Aug-88	Gas Turbine (2)	499.9 MMBtu/hr	—	—	—	39	@ 15% O2	Water Injection	—
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	—	—	—	42	ppm	Steam Injection	—
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	—	—	—	42	@ 15% O2, 1H Av	H20 Injection	59.00%
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	—	—	—	36	@ 15% O2	Water Injection	—
Merck Sharp & Pohme	PA	May-88	Turbine	310 MMBTU/hr	—	—	—	42	@ 15% O2	Steam Injection	—
Virginia Power	VA	Apr-88	GE Turbine	1,875 MMBTU/hr	—	490		42	@ 15% O2	Steam Injection	—
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.2	—	—	75	ppm	H2O Inj. & Combustion Controls	—
Combined Energy Resources	CA	Feb-88	Gas Turbine	25.94 MW	—	199.0	—	—		H2O Injection & SCR	81.00%
Texas Gas Transmission Corp.	KY	Feb-88	Gas Turbine	14300 HP	—	—	—	—		NOx 0.015 % by Volume	—
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBTU/hr	—	—	—	42	@ 15% O2	Steam Injection	—
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	—	85	—	—		Water Inj. & Quiet Combustion	—
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	—	—	—	42	ppmvd @ 15% O2	Water Injection	—
BAF Energy	CA	Jul-87	Turbine, Generator	887.2 MMBTU/hr	—	30.1	—	9	ppm @ 15% O2	Steam Injection & SCR	80.00%
AES Placerita, Inc.	CA	Jul-87	Turbine	530 MMBTU/hr	—	14.2	—	9	@ 15% O2	St./F Ratio 2.2:1 & SCR	—
AES Placerita, Inc.	CA	Jul-87	Gas Turbine	530 MMBTU/hr	—	12.0	—	9	@ 15% O2	St./F Ratio 2.2:1 & SCR	—
Power Development Co.	CA	Jun-87	Gas Turbine	49 MMBTU/H	—	1.5	—	9	@ 15% O2	H2O Injection & SCR	—
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	—	10.4	—	6	@ 15% O2	H2O Injection & SCR	76.00%
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	—	—	—	9.6	@ 15% O2	H2O Injection & SCR	95.00%
Trunkline LNG	LA	May-87	Gas Turbine	147,102 SCF/hr	—	59		—		—	—

Table 4-3. Summary of BACT Determinations for NOx from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	pmvd basis)	Control Method	Eff. (%)
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	—	50.3	—	154	Combustion Control	—
Anheuser-Busch	FL	Apr-87	Gas Turbine	95.7 MMBTU/hr	0.10	—	—	—	—	—
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW	—	—	—	75 @ 15% O2	H2O Injection	—
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	—	—	—	—	—	—
U.S. Borax & Chemical Corp.	CA	Feb-87	Gas Turbine	45 MW	—	40	—	25 ppm @ 15% O2	Proper Combust. Techniques	—
Sierra LTD.	CA	Feb-87	GE Gas Turbine	11.34 MMCF/D	0.016	4.04	—	—	Steam Injection & SCR	95.86%
Midway-Sunset Project	CA	Jan-87	Gas Turbines (3)	973 MMBTU/hr	—	113.4	—	16.31 ppmv	H2O Injection	73.00%
City of Santa Clara	CA	Jan-87	Gas Turbine	—	—	—	—	42 @ 15% O2	Water Injection	—
O'Brien NRG Systems/Merchants Re	CA	Dec-86	Gas Turbine	359.5 MMBtu/hr	—	30.3	—	15 @ 15% O2	Water Injection & SCR	—
California Dept. of Corr.	CA	Dec-86	Gas Turbine	5.1 MW	—	—	—	38 @ 15% O2	1:1 H2O Injection	—
Double 'C' Limited	CA	Nov-86	Gas Turbine	25 MW	—	8.08	—	—	H2O Inj. & Selected Catalytic Red.	—
Kern Front Limited	CA	Nov-86	Gas Turbine (2)	50 MW	—	8.08	—	4.5 @ 15% O2	Water Injection & SCR	95.80%
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBTU/hr	—	63	—	25 ppm @ 15% O2	Steam Injection @ St/F Ratio of 1.7/	75.00%
Wichita Falls E. 1., 1.	TX	Jun-86	Gas Turbine	20 MW	—	—	684	—	Steam Injection	—
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	—	—	640	—	Steam Injection	—
Kern Energy Corp.	CA	Apr-86	Gas Turbine	8.8 MMCF/D	0.023	8.29	—	—	Steam Inj., Low NOx Config. & SC	87.00%
Monarch Cogen	CA	Apr-86	Combined Cycle	92.20 MMBtu/hr	—	8.02	—	22 @ 15% O2	SCR	—
Moran Power, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.02	8.29	—	—	Steam Inj., Low NOx Config. & SC	87.00%
Southeast Energy, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.023	8.29	—	—	Steam Inj., Low NOx Config. & SC	87.00%
Western Power System, Inc	CA	Mar-86	GE Gas Turbine	26.5 MW	—	—	—	9 @ 15% O2	H2O Injection & SCR	80.00%
AES Placerita, Inc.	CA	Mar-86	Turbine	519 MMBTU/hr	—	26.2	—	7 @ 15% O2	H2O Injection & SCR	—
OLS Energy	CA	Jan-86	GE Gas Turbine	256 MMBTU/hr	—	—	—	9 @ 15% O2	H2O Injection & Scrubber	80.00%
Union Cogeneration	CA	Jan-86	Gas Turbine	16 MW	—	—	—	25 @ 15% O2	H2O Injection & Scrubber	—

83 percent (i.e., 109) of the projects have been in California. Of these 109 projects that have either installed SCR or have been permitted with SCR, 43 percent have been in the Southern California NO_2 nonattainment area where SCR was required not as BACT but as LAER, a more stringent requirement. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation plan of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51, Appendix S.II, A.18).

As noted previously, there are distinct regulatory and policy differences between LAER and BACT.

All the projects in California have natural gas as the primary fuel, and only 15 of the SCR applications in California have distillate fuel as backup.

The remaining projects with SCR (i.e., 23 projects) are located in the eastern United States. These projects are located in Vermont, Massachusetts, Connecticut, New Jersey, New York, Rhode Island, and Virginia. A majority of these projects are cogenerators or independent power producers. The size of these projects ranges from 22 MW to 450 MW, with 87 percent less than 100 MW in size. While almost all of the facilities have distillate oil as backup fuel, distillate oil generally is restricted by permit to 1,000 hours or less per CT.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80 percent. The most stringent emission limiting standards associated with SCR are approximately 9 ppm for natural gas firing. However, two facilities have reported emission limits of about 4.5 ppm. These emission limits were clearly determined to be LAER on CTs using water injection with uncontrolled NO_x levels below 42 ppm. SCR has not been installed or permitted on simple cycle CTs.

Wet injection has been the primary method of reducing NO_x emissions from CTs. This method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when burning natural gas. More recently, CT manufacturers have developed dry low-NO_x combustors that can reduce NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

In Florida, a majority of the most recent PSD permits and BACT determinations for gas turbines have required either wet injection or dry low-NO_x technology for NO_x control. The emission limits included in these permits and BACT determinations are 25 ppm (corrected to 15 percent O_2, dry conditions) for natural-gas firing.

4.3.1.2 Technology Description and Feasibility

Selective Catalytic Reduction (SCR)--SCR uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined

cycle configuration; no simple cycle facilities have SCR. Exhaust gas temperatures of simple cycle CTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been limited to facilities that burn natural gas or small amounts of fuel oil since SCR catalysts are contaminated by sulfur-containing fuels (i.e., fuel oil). For most fuel-oil-burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience has not been extensive, certain cost, technical, and environmental considerations have surfaced. These considerations are summarized in Table 4-4.

As presented in Table 4-4, ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required. Ammonium sulfate is emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts.

Zeolite catalysts, which are reported to be capable of operating in temperature ranges from 600°F to 950°F, have been available commercially only recently. Their application with SCR primarily has been limited to internal combustion engines. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800°F to 900°F. At temperatures of 1,000°F and above, the zeolite catalyst will be irreparably damaged. Therefore, application of an SCR system using a zeolite catalyst on a simple cycle operation is technically infeasible without exhaust gas cooling. Moreover, since zeolite catalysts have not been operated continuously in combustion exhausts greater than 900°F, the cooling system

Table 4-4. Cost, Technical, and Environmental Considerations of SCR Used on Combustion Turbines (Page 1 of 2)

Consideration	Description
COST:	
Catalyst Replacement	Catalyst life varies depending on the application. Cost ranges from 20 to 40 percent of total capital cost and is the dominant annual cost factor.
Ammonia	Ratio of at least 1:1 NH_3 to NO_x generally needed to obtain high removal efficiencies. Special storage and handling equipment required.
Space Requirements	For new installations, space in the catalyst is needed for replacement layers. Additional space is also required for catalyst maintenance and replacement.
Backup Equipment	Reliability requirements necessitate redundant systems, such as ammonia control and vaporization equipment.
Catalyst Back Pressure Heat Rate Reduction	Addition of catalyst creates backpressure on theturbine, which reduces overall heat rate.
Electrical	Additional usage of energy to operate ammonia pumps and dilution fans.
TECHNICAL:	
Ammonia Flow Distribution	NH_3 must be uniformly distributed in the exhaust stream to assure optimum mixing with NO_x before to reaching the catalyst.
Temperature	The narrow temperature range that SCR systems operate within (i.e., about 100°F) must be maintained even during load changes. Operational problems could occur if this range is not maintained. HRSG duct firing requires careful monitoring.

Table 4-4. Cost, Technical, and Environmental Considerations of SCR Used on Combustion Turbines (Page 2 of 2)

Consideration	Description
Ammonia Control	Quantity of NH_3 introduced must be carefully controlled. With too little NH_3, the desired control efficiency is not reached; with too much NH_3, NH_3 emissions (referred to as slip) occur.
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip (NH_3 that passes unreacted through the catalyst and into the atmosphere) can occur if 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or 4) the proper temperature is not maintained.
Ammonium Salts	Ammonium salts (ammonium sulfate and bisulfate) can lead to increased corrosion. These salts can occur when firing natural gas. These compounds are emitted as particulates.
Ammonia Transportation and Storage	Storage and handling of anhydrous ammonia produces additional environmental risks. Appropriate controls and contingency plans in the event of a release is required.

would have to reduce turbine exhaust temperatures about 200°F (i.e., to around 800°F).

Wet Injection--The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion will occur (i.e., CO and VOC emissions).

For oil or propane firing, water injection will be used. The NO_x emission level guaranteed by GE is 42 ppmvd corrected to 15 percent oxygen.

Dry Low-NO_x Combustor--In the past several years, CT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on machines manufactured by GE, Kraftwork Union, and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the CT being considered for the project, the combustion chamber design includes the use of dry low-NO_x combustor technology. The NO_x emission level guaranteed by GE for the project is 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

NO_xOUT Process--The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F. In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

1. Low capital and operating costs as a result of use of urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

Commercial application of the NO_xOUT system is limited to three reported cases:

1. Trial demonstration on a 62.5-ton-per-hour (TPH) stoker-fired wood waste boiler with 60 to 65 percent NO_x reduction,
2. A 600 x 10^6 Btu CO boiler with 60 to 70 percent NO_x reduction, and
3. A 75-MW pulverized coal-fired unit with 65 percent NO_x reduction.

The NO_xOUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the CT is about 1,000°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of

gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

Thermal $DeNO_x$--Thermal $DeNO_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal $DeNO_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection.

The only known commercial applications of Thermal $DeNO_x$ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with CTs. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of construction-specified material, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Thus, the Thermal $DeNO_x$ process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The maximum exhaust gas temperature of a combustion turbine is typically about 1,000°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

Nonselective Catalytic Reduction--Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also have high oxygen

levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for CTs.

Control Technologies for Duct Firing--The proposed control technology for duct firing in the secondary HRSG will be the use of combustion controls that will limit the emissions to 0.16 lb/10^6 Btu heat input.

The applicable NSPS for the secondary HRSG is the recently promulgated standards for small industrial-commercial-institutional steam generating units contained in 40 CFR Part 60 Subpart Dc. There are no NO_x emission limits applicable to these sizes of sources (i.e., less than 100 million Btu per hour heat input). The NSPS for larger steam generators (i.e., greater than 100 million Btu per hour heat input) is found in 40 CFR Part 60 Subpart Db. The NO_x emission limit for natural gas firing is 0.2 lb NO_x per million Btu heat input. BACT emission limits for duct burners located in primary HRSGs associated with combined cycle power plants are typically 0.1 lb NO_x per million Btu heat input.

The secondary HRSG associated with this project is quite different in terms of heat release and purpose than those normally associated with combined cycle plants. In typical combined cycle plants, the purpose of the secondary HRSG is to enhance steam production. While the secondary HRSG proposed in this project will provide additional steam, it will enhance the source gas being provided to the CO_2 recovery plant. This step is necessary to reduce oxygen content to provide proper gas composition for CO_2 absorption.

The heat released relative to the volume of air flow is significantly greater for the proposed source than other combined cycle facilities. For this project, the heat released will be approximately 3,000 Btu per cfm, while the highest heat release from a recently permitted project in Florida (i.e., Pasco and Lake Cogen Limited) was approximately 700 Btu per cfm.

NO_x is related to heat release; therefore, a higher NO_x emission limit is requested for the proposed project.

Summary of Technically Feasible NO_x Control Methods--The available information suggests that SCR with dry low-NO_x combustor technology or with wet injection would produce the lowest NO_x emissions and is technically feasible. Dry low-NO_x combustion alone has increasingly been approved by regulatory agencies as BACT and is a technically feasible alternative for the project.

A technical evaluation of other tail gas controls (i.e., NO_xOUT, Thermal DeNO_x, and NSCR) indicates that these processes have not been applied to CT/HRSG and are technically infeasible for the project because of process constraints (e.g., temperature).

For the BACT analysis, SCR with dry low-NO_x combustion is capable of achieving a NO_x emission level of 9 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions) and dry low-NO_x combustion alone can achieve 25 ppm (corrected). When firing oil or propane, the emissions with SCR and wet injection would be about 15 ppm (corrected), whereas emissions with water injection alone would be 42 ppm (corrected).

4.3.1.3 Impact Analysis

A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12), Chapter 17-2.100(25), F.A.C., and Chapter 17-2.500(5)(c), F.A.C.]. The analysis must, by definition, be specific to the project (i.e., case-by-case).

The BACT analysis was performed for the following alternatives:

1. SCR and dry low-NO_x combustion at an emission rate of approximately 9 ppmvd corrected to 15 percent O_2 when firing gas and 15 ppmvd when firing oil or propane; and

2. Dry low-NO_x combustion at an emission rate of 25 ppmvd corrected to 15 percent O_2 when firing gas and 42 ppmvd (corrected) when firing oil or propane;

As discussed in Section 2.1, the CT will be fired with either natural gas, distillate oil, or propane during the first 3 years of operation. After this period, the primary fuel will be natural gas with distillate oil as backup (i.e., no greater than 30 days per year operation on oil). For the purpose of the economic analysis, it was assumed that during the first 3 years of operation natural gas would be utilized 50 percent of the time and distillate oil would be utilized 50 percent of the time.

The NO_x removed using SCR under this assumption would be 233 TPY when firing oil and 125 TPY when firing natural gas; the total NO_x removed would be 358 TPY. If only distillate oil were fired during the first 3 years, then 467 TPY of NO_x would be removed. After the first three years of operation, natural gas would, as a minimum, be used 91.8 percent of the time while oil would at most be utilized up to 8.2 percent of the time. Under this operational scenario, 229 TPY of NO_x would be removed during natural gas firing and 38 TPY of NO_x during distillate oil firing. In order to calculate a cost effectiveness over a twenty year period (i.e., the basis for the economic analysis), the cost effectiveness was weight-adjusted by the number of years under the specific operation scenario.

Economic--The total capital and annualized costs for SCR are presented in Tables 4-5 and 4-6, respectively. The total annualized cost of applying SCR with dry low-NO_x combustion is $1,957,900. The incremental reduction in NO_x emissions is 358 TPY for the first 3 years and 267 TPY after the third year of operation. The incremental cost effectiveness of SCR over dry low-NO_x combustion and water injection is estimated to be $5,463/ton of NO_x removed for the first 3 years and $7,311/ton of NO_x removed for the third to twentieth year of operation. The average cost effectiveness over the entire 20-year period would be $7,034/ton of NO_x removed. Assuming that distillate oil were fired during the entire first 3 years, the cost

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 1 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	597,800	Developed from manufacturer budget quotations[a]
Ammonia Storage Tank	165,600	Developed from manufacturer budget quotations[b]
HRSG Modification	291,400	Developed from manufacturer budget quotations[c]
Indirect Capital Costs		
Installation	405,600	20% of SCR associated equipment and catalyst[d]
Engineering, Erection Supervision, Startup, and O&M Training	289,100	10% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG costs, installation labor.[e]
Project Support	159,000	5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs, and installation labor.[f]
Ammonia Emergency Prepardness Program	19,200	Engineering estimate
Liability Insurance	15,900	0.5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs and installation labor.
Interest During Construction	506,100	15% of all direct and indirect capital costs, including catalyst cost[g]
Contingency	505,100	25% of all capital costs[h]
Total Capital Costs	2,954,800	Sum of all capital costs

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 2 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Annualized Capital Costs	347,100	Capital recovery of 10% over 20 years, 11.74% per year[i]
Recurring Capital Costs		
SCR Catalyst (Materials and Labor)	1,430,400	Developed from manufacturer budget quotations[j]
Contingency	357,600	25% of recurring capital costs[k]
Total Recurring Capital Costs	1,788,000	Sum of recurring capital costs
Annualized Recurring Capital Costs	719,000	Capital recovery of 10% over 3 years, 40.21% per year[l]

Note: HRSG = heat recovery steam generators.
SCR = selective catalytic reduction.

Footnotes for Table 4-5

Note: All calculations rounded to nearest 100.

a. Developed from various vendor data as an algorithim to account for mass flow (lb/hr) through HRSG.

The SCR associated cost is made up of 2 factors:

1. Catalyst Housing, vaporizer, and HRSG wash system is $98.7 per 1,000 lb/hr mass flow at ISO (59°F) conditions.

$98.7 x 2,384 10^3 lb/hr = $235,300

2. Control system costs = $362,500

Total is $597,800

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 3 of 4)

Footnotes for Table 4-5 (continued)

b. Ammonia tank size is based on SCR size as follows:

$69.45/1,000 lb mass flow x 2,384 x 10^3 lb/hr = $165,600

c. HRSG modifications based on mass flow at $122.2 per 1,000 lb mass flow.

$122.22/$10^3$ lb x 2,384 x 10^3 lb/hr = $291,400

d. From EPA OAQPS cost control manual

($597,800 + $1,430,400) x 0.2 = $405,600

e. From EPA OAQPS cost control manual

($597,800 + $165,600 + $1,430,400 + $291,400 + $405,600) x 0.10

= $289,100

f. Engineering estimate; same as engineering costs except use 0.005.

g. From OAQPS cost control manual and engineering estimate.

0.15 x ($597,800 + $165,600 + $291,400 + $405,600 + $289,100

+ $159,000 + $19,200 + $15,900 + $1,430,400) = $506,100

h. From EPA OAQPS cost control manual and engineering estimate

0.20 x ($597,800 + $165,600 + $291,400 + $405,600 + $289,100

+ $159,000 + $19,200 + $15,900 + $506,100) - (0.25 x 0.30

x $1,430,400)

= $505,100; note that the (0.25 x 0.30 x $1,430,400)

removes contingency for catalyst.

i. OAQPS cost control manual; standard statistical tables for 10% interest over 20 years

$2,954,800 x 0.1174 = $347,100

j. Developed from manufacturer data at $0.6/lb mass flow:

$0.6 x 2,384,000 = $1,430,400

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 4 of 4)

Footnotes for Table 4-5 (continued)

k. Same rationale as h:

0.25 x $1,430,400 = $357,600

l. Manufacturer guarantees of 3 years life or catalyst. Used OAQPS cost control manual interest of 10 percent over 3 years (40.21 percent per year):

0.4021 x $1,788,000 = $719,000

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR)
(Page 1 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Annual Costs		
Operating Personnel	20,800	16 hours/week @ $25/hour[a]
Ammonia	39,700	$300/ton; $NH_3:NO_x$ = 1:1 volume[b]
Accident/Emergency Response Plan	8,100	Consultant estimate, 80 hours/year @ $75/hour plus expenses @ 35% labor[c]
Inventory Cost	56,000	Capital recovery (11.74%/year) for 1/3 of catalyst cost[d]
Catalyst Disposal Cost	66,200	Engineering estimate[e]
Contingency	58,000	20% of indirect costs[f]
Energy Costs		
Electrical	35,000	80 kWh/hr; $0.05/kWh[g]
Heat Rate Penalty	185,000	4" back pressure, heat rate reduction of 0.5%, energy loss at $0.05/kWh[h]
MW Loss Penalty	106,600	84 MW lost for 3 days; lost capacity @ $0.05/kW; cost of natural gas @ $3/MMBtu subtracted[i]
Fuel Escalation Costs	100,000	Real cost increase of fuel [j]
Contingency	80,000	25% of energy costs; excludes fuel escalation[k]
Total Direct Annual Costs	755,400	Sum of all direct annual costs

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR)
(Page 2 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Indirect Annual Costs		
Overhead	41,300	60% of ammonia and 115% of O&M labor, and 15% of O&M labor (OAQPS Cost Control Manual)[l]
Property Taxes and Insurance	94,900	2% of total capital costs[m]
Annualized Capital Costs	347,100	Capital recovery of 10% over 20 years, 11.74% per year (from Table 4-5)
Recurring Capital Costs	719,000	Capital recovery of 10% over 3 years, 40.21% per year (from Table 4-5)
Total Indirect Annual Costs	1,202,300	Sum of all indirect annual costs
Total Annual Costs	1,957,700	Total annualized cost[n]

Note: All calculations rounded to the nearest $100.

kW = kilowatt.
kWh = kilowatt-hour.
kWh/hr = kilowatt-hour per hour.
MM/Btu = million British thermal units.
NH_3 = ammonia.
NO_x = nitrogen oxides.
O&M = operation and maintenance.

Footnotes for Table 4-6

Note: all calculations rounded to nearest 100

a. Engineering Estimate:

16 hours/week x 52 weeks/year x $25/hour = $20,800

b. Delivered cost of ammonia at $300/ton

358 TPY removed x $300 x 17/46 (molecular weight of ammonia to NO_x)

= 39,700

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR)
(Page 3 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate

Footnotes for Table 4-6 (continued)

c. 80 hours/yr x $75 x 1.35 = $8,100

d. Required to purchase and store 1/3 of a catalyst for replacement or required.

$1,430,400 x 0.1174 (20 years @ 10 percent) + 3 = $56,000

e. Estimated as $27.77/1,000 lb mass flow; based on catalyst volume.

$27.77 x 2,384 (1,000 lb mass flow) = $66,200

f. OAQPS cost control manual background documents

0.25 x ($20,800 + $39,700 + $8,100 + $56,000 + $66,200) = $58,000

g. 80 kWh/hr from SCR manufacturer; $0.05/kWh is cost of estimated energy:

80 kWh/hr x $8,760 hr/yr x $0.08/kWh = $35,000

h. 4" back pressure from SCR manufacturer; 0.8 percent energy loses from general CT performance curver; 78.83 MW power rating at 150 (59°F) conditions.

84.47 MW x 0.005 x 8,760 hrs/yr x 1,000 kW/mw x $0.05/kWh = $185,000

i. 3 days required to change catalyst or maintenance; saving in gas usage subtracted

84.47 MW x 3 days x 24 hours x $0.05/kWh x 1,000 mwh - (914.53 x 10^6 Btu/hr

x 3 days x 24 hours x $3/$10^6$ Btu) = $106,600

j. Escalation of fuel costs over inflation; 3 percent over 20 years; factor calculated as 0.454565; applies to electrical and heat rate costs only:

0.454565 x ($35,000 + $185,000) = $100,000

k. OAQPS cost control manual background documents

0.25 x ($35,000 + $185,000 x $106,600) = $80,000

1. 0.6 ($39,700 + 1.15 x $20,800) + 0.15 x $20,800 = $41,300

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR)
(Page 4 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate

Footnotes for Table 4-6 (continued)

m. From OAQPS cost control manual

0.02 x ($2,954,800 + $1,788,000) = $94,900

n. Total direct annual costs plus total indirect annual costs:

$755,400 + $1,202,300 = $1,957,700

effectiveness would be $4,245/ton of NO_x removed (467 tons would be removed). For the entire 20-year period, the cost effectiveness would be $6,928/ton of NO_x removed.

Environmental--The maximum predicted impacts of the alternative technologies are all considerably below the PSD increment for NO_x of 25 $\mu g/m^3$, annual average, and the AAQS for NO_x, 100 $\mu g/m^3$. Indeed, the impacts are less than the significant impact levels. Additional controls beyond dry low-NO_x combustors (i.e., SCR and SCR with water injection) would further reduce predicted impacts by much less than 1 percent of the PSD increment and the AAQS for the project.

The use of dry low-NO_x combustor technology is truly "pollution prevention". In contrast, use of SCR on the proposed project will cause emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate. Ammonia emissions associated with SCR are expected to be 10 ppm based on reported experience; previous permit conditions have specified this level. Ammonia emissions could be as high as 132 TPY. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM10; up to 23.3 TPY could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will generate secondary emissions since this lost energy will necessitate additional generation. These emissions, coupled with potential emissions of ammonia and ammonium salts, are presented in Table 4-7, which shows the emissions balance for the project with and without SCR. Emissions of carbon dioxide were included in this table since this gas is under study as required in the 1990 Clean Air Act Amendments. As noted from this table, the emissions including CO_2 would be greater with SCR than that proposed using dry low-NO_x combustion technology.

The replacement of the SCR catalyst will create additional economic and environmental impacts since certain catalysts contain materials that are

Table 4-7. Maximum Potential Emission Differentials TPY With and Without Selective Catalytic Reduction

Pollutants	Project With SCR			Project Without SCR	
	Primary	Secondary[a]	Total	CT/DB	Difference[b]
Particulate	23 [c]	2.19	25	0	25
Sulfur Dioxide	0	24.09	24	0	24
Nitrogen Oxides	193 [d]	12.05	205	551	(346)
Carbon Monoxide	0	0.72	1	0	1
Volatile Organic Compounds	0	0.11	0	0	0
Ammonia	132 [e]	0.00	132	0	132
Total	349	39.16	388	551	(163)
Carbon Dioxide[f]	--	3,760	3,760	--	3,760

Note: Btu/kWh = British thermal units per kilowatt-hour.
CT = combustion turbine.
DB = duct burner.
MW = megawatt.
% = percent.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Lost energy of 0.50 MW from heat rate penalty and electrical for 8,760 hours per year operation (0.5% of 84.47 MW plus 0.080 MW). Assumes Florida Power Corp. baseloaded oil-fired unit would replace lost energy. EPA emission factors used for 1% sulfur fuel oil and an assumed heat rate of 10,000 Btu/kWh. Emission factors use were (lb/10^6 Btu): PM = 0.1; SO_2 = 1.1; NO_x = 0.55, CO = 0.033 and VOC = 0.005. Example calculation for PM - 0.50 MW x 10,000 Btu/kwh x 1,000 kw/MW x 8,760 hr/yr x 0.1 lb pm/10^6 Btu + 2,000 lb/ton = 2.19 TPY.

[b] Difference = Total with SCR minus project without SCR.

[c] Assume sulfur reacts with ammonia; 17 TPY H_2SO_4 x 132 (MW of ammonia salt) + 98 (MW of H_2SO_4).

[d] 9 ppm NO_x emissions on gas and 15 ppm NO_x emissions on oil; assumes 50% capacity factor each fuel.

[e] 10 ppm ammonia slip (ideal gas law at actual flow rate from stack): 1,468,004 acfm x 60 m/hr x 10 ppm/10^6 x 2,116.8 lb/ft^2 + 1,545 x 17 (molecular weight of NH_3) + (460 +230) x 8,760 + 2,000.

[f] Reflects differential emissions due to lost energy efficiency with SCR (i.e., 0.50 MW CO_2 calculated based on 85.7% carbon in fuel oil and 18,300 Btu/lb).

listed as hazardous chemical wastes under Resource Conservation and Recovery Act (RCRA) regulations (40 CFR 261).

Ammonia delivery and storage must be handled with caution because of its hazardous nature. Special precautions would be required to assure that no environmental discharge occurs.

Energy--Energy penalties will occur with all control alternatives evaluated. However, significant energy penalties occur with SCR. With SCR, the output of the CT is reduced by about 0.50 percent over that of wet injection. This penalty is the result of the SCR pressure drop, which would be about 4 inches of water and would amount to about 3,700,000 kilowatt hours (kWh) in potential lost generation per year. The energy required by the SCR equipment would be about 700,800 kilowatt hours per year (kWh/yr). Taken together, the lost generation and energy requirements of SCR could supply the electrical needs of 400 residential customers. To replace this lost energy, an additional 5×10^{10} British thermal units per year (Btu/yr) or about 50 million cubic feet per year (ft^3/yr) of natural gas would be required.

4.3.1.4 Proposed BACT and Rationale

The proposed BACT for the project is dry low-NO_x combustion technology. The proposed NO_x emissions level using this technology is 25 ppmvd (corrected to 15 percent oxygen) when firing natural gas. This control technology is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds. The estimated incremental cost of SCR is about $7,000 per ton of NO_x removed. These costs are in the range for other projects that have rejected SCR as unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered (refer to Table 4-7). The cost effectiveness is over $10,000 per ton of pollutant removed when the emissions (exclusive of CO_2) are considered,

2. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary generations (to replace the lost generation); and from the generation of hazardous waste (i.e., spent catalyst replacement),
3. The energy impacts of SCR will reduce potential electrical power generation by more than 5 million kWh,
4. The proposed BACT (i.e, dry low-NO_x combustion) provides the most cost effective control alternative and results in low environmental impacts (less than the significant impact levels). Dry low-NO_x combustion at the proposed emissions levels has been adopted previously in BACT determinations. In addition, CT manufacturers have been willing to guarantee this level of NO_x emissions, and
5. The proposed emission limit for duct firing (i.e., 0.16 lb/10^6 Btu) is reasonable given the small HRSG gas flow volume.

4.3.2 CARBON MONOXIDE

4.3.2.1 Emission Control Hierarchy

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. Table 4-8 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. For the CT being evaluated, CO emissions will not exceed 20 ppmvd, corrected to dry conditions when firing natural gas under full load conditions and 35 ppmvd when firing distillate oil. For propane, the CO emissions will not exceed 10 ppmvd.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels

Table 4-8. *Summary of BACT Determinations for CO from Gas-fired Turbines*

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd	basis)	Control Method	Eff. (%)
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	42		78 ppmvd for oil firing	—
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	42		78 ppmvd for oil firing	—
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	—	—	—	—		25 ppmvd for oil firing	—
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	—	5.8	—	60	@ 15% O2	Base Case, No Additional Control	—
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	—	—	—	6	@ 15% O2	CO Catalyst	80.00%
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	—	—	—	30		33 ppmvd for oil firing	—
Commonwealth Atlantic LTD Partn	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	—	—	261	30	ppmvd	Combustion control	—
Commonwealth Atlantic LTD Partn	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	—	—	261	30	ppmvd	Combustion control	—
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	—	—	—	30		33 ppmvd for oil firing	—
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	—	—	—	10		26 ppmvd for oil firing	—
March Point Cogen	WA	Oct-90	Turbine	80 MW	—	—	—	37	@ 15% O2	Combustion Control	—
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	—	—	—	15	ppm	Good Combustion	—
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	—	25	—	—		Combustor Design & Operation	—
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	0.02	—	—	—		—	—
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	—	—	—	50	ppmvd @ iso	Design & Good Combustion Technique	—
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	—	—	—	25	ppm	Combustion Control	—
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	0.112	—	—	—		—	—
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.022	10.8	—	—		Combustion Control	—
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	0.028	—	—	—		Combustion Control	—
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	—	—	—	10	@ 15% O2	—	—
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	0.024	—	—	—		Combustion Control	—
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	0.026	—	—	—		Combustion Control	—
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	0.022	—	—	—		Combustion Control	—
Pawtucket Power	RI	Jan-89	Turbine	58 MW	—	—	—	23	@ 15% O2	—	—
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	—	—	—	25	@ 15% O2	—	—
Champion International	AL	Nov-88	Gas Turbine	35 MW	—	9	—	—		—	—
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	—	—	—	10	ppm	Combustion Control	—
Amtrak	PA	Oct-88	Turbine (2)	20 MW	—	30.76	—	—		—	—
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	0.021	—	—	—		Combustion Control	—
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	—	—	—	10	@ 15% O2	Combustion Control	—
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	—	—	—	15	ppm	Good Combustion	—
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	0.022	—	—	—		Combustion Control	—
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	0.1	—		—		Water Injection	—

Table 4-8. Summary of BACT Determinations for CO from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd basis)	Control Method	Eff. (%)
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	0.605	—	—	—	—	—
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.181	—	—	—	CO Catalyst	80.00%
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBTU/hr	—	26	—	—	Turbine Design	—
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	—	94	—	—	Proper Combustion	—
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	0.048	—	—	—	—	—
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	—	55.25	—	55 @ 15% O2	Combustion Control	—
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	—	—	—	50 ppmvd @ 15	—	—
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	—	6	25	—	—	—
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW				109 lb/scf fuel	Water Injection	—
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	—	—	—	10 @ 15% O2	CO Catalyst & Comb. Control	—
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBTU/hr	—	—	—	—	CO Catalyst (No limit indicated)	—
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	—	—	32.4	—	—	—

to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10 ppm range (corrected to dry conditions).

For duct firing, the specific burner design to control NO_x emissions has commonly established the ability of the burner to meet CO limits. Recent BACT decisions for duct firing have ranged from 0.14 lb/10^6 Btu for Tropicana Products, Inc. to 0.2 lb/10^6 Btu for the Lake and Pasco Cogen Limited projects. The proposed CO BACT emission limit for the project is 0.1 lb/10^6 Btu.

4.3.2.2 Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications primarily have been limited to smaller cogeneration facilities burning natural gas.

Oxidation catalysts have not been used on fuel-oil-fired CTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of SO_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

Since the units likely will require numerous startups, variations in exhaust conditions will influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling.

The lack of demonstrated operation with oil firing suggests rejection of catalytic oxidation as a technically feasible alternative. However, the advent of a second generation catalyst suggests that an oxidation catalyst could be used.

Combustion design is dependent upon the manufacturer's operating specifications, which include the air-to-fuel ratio and the amount of water injected. The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO emissions. Installations with an oxidation catalyst and combustion controls generally have controlled CO levels of 10 ppm as LAER and BACT.

For the project, the following alternatives were evaluated for natural gas firing as BACT:

1. Oxidation catalyst at 10 ppmvd; maximum annual CO emissions are 94 TPY assuming 50 percent operation on gas and 50 percent operation on oil;
2. Combustion controls; maximum annual CO emissions are 259 TPY (same assumption on operation).

4.3.2.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $1,041,267 (Table 4-9), with a cost effectiveness of about $6,320/ton of CO removed. The cost effectiveness is based on 50 percent operation on gas and 50 percent operation on oil, both at 10 ppmvd. No costs are associated with combustion techniques since they are inherent in the design.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be

Table 4-9. Capital and Annualized Cost for Oxidation Catalyst

Cost Component	Cost ($)	Basis
I. CAPITAL COSTS		
A. DIRECT:		
1. Associated Equipment for Catalyst	173,800	Manufacture Estimate - $1,750 per lb/sec mass flow
2. Exhaust Modification	165,600	Engineering Estimate
3. Installation	331,100	25% of Equipment Costs (I.A.1. & 2., and II.A.)
B. INDIRECT:		
1. Engineering & Supervision	99,300	7.5% of Equipment Costs (I.A.1. & 2., and II.A.)
2. Construction and Field Expense	132,400	10% of Equipment Costs (I.A.1. & 2., and II.A.)
3. Construction Contractor Fee	66,200	5% of Equipment Costs (I.A.1. & 2., and II.A.)
4. Startup & Testing	26,500	2% of Equipment Costs (I.A.1. & 2., and II.A.)
5. Contingency	248,700	25% of Direct and Indirect Capital Costs (I.A, and I.B.1-4)
6. Interest During Construction	334,300	15% of Direct and Indirect Capital Costs, and Recurring Capital Costs (I.A., I.B.1.-4 and II.A.)
TOTAL CAPITAL COSTS	1,578,100	Sum of Direct and Indirect Capital Costs
ANNUALIZED CAPITAL COSTS	185,400	Capital Recovery of 10% over 20 years
II. RECURRING CAPITAL COSTS		
A. Catalyst	985,100	Manufacture Estimate - $1,750 per lb/sec mass flow
B. Contingency	246,300	25% of Recurring Capital Costs (II.A)
TOTAL RECURRING CAPITAL COSTS	1,231,300	Sum of Recurring Capital Costs
ANNUALIZED RECURRING CAPITAL COSTS	495,100	Capital Recovery of 10% over 20 years
III. ANNUALIZED COST		
A. DIRECT:		
1. Labor - Operator & Supervisor	5,300	4 hours/week, 52 weeks/year, $22/hour and 15% supervisor cost
2. Maintenance	14,000	0.5% of Total and Recurring Capital Costs
3. Inventory Cost	38,600	Capital Carrying cost (10% over 20 years) for catalyst for 1 CT
B. ENERGY COSTS		
1. Heat Rate Penalty	74,000	0.2% heat rate penalty. $50/MW energy loss
2. MW Loss Penalty (catalyst changeout)	35,500	Loss of 84.43 MW for one day; cost of natural gas at $3/$10^6$ Btu deducted from cost
3. Fuel Escalation Costs	35,600	Fuel escalation of 3% over inflation; annualized over 20 years
4. Contingency	35,800	25% of energy costs
C. INDIRECT:		
1. Overhead	11,600	60% of Labor and Maintenance Costs (III.A.1. and 2.)
2. Property Taxes	28,100	1% of Total and Recurring Capital Cost
3. Insurance	28,100	1% of Total and Recurring Capital Cost
4. Administration	56,200	2% of Total and Recurring Capital Cost
Annualized Capital Costs	185,400	
Annualized Recurring Capital Costs	495,100	
TOTAL ANNUALIZED COSTS	1,041,267	Sum of Operating and Maintenance and Annualized Capital Costs

Note: All calculations using machine performance were based on 59 F conditions.
Assumptions based on percentage of costs were adapted from EPA OAQPS Control Cost Manual (1990).

expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 1,850,000 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 150 residential customers over a year. To replace this lost energy, about 1.8×10^{10} Btu/yr or about 18 million ft^3/yr of natural gas would be required.

4.3.2.4 Proposed BACT and Rationale

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts; and
2. The economic impacts are significant (i.e., an annualized cost of about one million dollars, with a cost effectiveness of over $6,000/ton of CO removed).

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable since it will not lower CO emissions substantially and will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for combustion turbines have set limits in the 30 ppmvd range. The cost of an oxidation catalyst would be significant and not cost-effective given the proposed emission limit of 20 ppmvd for the CT when firing gas and 35 ppmvd when firing distillate oil.

For the duct burner, the proposed BACT limit of 0.1 $lb/10^6$ Btu is lower than that proposed for similar projects.

4.3.3 SULFUR DIOXIDE (SO_2)

4.3.3.1 Emission Control Hierarchy

Sulfur dioxide (SO_2) emissions are a result of the oxidation of sulfur in fossil fuel and can be minimized by reducing the sulfur content in fuel or

through applying post-combustion removal techniques. For CTs, the use of low sulfur fuels is the only demonstrated control technology determined to be technically feasible. Post-combustion techniques, such as flue gas desulfurization (FGD), have not been applied to CTs.

FGD systems have been applied to oil- and coal-fired steam electric power plants. However, the relative gas volume for such facilities is significantly less than that for CTs (i.e., about 2 to 3 times), and the resultant SO_2 concentration is considerably higher. While the former factor will influence the cost of FGD, the latter poses significant technological constraints to removing SO_2. As a result, FGD is not feasible for application to CTs.

The BACT/LAER clearinghouse documents show that fuel sulfur contents from 0.8 percent to less than 0.1 percent have been specified as BACT for CTs. The lowest sulfur-containing fuels were required in California and the Northeastern U.S., where LAER decisions dictated more stringent standards. Furthermore, such requirements generally limited fuel oil use for backup or emergency purposes only.

In Florida, BACT determinations for CTs have restricted sulfur content in oil from 0.2 to 0.3 percent for an annual average period and 0.5 percent for a maximum. These facilities include the Florida Power and Light Company (FPL) Lauderdale Repowering Project, the Hardee Power Station, and the FPL Martin project. Recent cogeneration facilities have been permitted using 0.1 percent sulfur fuel oil for limited periods (i.e., approximately 10 days).

For the proposed CT, the only technically feasible control technology for SO_2 is low sulfur fuel use. The use of natural gas will minimize SO_2 emissions but natural gas is not available in sufficient quantities during the first 3 years to operate the plant at a 100-percent capacity factor. SO_2 emissions from distillate fuel can be minimized by specification of a lower sulfur content fuel. A maximum sulfur content of 0.1 percent was

selected as the top-down BACT level since it is in the range of the lowest sulfur contents being permitted by FDER or being recognized in other states as BACT.

4.3.3.2 Technology Description

The No. 2 fuel oil used in the proposed CTs will have a maximum sulfur content specification of 0.1 percent.

4.3.3.3 Impact Analysis

Economic--The estimated cost effectiveness of using 0.1 percent sulfur oil instead of standard No. 2 distillate oil with a maximum 0.5 percent sulfur fuel oil is $3,586 per ton of SO_2 removed. This was calculated assuming an initial difference of 6.9 percent between a specification of standard No. 2 fuel oil and 0.1 percent oil and a fuel escalation rate of 3 percent over inflation.

Environmental--Based upon use of 0.1 percent sulfur fuel oil, the maximum SO_2 impacts of the proposed turbines alone will be less than 6 percent of the AAQS for SO_2 and less than 17 percent of the allowable PSD Class II increments. The predicted impacts to the Chasshowitzka National Wilderness Class I area are less than the EPA significant impact levels. As a result, significant air quality impacts will not occur by using 0.1 percent sulfur fuel oil. The modeling results are contained in Section 7.0.

Energy--No substantial energy penalties are expected to result from using No. 2 fuel oil with different sulfur contents.

4.3.3.4 Proposed BACT and Rationale

The proposed BACT for the proposed turbine is the use of No. 2 fuel oil with a maximum sulfur content of 0.1 percent. The selection of this control alternative as BACT is consistent with previous determinations by FDER and the regulatory agencies of other states.

4.3.4 VOLATILE ORGANIC COMPOUNDS

4.3.4.1 Emission Control Hierarchy

The VOCs generated from the proposed project will be a result of two separate processes. First, the VOCs emitted by the CT are a result of incomplete combustion. These VOC emissions will be controlled through combustion technology so that emissions will not exceed 7 ppmvd when firing natural gas and propane and 10 ppmvd when firing distillate oil. These emission levels are similar to the BACT emission levels established for other similar sources.

The second source of VOC emissions is the CO_2 absorption vents where some of the solvent used to capture the CO_2 will be emitted. The organic compound that will be emitted is monoethanolamine (MEA, also known as ethanolamine - $H_2NCH_2CH_2OH$). The Material Safety Data Sheet on the solvent is presented in Appendix B. Under current FDER definitions of VOC (as found in Rule 17-2.100 (214), F.A.C.) and as indicated by recently promulgated changes in the definition by EPA (57 Federal Register 3945, February 3, 1992), monoethanolamine is a VOC. However, this compound has a relatively high boiling point and low vapor pressure; its photochemical reactivity is unknown. Review of the EPA BACT clearinghouse data (see Table 4-10) does not reveal any similar sources (i.e., CO_2 recovery plants) but does suggest that a percent reduction from 90 to 98 percent is applicable for VOC sources.

4.3.4.2 Technology Description

The nature of the emissions from the CO_2 absorber would require that the solvent (with MEA) be controlled by a scrubber. The scrubber would be either a packed tower, venturi, or impingement type similar to that presented in Appendix B. These scrubbers will remove at least 90 percent of the solvent from the absorber exhaust. The design basis for the scrubber exhaust is 2.36 lb VOC as carbon per ton of CO_2 produced; this is based on CO_2 plant vendor recommendations.

Table 4-10. Summary of BACT Determinations for VOC Controls from Chemical Processing Industries (Page 1 of 2)

Company Name	State	Date of Permit	Description	Unit/Process Control Method	Control Eff (%)
ADC-II, Ltd.	IA	17-Feb-85	Alchl. Fuel Prod. (Dryer,DDGS)	Vent Scrubber	--
	IA	17-Feb-85	Alchl. Fuel Prod. (Strg. Tnk)	Closed Vent Capture, Vapor Rec.	--
AeroJet Strategic Propulsion	CA	01-Apr-83	Chemical Process	Carbon Absorber	98.00
AKZO Chemie America	TX	19-Aug-85	NOURYSET 200V (Allyl Alchl)	Scrubber	98.80
Allied Corp.	NC	13-Aug-84	Fiber Process Alan 3&4	Condenser Sys. and Distall.	85.00
	NC	13-Aug-84	Fiber Process Alan 5	Condenser Sys. and Distall.	85.00
American Chrome & Chemical Co	TX	29-Dec-82	Scrubber #3	Venturi Scrubber	99.50
	TX	29-Dec-82	Scrubber #2	Venturi Scrubber	95.00
	TX	29-Dec-82	Scrubber #1	Venturi Scrubber	95.00
	TX	29-Dec-82	Scrubber #2	Venturi Scrubber	95.00
	TX	29-Dec-82	Scrubber #2	Venturi Scrubber	95.00
American Hoechst	TX	07-Jul-77	Storage Tank	Condenser and Carbon Absorber	90.00
Arco Chemical Co.	TX	09-Feb-84	Propylene Oxide plant	High Energy Venturi	--
Arco Oil & Gas Co.	TX	04-Apr-86	CO_2 Recovery, Sulfur	SRU Incinerator	--
Bofors Nobel, Inc.	MI	15-Jan-85	Mfg. of MBOCA	Wet Scrubber & Carbon Absorption	99.95
BYK-Chemie, USA	CT	17-Aug-89	Material Transfer, Mixing Tank	Condenser	95.00
	CT	17-Aug-89	Material Transfer, Mixing Tank	Condenser	95.00
Chemical Reclamation Services	TX	10-Jul-87	Pump, Vacuum, Halogen Process	Condenser/Carbon Absorber	--
	TX	10-Jul-87	Tank, Halogen Process	Carbon Absorber	--
	TX	10-Jul-87	Pump, Vacuum, Non-halogen	Condenser/Carbon Absorber	--
	TX	10-Jul-87	Tank, Non-halogen	Carbon Absorber	--
Chem-Trend, Inc.	MI	--	Storage Tank	Vapor Balance System, Zero Emission	100.00
	MI	--	Process. Vat, Filling/Purging	Pressure/Condensation Vapor Rec.	80.00
Chevron Chemical	WA	01-Aug-88	Plant	Auto. pH Trim Control System	--
Circle Energies Corp.	NE	22-Jan-85	Alcohol Fermenter	Packed Scrubber	95.00
Consolidated Energy Group, Lt	IA	13-Nov-81	Alchl. Fuel Production	Scrubbers, Floating Roof	--
Dow Chemical	MI	01-Mar-88	Process Equipment	Vapor Bal., Demister, Incinerator	99.00
	MI	09-Oct-87	Mfg. of Styrene/Butadiene/Latex	Afterburner	99.90
	MI	23-Mar-87	Material Handling	Scrubber, Vapor Bal.,Press. Tanks	--
	CA	12-Nov-86	Phenol/Acetone Storage tank	Spray Scrubber, Carbon Absorber	99.30
Dow Corning Corp.	KY	16-Oct-78	Chlorosilane/Methanol	Vapor Recovery	99.00
Dupont Spruance Plant	VA	15-Dec-86	Dimethyl Acetamide	Solvent Recovery System	99.00
Eli Lilly & Co.	IN	15-Feb-89	Pharmaceutical, Insulin	Low Temp. Venturi Condenser.	97.00
Ethyl Corp.	TX	24-Sep-86	Synth. Fuels/Fuel Conv.	Catalytic Incinerator	98.00
Firestone Tire Co.	GA	13-Nov-80	Synth. Rubber/Rubber Tires	Carbon Absorption	90.00
Georgia-Pacific Corp.	NC	17-Jan-80	Formaldehyde Production	Catalytic Converter	95.00
Globe Manufacturing Co.	NC	26-Jun-84	Elastic Fiber extruding line	Carbon Bed Absorption Units	77.00
	NC	01-Feb-83	Elastic Fiber extruding line	Carbon Bed Absorption Units	78.00
GoodYear Tire & Rubber Co.	TX	10-Jan-85	Butadiene, Mfg. process	Production Steam Stripper	90.00

Table 4-10. Summary of BACT Determinations for VOC Controls from Chemical Processing Industries (Page 2 of 2)

Company Name	State	Date of Permit	Description	Unit/Process Control Method	Control Eff (%)
Hercules Inc.	TX	11-May-87	Material Storage Soln.	Carbon Absorbers	--
	TX	11-May-87	Stabilizer make-up	Carbon Absorbers	--
	TX	11-May-87	Fugitive Emission	Monitoring and Maintenance Prog.	--
	TX	11-May-87	Material Prep. Soln.	Carbon Absorbers	--
	TX	11-May-87	Dryer	Carbon Absorbers	--
	TX	11-May-87	Material Shipping Product	Carbon Absorbers	--
	TX	11-May-87	Neutralizer	Carbon Absorbers	--
Himont USA, Inc.	TX	11-Feb-85	Polypropylene Process	Flare	99.00
Internat. Minerals & Chmcl Co	PA	12-Sep-79	Formaldehyde, Plant	Catalytic Afterburner	90.00
	PA	12-Sep-79	Methanol, Storage Tank	Vapor Recovery	90.00
	PA	12-Sep-79	Formaldehyde, Storage Tank	Vapor Recovery	90.00
Monsanto Co.	FL	26-Mar-81	Maleic Anhydride	Incineration	90.00
New England Ethanol, Inc.	ME	10-Aug-83	Ethanol (Truck & Rail Trnsfr)	Vapor Recovery	95.00
	ME	10-Aug-83	Aldehyde (Storage Tank)	Vapor Recovery	95.00
	ME	10-Aug-83	Ethanol (Storage Tank)	Vapor Recovery	95.00
	ME	10-Aug-83	Cyclohexane (Storage Tank)	Vapor Recovery	95.00
	ME	10-Aug-83	Gasoline/Diesel (Storage Tank)	Vapor Recovery	95.00
	ME	10-Aug-83	Oil (Storage Tank)	Vapor Recovery	95.00
North American Reiss Corp.	VA	17-Apr-87	Silicone Plastic Manu.	--	--
	VA	17-Apr-87	Solvent, Synthetic Fibers	--	--
Perstorp Polyvols	OH	01-Feb-89	Formaldehyde, Process	Catalytic Incinerator.	98.00
	OH	24-Aug-88	Formaldehyde, Tank	Catalytic Incinerator.	98.00
	OH	24-Aug-88	IMP and Formate	Catalytic Incinerator.	98.00
	OH	24-Aug-88	Butyraldehyde, Tank	Sub fill/Pressurized tank	--
Pittsylvania County	VA	06-Dec-88	Maleic Anhydride	Wet Scrubber	--
PMC Specialities Grp, Prodn D	CA	27-Oct-86	Phenol/Acetone Dryer/Cryst.	Incinerator	90.00
Sohio Chemical Co.	TX	04-Jun-84	Acrylonitrile production	Waste Gas Incinerator	99.80
Standard Oil Company	TX	14-Dec-87	Maleic Anhydride	Incinerator	99.60
3 M	IL	05-Feb-88	Fluorocarbons, Chem. Prod.	Condensers(-40F), Work Practice	--
Union Carbide Chemical	TX	11-Aug-88	Carbon Absorber	--	98.00
	TX	11-Aug-88	Fugitives	--	--
	TX	11-Aug-88	Acetic Acid, Tank	--	--
Velsicol Chemical Co.	TN	08-Oct-82	Expansion Plant	Wet Scrubber, Carbon Absorption	98.00
	TN	08-Oct-82	Benzyl Chloride Synthsis	Wet Scrubber, Carbon Absorption	80.00
	TN	08-Oct-82	Benzotrichloride synthsis	Wet Scrubber, Carbon Absorption	99.00
	TN	08-Oct-82	Benzyl Chloride Synthsis	Wet Scrubber, Carbon Absorption	80.00
Virginia Chemicals, Inc.	VA	05-Dec-86	Polyacrylic power	Uncontrolled	99.90
Wyckoff Chemicals Co., Inc.	MI	06-Jan-89	Pharmaceutical, Solvent	Caustic Scrubber/Demister,Carbon Adsorption	95.00
Yale Rubber Manufacturing Co.	MI	28-Jan-88	Synthetic Rubber/Rubber Tires	Regenerable Carbon Absorption	99.99
	Mi	28-Jan-88	Synthetic Rubber/Rubber Tires	Regenerable Carbon Absorption	99.99

4.3.4.3 Impact Analysis

Economic--The annualized cost of installing a scrubber of the type presented in Appendix B is $240,614. Table 4-11 presents the capital cost and Table 4-12 the operating and annualized costs. The cost effectiveness is estimated at approximately $400 per ton of VOC removed based on an uncontrolled emission rate of approximately about 645.4 TPY.

Environmental--The emissions of MEA were evaluated based on the maximum ground-level impacts and comparisons against the FDER no-threat-levels (NTLs) for toxic air pollutants. The results of this analysis, which is presented in Section 7.0, indicate that the potential impacts of MEA are below the NTLs recommended by the FDER.

Energy--The scrubber system will use approximately 14 kilowatts (kW) per hour or approximately 120,000 kW per hour per year. This energy is sufficient to supply electrical energy to approximately 10 residential customers for a year. This amount is relatively small.

4.3.4.4 Proposed BACT and Rationale

The proposed BACT for VOCs is combustion controls for the CT and scrubber for the CO_2 absorber exhausts. The selection of these control alternatives is based upon the following:

1. Combustion controls have been overwhelmingly approved as BACT for CTs. The proposed VOC emission limits for the CT are in the range approved for other similar sources. No additional controls have been installed for CTs that would substantially reduce VOC emissions. The environmental affect of reduced emissions would not be significant.
2. The proposed scrubber for the CO_2 absorber exhausts will remove VOC in the range of that approved as BACT for a wide range of VOC sources. BACT determinations for similar sources are not available in the BACT clearing house; therefore, the proposed level of control appears appropriate given the range of removal efficiencies for various VOC sources. The proposed scrubber

Table 4-11. Capital Cost Estimates for a Scrubber System to Control MEA Emissions.

Cost Items	Cost Factors		Scrubber System
DIRECT CAPITAL COSTS (DCC):			
(1) Purchased Equipment			
(a) Basic Equipment			
Scrubber System		Vendor Quote	$85,000
(b) Instrumentation & Controls*	0.10 x	(1a)	$8,500
(c) Freight*	0.05 x	(1a-1b)	$4,675
(d) Sales Tax (Florida)	0.06 x	(1a-1b)	$5,610
(e) Subtotal		(1a-1d)	$103,785
(2) Direct Installation			
(a) Foundations & Supports*	0.06 x	(1e)	$6,227
(b) Handling & Erection*	0.40 x	(1e)	$41,514
(c) Electrical*	0.01 x	(1e)	$1,038
(d) Piping*	0.05 x	(1e)	$5,189
(e) Insulation*	0.03 x	(1e)	$3,114
(f) Painting*	0.01 x	(1e)	$1,038
(g) Subtotal		(2a-2f)	$58,120
Total DCC:		(1) + (2)	$161,905
INDIRECT CAPITAL COSTS (ICC):			
(1) Indirect Installation			
(a) Engineering & Supervision*	0.10 x	(DCC)	$16,190
(b) Construction & Field Expenses	0.10 x	(DCC)	$16,190
(c) Construction Contractor Fee*	0.10 x	(DCC)	$16,190
(d) Contingencies	0.125 x	(DCC)	$20,238
(2) Other Indirect Costs			
(a) Startup & Testing*	0.02 x	(DCC)	$3,238
(b) Interest During Construction		15% of DCC	$24,286
Total ICC:		(3) + (4)	$96,333
TOTAL CAPITAL INVESTMENT (TCI):		DCC + ICC	$258,238

* Based on venturi scrubber, from William M. Vatavuk, Estimating Costs of Air Pollution Control, 1990.

Table 4-12. Operating and Annualized Cost Estimate for MEA Scrubber System

Cost Items	Basis	Scrubber System
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator[a]	32 hours per week, $25.0/hr.	$41,600
Supervisor[a]	15% of operator cost	$6,240
(2) Maintenance	10% of TCI	$12,912
(3) Replacement Parts (include freight & tax)	10% of TCI	$12,912
(4) Utilities		
(a) Electricity	$50.0 per MW-hr	$6,002
(b) Water, once-thru	$250 per million gallon	$19,710
(5) Wastewater Treatment	$2.50 per 1,000 gallons	$49,275
(6) Contingencies	10% of DOC	$14,865
Total DOC		$163,516
INDIRECT OPERATING COSTS (IOC):		
(1) Overhead[a]	60% of oper. labor & maint.	$36,451
(2) Property Taxes[a]	1% of total capital investment	$2,582
(3) Insurance[a]	1% of total capital investment	$2,582
(4) Administration[a]	2% of total capital investment	$5,165
Total IOC		$46,781
ANNUALIZED CAPITAL COST (ACC)	CRF of 0.1174 times TCI	$30,317
ANNUALIZED COST (AC):	DOC + IOC + ACC	$240,614

[a] Based on venturi scrubber, from William M. Vatavuk, Estimating Costs of Air Pollution Control, 1990.

system will be cost effective: in the range of $400 per ton of VOC removed. The environmental impacts at the proposed emission level are below the FDER NTL for the compound being used (i.e., MEA).

4.3.5 OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PSD source applicability analysis shows that the PSD significant emissions level is exceeded for PM/PM10 requiring PSD review (including BACT) for these pollutants. The emission of particulates from the CT is a result of incomplete combustion and trace solids in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on a gas-fueled CT.

The maximum particulate emissions from the CT will be lower in concentration than that normally specified for fabric filter designs (i.e., the grain loading associated with the maximum particulate emissions [about 15 pounds per hour (lb/hr)]) is less than 0.01 grain per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

Therefore, there are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Natural gas and distillate oil represent BACT for this pollutant.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; thus, natural gas represents BACT because of its inherent low contaminant content.

5.0 AIR QUALITY MONITORING DATA

5.1 PSD PRECONSTRUCTION

The CAA requires that an air quality analysis be conducted for each pollutant subject to regulation under the act before a major stationary source or major modification is constructed. This analysis may be performed by the use of modeling and/or by monitoring the air quality. The use of monitoring data refers to either the use of representative air quality data from existing monitoring stations or establishing a monitoring network to monitor existing air quality. Monitoring must be conducted for a period up to 1 year prior to submission of a construction permit application. In addition to establishing existing air quality, the air quality data are useful for determining background concentrations (i.e., concentrations from sources not considered in the modeling). The background concentrations can be added to the concentrations predicted for the sources considered in the modeling to estimate total air quality impacts. These total concentrations are then evaluated to determine compliance with the AAQS.

For the criteria pollutants, continuous air quality monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification. However, preconstruction monitoring data generally will not be required if the ambient air quality concentration before construction is less than the de minimis impact monitoring concentrations (refer to Table 3-2 for de minimis impact levels). Also, if the maximum predicted impact of the source or modification is less than the de minimis impact monitoring concentrations, the source generally would be exempt from preconstruction monitoring.

For noncriteria pollutants, EPA recommends that an analysis based on air quality modeling generally should be used instead of monitoring data. The permit-granting authority has discretion in requiring preconstruction monitoring data when:

1. The state has an air quality standard for the noncriteria pollutant, and emissions from the source or modification pose a threat to the standard;
2. The reliability of emission data used as input to modeling existing sources is highly questionable; or
3. Air quality models have not been validated or may be suspect for certain situations, such as complex terrain or building downwash conditions.

However, if the maximum concentrations from the major source or major modification are predicted to be above the significant monitoring concentrations, EPA recommends that an EPA-approved measurement method be available before a permit-granting authority requires preconstruction monitoring.

EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD) (EPA, 1987a) sets forth guidelines for preconstruction monitoring. The guidelines allow the use of existing air quality data in lieu of additional air monitoring if the existing data are representative. The criteria used in determining the representativeness of data are monitor location, quality of data, and currentness of data.

For the first criterion, monitor location, the existing monitoring data should be representative of three types of areas:

1. The location(s) of maximum concentration increase from the proposed source or modification;
2. The location(s) of the maximum air pollutant concentration from existing sources; and
3. The location(s) of the maximum impact area (i.e., where the maximum pollutant concentration hypothetically would occur, based on the combined effect of existing sources and the proposed new source or modification).

Basically, the locations and size of the three types of areas are determined through the application of air quality models. The areas of maximum concentration or maximum combined impact vary in size and are influenced by factors such as the size and relative distribution of ground level and elevated sources, the averaging times of concern, and the distances between impact areas and contributing sources.

For the second criteria, data quality, the monitoring data should be of similar quality as would be obtained if the applicant were monitoring according to PSD requirements. As a minimum, this would mean:

1. Use of continuous instrumentation,
2. Production of quality control records that indicate the instruments' operations and performances,
3. Operation of the instruments to satisfy quality assurance requirements, and
4. Data recovery of at least 80 percent of the data possible during the monitoring effort.

For the third criteria, currentness of data, the monitoring data must have been collected within a 3-year period preceding the submittal of permit application and must still be representative of current conditions.

5.2 PROJECT MONITORING APPLICABILITY

As determined by the source applicability analysis described in Section 3.4, an ambient monitoring analysis is required by PSD regulations for SO_2, PM(TSP), PM(PM10), NO_2, CO, VOCs, sulfuric acid mist, Be, and As emissions. Arsenic and sulfuric acid mist may be exempt from monitoring requirements because no acceptable monitoring technique has been established for that pollutant. Except for SO_2 and VOCs, the maximum predicted impacts (emissions in the case of VOCs) from the proposed facility also are less than de minimis levels for the applicable pollutants. Therefore, preconstruction monitoring is not required for those pollutants for this project. For VOC emissions, the maximum emission rate is greater than the de minimis emission rate of 100 TPY.

For SO_2 and ozone concentrations, the monitoring data collected in Polk county are proposed for use to satisfy the preconstruction monitoring requirements. The monitoring data collected at the Mulberry site (SAROAD No. 2860-006-F02) is assumed to represent SO_2 concentrations at the proposed facility's location because the site is located approximately 9.7 km away and is in an area of multiple sources similar to the proposed facility. The 1991 monitoring data collected in Polk county (SAROAD No. 3680-036-J01) is assumed to represent ozone concentrations near the proposed facility. This site is the only ozone monitoring site located in Polk county. The highest, second-highest 1-hour ozone concentration reported at this monitor for 1991 is 0.081 ppm (159.0 $\mu g/m^3$).

Although the proposed facility's impacts are only slightly greater than the de minimis impact and emission levels, the air quality levels are expected to be well below the AAQS after the proposed facility becomes operational. Also, the plant will be permitted to operate with distillate oil on a full-time basis for a 3-year period; however, the plant will be capable of using natural gas and propane during this time. After 3 years, the plant will be fired primarily with natural gas using distillate oil as a backup fuel for less than 1,000 hours per year. Therefore, predicted SO_2 and ozone impacts and emissions will decrease after distillate oil is phased out and used as a backup fuel only.

5.3 BACKGROUND SO_2 CONCENTRATIONS

A background SO_2 concentration must be estimated to account for SO_2 sources which are not explicitly included in the atmospheric dispersion modeling analysis. In order to estimate reasonable background SO_2 concentrations, a review of recent, available SO_2 monitoring data in the area of the proposed project was performed. Presented in Table 5-1 is a summary of ambient SO_2 data available from 1988 to 1991 for monitors located within Polk county. A total of four stations are located in Polk county, all of which have continuous SO_2 monitors. These monitors are operated by the State of Florida.

Table 5-1. Summary of Ambient SO_2 Monitoring Data for Sites Located Within Polk County, 1988 to 1991

SAROAD Site No. (Distance from Proposed Facility)	City	Monitoring Method	Period	No. of Obs.	Percent Data Recovery	SO_2 Concentration ($\mu g/m^3$) 3-Hour[a]	24-Hour[a]	Annual Average
2160-001-F01[c]	Lakeland	Continuous	1988	8646	98.4	154	53	11
(27.6)			1989	1465	16.7	101	37	10
			1990	--	--	--	--	--
3680-010-F02[b]	Nichols	Continuous	1988	8510	96.9	212	58	10
(14.1)			1989	8610	98.3	259	55	10
			1990	8612	98.3	252	62	9
			1991	8542	97.5	167	58	10
2160-004-F02[b]	Lakeland	Continuous	1989[d]	5835	66.6	114	29	5
(27.9)			1990	8683	99.1	122	27	5
2860-006-F02[b]	Mulberry	Continuous	1991[e]	7118	81.3	176	40	12
(9.7)								

Note: No. = number.
Obs. = observations.
SO_2 = sulfur dioxide.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Second-highest concentrations for calendar year are shown.
[b] Monitoring objective for this site is to measure the impact of air pollution sources.
[c] Monitoring objective for this site is to measure pollutant concentrations indicative of the general population. Monitoring ws discontinued at this site in 1989.
[d] Monitoring began at this site in May 1989.
[e] Monitoring began at this site in February 1991.

Source: FDER, 1988, 1989, 1990.

Site 2860-006-F02, located in Mulberry, is the closest monitoring site to the proposed project (9.7 km) and would thus be most representative of background SO_2 concentrations for the area. Monitoring at this site began in February 1991. Data capture for 1991 was 81.3 percent, just above the 80 percent criteria needed. The highest annual and highest, second-highest short-term concentrations reported for this monitor for 1991 are 176, 40, and 12 $\mu g/m^3$ for the 3-hour, 24-hour, and annual averaging periods, respectively. These background values will be added to modeled impacts for comparison to AAQS.

This monitor is located in an area where existing sources within a 10 km radius have maximum annual SO_2 emissions of greater than 20,000 tons per year. Therefore, the monitoring concentrations reported are expected to include substantial contributions from these sources. Since more than 99 percent of these sources' emissions are included in the modeling analyses, the use of these background values produces a conservative prediction of final impacts near the proposed facility.

6.0 AIR QUALITY MODELING APPROACH

6.1 ANALYSIS APPROACH AND ASSUMPTIONS

6.1.1 GENERAL MODELING APPROACH

The general modeling approach follows EPA and FDER modeling guidelines. The highest predicted concentrations are compared with both PSD significant impact levels and de minimis air quality levels. If a facility exceeds the significant impact level for a particular pollutant, current policies stipulate that the highest annual average and HSH short-term (i.e., 24 hours or less) concentrations be compared with AAQS and PSD increments when 5 years of meteorological data are used. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with the air quality standards, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the facility, the general modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. The basic difference between the two phases is the receptor grid used when predicting concentrations.

Concentrations for the screening phase were predicted using a coarse receptor grid and a 5-year meteorological record. After a final list of maximum short-term concentrations was developed, the refined phase of the analysis was conducted by predicting concentrations for a refined receptor grid centered on the receptor at which the HSH concentration from the screening phase was produced. The air dispersion model then was executed for the entire year during which HSH concentrations were predicted. This

approach was used to ensure that valid HSH concentrations were obtained. More detailed descriptions of the emission inventory and receptor grids used in the screening and refined phases of the analysis are presented in the following sections.

6.1.2 MODEL SELECTION

The selection of the appropriate air dispersion model was based on its ability to simulate impacts in areas surrounding the plant site. Within 50 km of the site, the terrain can be described as simple (i.e., flat to gently rolling). As defined in the EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Therefore, a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex (ISC) dispersion model (EPA, 1988a) was selected to evaluate the pollutant emissions from the proposed units and other modeled sources. This model is contained in EPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (EPA, 1988b). The ISC model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights.

The ISC model consists of two sets of computer codes that are used to calculate short- and long-term ground level concentrations. The main differences between the two codes are the input format of the meteorological data and the method of estimating the plume's horizontal dispersion.

The first model code, the ISC short-term (ISCST) model, is an extended version of the single-source (CRSTER) model (EPA, 1977). The ISCST model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term, and annual

averaging periods. For example, a 24-hour average concentration is based on twenty-four 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

The second model code within the ISC model is the ISC long-term (ISCLT) model. The ISCLT model uses joint frequencies of wind direction, wind speed, and atmospheric stability to calculate seasonal and/or annual average ground-level concentrations. Because the input wind directions are for 16 sectors, with each sector defined as 22.5 degrees, the model calculates concentrations by assuming that the pollutant is uniformly distributed in the horizontal plane within a 22.5-degree sector.

In this analysis, the ISCST model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output. Major features of the ISCST model are presented in Table 6-1. Concentrations caused by stack and volume sources are calculated by the ISCST model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST model is based on the equation for a continuous and finite crosswind line source. The ISC model has rural and urban options that affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground-level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

Table 6-1. Major Features of the ISCST Model

ISCST Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options that affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
• Procedures suggested by Huber and Snyder (1976); Huber (1977); Schulmann and Hanna (1986); and Schulmann and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple-point sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, and area sources
• Capability to calculate dry deposition
• Variation with height of wind speed (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average
• Terrain-adjustment procedures for elevated terrain, including a terrain truncation algorithm
• Receptors located above local terrain (i.e., "flagpole" receptors)
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing
• Wind speeds less than 1 m/s are set to 1 m/s.

Source: EPA, 1990.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by EPA (1987a) and are referred to as the regulatory options in the ISCST model:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours (i.e., reduce the SO_2 concentration emitted by 50 percent for every 4 hours of plume travel time).

In this analysis, the EPA regulatory options were used to address maximum impacts. Based on a review of the land use around the facility, the rural mode was selected because of the lack of residential, industrial, and commercial development within 3 km of the plant site.

6.2 METEOROLOGICAL DATA

Meteorological data used in the ISCST model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) station at Tampa International Airport. The 5-year period of meteorological data was from 1982 through 1986. The NWS station in Tampa, located approximately 65 km to the west-northwest of the site, was selected for use in the study because it is the closest primary weather station to the study area considered to have meteorological data representative of the project site. This station has surrounding topographical features similar to the project site and the most readily available and complete database.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor

program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Tampa using the Holzworth approach (Holzworth, 1972). Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the EPA RAMMET meteorological preprocessor program.

6.3 EMISSION INVENTORY

Stack operating parameters and emission rates for the proposed facility used in the modeling analysis are presented in Tables 6-2 and 6-3. Modeling of the proposed facility demonstrated that the facility's PM, NO_2, and CO impacts are below the significant impact levels. Therefore, further modeling for these pollutants for comparison to AAQS and PSD Class II increments is not required. The facility's impacts are above the SO_2 significant impact levels at a distance of not greater than 700 meters from the proposed CT stack. Therefore, the emission inventories for SO_2 were developed for sources within approximately 51 km of the Mulberry Cogeneration Facility. Using information provided by FDER, the Florida State Air Pollution Information System (APIS), PSD applications, and previous modeling analyses, SO_2 emitting facilities within 51 km of the proposed site were identified. These facilities are presented in Table 6-4.

FDER has recommended a technique for eliminating sources in the modeling analyses if the source's emissions do not meet an emission criteria. The technique is the "Screening Threshold" method, developed by the North

Table 6-2. Stack, Operating, and Emission Data Used in the Air Quality Impact Modeling for the Proposed Mulberry Cogeneration Facility

Parameter	Power Plant 20°F	Power Plant 100°F	CO_2 Plant 20°F	CO_2 Plant 100°F
Stack Data (ft)				
Height	125	125	170	170
Diameter	15	15	3.0	3.0
Operating Data				
Temperature (°F)	220	220	117	117
Velocity (ft/sec)	67.8[a]	55.5[a]	66.5	66.5

Maximum Emission Rate (lb/hr)[a,b]	Power Plant 20°F	Power Plant 100°F	CO_2 Plant 20°F Source CT	DB	CO_2 Abs	Total	CO_2 Plant 100°F Source CT	DB	CO_2 Abs	Total
SO_2	100.8	78.2	4.9	0.3	0.0	5.20	4.7	0.3	0.0	5.00
PM	14.3	14.3	0.69	0.99	5.0	6.68	0.84	0.99	5.0	6.83
NO_2	173.8	134.8	8.4	15.8	0.0	24.2	8.0	15.8	0.0	23.8
CO	78.8	62.8	3.8	9.9	0.0	13.7	3.7	9.9	0.0	13.6

Note: CT = combustion turbine.
DB = duct burner.
CO_2 Abs = CO^2 absorber.

[a] Exit velocity and emissions from the power plant stack were reduced to account for the mass flow of CT exhaust (120,000 lb/hr) diverted to the CO_2 plant.

[b] Based on burning distillate oil, which produces the highest emission rates among the fuels (distillate oil, natural gas, and propane) selected for this facility.

Table 6-3. Emission Data for Other Regulated and Non-Regulated Pollutants Considered in the Air Quality Impact Modeling for the Proposed Mulberry Cogeneration Facility

Maximum Emission Rate (lb/hr)[a,b]	Power Plant		CO_2 Plant							
			20°F				100°F			
			Source				Source			
	20°F	100°F	CT	DB	CO_2 Abs	Total	CT	DB	CO_2 Abs	Total
Antimony	$2.15x10^{-2}$	$1.67x10^{-2}$	$1.04x10^{-3}$	0.00	0.00	$1.04x10^{-3}$	$9.93x10^{-4}$	0.00	0.00	$9.93x10^{-4}$
Arsenic	$4.13x10^{-3}$	$3.21x10^{-3}$	$2.00x10^{-4}$	0.00	0.00	$2.00x10^{-4}$	$1.91x10^{-4}$	0.00	0.00	$1.91x10^{-4}$
Barium	$1.92x10^{-2}$	$1.49x10^{-2}$	$9.28x10^{-4}$	0.00	0.00	$9.28x10^{-4}$	$8.88x10^{-4}$	0.00	0.00	$8.88x10^{-4}$
Beryllium	$2.46x10^{-3}$	$1.91x10^{-3}$	$1.19x10^{-4}$	0.00	0.00	$1.19x10^{-4}$	$1.14x10^{-4}$	0.00	0.00	$1.14x10^{-4}$
Cadmium	$1.03x10^{-2}$	$8.01x10^{-3}$	$4.99x10^{-4}$	0.00	0.00	$4.99x10^{-4}$	$4.77x10^{-4}$	0.00	0.00	$4.77x10^{-4}$
Chlorine	$2.65x10^{-2}$	$2.06x10^{-2}$	$1.28x10^{-3}$	0.00	0.00	$1.28x10^{-3}$	$1.23x10^{-3}$	0.00	0.00	$1.23x10^{-3}$
Chromium	$4.67x10^{-2}$	$3.63x10^{-2}$	$2.26x10^{-3}$	0.00	0.00	$2.26x10^{-3}$	$2.16x10^{-3}$	0.00	0.00	$2.16x10^{-3}$
Colbalt	$8.92x10^{-3}$	$6.92x10^{-3}$	$4.31x10^{-4}$	0.00	0.00	$4.31x10^{-4}$	$4.12x10^{-4}$	0.00	0.00	$4.12x10^{-4}$
Copper	$2.76x10^{-1}$	$2.14x10^{-1}$	$1.33x10^{-2}$	0.00	0.00	$1.33x10^{-2}$	$1.27x10^{-2}$	0.00	0.00	$1.27x10^{-2}$
Ethanolamine	0.00	0.00	0.00	0.00	$147x10^{1}$	$147x10^{1}$	0.00	0.00	$147x10^{1}$	$1.47x10^{1}$
Fluoride	$3.20x10^{-2}$	$2.48x10^{-2}$	$1.54x10^{-3}$	0.00	0.00	$1.54x10^{-3}$	$1.48x10^{-3}$	0.00	0.00	$1.48x10^{-3}$
Formaldehyde	$3.98x10^{-1}$	$3.09x10^{-1}$	$1.92x10^{-2}$	$3.76x10^{-3}$	0.00	$2.30x10^{-2}$	$1.84x10^{-2}$	$3.76x10^{-3}$	0.00	$2.22x10^{-2}$
Manganese	$6.34x10^{-3}$	$4.92x10^{-3}$	$3.06x10^{-4}$	0.00	0.00	$3.06x10^{-4}$	$2.93x10^{-4}$	0.00	0.00	$2.93x10^{-4}$
Mercury	$2.95x10^{-3}$	$2.29x10^{-3}$	$1.43x10^{-4}$	0.00	0.00	$1.43x10^{-4}$	$1.36x10^{-4}$	0.00	0.00	$1.36x10^{-4}$
Nickel	$1.67x10^{-1}$	$1.30x10^{-1}$	$8.08x10^{-3}$	0.00	0.00	$8.08x10^{-3}$	$7.73x10^{-3}$	0.00	0.00	$7.73x10^{-3}$
Polyorganic Matter	$2.74x10^{-4}$	$2.13x10^{-4}$	$1.33x10^{-5}$	$1.10x10^{-4}$	0.00	$1.24x10^{-4}$	$1.27x10^{-5}$	$1.10x10^{-4}$	0.00	$1.23x10^{-4}$
Selenium	$2.31x10^{-2}$	$1.79x10^{-2}$	$1.12x10^{-3}$	0.00	0.00	$1.12x10^{-3}$	$1.07x10^{-3}$	0.00	0.00	$1.07x10^{-3}$
Sulfuric Acid Mist	8.12	6.30	$3.92x10^{-1}$	$2.40x10^{-2}$	0.00	$4.16x10^{-1}$	$3.75x10^{-1}$	$2.40x10^{-2}$	0.00	$3.99x10^{-1}$
Vanadium	$6.86x10^{-2}$	$5.32x10^{-2}$	$3.31x10^{-3}$	0.00	0.00	$3.31x10^{-3}$	$3.17x10^{-3}$	0.00	0.00	$3.17x10^{-3}$
Zinc	$6.72x10^{-1}$	$5.21x10^{-1}$	$3.25x10^{-2}$	0.00	0.00	$3.25x10^{-2}$	$3.11x10^{-2}$	0.00	0.00	$3.11x10^{-2}$

Note: CT = combustion turbine.
DB = duct burner.
CO_2 Abs = CO^2 absorber.

[a] Exit velocity and emissions from the power plant stack were reduced to account for the mass flow of CT exhaust (120,000 lb/hr) diverted to the CO_2 plant.

[b] Based on burning distillate oil, which produces the highest emission rates among the fuels (distillate oil, natural gas, and propane) selected for this facility.

Table 6-4. SO_2 Emission Inventory of Sources Considered in the Modeling Analysis (Page 1 of 2)

APIS Number	Facility	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative Location to Proposed Facility[a] X (km)	Relative Location to Proposed Facility[a] Y (km)	Relative Location to Proposed Facility[a] Distance (km)	Relative Location to Proposed Facility[a] Direction (degrees)	Screening Threshold Emissions (TPY)[b]	Maximum Allowable Emissions (TPY)	PSD Source?	Included in the AAQS Modeling Analysis?
40TPA530027	IMC-Noralyn Mine Road	414.7	3080.3	1.1	-0.3	1.1	105	9	504	No	Yes
40TPA530053	Farmland Industries	409.5	3080.1	-4.1	-0.5	4.1	263	69	3,878	Yes	Yes
40TPA530065	Kaplan Industries	418.3	3079.3	4.7	-1.3	4.9	105	84	398	No	Yes
40TPA530052	C.F. Industries	408.0	3082.4	-5.6	1.8	5.9	288	104	1,989	Yes	Yes
40TPA530046	W.R. Grace/Seminole Fertilizer	409.8	3086.7	-3.8	6.1	7.2	328	130	8,938	Yes	Yes
40TPA530048	Royster Co.	406.8	3085.1	-6.8	4.5	8.2	303	149	1,284	Yes	Yes
40TPA530054	Agrico Chemical Co. (Pierce)	403.7	3079.0	-9.9	-1.6	10.0	261	187	417	No	Yes
40TPA530055	Agrico Chemical Co. (S. Pierce)	407.5	3071.5	-6.1	-9.1	11.0	214	205	7,722	Yes	Yes
40TPA530051	U.S. Agri-Chemicals	416.0	3069.0	2.4	-11.6	11.8	168	223	4,603	Yes	Yes
40TPA530059	IMC-Praire	402.9	3087.0	-10.7	6.4	12.5	301	235	109	No	No
40TPA530080	Imperial Phosphate	404.8	3069.5	-8.8	-11.1	14.2	218	269	275	No	Yes
40TPA530167	Laidlaw Env. Services[c]	422.7	3091.9	9.1	11.3	14.5	39	276	240	No	No
40TPA530057	Conserve Chemicals	398.7	3084.2	-14.9	3.6	15.3	284	293	1,597	Yes	Yes
40TPA530047	Mobil Chemical Co.-Nichols	398.4	3085.3	-15.2	4.7	15.9	287	304	755	Yes	Yes
40TPA530059	IMC-New Wales	396.7	3079.4	-16.9	-1.2	16.9	266	325	13,884	Yes	Yes
40TPA530044	Gardinier	415.3	3063.3	1.7	-17.3	17.4	174	334	1,173	No	Yes
40HIL290102	Mobil Oil Big Four Mine	394.7	3069.6	-18.9	-11.0	21.9	240	423	569	No	Yes
NA	AMAX	394.8	3067.7	-18.8	-12.9	22.8	236	442	589	Yes	Yes
NA	Hardee Power Station	404.8	3057.4	-8.8	-23.2	24.8	201	482	9,649	Yes	Yes
40HIL290075	Consolidated Minerals	393.8	3096.3	-19.8	15.7	25.3	308	491	1,344	No	Yes
40TPA530004	Lakeland City Power	409.2	3106.2	-4.4	25.6	26.0	350	506	30,496	Yes	Yes
40TPA530003	Lakeland City Power	409.0	3106.2	-4.6	25.6	26.0	350	506	4,375	Yes	Yes
40HIL290101	IMC-Fort Lonesome	389.5	3067.9	-24.1	-12.7	27.2	242	531	1,386	Yes	Yes
40TPA530002	Citrus World	441.0	3087.3	27.4	6.7	28.2	76	550	877	No	Yes
40TPA250009	Wachula City Power Plant	418.4	3047.0	4.8	-33.6	33.9	172	665	180	No	No

Table 6-4. SO_2 Emission Inventory of Sources Considered in the Modeling Analysis (Page 2 of 2)

APIS Number	Facility	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative Location to Proposed Facility[a] X (km)	Y (km)	Distance (km)	Direction (degrees)	Screening Threshold Emissions (TPY)[b]	Maximum Allowable Emissions (TPY)	PSD Source?	Included in the AAQS Modeling Analysis?
40TPA530019	Citrus Hill	447.9	3068.3	34.3	-12.3	36.4	110	715	411	No	No
40TPA250011	American Orange Corp.	429.8	3047.3	16.2	-33.3	37.0	154	727	198	No	No
40TPA530001	Alcoma Packing	451.6	3085.5	38.0	4.9	38.3	83	752	327	No	No
NA	C. F. Industries	388.0	3116.0	-25.6	35.4	43.7	324	860	3,796	Yes	Yes
40HIL290261	Hillsborough Co. Res. Rec.	368.2	3092.7	-45.4	12.1	47.0	285	926	744	Yes	No
52FTM280003	FPL-Avon Park	451.4	3050.5	37.8	-30.1	48.3	129	952	67	No	No
40HIL290076	Delta Asphalt	372.1	3105.4	-41.5	24.8	48.3	301	953	51	No	No

Note: APIS = Florida Air Pollution Inventory System.
km = kilometer.
NA = not available or unknown.
SO_2 = sulfur dioxide.
TPY = tons per year.

[a] Proposed facility located at 413.6 km east and 3080.6 km north.

[b] Screening threshold emissions (Q) are equal to 20 times the distance from the source in question to the edge of the proposed facility's SO2 significant impact area (0.7 km). Sources with maximum allowable emissions less than Q were eliminated from the AAQS modeling analysis (see text for details).

[c] Formerly Tricil Recovery Services.

Carolina Department of Natural Resources and Community Development, and approved by the EPA (refer to Appendix C). The method is designed to objectively eliminate from the emission inventory those sources which are not likely to have a significant interaction with the source undergoing evaluation. In general, sources that should be considered in the modeling analyses are those with emissions greater than Q (in TPY) which is calculated by the following criteria:

$$Q = 20 \times D$$

where D is:

1. the distance (km) from the proposed facility to the source undergoing evaluation for short-term analysis, or
2. the distance (km) from the edge of the proposed facility's significant impact area (0.7 km) to the source undergoing evaluation for long-term analysis.

For this analysis the long-term criteria was used since less sources would be eliminated than with the short-term criteria and would thus result in a more conservative approach. Referencing Table 6-4, those sources with maximum allowable SO_2 emissions which are below the calculated "screening threshold" emissions were eliminated from further consideration in the AAQS modeling analysis.

PSD sources are also noted in Table 6-4. These sources were identified from inventories provided by FDER. All PSD sources within 51 km of the proposed facility were explicitly modeled in the PSD Class II analysis.

The individual emissions, stack, and operating parameters for the sources considered in the AAQS analysis are presented in Appendix D, Table D-1. These sources represent all identified facilities within 51 km of the proposed facility. Those facilities eliminated from the modeling analysis using the screening threshold technique are noted.

Where possible, individual sources within a facility were combined in order to obtain a manageable source inventory for modeling purposes. Those

facilities located near the proposed Mulberry Cogeneration Facility (i.e., within 5 km) were not combined as to maintain the integrity of the facility's emissions. Sources located more than 5 km from the proposed facility were combined based on like sources within the facility, or sources within the facility which dominate emissions. For the latter case, smaller source's emissions were added and combined with the dominant source's emissions and then modeled using the dominant source's stack and operating parameters. A summary of the combined sources used in the modeling analysis is presented in Appendix D, Table D-2.

A summary of SO_2 sources used in the PSD Class II modeling analysis is presented in Appendix D, Table D-3. These sources were taken from a PSD Class I inventory provided by FDER. Only those sources within 51 km of the proposed facility were used in the Class II analysis.

6.4 RECEPTOR LOCATIONS

As discussed in Section 6.1.1, the general modeling approach considered screening and refined phases to address compliance with AAQS and PSD increments. For the screening phase, concentrations were predicted for the following receptor locations:

1. For determination of the SO_2 significant impact area, 432 receptors located at distances of 300; 500; 700; 1,000; 1,500; 2,000; 3,000; 4,000; 5,000, 7,500; 10,000; and 20,000 m along 36 radials with each radial spaced at 10-degree increments. This grid was centered at the proposed CT stack location.
2. For the AAQS and PSD Class II analysis, 360 total receptors located in a radial grid centered at the proposed CT stack location. These receptors were classified into two main groups:
   a. 36 plant property receptors placed at the nearest plant boundary along 36 radials spaced at 10-degree increments. These receptors are presented in Table 6-5.

Table 6-5. Plant Property Receptors Used in the Screening Modeling Analysis

Receptor Location		Receptor Location	
Direction (degrees)	Distance (meters)	Direction (degrees)	Distance (meters)
10	115	190	104
20	140	200	108
30	188	210	115
40	201	220	122
50	199	230	121
60	116	240	121
70	81	250	125
80	84	260	132
90	92	270	146
100	105	280	145
110	114	290	130
120	122	300	121
130	136	310	117
140	127	320	98
150	114	330	83
160	107	340	86
170	104	350	91
180	104	360	100

Note: Direction and distance are relative to the proposed CT stack.

b. 324 general grid receptors located at distances of 300; 500; 700; 1,000; 1,500; 2,000; 3,000; 4,000; and 5,000 m along 36 radials with each radial spaced at 10-degree increments.

Because the proposed facility's significant impact distance was only 700 m, PSD Class II and AAQS impacts were predicted at a maximum distance of 5 km from the proposed CT stack.

After the screening modeling was completed, refined modeling was conducted using a receptor grid centered on the receptor that had the highest concentration from the screening analysis. The receptors were located at intervals of 100 m between the distances considered in the screening phase, along 9 radials spaced at 2-degree increments, centered on the radial along which the maximum concentration was produced. For example, if the maximum concentration was produced along the 90-degree radial at a distance of 1.0 km, the refined receptor grid would consist of receptors at the following locations:

Directions (degrees)	Distance (km)
82, 84, 86, 88, 90, 92, 94, 96, 98	0.8, 0.9, 1.0, 1.1, 1.2, 1.3, and 1.4 per direction

To ensure that a valid maximum concentration was calculated, concentrations were predicted using the refined grid for the entire year that produced the highest concentration from the screening receptor grid. If maximum concentrations for other years were within 10 percent of that for the highest year, they also were refined.

Refined modeling analysis was not performed for the annual averaging period because the spatial distribution of annual average concentrations are not expected to vary significantly from those produced from the screening analysis.

The maximum PSD increment consumption at the Chassahowitzka Wilderness Area was determined for the proposed facility alone at 13 discrete receptors located along the boundary of the Class I area. The highest predicted concentrations for the proposed facility for the 5 years of meteorological data were compared with the proposed PSD Class I significance values for SO_2, PM, and NO_2 (see Section 3.2.6).

6.5 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings and structures planned at the plant, the stacks for the proposed CT and CO_2 plant will be less than GEP. Therefore, the potential for building downwash to occur was considered in the modeling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than $H_b + 0.5\ l_b$, where H_b is the building height and l_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. If this method is used, then direction-specific building dimensions are input for H_b and l_b for 36 radial directions, with each direction representing a 10-degree sector. The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than $H_b + 0.5\ l_b$ but less than GEP, the Huber-Snyder (1976) method is used. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. If a specific

width is to be modeled, then the value input to the model must be adjusted according to the following formula:

$$M_w^2 = \frac{\pi W^2}{4}$$

$$M_w = 0.886\ W$$

where: M_w is input to the model to produce a building width of W used in the dispersion calculation. W is the actual building width.

The building dimensions considered in the modeling analysis are presented in Table 6-6. The height of the CT stack and the CO_2 plant stack are greater than $H_b + 0.5\ l_b$ but less than GEP. Therefore, the Huber-Snyder method was used for downwash calculations in the modeling analysis.

6.6 BACKGROUND SO_2 CONCENTRATIONS

Background SO_2 concentrations were taken from 1991 monitoring data collected at Mulberry and were assumed to represent background concentrations near the proposed facility. Background values of 176, 40, and 12 $\mu g/m^3$ were added to the modeling results for the 3-hour, 24-hour, and annual averaging periods, respectively. Refer to Section 5.3 for details.

Table 6-6. Building Dimensions Used in ISCST Modeling Analysis To Address Potential Building Wake Effects

Source	Dominant Building	Actual Building Dimensions (m) Length	Width	Height	Projected Width[a] (m)	Modeled Building Dimensions (m) Length, Width	Height
Proposed Turbine	Steam Generation Building	21.34	10.67	21.34	23.85	21.13	21.34
CO_2 Plant Stack	Steam Generation Building	21.34	10.67	21.34	23.85	21.13	21.34

[a]Diagonal of actual building dimensions.

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED FACILITY ONLY

7.1.1 SIGNIFICANT IMPACT LEVELS

A summary of the maximum concentrations as a result of the proposed facility operating at maximum load conditions and 20°F and 100°F design temperatures are presented in Tables 7-1 and 7-2, respectively. The results are presented for all regulated pollutants to be considered in the modeling analysis. The modeling was performed based on the operating conditions for the two temperatures, because the highest emissions and flow rate occur at the 20°F design condition while the lowest emissions and flow rate occur at the 100°F design condition. This approach will ensure that the maximum impacts from the proposed facility will be obtained either for the maximum emission condition or minimum flow rate (i.e., minimum plume height) condition.

A summary of the refined impacts for the five applicable averaging times, the regulated pollutants, and the two design temperatures are presented in Tables 7-3 and 7-4. Based on these results, a summary of the maximum predicted impacts of regulated pollutants caused by the proposed facility only for comparison to the significant impact and de minimis monitoring levels is presented in Table 7-5.

The maximum predicted 3-hour, 24-hour, and annual SO_2 concentrations due to the proposed facility are 42.5, 15.5, and 0.28 $\mu g/m^3$, respectively. The maximum 3-hour and 24-hour impacts are above the significance and de minimis levels established by EPA and FDER and, therefore, further modeling analysis is required for SO_2 to demonstrate compliance with PSD increments and AAQS.

The maximum predicted 24-hour and annual average PM(TSP) concentrations due to the proposed facility are 2.81 and 0.23 $\mu g/m^3$, respectively. Maximum PM10 impacts are assumed to be identical to the PM(TSP) impacts. Since these maximum concentrations are below the significance and de minimis levels for these pollutants, no further modeling analysis is necessary.

Table 7-1. Maximum Predicted Screening Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 20°F Design Temperature (Page 1 of 2)

Averaging Period	Year	Maximum Pollutant Concentration ($\mu g/m^3$)[a]						
		Sulfur Dioxide	Nitrogen Dioxide	Particulate Matter	Carbon Monoxide	Sulfuric Acid Mist	Beryllium	Inorganic Arsenic
1-hour	1982	41.4	71.3	12.8	32.3	NM	NM	NM
	1983	41.4	71.4	18.1	37.3	NM	NM	NM
	1984	58.8	101.0	11.4	46.0	NM	NM	NM
	1985	39.6	68.3	11.5	31.0	NM	NM	NM
	1986	28.5	49.1	11.5	23.7	NM	NM	NM
3-hour	1982	23.9	41.3	6.65	NM	NM	NM	NM
	1983	18.1	32.3	8.85	NM	NM	NM	NM
	1984	33.1	57.1	7.31	NM	NM	NM	NM
	1985	23.0	39.6	7.24	NM	NM	NM	NM
	1986	12.1	28.4	7.73	NM	NM	NM	NM
8-hour	1982	11.1	19.1	4.22	8.88	0.88	0.0003	0.0005
	1983	13.8	23.8	4.68	10.8	1.11	0.0003	0.0006
	1984	20.5	35.4	4.85	16.1	1.65	0.0005	0.0008
	1985	15.7	27.0	4.47	12.3	1.26	0.0004	0.0006
	1986	6.03	19.4	5.33	11.0	0.48	0.0002	0.0003
24-hour	1982	4.91	8.47	1.90	NM	0.39	0.0001	0.0002
	1983	5.08	8.75	2.08	NM	0.41	0.0001	0.0002
	1984	11.2	19.4	1.76	NM	0.90	0.0003	0.0005
	1985	9.02	15.6	1.86	NM	0.72	0.0002	0.0004
	1986	3.11	6.94	1.88	NM	0.25	0.0001	0.0001

Table 7-1. Maximum Predicted Screening Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 20°F Design Temperature (Page 2 of 2)

Averaging Period	Year	Maximum Pollutant Concentration ($\mu g/m^3$)[a]						
		Sulfur Dioxide	Nitrogen Dioxide	Particulate Matter	Carbon Monoxide	Sulfuric Acid Mist	Beryllium	Inorganic Arsenic
Annual	1982	0.25	0.75	0.18	NM	0.020	0.00001	0.00001
	1983	0.19	0.61	0.15	NM	0.015	0.00000	0.00001
	1984	0.24	0.73	0.18	NM	0.019	0.00001	0.00001
	1985	0.24	0.67	0.17	NM	0.019	0.00001	0.00001
	1986	0.28	0.83	0.22	NM	0.022	0.00001	0.00001

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.

NM = this averaging period not modeled for this pollutant.

[a] Highest concentrations reported for all averaging periods.

Table 7-2. Maximum Predicted Screening Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 100°F Design Temperature (Page 1 of 2)

Averaging Period	Year	Maximum Pollutant Concentration ($\mu g/m^3$)[a]						
		Sulfur Dioxide	Nitrogen Dioxide	Particulate Matter	Carbon Monoxide	Sulfuric Acid Mist	Beryllium	Inorganic Arsenic
1-hour	1982	45.6	78.7	13.2	36.6	NM	NM	NM
	1983	46.0	79.3	18.5	37.0	NM	NM	NM
	1984	63.2	109	11.7	50.7	NM	NM	NM
	1985	42.2	72.7	11.8	33.9	NM	NM	NM
	1986	34.2	59.0	11.8	27.5	NM	NM	NM
3-hour	1982	26.8	46.2	6.82	NM	NM	NM	NM
	1983	19.1	32.9	9.08	NM	NM	NM	NM
	1984	37.5	64.6	7.48	NM	NM	NM	NM
	1985	26.7	46.1	7.42	NM	NM	NM	NM
	1986	12.5	28.4	7.96	NM	NM	NM	NM
8-hour	1982	12.7	21.9	4.37	10.2	1.02	0.0003	0.0005
	1983	14.6	25.2	4.80	11.7	1.17	0.0004	0.0006
	1984	24.7	42.5	5.01	19.8	1.98	0.0006	0.0010
	1985	19.0	32.8	4.60	15.3	1.53	0.0005	0.0008
	1986	6.67	19.1	5.46	10.9	0.54	0.0002	0.0003
24-hour	1982	5.70	9.83	1.98	NM	0.46	0.0001	0.0002
	1983	6.51	11.2	2.14	NM	0.52	0.0002	0.0003
	1984	15.1	26.0	2.74	NM	1.21	0.0004	0.0006
	1985	10.2	17.6	1.92	NM	0.82	0.0003	0.0004
	1986	3.53	6.96	1.94	NM	2.80	0.0001	0.0001

Table 7-2. Maximum Predicted Screening Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 100°F Design Temperature (Page 2 of 2)

Averaging Period	Year	Maximum Pollutant Concentration ($\mu g/m^3$)[a]						
		Sulfur Dioxide	Nitrogen Dioxide	Particulate Matter	Carbon Monoxide	Sulfuric Acid Mist	Beryllium	Inorganic Arsenic
Annual	1982	0.25	0.76	0.19	NM	0.020	0.00001	0.00001
	1983	0.19	0.62	0.16	NM	0.015	0.00000	0.00001
	1984	0.24	0.74	0.19	NM	0.019	0.00001	0.00001
	1985	0.23	0.69	0.18	NM	0.019	0.00001	0.00001
	1986	0.27	0.85	0.23	NM	0.022	0.00001	0.00001

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.

NM = this averaging period not modeled for this pollutant.

[a] Highest concentrations reported for all averaging periods.

Table 7-3. Maximum Predicted Refined Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 20°F Design Temperature (Page 1 of 2)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b]		Time Period		
			Direction (degrees)	Distance (meters)	Julian Day	Hour Ending	Year
Sulfur Dioxide	3-hour	40.5	128	200	59	12	1984
	24-hour	13.6	128	200	59	24	1984
	Annual	0.28	90	1500	--	--	1986
Particulate Matter (TSP)	24-hour	2.21	252	600	251	24	1983
	Annual	0.22	80	700	--	--	1986
Particulate Matter (PM10)	24-hour	2.21	252	600	251	24	1983
	Annual	0.22	80	700	--	--	1986
Nitrogen Dioxide	Annual	0.83	80	700	--	--	1986
Carbon Monoxide	1-hour	57.7	218	200	230	4	1984
	8-hour	21.2	122	200	89	16	1984
Sulfuric Acid Mist	8-hour	2.17	122	200	89	16	1984
	24-hour	1.09	128	200	59	24	1984
	Annual	0.022	90	1500	--	--	1986
Beryllium	8-hour	0.00066	122	200	89	16	1984
	24-hour	0.00033	128	200	59	24	1984
	Annual	0.00001	90	1500	--	--	1986

Table 7-3. Maximum Predicted Refined Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 20°F Design Temperature (Page 2 of 2)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b]		Time Period		
			Direction (degrees)	Distance (meters)	Julian Day	Hour Ending	Year
Inorganic Arsenic	8-hour	0.0011	122	200	89	16	1984
	24-hour	0.00056	128	200	59	24	1984
	Annual	0.00001	90	1500	--	--	1986

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.

[a] Highest concentrations reported for all averaging periods.
[b] Relative to the proposed CT stack.

Table 7-4. Maximum Predicted Refined Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 100°F Design Temperature

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Time Period Julian Day	Time Period Hour Ending	Time Period Year
Sulfur Dioxide	3-hour	42.5	128	200	59	12	1984
	24-hour	15.5	128	139	59	24	1984
	Annual	0.27	90	1500	--	--	1986
Particulate Matter (TSP)	24-hour	2.81	128	139	59	24	1984
	Annual	0.23	80	700	--	--	1986
Particulate Matter (PM10)	24-hour	2.81	128	139	59	24	1984
	Annual	0.23	80	700	--	--	1986
Nitrogen Dioxide	Annual	0.85	80	700	--	--	1986
Carbon Monoxide	1-hour	58.9	218	200	230	4	1984
	8-hour	23.6	122	200	89	16	1984
Sulfuric Acid Mist	8-hour	2.35	122	200	89	16	1984
	24-hour	1.24	128	139	59	24	1984
	Annual	0.022	90	1500	--	--	1986
Beryllium	8-hour	0.00072	122	200	89	16	1984
	24-hour	0.00038	128	139	59	24	1984
	Annual	0.00001	90	1500	--	--	1986
Inorganic Arsenic	8-hour	0.0012	122	200	89	16	1984
	24-hour	0.00063	128	139	59	24	1984
	Annual	0.00001	90	1500	--	--	1986

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.

[a] Highest concentrations reported for all averaging periods.
[b] Relative to the proposed CT stack.

Table 7-5. Summary of Maximum Regulated Pollutant Concentrations Due to the Proposed Project for Comparison to EPA Significance Levels and Florida No Threat Levels (Page 1 of 2)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Significance Impact Level ($\mu g/m^3$)	de minimis Monitoring Level ($\mu g/m^3$)
Sulfur Dioxide	3-hour	42.5	128	200	25	NA
	24-hour	15.5	128	139	5	13
	Annual	0.28	90	1500	1	NA
Particulate Matter (TSP)	24-hour	2.81	128	139	5	10
	Annual	0.23	80	700	1	NA
Particulate Matter (PM10)	24-hour	2.81	128	139	5	10
	Annual	0.23	80	700	1	NA
Nitrogen Dioxide	Annual	0.85	80	700	1	14
Carbon Monoxide	1-hour	58.9	218	200	2000	NA
	8-hour	23.6	122	200	500	575
Sulfuric Acid Mist	8-hour	2.35	122	200	NA	NM
	24-hour	1.24	128	139	NA	NM
	Annual	0.022	90	1500	NA	NM
Beryllium	8-hour	0.00072	122	200	NA	NA
	24-hour	0.00038	128	139	NA	0.001
	Annual	0.00001	90	1500	NA	NA

Table 7-5. Summary of Maximum Regulated Pollutant Concentrations Due to the Proposed Project for Comparison to EPA Significance Levels and Florida No Threat Levels (Page 2 of 2)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Significance Impact Level ($\mu g/m^3$)	de minimis Monitoring Level ($\mu g/m^3$)
Inorganic Arsenic	8-hour	0.0012	122	200	NA	NM
	24-hour	0.00063	128	139	NA	NM
	Annual	0.00001	90	1500	NA	NM

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content. Concentrations reported are the highest of the 20°F or 100°F design case and represent refined values.

NA = not applicable.
NM = no ambient measurement method.

[a] Highest concentrations reported for all averaging periods.
[b] Relative to the proposed CT stack.

The maximum predicted annual NO_2 concentration due to the proposed facility is 0.85 $\mu g/m^3$. Because this level of impact is below the significance and de minimis levels, no further modeling analysis was performed.

The maximum predicted 1- and 8-hour average CO concentrations due to the proposed facility are 58.9 and 23.6 $\mu g/m^3$, respectively. These maximum impacts are less than the CO significance impact levels. Because the maximum predicted impacts due to the proposed facility are less than the CO significance and de minimis levels, additional modeling is not required for this pollutant.

The maximum 24-hour Be concentration due to the proposed facility is predicted to be 0.00038 $\mu g/m^3$. No significance level has been established for Be, but a de minimis monitoring concentration has been set at 0.001 $\mu g/m^3$, 24-hour average. Since the predicted impacts due to the proposed facility only are well below the de minimis, no further PSD modeling analysis was conducted. Beryllium was addressed as a toxic air pollutant for comparison to the Florida NTLs (refer to Section 7.1.3).

No significance levels have been established for sulfuric acid mist or As. There is also no ambient measurement method established for these pollutants and, thus, no de minimis monitoring concentration. Therefore, no further PSD modeling analysis was conducted. These pollutants were addressed as toxic air pollutants for comparison to the Florida NTLs (refer to Section 7.1.3).

7.1.2 PSD CLASS I SIGNIFICANCE ANALYSIS

Maximum SO_2, NO_2, and PM concentrations predicted at the PSD Class I area of the Chassahowitzka National Wildlife Area for comparison to EPA's recommended PSD Class I significance levels are presented in Tables 7-6 and 7-7. Separate analyses were performed to predict impacts for the proposed CT at the 20°F design temperature and 100°F design temperature. Based upon

Table 7-6. Maximum Predicted Pollutant Concentrations Due to the Proposed Project at 20°F Design Temperature at the Chassahowitzka NWA for Comparison to PSD Class I Significance Values

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Time Period Julian Day	Time Period Hour Ending	Time Period Year	EPA's Recommended Class I Significance Value ($\mu g/m^3$)
Sulfur Dioxide	3-hour	1.17	340700	3171900	176	24	1982	1.23
		0.94	342000	3174000	336	24	1983	
		0.65	340300	3165700	194	3	1984	
		0.67	340300	3167700	64	3	1985	
		0.71	340300	3169800	345	3	1986	
	24-hour	0.16	340700	3171900	210	24	1982	0.275
		0.13	342000	3174000	336	24	1983	
		0.15	341100	3183400	110	24	1984	
		0.12	343700	3178300	335	24	1985	
		0.16	343000	3176200	344	24	1986	
	Annual	0.0106	340700	3171900	NA	NA	1982	0.1
		0.0079	342000	3174000	NA	NA	1983	
		0.0060	340300	3165700	NA	NA	1984	
		0.0070	340700	3171900	NA	NA	1985	
		0.0086	340300	3165700	NA	NA	1986	

Table 7-6. Maximum Predicted Pollutant Concentrations Due to the Proposed Project at 20°F Design Temperature at the Chassahowitzka NWA for Comparison to PSD Class I Significance Values

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Time Period Julian Day	Time Period Hour Ending	Time Period Year	EPA's Recommended Class I Significance Value ($\mu g/m^3$)
Particulate Matter (TSP)	24-hour	0.041	340700	3171900	210	24	1982	1.35
		0.030	342000	3174000	336	24	1983	
		0.032	341100	3183400	110	24	1984	
		0.024	343700	3178300	335	24	1985	
		0.035	343000	3176200	344	24	1986	
	Annual	0.0023	340700	3171900	NA	NA	1982	0.27
		0.0017	342000	3174000	NA	NA	1983	
		0.0013	340300	3165700	NA	NA	1984	
		0.0015	340700	3171900	NA	NA	1985	
		0.0019	340300	3165700	NA	NA	1986	
Nitrogen Dioxide	Annual	0.020	340700	3171900	NA	NA	1982	0.1
		0.015	342000	3174000	NA	NA	1983	
		0.011	340300	3165700	NA	NA	1984	
		0.013	340700	3171900	NA	NA	1985	
		0.016	340300	3165700	NA	NA	1986	

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.
NA = not applicable.

[a] Highest concentrations reported for all averaging periods.
[b] In UTM coordinates. Proposed facility location is 413.6 km east and 3080.6 km north.

Table 7-7. Maximum Predicted Pollutant Concentrations Due to the Proposed Project at 100°F Design Temperature at the Chassahowitzka NWA for Comparison to PSD Class I Significance Values

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Time Period Julian Day	Time Period Hour Ending	Time Period Year	EPA's Recommended Class I Significance Value ($\mu g/m^3$)
Sulfur Dioxide	3-hour	0.99	340700	3171900	176	24	1982	1.23
		0.79	342000	3174000	336	24	1983	
		0.55	340300	3165700	194	3	1984	
		0.57	340300	3167700	64	3	1985	
		0.59	340300	3169800	345	3	1986	
	24-hour	0.13	340700	3171900	210	24	1982	0.275
		0.11	342000	3174000	336	24	1983	
		0.12	341100	3183400	110	24	1984	
		0.09	343700	3178300	335	24	1985	
		0.13	343000	3176200	344	24	1986	
	Annual	0.0086	340700	3171900	NA	NA	1982	0.1
		0.0065	342000	3174000	NA	NA	1983	
		0.0049	340300	3165700	NA	NA	1984	
		0.0057	340700	3171900	NA	NA	1985	
		0.0071	340300	3165700	NA	NA	1986	

Table 7-7. Maximum Predicted Pollutant Concentrations Due to the Proposed Project at 100°F Design Temperature at the Chassahowitzka NWA for Comparison to PSD Class I Significance Values

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Time Period Julian Day	Time Period Hour Ending	Time Period Year	EPA's Recommended Class I Significance Value ($\mu g/m^3$)
Particulate Matter (TSP)	24-hour	0.043	340700	3171900	210	24	1982	1.35
		0.031	342000	3174000	336	24	1983	
		0.034	341100	3183400	110	24	1984	
		0.024	343700	3178300	335	24	1985	
		0.036	343000	3176200	344	24	1986	
	Annual	0.0023	340700	3171900	NA	NA	1982	0.27
		0.0018	342000	3174000	NA	NA	1983	
		0.0013	340300	3165700	NA	NA	1984	
		0.0015	340700	3171900	NA	NA	1985	
		0.0020	340300	3165700	NA	NA	1986	
Nitrogen Dioxide	Annual	0.017	340700	3171900	NA	NA	1982	0.1
		0.013	342000	3174000	NA	NA	1983	
		0.010	340300	3165700	NA	NA	1984	
		0.011	340700	3171900	NA	NA	1985	
		0.014	340300	3165700	NA	NA	1986	

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.
NA = not applicable.

[a] Highest concentrations reported for all averaging periods.
[b] In UTM coordinates. Proposed facility location is 413.6 km east and 3080.6 km north.

these results, the 20°F case produces the worst case impacts in the Class I area. Therefore, these results will be used for comparison to the Class I significance levels.

The maximum predicted SO_2 3-hour, 24-hour and annual concentrations in the Class I area are 1.17, 0.16, and 0.011 $\mu g/m^3$, respectively. These predicted impacts are below EPA's recommended Class I significance levels of 1.22, 0.275, and 0.10 $\mu g/m^3$ for the 3-hour, 24-hour, and annual significance levels, respectively.

The maximum predicted PM 24-hour and annual concentrations in the Class I area are 0.041 and 0.0023 $\mu g/m^3$, respectively. These predicted impacts are below the Class I 24-hour and annual significance levels of 1.35 and 0.27 $\mu g/m^3$, respectively.

The maximum predicted NO_2 annual concentration in the Class I area is 0.020 $\mu g/m^3$. This predicted impact is below the Class I annual significance level of 0.10 $\mu g/m^3$.

As the results indicate, the proposed facility's impacts are below EPA's recommended Class I significance values for all averaging periods and modeled pollutants. Therefore, no further Class I modeling analysis was conducted.

7.1.3. TOXIC POLLUTANT ANALYSIS

The maximum impacts of regulated and nonregulated hazardous pollutants that will be emitted in significant amounts by the proposed facility are presented in Table 7-8. These impacts represent the highest impacts of either the 20- or 100-degree design case. The detailed impacts for each pollutant and design case are presented in Appendix E, Table E-1. Pollutants presented were either modeled at their actual emission rates or their impacts derived using a ratio based on the stack emissions from the CT and CO_2 plant. All regulated pollutants or pollutants which had a CT to CO_2 plant emission ratio different from most other pollutants were modeled using their actual emission rates. These pollutants include Be, As,

Table 7-8. Summary of Maximum Concentrations Due to the Proposed Mulberry Cogeneration Facility for the Air Toxic Modeling Analysis (Page 1 of 3)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Florida No Threat Level ($\mu g/m^3$)
Antimony	8-hour	0.0063	5
	24-hour	0.0033	1.2
	Annual	0.000059	0.3
Arsenic	8-hour	0.0012	2
	24-hour	0.00064	0.48
	Annual	0.000011	0.00023
Barium	8-hour	0.0056	5
	24-hour	0.0030	1.2
	Annual	0.000052	50
Beryllium	8-hour	0.00072	0.02
	24-hour	0.00038	0.0048
	Annual	0.000007	0.00042
Cadmium	8-hour	0.0030	0.5
	24-hour	0.0016	0.12
	Annual	0.000028	0.00056
Chlorine	8-hour	0.0078	15
	24-hour	0.0041	3.6
	Annual	0.000072	NE
Chromium	8-hour	0.014	5
	24-hour	0.0072	1.2
	Annual	0.00013	1000
Colbalt	8-hour	0.0026	0.5
	24-hour	0.0014	0.12
	Annual	0.000024	NE
Copper	8-hour	0.081	1
	24-hour	0.043	0.24
	Annual	0.00075	NE
Ethanolamine	8-hour	31.2	80
	24-hour	12.4	19.2
	Annual	1.19	NE

Table 7-8. Summary of Maximum Concentrations Due to the Proposed Mulberry Cogeneration Facility for the Air Toxic Modeling Analysis (Page 2 of 3)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Florida No Threat Level ($\mu g/m^3$)
Fluoride	8-hour	0.0094	2
	24-hour	0.0049	0.48
	Annual	0.000087	50
Formaldehyde	8-hour	0.12	4.5
	24-hour	0.062	1.08
	Annual	0.0011	0.077
Lead	8-hour	0.0026	1.5
	24-hour	0.0014	0.36
	Annual	0.000024	0.09
Manganese	8-hour	0.0019	50
	24-hour	0.0010	12
	Annual	0.000017	NE
Mercury	8-hour	0.00086	0.5
	24-hour	0.00046	0.12
	Annual	0.000008	0.3
Nickel	8-hour	0.049	0.5
	24-hour	0.026	0.12
	Annual	0.00046	0.0042
Polyorganic Matter	8-hour	0.000080	NE
	24-hour	0.000042	NE
	Annual	0.000002	NE
Selenium	8-hour	0.0068	2
	24-hour	0.0036	0.48
	Annual	0.000063	NE
Sulfuric Acid Mist[c]	8-hour	2.35	10
	24-hour	1.24	2.38
	Annual	0.022	NE
Vanadium	8-hour	0.020	0.5
	24-hour	0.011	0.12
	Annual	0.00019	20

Table 7-8. Summary of Maximum Concentrations Due to the Proposed Mulberry Cogeneration Facility for the Air Toxic Modeling Analysis (Page 3 of 3)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Florida No Threat Level ($\mu g/m^3$)
Zinc[b]	8-hour	0.20	50
	24-hour	0.10	12
	Annual	0.002	NE

Note: NE = none established.

[a] Concentration reported is the highest of the impacts predicted for the 20- and 100-degree design case. Refer to Table E-1 in Appendix E for detailed impacts.

[b] As zinc oxide.

[c] Not in current FDER NTL list. NTL in table is based on dividing the time-weighted average by 100 and 420 for the 8-hour and 24-hour NTL, respectively.

sulfuric acid mist, and ethanolamine. Impacts for all other hazardous pollutants were derived by using a ratio method with impacts produced for Be, since the ratio of CT to CO_2 plant emissions for most other hazardous pollutants were the same as that for Be.

The maximum 8-hour, 24-hour, and annual concentrations are compared in Table 7-8 to the Florida NTLs. As shown, the predicted impacts are below the NTLs for all pollutants and averaging times. Therefore, the emissions from the proposed facility are not expected to pose a health risk to the public.

7.2 PSD CLASS II INCREMENT ANALYSIS

Maximum SO_2 concentrations predicted from the screening analysis for comparison to the PSD Class II increments are presented in Table 7-9. Based upon these results, the refined analysis was based on modeling the year during which the overall highest, second-highest 3-hour and 24-hour SO_2 concentrations were predicted in the screening analysis. In addition, any other year that produced an overall highest, second-highest concentration that was within ten percent of this maximum concentration also was refined. As stated earlier, a refined analysis for annual average concentrations was not performed. A summary of the maximum SO_2 PSD Class II increment consumption concentrations predicted in the refined analysis is presented in Table 7-10.

The maximum 3-hour average SO_2 PSD increment consumption from the refined analysis is predicted to be 139 $\mu g/m^3$, which is 27 percent of the maximum allowable PSD Class II increment of 512 $\mu g/m^3$, not to be exceeded more than once per year. The proposed project contributed 0.0 $\mu g/m^3$ to this value. The maximum 24-hour average SO_2 PSD Class II increment consumption is predicted to be 38.8 $\mu g/m^3$, which is 43 percent of the maximum allowable PSD Class II increment of 91 $\mu g/m^3$, not to be exceeded more than once per year. The proposed project contributed 0.0 $\mu g/m^3$ to this total.

The maximum annual average SO_2 PSD increment consumption is predicted to be -0.42 $\mu g/m^3$, which is well below the maximum allowable PSD Class II

Table 7-9. Maximum Predicted SO_2 Concentrations from the Screening Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (°)	Receptor Location[a] Distance (km)	Period Julian Day	Period Hour Ending	Period Year
3-Hour[b]	117	270	4.0	239	15	1982
	112	250	5.0	126	15	1983
	117	250	3.0	154	15	1984
	119	250	3.0	118	15	1985
	122	250	3.0	62	15	1986
24-Hour[b]	22.3	270	4.0	157	24	1982
	24.1	220	3.0	45	24	1983
	28.1	240	2.0	177	24	1984
	28.8	250	3.0	179	24	1985
	32.5	250	3.0	98	24	1986
Annual	-0.43	90	5.0	–	–	1982
	-0.84	60	5.0	–	–	1983
	-0.42	210	5.0	–	–	1984
	-1.00	170	5.0	–	–	1985
	-0.53	220	5.0	–	–	1986

Note: Based on the CT operating at maximum load and 100°F design temperature and firing fuel oil with 0.1 percent sulfur content.

– = Not applicable.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed CT unit.
[b] Highest, second-highest concentrations predicted for this averaging period.

Table 7-10. Maximum Predicted SO_2 Concentrations from the Refined Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (°)	Receptor Location[a] Distance (km)	Period Julian Day	Period Hour Ending	Period Year	PSD Class II Increment
SO_2 Concentrations							
3-Hour[b]	139	250	3.2	157	18	1986	512
24-Hour[b]	38.8	252	3.3	278	24	1986	91
Annual	-0.42	210	5.0	–	–	1984	20

Note: Based on the CT operating at maximum load and 100°F design temperature and firing fuel oil with 0.1 percent sulfur content.

– = Not applicable.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed CT unit.
[b] Highest, second-highest concentrations predicted for this averaging period.

increment of 20 $\mu g/m^3$. The proposed project contributed 0.08 $\mu g/m^3$ to this value.

7.3 AAQS ANALYSIS

The maximum 3-hour, 24-hour, and annual average total SO_2 concentrations predicted from the screening analysis are presented in Table 7-11. The total concentrations were determined from the impacts of the modeled sources added to the background concentration (refer to Section 5.0). These results show that the maximum SO_2 concentrations due to all sources are below the AAQS for the 3-hour, 24-hour, and annual averaging periods.

Similar to the PSD Class II increment analysis, the refined AAQS analysis was based on modeling the year during which the overall HSH 3-hour and 24-hour concentrations were predicted in the screening analysis and any other years that produced a highest, second-highest concentration within ten percent of this maximum. The maximum SO_2 concentrations predicted in the refined analysis are presented in Table 7-12.

The maximum 3-hour average SO_2 concentration due to all sources from the refined analysis is predicted to be 837 $\mu g/m^3$, which is 64 percent of the AAQS of 1,300 $\mu g/m^3$, not to be exceeded more than once per year. The project contributed 0.0 $\mu g/m^3$ to this maximum 3-hour average concentration.

The maximum 24-hour average SO_2 concentration due to all sources is predicted to be 234 $\mu g/m^3$, which is 90 percent of the 24-hour AAQS of 260 $\mu g/m^3$, not to be exceeded more than once per year. The project contributed 0.0 $\mu g/m^3$ to this maximum 24-hour average concentration.

The maximum annual average SO_2 concentration due to all sources is predicted to be 42.0 $\mu g/m^3$, which is 70 percent of the AAQS of 60 $\mu g/m^3$. The project contributed 0.15 $\mu g/m^3$ to the maximum concentration.

Table 7-11. Maximum Predicted Total SO_2 Concentrations from the Screening Analysis for Comparison to AAQS

Averaging Period	Concentration (µg/m³) Total	Total Due To: Modeled Sources	Total Due To: Background	Receptor Location[a]: Direction (°)	Receptor Location[a]: Distance (km)	Period: Julian Day	Period: Hour Ending	Period: Year
3-Hour[b]	717	541	176	330	5.0	255	18	1982
	837	661	176	330	5.0	38	18	1983
	731	555	176	330	5.0	222	21	1984
	757	581	176	340	5.0	4	15	1985
	741	565	176	110	5.0	303	9	1986
24-Hour[b]	192	152	40	340	5.0	234	24	1982
	214	174	40	330	5.0	38	24	1983
	218	178	40	100	5.0	124	24	1984
	234	194	40	340	5.0	43	24	1985
	204	164	40	100	5.0	10	24	1986
Annual	41.8	29.8	12	260	5.0	–	–	1982
	40.1	28.1	12	260	5.0	–	–	1983
	42.0	30.0	12	260	5.0	–	–	1984
	40.7	28.7	12	260	3.0	–	–	1985
	41.8	29.8	12	260	3.0	–	–	1986

Note: Based on the CT operating at maximum load and 100°F design temperature and firing fuel oil with 0.1 percent sulfur content.

– = Not applicable.
µg/m³ = micrograms per cubic meter.

[a] Relative to the location of the proposed CT unit.
[b] Highest, second-highest concentrations predicted for this averaging period.

Table 7-12. Maximum Predicted SO_2 Concentrations from the Refined Analysis for Comparison to AAQS

Averaging Period	Concentration ($\mu g/m^3$) Total	Total due to Modeled Sources	Total due to Background	Receptor Location[a] Direction (°)	Receptor Location[a] Distance (km)	Period Julian Day	Period Hour Ending	Period Year	AAQS
SO_2 Concentrations									
3-Hour[b]	837	661	176	330	5.0	38	18	1983	1,300
24-Hour[b]	234	194	40	340	5.0	43	24	1985	260
Annual	42.0	30.0	12	260	5.0	–	–	1984	60

Note: Based on the CT operating at maximum load and 100°F design temperature and firing fuel oil with 0.1 percent sulfur content.

– = Not applicable.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed CT unit.
[b] Highest, second-highest concentrations predicted for this averaging period.

7.4 ADDITIONAL IMPACT ANALYSIS

7.4.1 IMPACTS UPON VEGETATION

The response of vegetation to atmospheric pollutants is influenced by the concentration of the pollutant, duration of the exposure and the frequency of exposures. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term higher doses. A dose is the product of the concentration of the pollutant and the duration of the exposure. The impact of the proposed facility on regional vegetation was assessed by comparing pollutant doses that are predicted from modeling with threshold doses reported from the scientific literature which could adversely affect plant species typical of those present in the region.

7.4.1.1 Sulfur Dioxide

The maximum total 3-hour average SO_2 concentration (i.e., impacts due to all modeled sources added to a background concentration) is predicted to be 837 $\mu g/m^3$ (see Table 7-12). This concentration is predicted to occur about 5.0 km to the northwest of the facility and represents the concentration that would occur during the worst-case meteorological conditions of the modeled five years. The maximum 3-hour average ground-level concentration predicted for the other 4 years are 90 percent or less of the maximum concentration. Concentrations decrease with distance beyond the location of the maximum concentration.

The maximum total predicted 24-hour average SO_2 concentration is 234 $\mu g/m^3$ (see Table 7-12) and is located approximately 5.0 km to the northwest of the facility. The maximum total predicated annual SO_2 concentration is 42.0 $\mu g/m^3$ (see Table 7-12). This concentration is predicted to occur 5.0 km to the west of the facility.

These concentrations and averaging times can be compared with SO_2 doses known to adversely affect plant species (see Table 7-13). The expected doses from the proposed project combined with background sources are much lower than doses known to cause a detrimental effect on vegetation.

7.4.1.2 Other Pollutants

Predicted impacts of other regulated pollutants are less than the significant impact levels (see Table 7-5). As a result, no impacts are expected to occur to vegetation as a result of the proposed emissions of other regulated pollutants.

7.4.2 IMPACTS TO SOILS

SO_2 that reaches the soil by deposition from the air is converted by physical and biotic processes to sulfates. (Particulates have no affect on soils at the levels predicted.) The effects can be beneficial to plants if sulfates in native soils are less than plant requirements for optimum growth. However, sulfates can also increase acidity of unbuffered soils, causing adverse effects due to changes in nutrient availability and cycling. The predicted concentrations of SO_2 from stack emissions are not expected to have a significant adverse effect on soils in the vicinity because:

1. The predicted concentrations are low; and
2. Fertilizer and ground limestone is generally applied to lands being used for crops, pasture, and citrus.

Therefore, the facility is not expected to have a significant adverse impact on regional vegetation or soils.

7.4.3 IMPACTS DUE TO ADDITIONAL GROWTH

A limited number of additional personnel may be added to the current plant personnel complement. These additional personnel are expected to have an insignificant effect on the residential, commercial, and industrial growth in Polk County.

Table 7-13. Sulfur Dioxide Doses Reported to Affect Plant Species Similar to Vegetation in the Region of the Mulberry Cogeneration Facility

Species	Dose and Effect	Reference
Strawberry	1,040 $\mu g/m^3$ for 6 hours per day for 3 days had no affect on growth	Rajput et al., 1977
Citrus	2,080 $\mu g/m^3$ for 23 days with 10 day interruption reduced leaf area	Matsushima and Brewer, 1972
Ryegrass	42 $\mu g/m^3$ for 26 weeks or 367 $\mu g/m^3$ for 131 days reduced dry weight	Bell et al., 1979; Ayazaloo and Bell, 1981
Tomato	1,258 $\mu g/m^3$ for 5 hours per day, for 57 days, reduced growth	Kohut et al., 1983
Duckweed	390 $\mu g/m^3$ for 6 weeks reduced growth	Fankhauser et al., 1976
Lichens (Parmotrema and Ramalina spp.)	400 $\mu g/m^3$ 6 hours per week for 10 weeks reduced CO_2 uptake and biomass gain of Ramalina, not Parmotrema	Hart et al., 1988
Bald Cypress	1,300 and 2,600 $\mu g/m^3$ for 48 hours. Only 2,600 $\mu g/m^3$ reduced leaf area.	Shanklin and Kozlowski, 1985
Green Ash	210 $\mu g/m^3$ for 4 hours per day, 5 days per week for 6 weeks reduced growth	Chappelka et al., 1988

7.4.4 IMPACTS TO VISIBILITY

The Mulberry Cogeneration Facility is located approximately 120 km from the Chassahowitzka Wilderness Area, a PSD Class I area. Impacts to visibility were estimated using the VISCREEN computer model. Impacts were calculated for particulates and nitrogen oxides (as nitrogen dioxide). Worst-case emissions at the 20-degree design temperature were used in order to maximize impacts at the Class I area. The results of the screening analysis are presented in Table 7-14. Based on these results the proposed facility is not expected to significantly impair visibility in the Chassahowitzka Wilderness Area.

Table 7-14. Visibility Analysis for the Mulberry Cogeneration Facility on the PSD Class I Area

Visual Effects Screening Analysis for
Source: MULBERRY COGENERATION FACILITY
Class I Area: CHASSAHOWITZKA NWA

*** Level-1 Screening ***

Input Emissions for

Particulates	91.94	TON/YR
NOx (as NO2)	867.41	TON/YR
Primary NO2	.00	TON/YR
Soot	.00	TON/YR
Primary SO4	.00	TON/YR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	120.00 km
Min. Source-Class I Distance:	120.00 km
Max. Source-Class I Distance:	152.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	120.0	84.	2.00	.013	.05	.000
SKY	140.	84.	120.0	84.	2.00	.004	.05	-.000
TERRAIN	10.	84.	120.0	84.	2.00	.001	.05	.000
TERRAIN	140.	84.	120.0	84.	2.00	.000	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	75.	116.2	94.	2.00	.014	.05	.000
SKY	140.	75.	116.2	94.	2.00	.004	.05	-.000
TERRAIN	10.	60.	109.7	109.	2.00	.001	.05	.000
TERRAIN	140.	60.	109.7	109.	2.00	.000	.05	.000

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APPENDIX A

- DESIGN INFORMATION, STACK PARAMETERS, AND EMISSIONS
- STACK, OPERATING, AND EMISSION DATA USED IN THE AIR QUALITY MONITORING
- EXAMPLE CALCULATIONS
- EMISSION FACTORS

Design Information, Stack Parameters, and Emissions

Table A-1. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Data	Gas Turbine Fuel Oil 20of	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
General:					
Power (kW)	95,860.0	90,080.0	84,470.0	77,930.0	71,250.0
Heat Rate (Btu/kwh)	10,760.0	10,870.0	10,990.0	11,150.0	11,350.0
Heat Input (mmBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
Fuel Oil (lb/hr)	55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
Fuel:					
Heat Content,LHV (Btu/lb)	18,550	18,550	18,550	18,550	18,550
CT Exhaust:					
Volume Flow (acfm)	1,600,590	1,518,533	1,468,004	1,410,850	1,352,891
Volume Flow (scfm)	585,257	560,297	536,777	510,575	484,289
Mass Flow (lb/hr)	2,605,000	2,492,000	2,384,000	2,261,000	2,134,000
Temperature (oF)	984	971	984	999	1,015
Moisture (% Vol.)	7.53	7.70	8.03	8.72	9.93
Oxygen (% Vol.)	13.22	13.23	13.23	13.18	13.04
Molecular Weight	28.59	28.57	28.53	28.44	28.30
Water Injected (lb/hr)	43,420	40,820	37,300	31,540	23,540
HRSG Stack:					
Volume Flow (acfm)	753,740	721,595	691,304	657,559	623,705
Temperature (oF)	220	220	220	220	220
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	71.1	68.1	65.2	62.0	58.8
Stack Height (ft)	125	125	125	125	125

Source: General Electric, 1991.

Table A-2. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant	Gas Turbine Fuel Oil 20oF	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/hr (manufacturer)	15.0	15.0	15.0	15.0	15.0
lb/hr	15.0	15.0	15.0	15.0	15.0
TPY	65.7	65.7	65.7	65.7	65.7
Sulfur Dioxide:					
Basis, % sulfur	0.1	0.1	0.1	0.1	0.1
lb/hr	105.65	100.29	95.08	89.00	82.83
TPY	462.7	439.3	416.5	389.8	362.8
Nitrogen Oxides:					
Basis, ppm*	42.0	42.0	42.0	42.0	42.0
lb/hr	182.2	173.1	164.0	153.5	142.8
TPY	798.0	758.3	718.2	672.4	625.6
Carbon Monoxide:					
Basis, ppm+	35.0	35.0	35.0	35.0	35.0
lb/hr	82.6	78.9	75.3	71.1	66.6
TPY	361.7	345.6	329.9	311.5	291.5
VOC's:					
Basis, ppm+	10.0	10.0	10.0	10.0	10.0
lb/hr	10.11	9.66	9.22	8.71	8.15
TPY	44.3	42.3	40.4	38.1	35.7
Lead:					
Basis, lb/10E+12 Btu	8.9	8.9	8.9	8.9	8.9
lb/hr	9.18E-03	8.71E-03	8.26E-03	7.73E-03	7.20E-03
TPY	0.040	0.038	0.036	0.034	0.032

* corrected to 15% 02 dry conditions
+ corrected to dry conditions

Table A-3. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2	4.2	4.2	4.2	4.2
	lb/hr	4.33E-03	4.11E-03	3.90E-03	3.65E-03	3.40E-03
	TPY	1.90E-02	1.80E-02	1.71E-02	1.60E-02	1.49E-02
Beryllium	lb/10E+12 Btu (1)	2.5	2.5	2.5	2.5	2.5
	lb/hr	2.58E-03	2.45E-03	2.32E-03	2.17E-03	2.02E-03
	TPY	1.13E-02	1.07E-02	1.02E-02	9.51E-03	8.86E-03
Mercury	lb/10E+12 Btu (1)	3	3	3	3	3
	lb/hr	3.09E-03	2.94E-03	2.78E-03	2.61E-03	2.43E-03
	TPY	1.36E-02	1.29E-02	1.22E-02	1.14E-02	1.06E-02
Fluoride	lb/10E+12 Btu (2)	32.5	32.5	32.5	32.5	32.5
	lb/hr	3.35E-02	3.18E-02	3.02E-02	2.82E-02	2.63E-02
	TPY	1.47E-01	1.39E-01	1.32E-01	1.24E-01	1.15E-01
Sulfuric Acid Mist	% of SO2	5	5	5	5	5
	lb/hr	8.51E+00	8.08E+00	7.66E+00	7.17E+00	6.68E+00
	TPY	3.73E+01	3.54E+01	3.36E+01	3.14E+01	2.92E+01

Sources: (1) EPA, 1990; (2) EPA, 1980

Table A-4. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	6.44	6.44	6.44	6.44	6.44
	lb/hr	6.64E-03	6.31E-03	5.98E-03	5.60E-03	5.21E-03
	TPY	7.97E-04	7.57E-04	7.17E-04	6.72E-04	6.25E-04
Nickel	lb/10E+12 Btu (1)	170	170	170	170	170
	lb/hr	1.75E-01	1.66E-01	1.58E-01	1.48E-01	1.37E-01
	TPY	2.10E-02	2.00E-02	1.89E-02	1.77E-02	1.65E-02
Cadmium	lb/10E+12 Btu (1)	10.5	10.5	10.5	10.5	10.5
	lb/hr	1.08E-02	1.03E-02	9.75E-03	9.12E-03	8.49E-03
	TPY	1.30E-03	1.23E-03	1.17E-03	1.09E-03	1.02E-03
Chromium	lb/10E+12 Btu (1)	47.5	47.5	47.5	47.5	47.5
	lb/hr	4.90E-02	4.65E-02	4.41E-02	4.13E-02	3.84E-02
	TPY	5.88E-03	5.58E-03	5.29E-03	4.95E-03	4.61E-03
Copper	lb/10E+12 Btu (1)	280	280	280	280	280
	lb/hr	2.89E-01	2.74E-01	2.60E-01	2.43E-01	2.26E-01
	TPY	3.47E-02	3.29E-02	3.12E-02	2.92E-02	2.72E-02
Vanadium	pg/J (1)	30	30	30	30	30
	lb/hr	7.19E-02	6.83E-02	6.47E-02	6.06E-02	5.64E-02
	TPY	8.63E-03	8.19E-03	7.77E-03	7.27E-03	6.77E-03
Selenium	pg/J (1)	10.1	10.1	10.1	10.1	10.1
	lb/hr	2.42E-02	2.30E-02	2.18E-02	2.04E-02	1.90E-02
	TPY	2.91E-03	2.76E-03	2.61E-03	2.45E-03	2.28E-03
Polyorganic Matter	pg/J (1)	0.12	0.12	0.12	0.12	0.12
	lb/hr	2.88E-04	2.73E-04	2.59E-04	2.42E-04	2.26E-04
	TPY	3.45E-05	3.28E-05	3.11E-05	2.91E-05	2.71E-05
Formaldehyde	lb/10E+12 Btu (1)	405	405	405	405	405
	lb/hr	4.18E-01	3.97E-01	3.76E-01	3.52E-01	3.28E-01
	TPY	5.01E-02	4.76E-02	4.51E-02	4.22E-02	3.93E-02

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant
Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4	9.4	9.4	9.4	9.4
	lb/hr	2.25E-02	2.14E-02	2.03E-02	1.90E-02	1.77E-02
	TPY	9.87E-02	9.37E-02	8.88E-02	8.31E-02	7.74E-02
Barium	pg/J (1)	8.4	8.4	8.4	8.4	8.4
	lb/hr	2.01E-02	1.91E-02	1.81E-02	1.70E-02	1.58E-02
	TPY	8.82E-02	8.37E-02	7.94E-02	7.43E-02	6.91E-02
Colbalt	pg/J (1)	3.9	3.9	3.9	3.9	3.9
	lb/hr	9.35E-03	8.87E-03	8.41E-03	7.88E-03	7.33E-03
	TPY	4.09E-02	3.89E-02	3.69E-02	3.45E-02	3.21E-02
Zinc	pg/J (1)	294	294	294	294	294
	lb/hr	7.05E-01	6.69E-01	6.34E-01	5.94E-01	5.53E-01
	TPY	3.09E+00	2.93E+00	2.78E+00	2.60E+00	2.42E+00
Chlorine	ppm	0.5	0.5	0.5	0.5	0.5
	lb/hr	2.78E-02	2.64E-02	2.50E-02	2.34E-02	2.18E-02
	TPY	1.22E-01	1.16E-01	1.10E-01	1.03E-01	9.55E-02

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Table A-6. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Data	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A	B	C	D	E	F
General:					
Power (kW)	93,110.0	87,470.0	82,040.0	75,880.0	69,900.0
Heat Rate (Btu/kwh)	10,340.0	10,450.0	10,590.0	10,790.0	11,050.0
Heat Input (mmBtu/hr)	962.8	914.1	868.8	818.7	772.4
Natural Gas (lb/hr)	49,876.1	47,353.3	45,008.7	42,415.4	40,014.2
(cf/hr)	1,013,429	962,170	914,530	861,837	813,047
Fuel:					
Heat Content, LHV (Btu/lb)	19,303	19,303	19,303	19,303	19,303
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	1,546,476	1,495,987	1,446,407	1,393,785	1,341,523
Volume Flow (scfm)	574,219	550,057	527,419	503,020	479,569
Mass Flow (lb/hr)	2,558,000	2,448,000	2,343,000	2,226,000	2,108,000
Temperature (oF)	962	976	988	1,003	1,017
Moisture (% Vol.)	6.10	6.32	6.77	7.75	9.46
Oxygen (% Vol.)	14.03	14.04	14.00	13.85	13.55
Molecular Weight	28.61	28.58	28.53	28.42	28.23
Water Injected (lb/hr)	0	0	0	0	0
HRSG Stack:					
Volume Flow (acfm)	739,524	708,406	679,252	647,829	617,627
Temperature (oF)	220	220	220	220	220
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	69.7	66.8	64.1	61.1	58.3
Stack Height (ft)	125	125	125	125	125

Source: General Electric, 1991.

Table A-7. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Pollutant	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/hr (manufacturer)	7.00	7.00	7.00	7.00	7.00
lb/hr	7.00	7.00	7.00	7.00	7.00
TPY	30.66	30.66	30.66	30.66	30.66
Sulfur Dioxide:					
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	2.90	2.75	2.61	2.46	2.32
TPY	12.68	12.04	11.44	10.79	10.17
Nitrogen Oxides:					
Basis, ppm*	25.0	25.0	25.0	25.0	25.0
lb/hr	97.5	92.5	87.8	82.9	78.2
TPY	427.05	404.98	384.53	363.07	342.49
Carbon Monoxide:					
Basis, ppm+	20.0	20.0	20.0	20.0	20.0
lb/hr	47.0	44.9	42.9	40.5	37.9
TPY	205.91	196.78	187.78	177.21	165.81
VOC's:					
Basis, ppm+	7.0	7.0	7.0	7.0	7.0
lb/hr	7.05	6.74	6.43	6.07	5.68
TPY	30.9	29.5	28.2	26.6	24.9
Lead:					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% 02 dry conditions
+ corrected to dry conditions

Table A-8. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid Mist	% of SO2	5	5	5	5	5
	lb/hr	2.33E-01	2.22E-01	2.11E-01	1.98E-01	1.87E-01
	TPY	1.02E+00	9.70E-01	9.22E-01	8.69E-01	8.20E-01

Sources: EPA, 1988; EPA, 1980

Table A-9. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polyorganic Matter	pg/J (1)	0.48	0.48	0.48	0.48	0.48
	lb/hr	1.07E-03	1.02E-03	9.69E-04	9.13E-04	8.62E-04
	TPY	4.70E-03	4.47E-03	4.24E-03	4.00E-03	3.77E-03
Formaldehyde	pg/J (1)	38	38	38	38	38
	lb/hr	8.50E-02	8.07E-02	7.67E-02	7.23E-02	6.82E-02
	TPY	3.72E-01	3.54E-01	3.36E-01	3.17E-01	2.99E-01

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

Table A-10. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), MNQC, Propane, Base Load

Data	Gas Turbine Propane 20oF	Gas Turbine Propane 40oF	Gas Turbine Propane 59oF	Gas Turbine Propane 80oF	Gas Turbine Propane 100oF
A	B	C	D	E	F
General:					
Power (kW)	97,670.0	91,900.0	86,320.0	79,810.0	73,120.0
Heat Rate (Btu/kwh)	10,740.0	10,850.0	10,980.0	11,140.0	11,340.0
Heat Input (mmBtu/hr)	1,049.0	997.1	947.8	889.1	829.2
Fuel Propane (lb/hr)	52,685.9	50,081.1	47,603.9	44,655.1	41,646.4
(cf/hr)	1,104,185	1,049,595	997,677	935,877	872,822
Fuel:					
Heat Content, LHV (Btu/lb)	19,910	19,910	19,910	19,910	19,910
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	1,583,507	1,530,580	1,480,793	1,422,861	1,365,207
Volume Flow (scfm)	590,460	565,533	542,204	515,628	489,361
Mass Flow (lb/hr)	2,612,000	2,499,000	2,392,000	2,268,000	2,142,000
Temperature (oF)	956	969	982	997	1,013
Moisture (% Vol.)	8.63	8.86	9.24	9.97	11.20
Oxygen (% Vol.)	13.19	13.18	13.16	13.08	12.93
Molecular Weight	28.41	28.38	28.34	28.25	28.11
Water Injected (lb/hr)	53,320	51,160	48,060	42,440	34,450
HRSG Stack:					
Volume Flow (acfm)	760,441	728,338	698,293	664,067	630,238
Temperature (oF)	220	220	220	220	220
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	71.7	68.7	65.9	62.6	59.4
Stack Height (ft)	125	125	125	125	125

Source: General Electric, 1991.

Table A-11. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), MNQC, Propane, Base Load

Pollutant	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/hr (manufacturer)	6.00	6.00	6.00	6.00	6.00
lb/hr	6.00	6.00	6.00	6.00	6.00
TPY	26.28	26.28	26.28	26.28	26.28
Sulfur Dioxide:					
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	3.15	3.00	2.85	2.67	2.49
TPY	13.82	13.13	12.49	11.71	10.92
Nitrogen Oxides:					
Basis, ppm*	42.0	42.0	42.0	42.0	42.0
lb/hr	177.8	169.2	160.6	150.8	140.4
TPY	778.76	741.08	703.32	660.49	615.14
Carbon Monoxide:					
Basis, ppm+	10.0	10.0	10.0	10.0	10.0
lb/hr	23.5	22.5	21.5	20.2	18.9
TPY	103.01	98.42	93.96	88.64	82.97
VOC's:					
Basis, ppm+	7.0	7.0	7.0	7.0	7.0
lb/hr	7.06	6.74	6.44	6.07	5.68
TPY	30.9	29.5	28.2	26.6	24.9
Lead:					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% 02 dry conditions
+ corrected to dry conditions

Table A-12. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), MNQC, Propane, Base Load

Pollutant	Units	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid Mist	% of SO2	5	5	5	5	5
	lb/hr	2.54E-01	2.42E-01	2.30E-01	2.15E-01	2.01E-01
	TPY	1.11E+00	1.06E+00	1.01E+00	9.44E-01	8.80E-01

Sources: EPA, 1988; EPA, 1980

Table A-13. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), MNQC, Propane, Base Load

Pollutant	Units	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polyorganic Matter	pg/J (1)	0.48	0.48	0.48	0.48	0.48
	lb/hr	1.17E-03	1.11E-03	1.06E-03	9.92E-04	9.25E-04
	TPY	5.13E-03	4.87E-03	4.63E-03	4.34E-03	4.05E-03
Formaldehyde	pg/J (1)	38	38	38	.38	38
	lb/hr	9.26E-02	8.81E-02	8.37E-02	7.85E-02	7.32E-02
	TPY	4.06E-01	3.86E-01	3.67E-01	3.44E-01	3.21E-01

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

Stack, Operating, and Emission Data Used in the Air Quality Modeling

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Table A-14. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Data	Gas Turbine Fuel Oil 20oF	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
General:					
Power (kW)	95,860.0	90,080.0	84,470.0	77,930.0	71,250.0
Heat Rate (Btu/kwh)	10,760.0	10,870.0	10,990.0	11,150.0	11,350.0
Heat Input (mmBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
Fuel Oil (lb/hr)	55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
Fuel:					
Heat Content,LHV (Btu/lb)	18,550	18,550	18,550	18,550	18,550
CT Exhaust (Adjusted for CO2 plant):					
Volume Flow (acfm)	1,526,858	1,445,409	1,394,112	1,335,971	1,276,814
Volume Flow (scfm)	558,297	533,317	509,758	483,477	457,056
Adjusted Mass Flow (lb/hr)	2,485,000	2,372,000	2,264,000	2,141,000	2,014,000
Temperature (oF)	984	971	984	999	1,015
Moisture (% Vol.)	7.53	7.70	8.03	8.72	9.93
Oxygen (% Vol.)	13.22	13.23	13.23	13.18	13.04
Molecular Weight	28.59	28.57	28.53	28.44	28.30
Mass flow to CO2 plant (lb/hr)	120,000	120,000	120,000	120,000	120,000
Mass Flow Adj. (Design/adjusted)	0.954	0.952	0.950	0.947	0.944
HRSG Stack:					
Volume Flow (acfm)	719,019	686,847	656,507	622,659	588,633
Temperature (oF)	220	220	220	220	220
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	67.8	64.8	61.9	58.7	55.5
Stack Height (ft)	125	125	125	125	125

Source: General Electric, 1991.

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Table A-15. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Pollutant	Gas Turbine Fuel Oil 20oF	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/hr (manufacturer)	15.0	15.0	15.0	15.0	15.0
lb/hr	14.3	14.3	14.2	14.2	14.2
TPY	62.7	62.5	62.4	62.2	62.0
Sulfur Dioxide:					
Basis, % sulfur	0.1	0.1	0.1	0.1	0.1
lb/hr	100.78	95.46	90.30	84.28	78.17
TPY	441.4	418.1	395.5	369.1	342.4
Nitrogen Oxides:					
Basis, ppm*	42.0	42.0	42.0	42.0	42.0
lb/hr	173.8	164.8	155.7	145.4	134.8
TPY	761.3	721.8	682.0	636.7	590.4
Carbon Monoxide:					
Basis, ppm+	35.0	35.0	35.0	35.0	35.0
lb/hr	78.8	75.1	71.5	67.3	62.8
TPY	345.0	329.0	313.3	294.9	275.1
VOC's:					
Basis, ppm+	10.0	10.0	10.0	10.0	10.0
lb/hr	9.65	9.20	8.76	8.25	7.69
TPY	42.2	40.3	38.4	36.1	33.7
Lead:					
Basis, lb/10E+12 Btu	8.9	8.9	8.9	8.9	8.9
lb/hr	8.76E-03	8.29E-03	7.85E-03	7.32E-03	6.79E-03
TPY	0.038	0.036	0.034	0.032	0.030

* corrected to 15% 02 dry conditions
\+ corrected to dry conditions

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Table A-16. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2	4.2	4.2	4.2	4.2
	lb/hr	4.13E-03	3.91E-03	3.70E-03	3.46E-03	3.21E-03
	TPY	1.81E-02	1.71E-02	1.62E-02	1.51E-02	1.40E-02
Beryllium	lb/10E+12 Btu (1)	2.5	2.5	2.5	2.5	2.5
	lb/hr	2.46E-03	2.33E-03	2.20E-03	2.06E-03	1.91E-03
	TPY	1.08E-02	1.02E-02	9.65E-03	9.01E-03	8.36E-03
Mercury	lb/10E+12 Btu (1)	3	3	3	3	3
	lb/hr	2.95E-03	2.80E-03	2.64E-03	2.47E-03	2.29E-03
	TPY	1.29E-02	1.22E-02	1.16E-02	1.08E-02	1.00E-02
Fluoride	lb/10E+12 Btu (2)	32.5	32.5	32.5	32.5	32.5
	lb/hr	3.20E-02	3.03E-02	2.87E-02	2.67E-02	2.48E-02
	TPY	1.40E-01	1.33E-01	1.25E-01	1.17E-01	1.09E-01
Sulfuric Acid	% of SO2	5	5	5	5	5
Mist	lb/hr	8.12E+00	7.69E+00	7.28E+00	6.79E+00	6.30E+00
	TPY	3.56E+01	3.37E+01	3.19E+01	2.97E+01	2.76E+01

Sources: (1) EPA, 1990; (2) EPA, 1980

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Table A-17. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	6.44	6.44	6.44	6.44	6.44
	lb/hr	6.34E-03	6.00E-03	5.68E-03	5.30E-03	4.92E-03
	TPY	2.78E-02	2.63E-02	2.49E-02	2.32E-02	2.15E-02
Nickel	lb/10E+12 Btu (1)	170	170	170	170	170
	lb/hr	1.67E-01	1.58E-01	1.50E-01	1.40E-01	1.30E-01
	TPY	7.33E-01	6.94E-01	6.56E-01	6.13E-01	5.68E-01
Cadmium	lb/10E+12 Btu (1)	10.5	10.5	10.5	10.5	10.5
	lb/hr	1.03E-02	9.79E-03	9.26E-03	8.64E-03	8.01E-03
	TPY	4.53E-02	4.29E-02	4.05E-02	3.78E-02	3.51E-02
Chromium	lb/10E+12 Btu (1)	47.5	47.5	47.5	47.5	47.5
	lb/hr	4.67E-02	4.43E-02	4.19E-02	3.91E-02	3.63E-02
	TPY	2.05E-01	1.94E-01	1.83E-01	1.71E-01	1.59E-01
Copper	lb/10E+12 Btu (1)	280	280	280	280	280
	lb/hr	2.76E-01	2.61E-01	2.47E-01	2.30E-01	2.14E-01
	TPY	1.21E+00	1.14E+00	1.08E+00	1.01E+00	9.36E-01
Vanadium	pg/J (1)	30	30	30	30	30
	lb/hr	6.86E-02	6.50E-02	6.15E-02	5.74E-02	5.32E-02
	TPY	3.00E-01	2.85E-01	2.69E-01	2.51E-01	2.33E-01
Selenium	pg/J (1)	10.1	10.1	10.1	10.1	10.1
	lb/hr	2.31E-02	2.19E-02	2.07E-02	1.93E-02	1.79E-02
	TPY	1.01E-01	9.58E-02	9.06E-02	8.46E-02	7.85E-02
Polyorganic Matter	pg/J (1)	0.12	0.12	0.12	0.12	0.12
	lb/hr	2.74E-04	2.60E-04	2.46E-04	2.29E-04	2.13E-04
	TPY	1.20E-03	1.14E-03	1.08E-03	1.01E-03	9.32E-04
Formaldehyde	lb/10E+12 Btu (1)	405	405	405	405	405
	lb/hr	3.98E-01	3.77E-01	3.57E-01	3.33E-01	3.09E-01
	TPY	1.75E+00	1.65E+00	1.56E+00	1.46E+00	1.35E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

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Table A-18. Maximum Emissions for Additional Non-Regulated Pollutant
Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4	9.4	9.4	9.4	9.4
	lb/hr	2.15E-02	2.04E-02	1.93E-02	1.80E-02	1.67E-02
	TPY	9.41E-02	8.92E-02	8.44E-02	7.87E-02	7.30E-02
Barium	pg/J (1)	8.4	8.4	8.4	8.4	8.4
	lb/hr	1.92E-02	1.82E-02	1.72E-02	1.61E-02	1.49E-02
	TPY	8.41E-02	7.97E-02	7.54E-02	7.04E-02	6.53E-02
Colbalt	pg/J (1)	3.9	3.9	3.9	3.9	3.9
	lb/hr	8.92E-03	8.45E-03	7.99E-03	7.46E-03	6.92E-03
	TPY	3.91E-02	3.70E-02	3.50E-02	3.27E-02	3.03E-02
Zinc	pg/J (1)	294	294	294	294	294
	lb/hr	6.72E-01	6.37E-01	6.02E-01	5.62E-01	5.21E-01
	TPY	2.94E+00	2.79E+00	2.64E+00	2.46E+00	2.28E+00
Chlorine	ppm	0.5	0.5	0.5	0.5	0.5
	lb/hr	2.65E-02	2.51E-02	2.38E-02	2.22E-02	2.06E-02
	TPY	1.16E-01	1.10E-01	1.04E-01	9.71E-02	9.01E-02

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

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Table A-19. Maximum Emissions for Criteria Pollutants-
Emissions from CT to CO2 plant (based on 120,000 lb/hr steam to CO2)

Pollutant	Gas Turbine Fuel Oil 20of	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
Particulate:					
lb/hr	0.69	0.72	0.76	0.80	0.84
TPY	3.03	3.16	3.31	3.49	3.69
Sulfur Dioxide:					
lb/hr	4.87	4.83	4.79	4.72	4.66
TPY	21.32	21.15	20.96	20.69	20.40
Nitrogen Oxides:					
lb/hr	8.39	8.34	8.25	8.15	8.03
TPY	36.76	36.52	36.15	35.69	35.18
Carbon Monoxide:					
lb/hr	3.80	3.80	3.79	3.77	3.74
TPY	16.66	16.64	16.61	16.53	16.39
VOC's:					
lb/hr	0.47	0.47	0.46	0.46	0.46
TPY	2.04	2.04	2.03	2.02	2.01
Lead:					
lb/hr	4.23E-04	4.20E-04	4.16E-04	4.10E-04	4.05E-04
TPY	1.85E-03	1.84E-03	1.82E-03	1.80E-03	1.77E-03

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Table A-20. Maximum Emissions for Other Regulated Pollutants-
Emissions from CT to CO2 plant (based on 120,000 lb/hr steam to CO2)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Arsenic	lb/hr	2.00E-04	1.98E-04	1.96E-04	1.94E-04	1.91E-04
	TPY	8.74E-04	8.67E-04	8.60E-04	8.48E-04	8.37E-04
Beryllium	lb/hr	1.19E-04	1.18E-04	1.17E-04	1.15E-04	1.14E-04
	TPY	5.20E-04	5.16E-04	5.12E-04	5.05E-04	4.98E-04
Mercury	lb/hr	1.43E-04	1.41E-04	1.40E-04	1.38E-04	1.36E-04
	TPY	6.24E-04	6.20E-04	6.14E-04	6.06E-04	5.98E-04
Fluoride	lb/hr	1.54E-03	1.53E-03	1.52E-03	1.50E-03	1.48E-03
	TPY	6.76E-03	6.71E-03	6.65E-03	6.56E-03	6.47E-03
Sulfuric Acid Mist	lb/hr	3.92E-01	3.89E-01	3.86E-01	3.81E-01	3.75E-01
	TPY	1.72E+00	1.70E+00	1.69E+00	1.67E+00	1.64E+00

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Table A-21. Maximum Emissions for Non-Regulated Pollutants-
Emissions from CT to CO2 plant (based on 120,000 lb/hr steam to CO2)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Manganese	lb/hr	3.06E-04	3.04E-04	3.01E-04	2.97E-04	2.93E-04
	TPY	1.34E-03	1.33E-03	1.32E-03	1.30E-03	1.28E-03
Nickel	lb/hr	8.08E-03	8.02E-03	7.94E-03	7.84E-03	7.73E-03
	TPY	3.54E-02	3.51E-02	3.48E-02	3.43E-02	3.39E-02
Cadmium	lb/hr	4.99E-04	4.95E-04	4.91E-04	4.84E-04	4.77E-04
	TPY	2.19E-03	2.17E-03	2.15E-03	2.12E-03	2.09E-03
Chromium	lb/hr	2.26E-03	2.24E-03	2.22E-03	2.19E-03	2.16E-03
	TPY	9.89E-03	9.81E-03	9.72E-03	9.59E-03	9.46E-03
Copper	lb/hr	1.33E-02	1.32E-02	1.31E-02	1.29E-02	1.27E-02
	TPY	5.83E-02	5.78E-02	5.73E-02	5.66E-02	5.58E-02
Vanadium	lb/hr	3.31E-03	3.29E-03	3.26E-03	3.22E-03	3.17E-03
	TPY	1.45E-02	1.44E-02	1.43E-02	1.41E-02	1.39E-02
Selenium	lb/hr	1.12E-03	1.11E-03	1.10E-03	1.08E-03	1.07E-03
	TPY	4.88E-03	4.85E-03	4.80E-03	4.74E-03	4.68E-03
Polyorganic Matter	lb/hr	1.33E-05	1.31E-05	1.30E-05	1.29E-05	1.27E-05
	TPY	5.80E-05	5.76E-05	5.71E-05	5.63E-05	5.55E-05
Formaldehyde	lb/hr	1.92E-02	1.91E-02	1.89E-02	1.87E-02	1.84E-02
	TPY	8.43E-02	8.36E-02	8.29E-02	8.18E-02	8.07E-02

TAB1922
4/03/92

Table A-22. Maximum Emissions for Additional Non-Regulated Pollutants-
Emissions from CT to CO2 plant (based on 120,000 lb/hr steam to CO2)

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Antimony						
	lb/hr	1.04E-03	1.03E-03	1.02E-03	1.01E-03	9.93E-04
	TPY	4.55E-03	4.51E-03	4.47E-03	4.41E-03	4.35E-03
Barium						
	lb/hr	9.28E-04	9.20E-04	9.12E-04	9.00E-04	8.88E-04
	TPY	4.06E-03	4.03E-03	4.00E-03	3.94E-03	3.89E-03
Colbalt						
	lb/hr	4.31E-04	4.27E-04	4.24E-04	4.18E-04	4.12E-04
	TPY	1.89E-03	1.87E-03	1.86E-03	1.83E-03	1.81E-03
Zinc						
	lb/hr	3.25E-02	3.22E-02	3.19E-02	3.15E-02	3.11E-02
	TPY	1.42E-01	1.41E-01	1.40E-01	1.38E-01	1.36E-01
Chlorine						
	lb/hr	1.28E-03	1.27E-03	1.26E-03	1.24E-03	1.23E-03
	TPY	5.61E-03	5.57E-03	5.52E-03	5.44E-03	5.37E-03

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Table A-23. Stack Parameters for CO2 Facility (Includes Duct Burner on Natural Gas)

Data	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
	20of	40oF	59oF	80oF	100oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kwh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	99.0	99.0	99.0	99.0	99.0
Fuel Natural Gas (lb/hr)	5,128.7	5,128.7	5,128.7	5,128.7	5,128.7
(cf/hr)	104,211	104,211	104,211	104,211	104,211
Fuel:					
Heat Content,LHV (Btu/lb)	19,303	19,303	19,303	19,303	19,303
(Btu/cf)	950.0	950.0	950.0	950.0	950.0
From CT and Duct Burner Exhaust:					
Volume Flow (acfm)	33,235	33,235	33,235	33,235	33,235
Volume Flow (scfm)	25,806	25,806	25,806	25,806	25,806
Mass Flow (lb/hr) *	112,500	112,500	112,500	112,500	112,500
Temperature (oF)	220	220	220	220	220
Molecular Weight	28.00	28.00	28.00	28.00	28.00
Amine Absorber Stack:					
Volume Flow (acfm)	28,201	28,201	28,201	28,201	28,201
Temperature (oF)	117	117	117	117	117
Diameter (ft)	3.00	3.00	3.00	3.00	3.00
Velocity (ft/sec)	66.5	66.5	66.5	66.5	66.5
Stack Height (ft)	170	170	170	170	170

* Based on 120,000 lb/hr from CT; 5,000 lb/hr from duct burner; less 12,500 lb/hr (10 %) due to CO2 removal.

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Table A-24. Maximum Criteria Pollutant Emissions for CO2 Plant (Without Contribution from CT)

Pollutant	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
	20of	40oF	59oF	80oF	100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	0.99	0.99	0.99	0.99	0.99
TPY	4.3	4.3	4.3	4.3	4.3
Sulfur Dioxide:					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.3	1.3	1.3	1.3	1.3
Nitrogen Oxides:					
Basis, lb/MMBtu	0.16	0.16	0.16	0.16	0.16
lb/hr	15.84	15.84	15.84	15.84	15.84
TPY	69.4	69.4	69.4	69.4	69.4
Carbon Monoxide:					
Basis, lb/MMBtu	0.1	0.1	0.1	0.1	0.1
lb/hr	9.9	9.9	9.9	9.9	9.9
TPY	43.4	43.4	43.4	43.4	43.4
VOCs:					
Basis, lb/MMBtu	0.03	0.03	0.03	0.03	0.03
lb/hr	2.97	2.97	2.97	2.97	2.97
TPY	13.0	13.0	13.0	13.0	13.0
Lead:					
Basis, lb/10E+12 Btu	Neg.	Neg.	Neg.	Neg.	Neg.
lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
TPY	0.000	0.000	0.000	0.000	0.000

Note: Additional 5 lb/hr of PM are emitted due to heat stable salts from amine absorber.
Additional 14.7 lb/hr of VOCs are emitted due to monoethanolamine (as carbon) from amine absorber.

TABA2327
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Table A-25. Maximum Other Regulated Pollutant Emissions for CO2 Plant (Without Contribution from CT)

Pollutant	Units	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
		20of	40oF	59oF	80oF	100oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Beryllium	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Mercury	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoride	lb/10E+12 Btu (2)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sulfuric Acid	% of SO2	5	5	5	5	5
Mist	lb/hr	2.40E-02	2.40E-02	2.40E-02	2.40E-02	2.40E-02
	TPY	1.05E-01	1.05E-01	1.05E-01	1.05E-01	1.05E-01

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Table A-26. Maximum Non-Regulated Pollutant Emissions for CO2 Plant (Without Contribution from CT)

Pollutant	Units	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
		20oF	40oF	59oF	80oF	100oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Nickel	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cadmium	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Copper	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Vanadium	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Selenium	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Polyorganic Matter	pg/J (1)	0.48	0.48	0.48	0.48	0.48
	lb/hr	1.10E-04	1.10E-04	1.10E-04	1.10E-04	1.10E-04
	TPY	4.84E-04	4.84E-04	4.84E-04	4.84E-04	4.84E-04
Formaldehyde	lb/10E+12 Btu (1)	38	38	38	38	38
	lb/hr	3.76E-03	3.76E-03	3.76E-03	3.76E-03	3.76E-03
	TPY	1.65E-02	1.65E-02	1.65E-02	1.65E-02	1.65E-02

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Table A-27. Maximum Emissions for Additional Non-Regulated Pollutant for CO2 Plant (Without Contribution from CT)

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Antimony	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Barium	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Colbalt	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Zinc	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chlorine	ppm	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Example Calculations

MULBERRY COGENERATION PROJECT

EXAMPLE CALCULATIONS - 20°F CONDITIONS

(On Distillate Oil; All Other Calculations on Spreadsheet are Identical.)

Table A-1: (Note: all other data not calculated but supplied by Manufacturer)

Heat Input (10^6 Btu/hr):

Power (kW) x Heat Rate (10^6 Btu/kWh)

$95,860 \times 10,760/10^6 = 1,031.5 \times 10^6$ Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) + Fuel Heat Content (Btu/lb)

$1,031.5 \times 10^6 + 18,550 = 55,604$ lb/hr

Volume Flow (acfm) - See Note A:

$V = mRT/PM$

$2,605,000$ lb/hr x $1,545 \times (984°F + 460°R) + (28.59 \times 2,116.8$ lb/ft^2)

+ 60(min/hr)

= 1,600,590 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

$2,605,000$ lb/hr x $1,545 \times (68°F + 460°R) + (28.59 \times 2,116.8) + 60$

= 585,257 scfm

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,600,590 (acfm) x (220°F + 460°R) + (984°F + 460°R)

= 753,740 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) + Area (ft^2) + 60 sec/min

753,740 ft^3/min + 60 + (15.0^2 + 4 x 3.14159)

= 71.1 ft/sec

Table A-2:

Emissions in tons per year; example for particulate:

15 lb/hr x 8,760 hr/yr + 2,000 lb/ton

= 65.7 ton/yr

SO_2 Emissions--Oil (lb/hr)

55,604.0 lb/hr x 0.001 lb S/lb x 2 lb SO_2/lb S x 0.95 (emitted as SO_2)

= 105.65 lb/hr

SO_2 Emissions--Natural Gas (20°F) (lb/hr):

1,013,429 cf/hr x 1 gr + 7,000 gr/lb x 2 lb SO_2/lb S + 100 cf

= 2.9 lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 + 5.9 (1 - 7.53/100) - 13.22] x 2,116.8 lb/ft^2 x 1,600,590 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (984°F + 460°R) x 10^6 (adjust for ppm)]

= 182.2 lb/hr

CO Emissions (lb/hr) - See Note C:

35 ppm x (1 - 7.53/100) x 1,600,590 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr + (1,545 x (984 + 460) x 10^6)

= 82.6 lb/hr

VOC Emissions (lb/hr) - See Note C:

10 ppm x (1-7.53/100) x 1,600,590 acfm x 2,116.8 lb/ft^2 x 12 (molecular wgt. of carbon)

x 60 min/hr + (1,545 x (984 + 460) x 10^6)

= 10.11 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x 1,031.5 x 10^6 Btu/hr = 9.18 x 10^{-3} lb/hr

Table A-3:

H_2SO_4 Mist Emissions (lb/hr):

Based on 5 percent of sulfur converted to acid mist

55,604 lb/hr x 0.001 lb S/lb x 3.06 lb H_2SO_4/lb 5 x 0.05 (converted)

= 8.51 lb/hr

Tables A-4 and A-5:

EPA emission factor as noted in printout; example for manganese:

1,031.55 (MMBtu) x 6.44 lb/10^{12} Btu

= 6.64 x 10^{-3} lb/hr

NOTE A

Volume is calculated based on ideal gas law:

$$PV = mRT/M$$

where:
- P = pressure = 2116.8 lb/ft^2
- m = mass flow of gas (lb/hr)
- R = universal gas constant = 1545
- M = molecular weight of gas
- T = temperature (°R)

NOTE B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

(From 40 CFR Part 60; Appendix A, Method 20, Equation 20-4)

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry}) / 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act} / (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

(From Method 20; Equation 20-1)

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O);$$ (From Method 20; Equation 20-1)

Substituting:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O) / 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act} / (1 - \%H_2O))]\ (1 - \%H_2O) / 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) / 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx} / (RT * 5.9)$$

NOTE C

Same as D except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$m_{CO} = PV_{CO\ Act}M_{CO} / RT$$
$$= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO} / RT$$

Emission Factors

PB89-194229

United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-89-001
April 1989

AIR

EPA

ESTIMATING AIR TOXICS EMISSIONS FROM COAL AND OIL COMBUSTION SOURCES

REPRODUCED BY
U.S. DEPARTMENT OF COMMERCE
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INFORMATION SERVICE
SPRINGFIELD, VA 22161

TABLE 4-1. SUMMARY OF TOXIC POLLUTANT EMISSION FACTORS FOR OIL COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^{12}$ Btu)	
	Residual Oil	Distillate Oil
Arsenic	19	4.2
Beryllium	4.2	2.5
Cadmium	15.7	10.5
Chromium	21	48
Copper	280	280
Lead	28[c]	8.9[d]
Mercury	3.2	3.0
Manganese	26	14
Nickel	1260	170
POM	8.4[b]	22.5
Formaldehyde	405[e]	405[e]

[a]All emission factors are uncontrolled, and are applicable to oil-fired boilers and furnaces in all combustion sectors unless otherwise noted.

[b]This value was calculated using all available residual oil data given in Table 4-35. If the upper end of the range of available data is excluded when calculating an average value (which could be used in this table), the average factor for POM from residual oil combustion becomes 4.1 $lb/10^{12}$ BTU.

[c]Applicable to utility boilers only.

[d]Applicable to industrial, commercial, and residential boilers.

[e]The formaldehyde factors are based on very limited and relatively old data. Consult Table 4-37 and accompanying discussion for more detailed information.

PB81-229559

Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

U.S. Department of Commerce
National Technical Information Service

TABLE 61. COMPARISON OF EXISTING TRACE ELEMENT EMISSION FACTOR DATA WITH RESULTS OF CURRENT STUDY OF OIL-FIRED INDUSTRIAL COMBUSTION SOURCES, pg/J

	Distillate oil-fired boilers			Residual oil-fired boilers			
		Existing data			Existing data		
Element	Current study	Ref. 42	Ref. 43	Current study	Ref. 42	Ref. 21	Ref. 28
Aluminum (Al)	178	15	250	177	156	87	132
Arsenic (As)	3.5	1.3	1.5	1.2	9.1	18	12
Barium (Ba)	1.2	8.4	16	3.3	9.5	29	31
Calcium (Ca)	75	845	450	229	780	320	1428
Cadmium (Cd)	1.3	2.5	11	0.66	0.2	52	6.9
Cobalt (Co)	3.6	2.3	1.0	11	23	50	10
Chromium (Cr)	24	36	29	29	50	30	21
Copper (Cu)	37	205	160	10	93	64	350
Fluorine (F)	—	14	—	—	1.0	2.7	149
Iron (Fe)	383	545	140	83	379	411	453
Mercury (Hg)	—	1.7	1.2	—	1.9	0.9	1.5
Potassium (K)	85	60	230	261	213	777	392
Lithium (Li)	0.5	1.5	1.2	1.1	1.0	1.4	1.7
Magnesium (Mg)	42	40	210	24	111	297	2384
Nickel (Ni)	255	112	290	728	804	964	433
Lead (Pb)	24	48	42	2	7	80	34
Antimony (Sb)	—	1.7	5.7	—	21	10	25
Silicon (Si)	735	173	—	8655	1610	400	595
Vanadium (V)	195	30	2.9	366	250	3656	714
Zinc (Zn)	42	40	110	33	46	29	66

Ave. 50.9

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National Technical Information Service
PB-296 390

Emission Assessment of Conventional Stationary Combustion Systems; Volume II Internal Combustion Sources

TRW, Inc, Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, NC

Feb 1979

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TABLE 52. COMPARISON OF TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FUELED GAS TURBINES AND DISTILLATE OIL ENGINES

Trace Element	Mean Emission Factor, pg/J	
	Distillate Oil Fueled Gas Turbine	Distillate Oil Reciprocating Engine
Aluminum	64	66
Antimony	9.4	12
Arsenic	2.1	2.2
Barium	8.4	14
Beryllium	0.14	0.03
Boron	28	11
Bromine	1.8	4.0
Cadmium	1.8	3.1
Calcium	330	237
Chromium	20	26
Cobalt	3.9	5.7
Copper	578	453
Iron	256	325
Lead	25	26
Magnesium	100	44
Manganese	145	16
Mercury	0.39	0.13
Molybdenum	3.6	12.5
Nickel	526	564
Phosphorus	127	97
Potassium	185	179
Selenium	2.3	2.1
Silicon	575	301
Sodium	590	1625
Tin	35	9.1
Vanadium	1.9	0.95
Zinc	294	178

EPA-450/2-88-006
October 1988

Toxic Air Pollutant Emission Factors—A Compilation For Selected Air Toxic Compounds And Sources

By
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U.S. ENVIRONMENTAL PROTECTION AGENCY
Office Of Air And Radiation
Office Of Air Quality Planning And Standards
Research Triangle Park, North Carolina 27711

October 1988

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Scotch marine boilers, distillate oil	10300501	PCM		17.7 pg/J	Uncontrolled	114
Oil combustion		Cast iron sectional boilers, distillate oil	10300501	PCM		<14.9 pg/J	Uncontrolled, home heating application	114
Oil combustion		Hot air furnace, distillate oil	10300501	PCM		<0.14 pg/J	Uncontrolled, same reference also lists <15.4 for same boiler/fuel type	114
Oil combustion	49	Boiler flue gas	1	Tetrachlorodibenzo-p-dioxin, 2,3,7,8-	1746016	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<4.2-<7.9 ng/m3	119
Oil combustion	49	Flue gas	1	Tetrachlorodibenzofuran, 2,3,7,8-	51207319	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<0.67-<1.3ng/m3	119
Oil combustion, commercial		Residual oil-fired tangential furnaces	103004	Vanadium	7440622	3660 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Residual oil-fired wall furnaces	103004	Vanadium	7440622	3660 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Tangential furnace, residual oil	103004	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Wall furnace, residual oil	103004	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Scotch marine boilers, residual oil	10300401	PCM		0.95 pg/J heat input	Uncontrolled, represents benzo(a)pyrene only	114
Oil combustion, commercial		Distillate oil-fired tangential furnaces	103005	Vanadium	7440622	30.0 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Distillate oil-fired wall furnaces	103005	Vanadium	7440622	30.0 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Tangential furnace, distillate oil	103005	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54

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APPENDIX B

MSDS FOR FS-1 SOLVENT; AND SCRUBBER VENDOR INFORMATION

265

MATERIAL SAFETY DATA SHEET

Dow Chemical U.S.A.* Midland, MI 48674 Emergency Phone: 517-636-4400

Product Code: 09900 Page: 1

PRODUCT NAME: GAS/SPEC (R) FS-1 SOLVENT

Effective Date: 05/05/89. Date Printed: 07/01/89 MSDS:001620

1. INGREDIENTS: (% w/w, unless otherwise noted)

MonoetHanolamine	CAS# 000141-43-5	85%
Water	CAS# 007732-18-5	14%

This document is prepared pursuant to the OSHA Hazard Communication Standard (29 CFR 1910.1200). In addition, other substances not 'Hazardous' per this OSHA Standard may be listed. Where proprietary ingredient shows, the identity may be made available as provided in this standard.

2. PHYSICAL DATA:

BOILING POINT: 266F, 130C
VAP.PRESS: .429 psia
VAP DENSITY: Not applic.
SOL. IN WATER: Complete.
SP. GRAVITY: 1.0
APPEARANCE: Clear blue liquid.
ODOR: Amine odor.
FREEZE POINT: 9F, -13C

3. FIRE AND EXPLOSION HAZARD DATA:

FLASH POINT: 208F, 98C
METHOD USED: COC
*No flash point observed up to boiling point via Seta Flash CC.

FLAMMABLE LIMITS
LFL: Not deter.
UFL: Not deter.

EXTINGUISHING MEDIA: Water fog, alcohol foam, CO2, dry chemical.

FIRE & EXPLOSION HAZARDS: Amine vapor, possible nitrogen oxide. NOx

(Continued on Page 2)
(R) Indicates a Trademark of The Dow Chemical Company

* An Operating Unit of The Dow Chemical Company

MATERIAL SAFETY DATA SHEET

Dow Chemical U.S.A.* Midland, MI 48674 Emergency Phone: 517-636-4400

PRODUCT NAME: GAS/SPEC (R) FS-1 SOLVENT

Effective Date: 05/05/89 Date Printed: 07/01/89 MSDS:001620

3. FIRE AND EXPLOSION HAZARD DATA: (CONTINUED)

Water and foam may cause frothing.

FIRE-FIGHTING EQUIPMENT: Wear positive pressure self-contained breathing apparatus.

4. REACTIVITY DATA:

STABILITY: (CONDITIONS TO AVOID) Conditions incident to normal shipping and handling do not constitute a hazardous situation.

INCOMPATIBILITY: (SPECIFIC MATERIALS TO AVOID) Strong oxidizers, strong acids.

HAZARDOUS DECOMPOSITION PRODUCTS: Possible nitrogen oxides. This product should not be stored in aluminum due to possible discoloration and excessive corrosion and potential chemical reaction releasing flammable hydrogen gas.

HAZARDOUS POLYMERIZATION: Will not occur.

5. ENVIRONMENTAL AND DISPOSAL INFORMATION:

ACTION TO TAKE FOR SPILLS/LEAKS: Apply absorbent material or sand. Shovel into container.

DISPOSAL METHOD: Burn in approved incinerator in accordance with all local, state and federal regulations. Do not discharge into water environment.

(Continued on Page 3)

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MATERIAL SAFETY DATA SHEET

Dow Chemical U.S.A.* Midland, MI 48674 Emergency Phone: 517-636-4400

Product Code: 09900 Page: 3

PRODUCT NAME: GAS/SPEC (R) FS-1 SOLVENT

Effective Date: 05/05/89 Date Printed: 07/01/89 MSDS:001620

6. HEALTH HAZARD DATA:

EYE: May cause severe irritation with corneal injury which may result in permanent impairment of vision, even blindness. Vapors may irritate eyes.

SKIN CONTACT: Short single exposure may cause skin burns. Classified as DOT corrosive.

SKIN ABSORPTION: A single prolonged exposure may result in the material being absorbed in harmful amounts. The LD50 for skin absorption in rabbits is approximately 2000 mg/kg.

INGESTION: Single dose oral toxicity is low. The oral LD50 for rats is in the 1000 - 2000 mg/kg range. Ingestion may cause gastrointestinal irritation or ulceration and burns of mouth and throat.

INHALATION: Excessive exposure may cause liver and kidney injury and irritation to upper respiratory tract.

SYSTEMIC & OTHER EFFECTS: Repeated excessive exposures may cause liver and kidney injury. Birth defects are unlikely. Exposures having no adverse effects on the mother should have no effect on the fetus. In animal studies, monoethanolamine has been shown not to interfere with reproduction. Results of in vitro ("testtube") mutagenicity tests monoethanolamine have been negative.

7. FIRST AID:

EYES: Immediate and continuous irrigation with flowing water for at least 30 minutes is imperative. Prompt medical consultation is essential.

SKIN: In case of contact, immediately flush skin with plenty of water for at least 15 minutes while removing contaminated clothing and shoes. Call a physician if irritation persists. Wash clothing before reuse. Destroy contaminated shoes and

(Continued on Page 4)

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MATERIAL SAFETY DATA SHEET

Dow Chemical U.S.A.* Midland, MI 48674 Emergency Phone: 517-636-4400

Product Code: 09900 Page: 4

PRODUCT NAME: GAS/SPEC (R) FS-1 SOLVENT.

Effective Date: 05/05/89 Date Printed: 07/01/89 MSDS:001620

7. FIRST AID: (CONTINUED)

other leather articles.

INGESTION: Do not induce vomiting. Give large amounts of water or milk if available and transport to medical facility.

INHALATION: Remove to fresh air if effects occur. Consult a physician.

NOTE TO PHYSICIAN: The decision of whether to induce vomiting or not should be made by an attending physician. Corrosive. May cause stricture. If lavage is performed, suggest endotracheal and/or esophagoscopic control. If burn is present, treat as any thermal burn, after decontamination. No specific antidote. Supportive care. Treatment based on judgment of the physician in response to reactions of the patient.

8. HANDLING PRECAUTIONS:

EXPOSURE GUIDELINE(S): Ethanolamine: ACGIH TLV and OSHA PEL are 3 ppm TWA, 6 ppm STEL.

VENTILATION: Control airborne concentrations below the exposure guideline. Good general ventilation should be sufficient for most conditions. Local exhaust ventilation may be necessary for some operations.

RESPIRATORY PROTECTION: Atmospheric levels should be maintained below the exposure guideline. When respiratory protection is required for certain operations, use an approved air-purifying respirator.

SKIN PROTECTION: Use protective clothing impervious to this material. Selection of specific items such as gloves, boots, apron, or full-body suit will depend on operation. Safety shower should be located in immediate work area. Remove contaminated clothing immediately, wash skin area with soap and water, and launder clothing before reuse. Contaminated leather

(Continued on Page 5)

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MATERIAL SAFETY DATA SHEET

Dow Chemical U.S.A.* Midland, MI 48674 Emergency Phone: 517-636-4400

Product Code: 09900 Page: 5

PRODUCT NAME: GAS/SPEC (R) FS-1 SOLVENT

Effective Date: 05/05/89 Date Printed: 07/01/89 MSDS:001620

8. HANDLING PRECAUTIONS: (CONTINUED)

items, such as shoes, belts and watchbands, should be removed and destroyed.

EYE PROTECTION: Use chemical goggles. Wear full-face respirator to prevent contact with vapors.

9. ADDITIONAL INFORMATION:

REGULATORY REQUIREMENTS:

SARA HAZARD CATEGORY: This product has been reviewed according to the EPA 'Hazard Categories' promulgated under Sections 311 and 312 of the Superfund Amendment and Reauthorization Act of 1986 (SARA Title III) and is considered, under applicable definitions, to meet the following categories:

An immediate health hazard
A delayed health hazard
A fire hazard

SPECIAL PRECAUTIONS TO BE TAKEN IN HANDLING AND STORAGE: Prevent eye and skin contact. Avoid breathing vapors. Storage in aluminum is not recommended.

MSDS STATUS: Revised Section 8.

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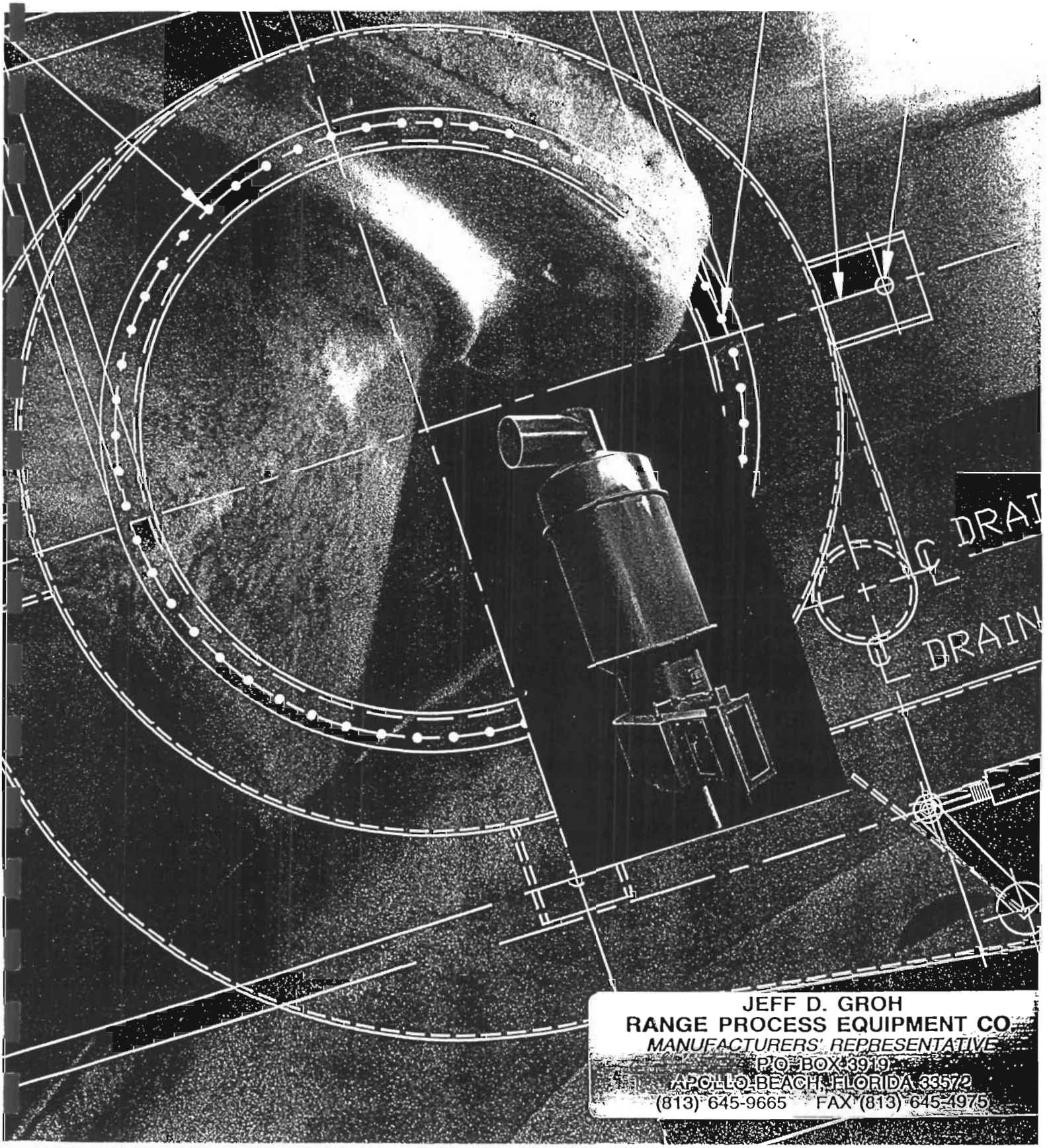
The Information Herein Is Given In Good Faith, But No Warranty, Express Or Implied, Is Made. Consult The Dow Chemical Company For Further Information.

* An Operating Unit of The Dow Chemical Company

Fisher-Klosterman, Inc.

MPS–MULTIPLE PURPOSE SCRUBBER

FISHER-KLOSTERMAN'S NEW MPS SCRUBBER SAVES SPACE, SAVES ENERGY, SAVES MONEY.



JEFF D. GROH
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MANUFACTURERS' REPRESENTATIVE
P.O. BOX 3919
APOLLO BEACH, FLORIDA 33572
(813) 645-9665 FAX (813) 645-4975

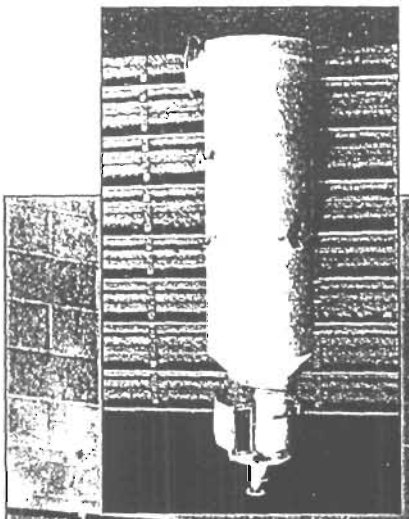
FKI PRESENTS A SINGLE UNIT THAT DOES THE JOB OF THREE

Fisher-Klosterman, Inc. (FKI), a leader in the custom design, fabrication and installation of high efficiency pollution control equipment since 1948 has recently developed a revolutionary new approach to scrubber system design that combines the superior scrubbing technologies of a venturi scrubber, a cyclonic separator and a packed tower in a single, compact, efficient unit. Of course, FKI continues to be the leader in the design and manufacturing of these components separately, but if your situation calls for the removal of the broadest range of contaminants and pollutants from a gaseous stream, the new MPS Series of multiple purpose scrubbers eliminates everything from particulates to gases without the cumbersome need for three separate and expensive components. One unit does it all.

Now a single unit can cleanse

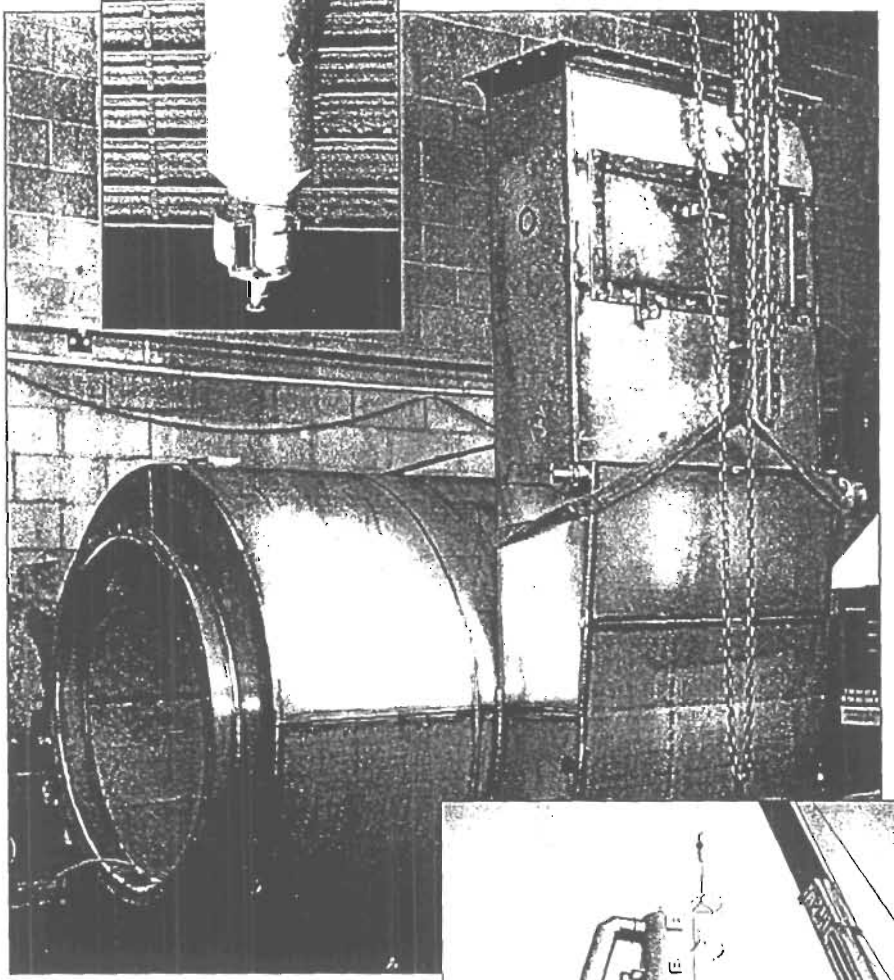
PARTICULATE	FUMES
• Ash	• HF
• Grit	• Acids
• Plastics	• Formaldehydes
• Chemicals	• HCL
• Pharmaceuticals	• SO_x
• Sand	• NO_x
• Minerals	• NH_3
• Metals	

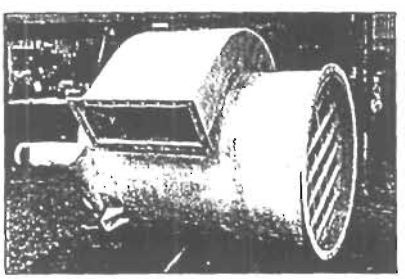
easily, efficiently and economically.



FRP MPS Scrubber (*left*) for nuisance dust and acid gases

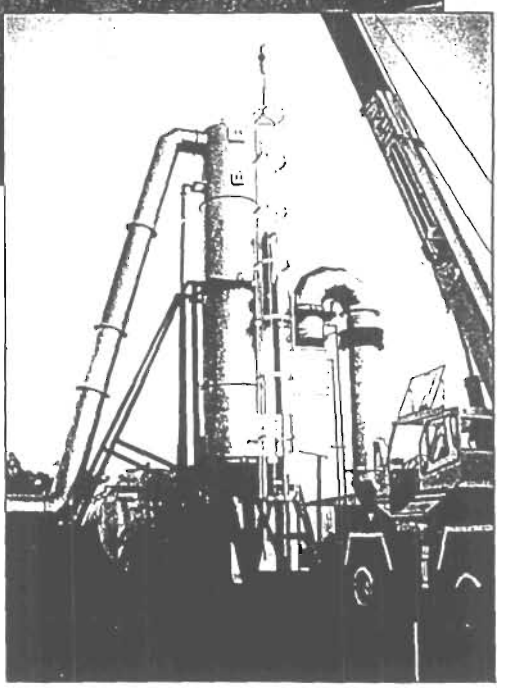
Stainless steel MPS Scrubber (*below*) in fabrication



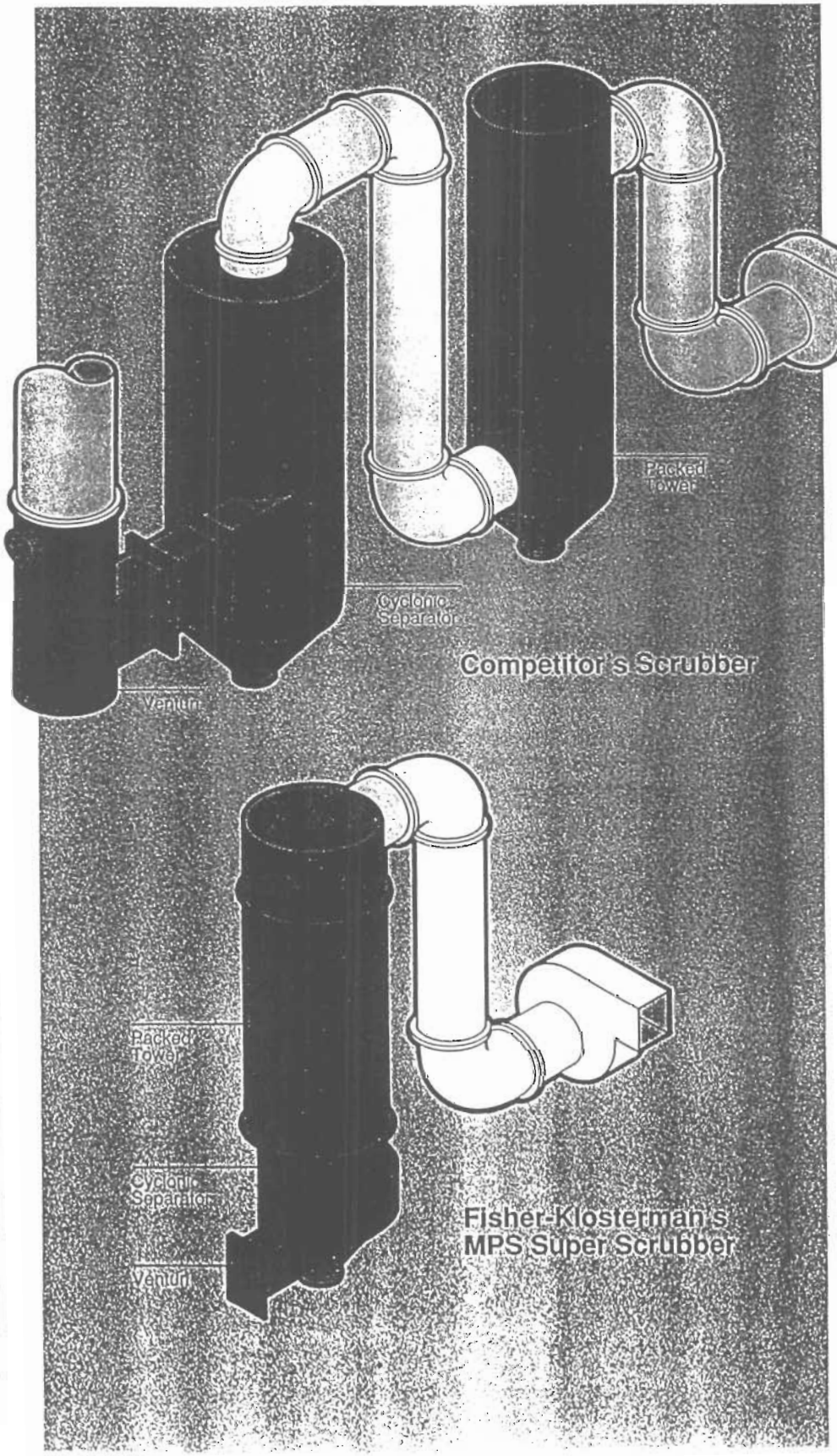


FRP MPS Scrubber (*above*) in fabrication

MPS Scrubber (*right*) being installed on hazardous waste incineration system (on-site at major oil spill)



. . . AND DOES IT FOR LESS!



The entire scrubbing operation has been combined into a single compact unit eliminating much of the concrete work, steel fabrication and piping that add to the cost of other systems. Therefore, the equipment, installation and operating costs of the MPS Series are dramatically reduced.

Plus, thanks to a design breakthrough in the cyclonic separator, the MPS Series scrubbers are significantly smaller than any comparable, three-unit system. Because the cyclone chamber has only 1/2 the cross-sectional area and only 1/3 the height of other cyclonic separators, the whole design takes up less floor space, uses less energy, requires less maintenance and saves on operating costs.

And it's a Fisher-Klosterman system, so it can be custom designed to meet your specific needs. It's the ideal device for the removal of multiple pollutants at all sorts of job sites, from the largest chemical and utilities companies to more modest operations that couldn't afford such a complete system until now. It's the MPS Series from Fisher-Klosterman.

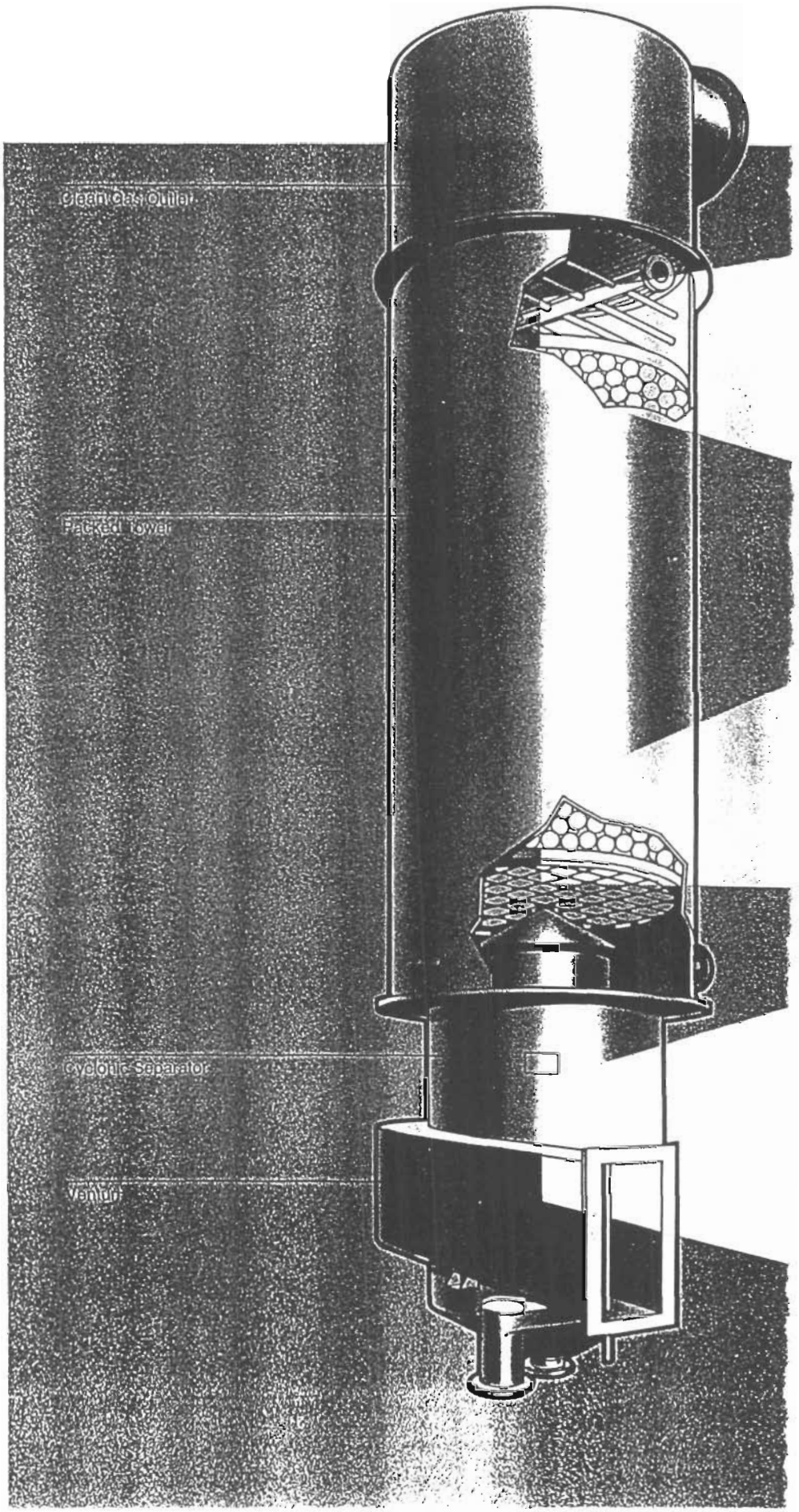
HERE'S HOW IT WORKS

Stage One: The Venturi Scrubber

The first step in eliminating multiple pollutants from a gaseous stream is to remove the dust and other particulate from the gas. This is done by accelerating the dust-laden gas through a narrow-throat venturi, where liquid is injected into the stream. The resulting turbulence causes the liquid droplets to collide with the particles. These particles adhere to the liquid, so that they may be effectively separated from the gas stream in the next stage of the process.

Stage Two: The Cyclonic Separator

This stage of the process utilizes a high speed vortex to separate the particle-laden liquid droplets from the gaseous stream. The force of the vortex sends the heavier droplets out against the walls of the cyclone chamber, where they form a liquid film that flows down and out of the chamber through two drains. At the same time the lighter gas is sent out the top of the chamber and on to the third stage of the process.



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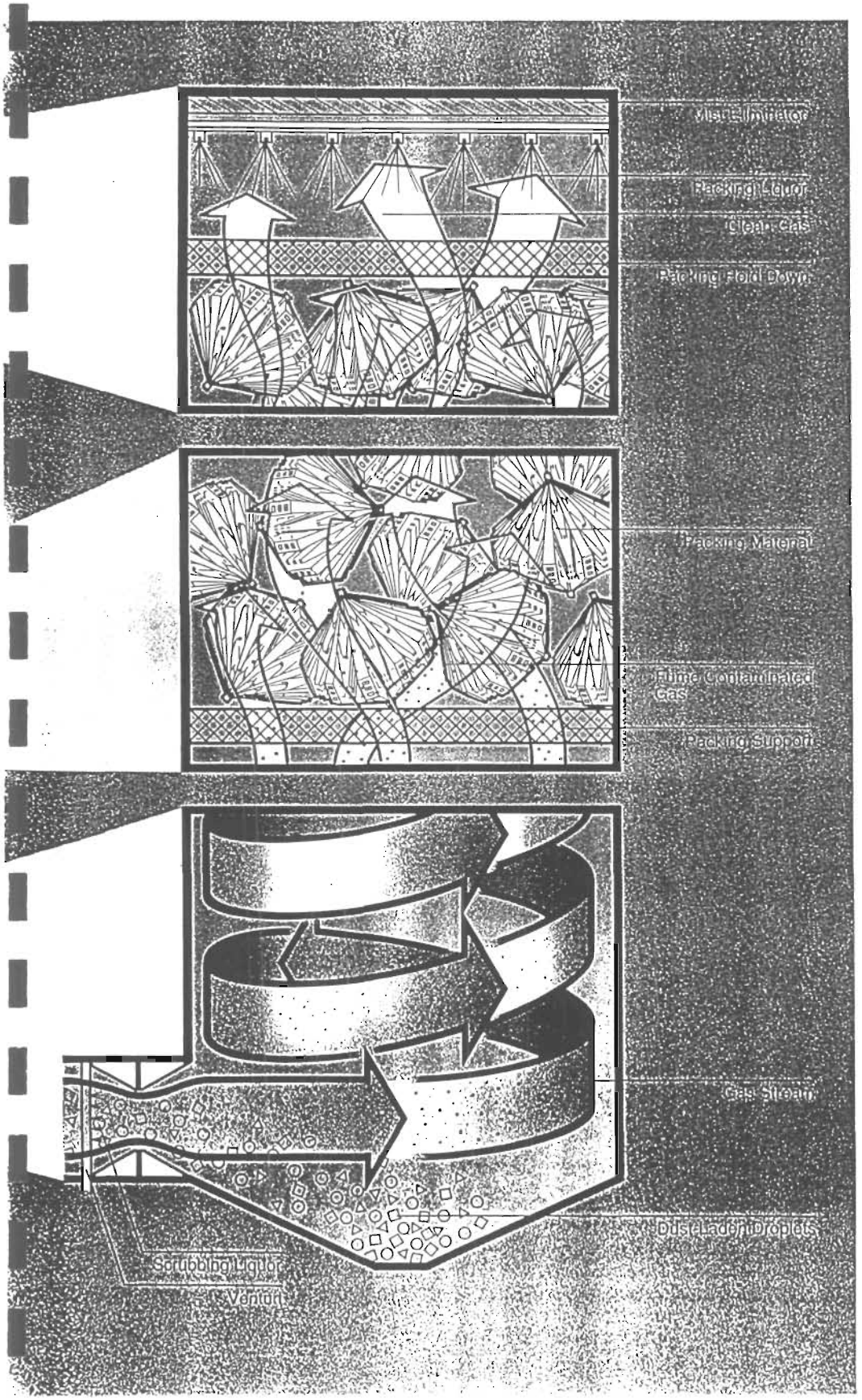


Stage Three: The Packed Tower

Also known as a packed bed scrubber, the packed tower removes any gaseous pollutant from the stream by contacting the contaminated gas with a scrubbing liquor that absorbs the contaminant into the liquid film. In order to increase the total surface area of the liquor so that it absorbs more contaminant gas, a packing material fills the tower. The gas is forced to work its way slowly up a tortuous route to the top of the tower, all the while contacting the scrubbing liquor on its way down. The result is a clean gas stream exiting the system free of particulate and gaseous contaminants.

The packing material is the secret to a truly efficient packed tower. Packing materials are quite diverse with many different shapes, sizes and materials of construction. Factors to be considered when choosing a packing are efficiency of absorption, chemical compatibility with the contaminant gas and scrubbing liquor, ease of maintenance and cost. Engineers at FKI will select the packing best suited to your specific needs.

THE FISHER-KLOSTERMAN STORY: PRODUCT INNOVATION, SERVICE AND PERFORMANCE

Particulate pollution takes many forms, and no two applications are just alike. That's why plant operators and engineers often turn to Fisher-Klosterman. We've built a special niche in our industry as an experienced, innovative supplier of pollution control equipment for custom applications.

We're not a new firm — we've been custom designing and fabricating pollution control equipment since 1948. Most jobs involve the following steps:

1. First, we help identify and quantify your needs through test sampling and laboratory analysis.

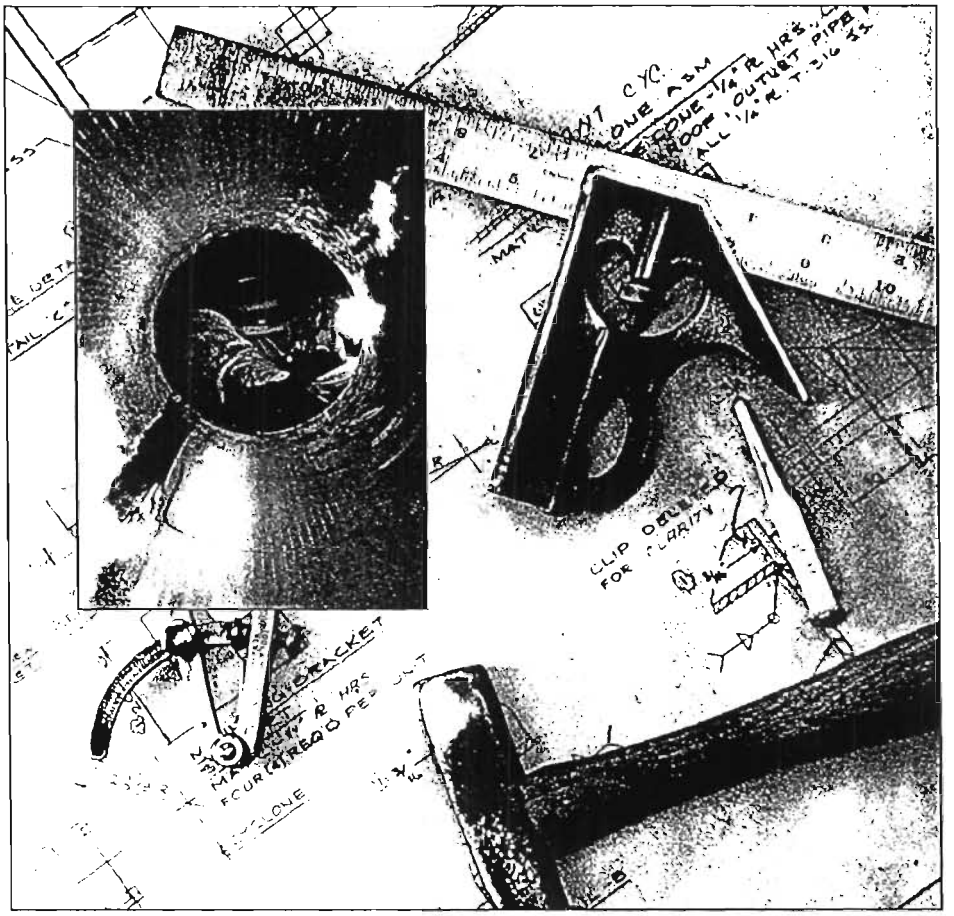
2. Next, we make equipment recommendations and provide cost estimates.

3. Then we custom design and fabricate the system.

4. We can provide field and/or engineering supervision, turn-key installation, system start-up, calibration and check out as well. Fisher-Klosterman systems and equipment are available for a variety of applications including:

- in-plant environmental improvement
- air pollution control
- pneumatic conveying
- product classification
- product recovery
- waste or scrap disposal
- processing equipment

All of our services and products are backed by an unequivocal warranty covering quality of materials and workmanship, and performance according to specifications.



TELL US ABOUT YOUR NEEDS

We can help you select the right scrubber for your application — that's one of our customer services. But we will need help from you. Please provide us with the following information:

Gas conditions at collector inlet:

1. Volume (ACFM)_____
2. Pressure (PSIG or PSIA)_____
3. Temperature given in °F or °C_____
4. Moisture content — specify by weight or volume_____
5. Attach gas analysis if other than air — specify by weight or by volume_____

Dust conditions at inlet:

1. Identity or origin _____
2. Particulate specific gravity or density _____
3. Bulk density in lbs./cu. ft. _____
4. Type of material: corrosive, abrasive, sticky, explosive, toxic _____
5. Dust load (lb./hr. or grain/ACF) _____
6. Attached aerodynamic particle size distribution _____
7. Method of particle size distribution determination _____

Collector information:

1. Required collection efficiency _____ (List by contaminant)
2. Fan on inlet or outlet side of collector _____
3. Maximum allowable pressure drop given in " w.c. _____
4. Materials of construction _____
5. Design pressure _____
6. Physical space/size restrictions _____

If you are unable to determine the aerodynamic particle size distribution (APSD), we will be glad to analyze a sample for you. A stack test may be required if you have difficulty collecting the above data. This test measures gas properties, the dust loading and APSD at the scrubber's installation point.

IF YOU'D LIKE HELP IN DETERMINING YOUR NEEDS OR MORE INFORMATION ABOUT OUR PRODUCTS, WRITE OR GIVE US A CALL. THERE'S A FISHER-KLOSTERMAN REPRESENTATIVE NEAR YOU.

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Decatur, GA (205) 355-2613
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Southern
Allen H. Jones Company
Los Angeles, CA (818) 246-3619

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Denver, CO (303) 458-8333

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Rochester, NY (716) 288-2110

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831-2142
Fayetteville, NC (919) 433-2295

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Southern
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831-2142
Mauldin, SC (803) 234-7931

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861-1801
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Sandy, UT (801) 572-2919

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ONTARIO
Shadrack Engineering (1978) Ltd.
Scarborough, ON (416) 293-3100

QUEBEC
Raycon Controls, Inc.
St. Laurent, PQ (514) 334-0931

SASKATCHEWAN
Bisco
Thunder Bay, ON
(807) 623-5551

SOUTH AMERICA

ARGENTINA
Catalist S.A.C.I.
Buenos Aires, Argentina
54-1-656-0805

CHILE
Ingam S.A.
Santiago. Chile
56-2-223-1872

COLOMBIA
Fisher-Klosterman Regional Office
Bogota. Colombia
57-1-215-3280

VENEZUELA
Moret y Cia., S.A.
Caracas. Venezuela
58-2-564-0178 / 0668

INDIA

Ushamil Pvt. Ltd.
New Delhi
91-11-643-1404

W.W. Sly Manufactures Two Types of Scrubbers...

Impinjet®

Impinjet® Scrubbers Cool, Clean and Absorb Odors, Vapors and Gases. The Impinjet Scrubber removes materials such as odors, vapors or gases suspended in gas streams, as well as larger particles.

Rugged and uncomplicated in design, Impinjet Scrubbers offer the highest efficiency available in modern gas scrubbers removing gases, odors and vapors. Engineered to provide *minimum pressure drop*, the scrubber operates with resultant lower power requirements. Attractive benefits follow—thoroughly efficient gas cleaning and cooling with reduced operating costs.

Efficiencies in excess of 99% can be realized on most types of dust or gases. Impinjet Scrubber capacities range from 200 to over 1,000,000 CFM. Depending upon application, water requirements vary from less than 1½ GPM per 1,000 CFM to a typical 3 GPM per 1,000 CFM.

Unique flexibility is furnished by Impinjet Scrubbers. Made with the future in mind, additional stages can be added to existing installations to handle tomorrow's efficiency requirements—*without increasing liquid consumption*. No need to buy complete new units.

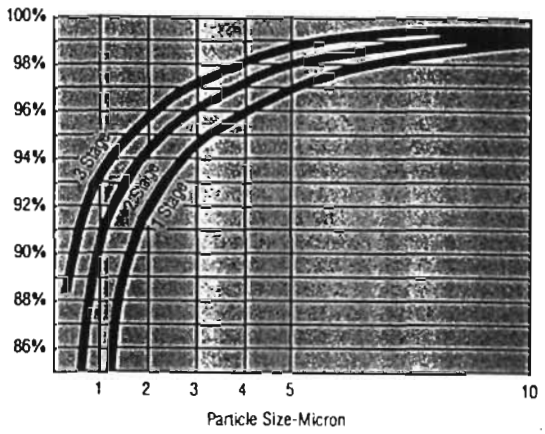
Venturi

Venturi Scrubbers Efficiently Collect Fine Particulate and Liquid Mists

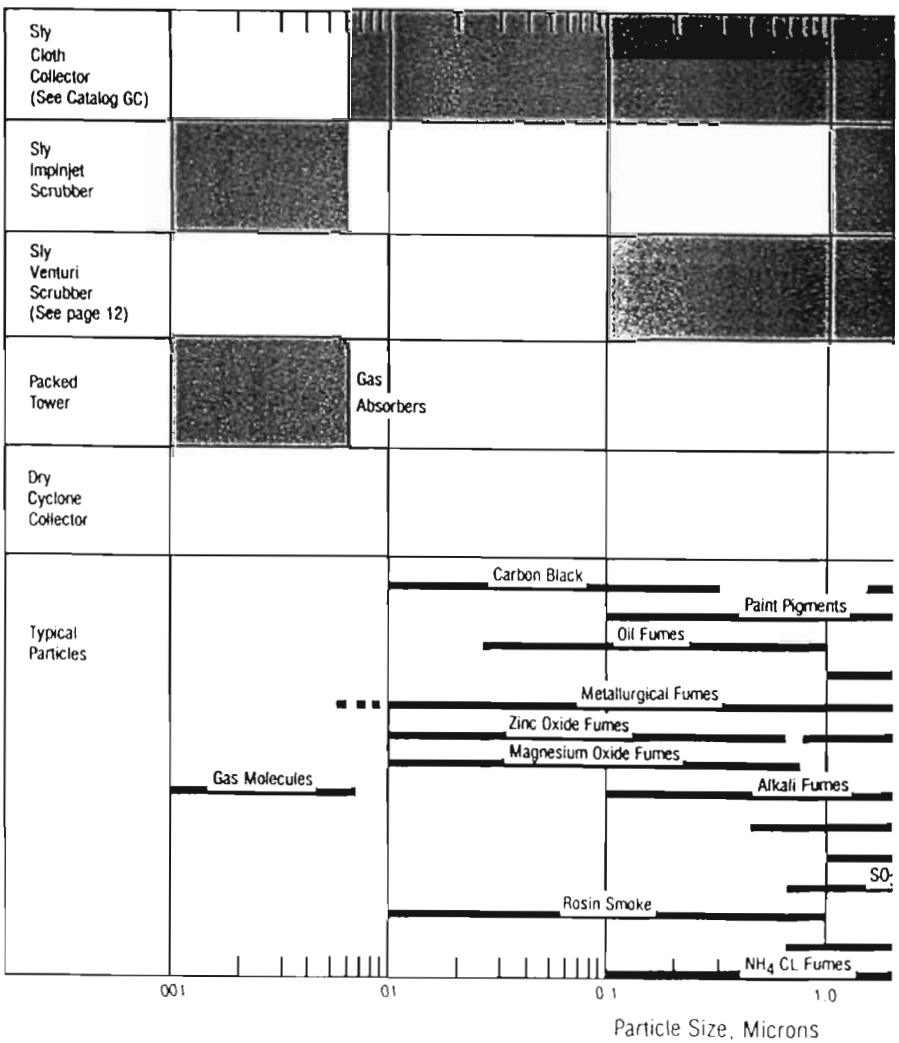
The Sly Venturi Scrubber uses the differential between high velocity gases and free-flowing water to create droplets which entrap contaminants, hold them in suspension and deliver them as a highly concentrated slurry. The Sly Venturi Scrubber offers more advantages in separating and recovering liquid mists and ultra-fine particulate than other gas cleaning methods.

See pages 12-15 for more Venturi information.

Standard Impinjet Efficiency@ Pressure Drop of 1-½" per Stage



Selecting the Right Collector



Advantages of the Sly Impinjet®

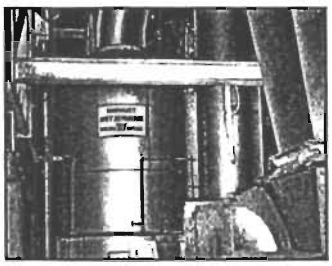
1.) High absorption efficiency for **gases, odors and vapors.** Experts agree that plate towers have the ability of removing gaseous pollutants to any desired concentration if a sufficient number of plates is used. This means high mass transfer rates can be achieved. Plate columns are preferable to packed towers whenever a large number of transfer units or theoretical stages are required.

2.) High collection efficiency for **particles** 1 micron in size or larger.

3.) These high efficiencies are achieved at a low pressure drop.

4.) Both particle collection and absorption of gases, odors, vapors, etc. can be done at the same time.

5.) Multiple stages can be provided.



Single stage No. 180 Impinjet Scrubber fabricated from 304 stainless steel, vents kiln handling lead and zinc ore. The unit operates at 20,000 CFM and a temperature of 200°F. Liquid consumption requirement is 60 GPM.

6.) Can be built in large sizes. Available in standard sizes.

7.) No moving parts to maintain.

8.) Extensive experience with many applications available.

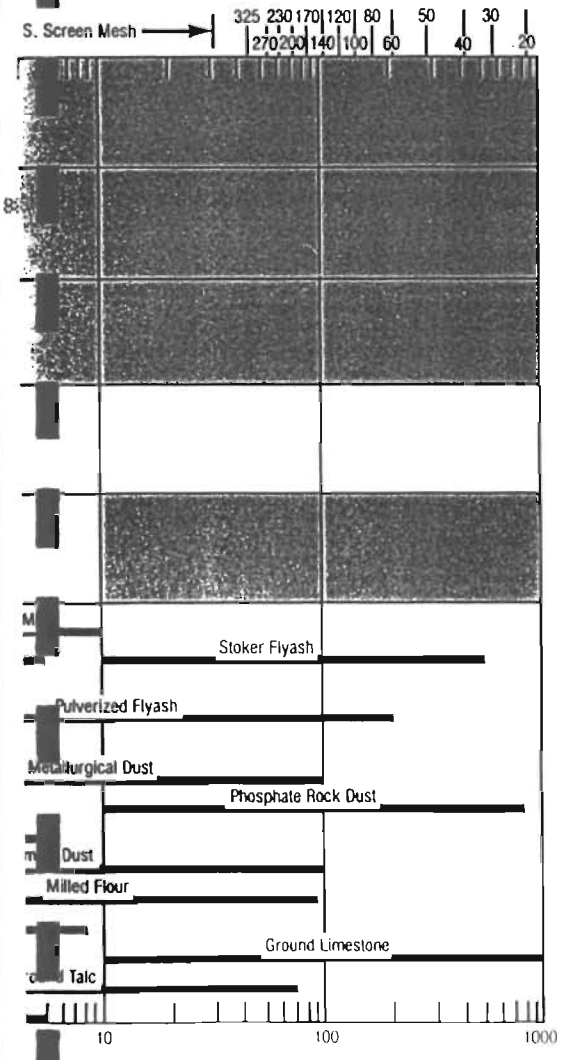
9.) Need less scrubbing fluid than most other scrubbers, but can handle higher liquid rates than packed towers.

10.) They can handle volume changes better than packed towers.

11.) They can handle high temperatures and temperature fluctuations. Cooling coils can be installed if heat of solution requires it.

12.) Cannot "channel" like packed towers.

13.) One plate is the equivalent of up to 8 feet of packing.

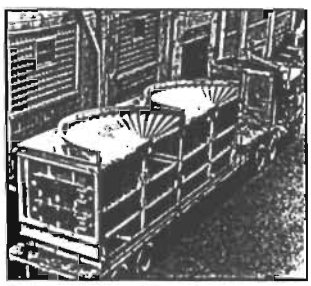


Cooling and Condensing

For these applications (heat transfer) thermal efficiencies of approximately 90% can be achieved. The outlet gas can be cooled to less than 5°F above the temperature of the incoming liquid. Often solvents such as alcohols, pentane, hexane, acetone, ethylene glycol, chloroform, etc. are recovered from inert gas streams such as nitrogen or carbon dioxide. Chilled solvent is used as direct contact condensing liquid and removes the heat from the gas stream as it gains heat. Scrubbers also recover waste heat. Heat from dryers and other processes that would normally be lost out of exhaust stacks is used to heat water being fed to the scrubber almost to the wet bulb temperature of the inlet gas. For cooling and condensing and for heat recovery the scrubber is capable of handling liquid rates of over 30 GPM per 1,000 CFM instead of the usual 2 to 3 GPM per 1,000 CFM.

Single stage units can be used wherever high efficiency at moderate temperatures is required. One stage (plate or tray) will do a thorough cleaning and cooling job, meeting codes on many applications.

Multi-stage units give a wide range of usefulness on high temperature applications, chemical absorption and where extremely high efficiency is needed.



Two stage Impinjet being shipped to site at a fluid bed coal dryer. 160,000 CFM enter at 150°. This is one of nineteen Sly Scrubbers sold to the same coal company.

Operating Principles

The gas passes up through the openings in the perforated plates (trays) which hold a bed of liquid. The secret is in the scrubber's design which uses an impingement baffle above each individual hole.

It is a modified sieve plate scrubber using flooded perforated plates with an impingement baffle over each hole. Over 4,750 holes/sq. ft.

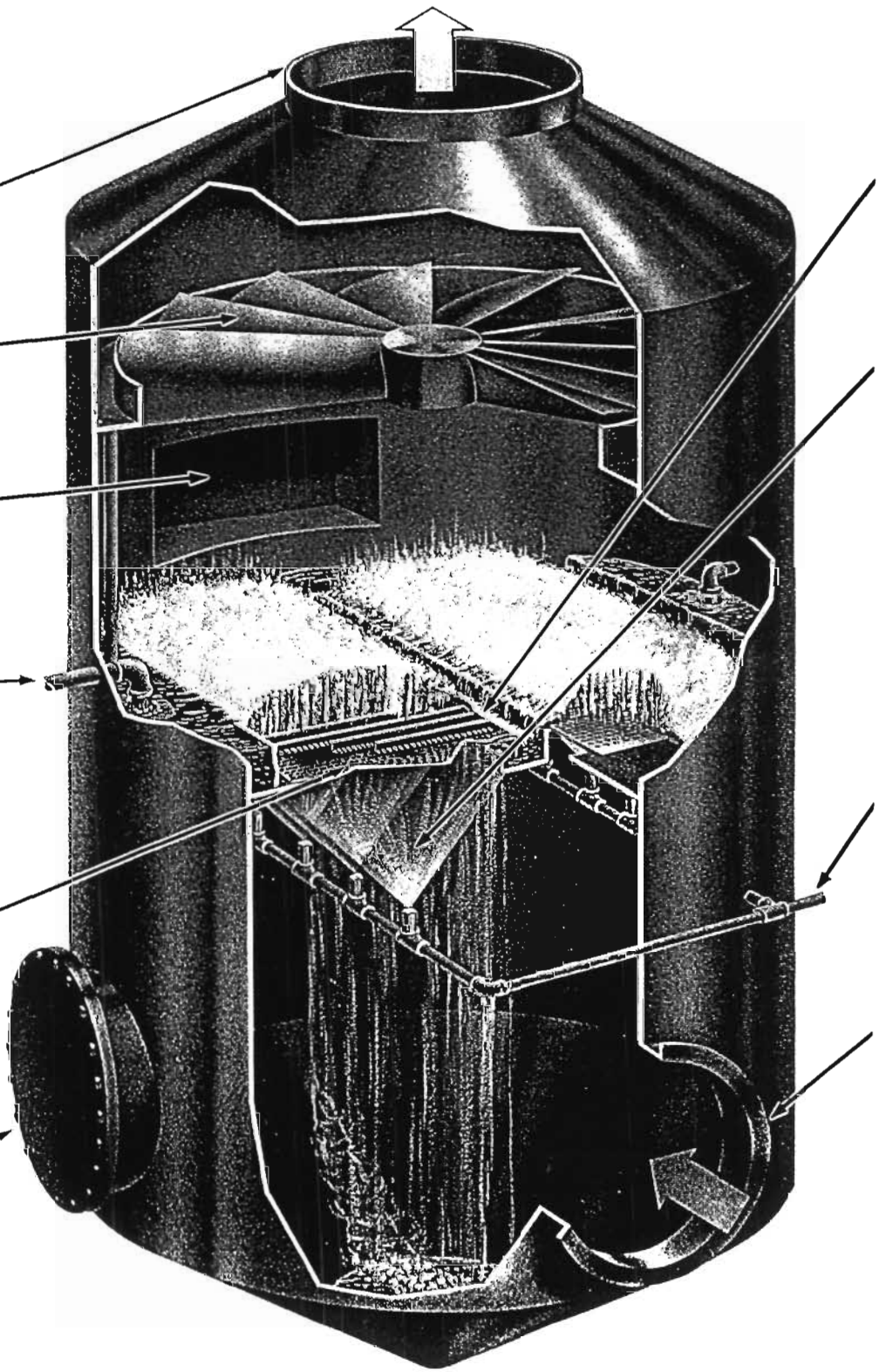
Gas velocities of 60 to 75 feet/second through the holes result in thousands of jets which atomize the liquid into droplets on the order of 100 microns/diameter to clean the contaminated gas. This entraps the particles in the scrubbing liquid. Each jet aspirates liquid from the blanket of scrubbing fluid and results in a wetted target surface on the baffle which is located just above the point of maximum velocity (vena contracta). This intimate gas liquid contact results in the maximum collection efficiency for particles and droplets as well as absorption (mass transfer) of gases, odors and vapors. When used for absorption, low outlet emissions can be achieved since at the top stage the fresh incoming scrubbing liquid contacts the air with the lowest concentration of contaminant after it passes through the lower stage or stages. Like all plate or tray type scrubbers, the Sly Impinjet Gas Scrubber is able to reduce gaseous pollutants to any desired concentration if a sufficient number of plate stages is used.

It is the tiny droplets, not the wetted baffles which are effective in collecting. Based on inertial impaction at 75 ft/sec for 1 micron sized particles with a specific gravity of 2.7, the efficiency of the 100 micron droplets is 80% but only 3% for the wetted target.

It is important to remember that the intimate contact of the gases and fine mist at the impingement baffle plates (trays, stages) results in very efficient a) cooling, b) absorption of gases, odors and vapors and c) collection of particles and mists.

An important feature of the particular design of scrubber is its freedom from pluggage in spite of the small holes. The continuous violent agitation of the blanket of scrubbing fluid prevents settling of particles and flushes them away. Sly's extensive experience with substances like clay prove this.

How The Impinjet® Operates



1. Scrubber Outlet - to fan, if suction system. To exhaust stack, if blow-in.
2. Fixed Blade Mist Eliminator - assures droplet-free air to process or atmosphere.
3. Access Door - permits inspection of plates. Peepholes and quick opening doors are available as options.
4. Liquid Supply and Weir (dam) - adjustable weir provides uniform liquid flow to plates. Recirculated slurries may be used if concentration does not exceed 10% by weight. Average flow 1-2 GPM/ 1000 CFM.
5. Impingement Baffle Plates - create interaction of gas stream and liquid. Additional plates (trays, stages) provide increased efficiency.
6. Access Door - for spray inspection and maintenance.

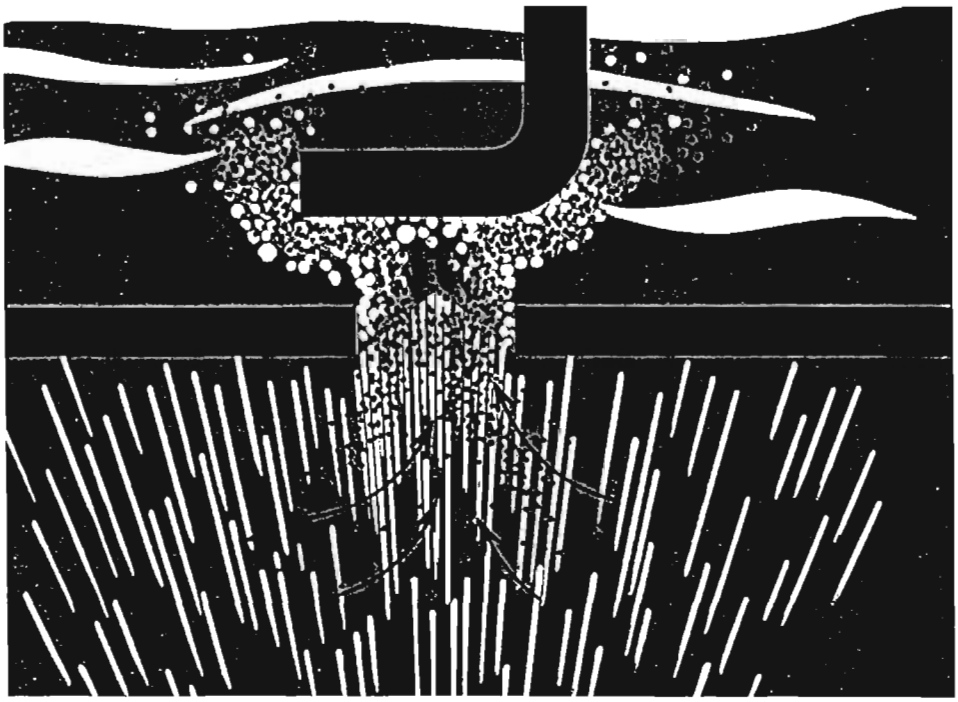
Impingement Baffle Plate Assures Thorough Scrubbing

7. Plate Discharge and Seal Drain - directs slurry to bottom of scrubber for removal. Non-clogging seal prevents short circuiting of gas.

8. Spray Section - for cooling and entrapment of larger particles. Spray washes under side of plate and walls to prevent material build-up. Sprays are non-clogging. Recirculated liquid may be used if particle sizes contained are below 3/32 inches.

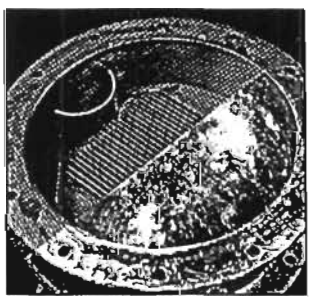
9. Liquid Spray Inlet - uses approximately 0.5 to 1 GPM/1,000 CFM at 20 PSIG. Liquid consumption is greater if cooling of gas is required. (Combining liquid utilized by liquid supply (No. 4) and spray inlet (No. 9) provides total liquid flow.)

10. Gas Inlet - if suction job, from process; if pressure, from blow-in fan.



Impinjet is actually two scrubbers in one. The spray section cools and humidifies entering gas while simultaneously removing larger particulate matter. In addition, the under-plate spray action keeps the plate and walls clean and prevents build-up.

Actual scrubbing is accomplished by the jet action of gas in the liquid, produced by the uniquely designed impingement baffle plate. This turbulent effect assures thorough wetting of particles. Impingement baffle plates are generally made of various stainless steels, but can also be fabricated from plastics and other materials.



Venturi Effect results in turbulent interaction of liquid and dirt laden gas flowing through perforated plate and striking wetted impingement baffle grid. (Each hole has an individual impingement surface). Minute liquid droplets are formed which entrap suspended matter in gas. Dirt carrying droplets mix with water flowing across baffles for ultimate disposal through drain. Cleaned gas passes into mist eliminator for return to process or atmosphere.

Two factors create the high efficiency found in our impingement plate design:

1. the formation of a great number of minute droplets of liquid at plate orifices, and
2. the high velocity, relative to the minute droplets, at which dust particles enter the orifices. (Few scrubbers have both high relative velocities and form minute droplets which in *combination* give the highest efficiency possible at any given pressure drop.)

Greater particle collection efficiency is attainable by increasing relative velocity (higher pressure drop). The net effect is an improvement in the relative velocity of dust and liquid droplets, intensifying the entrapment of dust particles by the liquid medium. This same principle is highly effective in gas cooling wherein high relative velocity and small droplet size assures intimate contact.

Impinjet® Scrubber Selection

For standard applications, Impinjet Scrubbers as shown in the chart below, are furnished with stainless steel type 304 baffle plates; 3/16-inch mild steel shell; all internal sprays and piping; mist eliminator; inspection doors and inlet and outlet flanges.

Coated mild steel, stainless steel, PVC, Polypropylene and FRP are all available for special chemical applications *(see chart on page 7)*.

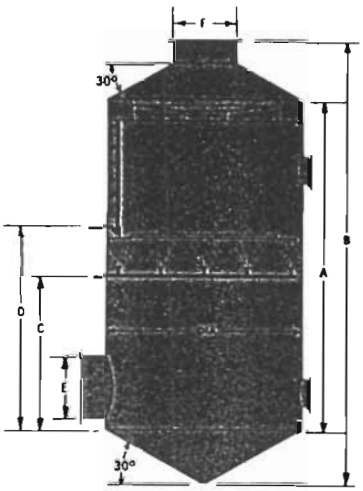
Complete or partial; alloy construction or capacities larger than tabulated below are engineered to your specific requirements. Consult your Sly representative or directly contact the factory.

Volume Correction

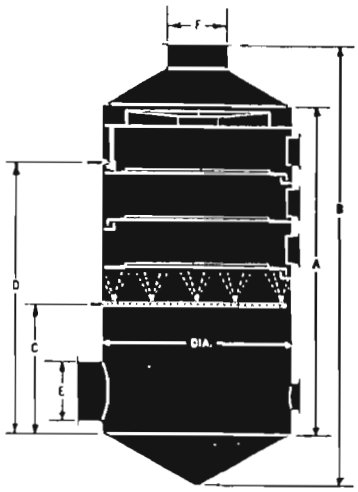
Converting inlet volume to outlet volume is necessary in sizing scrubber capacities. Inlet volume and inlet moisture content are either known or must be assumed from the application. The chart reflects the Volume Correction Factor needed to determine outlet volume by reading down from the intersection of inlet moisture and its temperature in °F. Inlet Volume x Correction Factor = Outlet Volume.

Example: Given Inlet Volume at 6000 CFM and Inlet Moisture at 0.10 #H_2O/#Dry Air @ 300 °F., chart shows Correction Factor of 0.83. Inlet Volume, 6000 CFM x Correction Factor, 0.83 = Outlet Volume of 4980 CFM.
Size Impinjet Scrubber for 4980 CFM. *In this case, you would select a 4'0" diameter scrubber.*

Single Stage

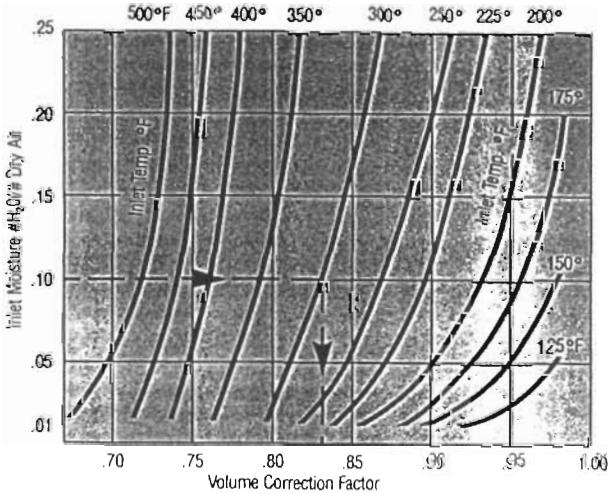


Three Stage



Volume Correction

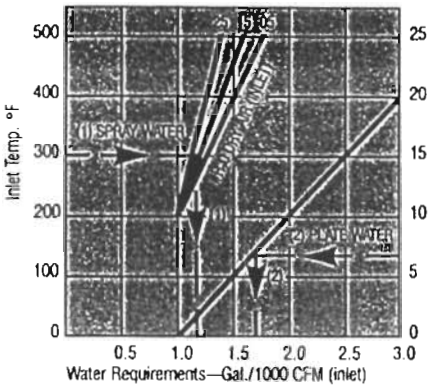
(use to determine outlet volume)



OUTLET VOLUME (CFM) Normal Capy 420 FPM	Max. Capy 560 FPM	Dia	Plate Water Inlet I.P.S. Inches	Spray Water Inlet I.P.S. Inches	Bottom Drain I.P.S. Inches	Impinjet Number	Single Stage Dimensions: Straight Side A	Over-All Height B	Spray Water Inlet C	Plate Water Inlet D	Inlet Flange Dia. E	Outlet Flange Dia. F
740	885	1'6"	½	½	1	115	5'4"	6' 4"	1' 3"	3' 3"	6"	7"
1350	1550	2'0"	¾	½	1	120	5'6"	6' 9"	1' 5"	3' 5"	8"	8"
2100	2450	2'6"	1	¾	1¼	125	5'9"	7' 2"	1' 7"	3' 7"	10"	11"
3080	3500	3'0"	1	¾	1¼	130	6'0"	7' 8"	1' 9"	3' 9"	1' 0"	1' 1"
4050	4800	3'6"	1¼	1	1½	135	6'3"	8' 2"	1'11"	3'11"	1' 2"	1' 3"
5300	6250	4'0"	1¼	1	1½	140	6'6"	8' 7"	2' 1"	4' 1"	1' 4"	1' 5"
6700	7950	4'6"	1¼	1	1½	145	6'9"	9' 1"	2' 3"	4' 3"	1' 6"	1' 7"
8250	9800	5'0"	1½	1¼	2	150	7'3"	9'10"	2' 3"	4' 3"	1' 7"	1' 9"
10000	11850	5'6"	1½	1½	2	155	7'6"	10' 3"	2' 5"	4' 5"	1' 9"	1'11"
11900	14100	6'0"	1½	1¼	2	160	7'9"	10' 9"	2' 8"	4' 8"	2' 0"	2' 2"
13950	16550	6'6"	2	1¼	2½	165	8'0"	11' 3"	2'10"	4'10"	2' 2"	2' 4"
16200	19200	7'0"	2	1½	2½	170	8'3"	11'10"	3' 1"	5' 1"	2' 4"	2' 5"
18600	22050	7'6"	2	1½	2½	175	8'6"	12' 3"	3' 3"	5' 3"	2' 6"	2' 8"
21150	25100	8'0"	2	1½	2½	180	9'3"	13' 3"	3' 6"	5' 6"	2' 8"	2'10"
23850	28350	8'6"	2½	2	3	185	9'9"	13'11"	4' 0"	6' 0"	2'10"	3' 0"
26750	31800	9'0"	2½	2	3	190	10'0"	14' 5"	4' 3"	6' 3"	3' 0"	3' 2"
29800	35400	9'6"	2½	2	3	195	10'6"	15' 2"	4' 8"	6' 8"	3' 2"	3' 4"
33000	39250	10'0"	2½	2	3	1100	10'9"	15' 8"	4'11"	6'11"	3'0"x8" 2"	3' 7"
36400	43250	10'6"	2½	2	3	1105	11'0"	16' 1"	5' 2"	7' 2"	3'0"x8" 6"	3' 9"
39950	47500	11'0"	3	2	4	1110	11'6"	16'10"	5' 6"	7' 6"	3'0"x8"10"	3'11"
43650	51900	11'6"	3	2	4	1115	13'0"	18' 7"	6' 0"	8' 0"	3'0"x4' 2"	4' 1"
47550	56500	12'0"	3	2½	4	1120	13'3"	19' 1"	6' 3"	8' 3"	3'0"x4' 6"	4' 4"
51550	61350	12'6"	3	2½	4	1125	13'6"	19' 7"	6' 6"	8' 6"	3'0"x5' 0"	4' 6"
55750	66500	13'0"	3	2½	4	1130	13'9"	20' 1"	6' 9"	8' 9"	3'0"x5' 4"	4' 8"
60150	71550	13'6"	3	2½	4	1135	14'0"	20' 6"	7' 0"	9' 0"	3'0"x5'10"	4'10"
64700	76950	14'0"	4	2½	4	1140	14'3"	21' 0"	7' 3"	9' 3"	3'0"x6' 4"	5' 0"

Water Requirements

(Fresh or Recirculated)



To use chart, the following inlet conditions must be known or assumed—temperature, moisture content, dust load and volume.

(1) Spray Water Requirements (at 20 psig) - apply inlet temperature and inlet moisture to chart; find intersection of the two values, read down to find Gals./1000 CFM.

(2) Plate Water Requirements (at free flow) is found by applying inlet dust load to average consumption curve; at intersection, read down to find Gals./1000 CFM.

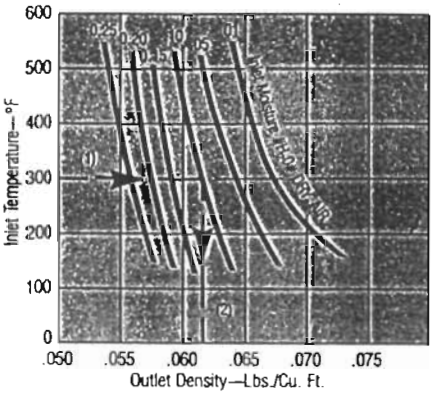
Example: Given an inlet temperature of 300°F., inlet moisture content of 0.10 #H_2O/#Dry Air, 7 Grains/Cu. Ft. inlet dust load and inlet volume of 6000 CFM.:

Spray Water Requirements (1) = 1.20 Gals/1000 CFM x 6000 = 7.20 GPM @ 20 psig

Plate Water Requirements (2) = 1.70 Gals./1000 CFM x 6000 = 10.20 GPM @ Free Flow

Total Water Requirements = 17.40 GPM

Density Correction



Outlet density is required in order to size exhaust equipment—ductwork and fans. At the intersection of inlet temperature and inlet moisture lines on chart, read down to find outlet density.

Example: Given (1) an inlet temperature of 300°F. and (2) inlet moisture content of 0.10 #H_2O/#, the chart reflects an outlet density of .0615 #/Cu. Ft.

Pressure Drop @ 70°F.

NUMBER OF STAGES	NORMAL CAPY. (INCHES, W.G.)	MAX. CAPY. (INCHES, W.G.)
ONE STAGE	3.0	4.25
TWO STAGE	4.5	6.4
THREE STAGE	6.0	8.5

Pressure drop is an important consideration in evaluating the efficiency expected of a scrubber in a given application and in fan, drive and motor.

When high efficiency is required, the use of additional stages provides a corresponding increase in pressure drop.

The above chart shows standard pressure drop in inches, w.g., across scrubber for 1 stage, 2 stages and 3 stages.

To correct pressure drop to operating conditions, multiply standard pressure drop by the ratio of outlet density to standard density.

Example: Using .0615 #/Cu. Ft. Dry Air from Density Correction example and the 1 stage average capacity pressure drop of 3" at 70°F. (density .075) the operating pressure drop is: 3" H_2O x .0615/.075 = 2.46 inches, w.g.

TWO STAGE DIMENSIONS

Impinjet Number	Straight Side A	Over-All Height B	Spray Water Inlet C	Plate Water Inlet D	Inlet Flange Dia. E	Outlet Flange Dia. F
215	7'4"	8' 4"	1' 3"	5' 3"	6"	7"
220	7'6"	8' 9"	1' 5"	5' 5"	8"	8"
225	7'9"	9' 2"	1' 7"	5' 7"	10"	11"
230	8'0"	9' 8"	1' 9"	5' 9"	1' 0"	1' 1"
235	8'3"	10' 2"	1'11"	5'11"	1' 2"	1' 3"
240	8'6"	10' 7"	2' 1"	6' 1"	1' 4"	1' 5"
245	8'9"	11' 1"	2' 3"	6' 3"	1' 6"	1' 7"
250	9'3"	11'10"	2' 3"	6' 3"	1' 7"	1' 9"
255	9'6"	12' 3"	2' 5"	6' 5"	1' 9"	1'11"
260	9'9"	12' 9"	2' 8"	6' 8"	2' 0"	2' 2"
265	10'0"	13' 3"	2'10"	6'10"	2' 2"	2' 4"
270	10'3"	13'10"	3' 1"	7' 1"	2' 4"	2' 6"
275	10'6"	14' 3"	3' 3"	7' 3"	2' 6"	2' 8"
280	11'3"	15' 3"	3' 6"	7' 6"	2' 8"	2'10"
285	11'9"	15'11"	4' 0"	8' 0"	2'10"	3' 0"
290	12'0"	16' 5"	4' 3"	8' 3"	3' 0"	3' 2"
295	12'6"	17' 2"	4' 6"	8' 8"	3' 2"	3' 4"
2100	12'9"	17' 8"	4'11"	8'11"	3'0"x3' 2"	3' 7"
2105	13'0"	18' 1"	5' 2"	9' 2"	3'0"x3' 6"	3' 9"
2110	13'6"	18'10"	5' 6"	9' 6"	3'0"x3'10"	3'11"
2115	15'0"	20' 7"	6' 0"	10' 0"	3'0"x4' 2"	4' 1"
2120	15'3"	21' 1"	6' 3"	10' 3"	3'0"x4' 6"	4' 4"
2125	15'6"	21' 7"	6' 6"	10' 6"	3'0"x5' 0"	4' 6"
2130	15'9"	22' 1"	6' 9"	10' 9"	3'0"x5' 4"	4' 8"
2135	16'0"	22' 6"	7' 0"	11' 0"	3'0"x5'10"	4'10"
2140	16'3"	23' 0"	7' 3"	11' 3"	3'0"x6' 4"	5' 0"

THREE STAGE DIMENSIONS

Impinjet Number	Straight Side A	Over-All Height B	Spray Water Inlet C	Plate Water Inlet D	Inlet Flange Dia. E	Outlet Flange Dia. F
315	9'4"	10' 4"	1' 3"	7' 3"	6"	7"
320	9'6"	10' 9"	1' 5"	7' 5"	8"	8"
325	9'9"	11' 2"	1' 7"	7' 7"	10"	11"
330	10'0"	11' 8"	1' 9"	7' 9"	1' 0"	1' 1"
335	10'3"	12' 2"	1'11"	7'11"	1' 2"	1' 3"
340	10'6"	12' 7"	2' 1"	8' 1"	1' 4"	1' 5"
345	10'9"	13' 1"	2' 3"	8' 3"	1' 6"	1' 7"
350	11'3"	13'10"	2' 3"	8' 3"	1' 7"	1' 9"
355	11'6"	14' 3"	2' 5"	8' 5"	1' 9"	1'11"
360	11'9"	14' 9"	2' 8"	8' 8"	2' 0"	2' 2"
365	12'0"	15' 3"	2'10"	8'10"	2' 2"	2' 4"
370	12'3"	15'10"	3' 1"	9' 1"	2' 4"	2' 6"
375	12'6"	16' 3"	3' 3"	9' 3"	2' 6"	2' 8"
380	13'3"	17' 3"	3' 6"	9' 6"	2' 8"	2'10"
385	13'9"	17'11"	4' 0"	10' 0"	2'10"	3' 0"
390	14'0"	18' 5"	4' 3"	10' 3"	3' 0"	3' 2"
395	14'6"	19' 2"	4' 6"	10' 8"	3' 2"	3' 4"
3100	14'9"	19' 8"	4'11"	10'11"	3'0"x3' 2"	3' 7"
3105	15'0"	20' 1"	5' 2"	11' 2"	3'0"x3' 6"	3' 9"
3110	15'6"	20'10"	5' 6"	11' 6"	3'0"x3'10"	3'11"
3115	17'0"	22' 7"	6' 0"	12' 0"	3'0"x4' 2"	4' 1"
3120	17'3"	23' 1"	6' 3"	12' 3"	3'0"x4' 6"	4' 4"
3125	17'6"	23' 7"	6' 6"	12' 6"	3'0"x5' 0"	4' 6"
3130	17'9"	24' 1"	6' 9"	12' 9"	3'0"x5' 4"	4' 8"
3135	18'0"	24' 6"	7' 0"	13' 0"	3'0"x5'10"	4'10"
3140	18'3"	25' 0"	7' 3"	13' 3"	3'0"x6' 4"	5' 0"

The Impinjet® Is Available Three Ways to Fit Your Dust or Fume Problems

Sly makes the Impinjet Scrubber in different configurations to meet different installation space problems. Each shape, however, contains the same high quality internal parts. Each type of scrubber employs the key to thorough, high efficiency cleaning— our singular impingement plate and baffle grid design.

These made-to-order shapes are:

Cylindrical-Round - capacities to 70,000 CFM. Shipped assembled—reduces installation time.

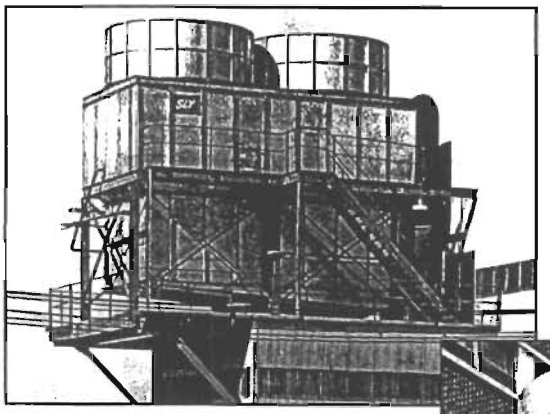
Square-Rectangular - 40,000 to over 1,000,000 CFM capacities. Shipped assembled to minimize field erection costs or shipped knocked down as required.

Impinjet Internals - components for use in silos, stacks or other receptacles are custom engineered to the container for the application. Field welding or cutting may not be required.

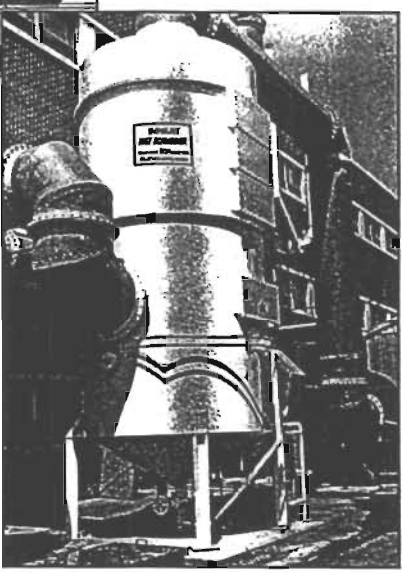
Three unique shapes accommodate unusual space limitations. This is only one of the reasons why Round and Square-rectangular Impinjet scrubbers and Impinjet Internals are progressive answers to many dust and fume control problems.

More important, each scrubber is engineered to economically meet capacity, temperature and liquid requirements for specific dust and fume applications.

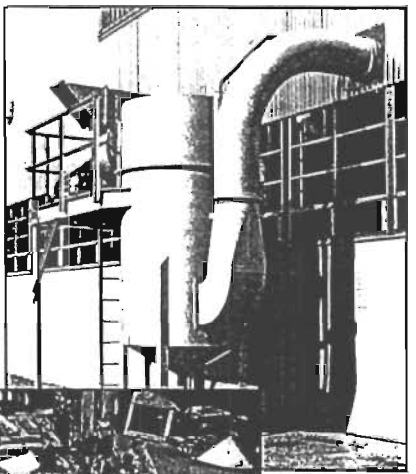
Depth of know-how and quality construction assure highest cleaning efficiencies, from the smallest 200 CFM capacity units to the large 1,000,000 CFM capacity models.



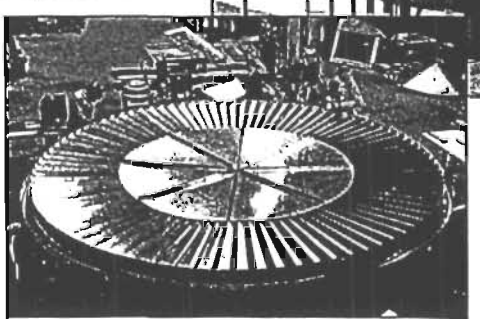
Rectangular Scrubber -Republic Steel Corp. Unit is used in processing coal. Operating to 146,000 CFM at 200°F, the scrubber collects coal dust and fly ash from a fluid bed coal dryer exhaust.



Round Scrubber - Sylvania Electric Products, Inc. This three stage Impinjet is used for dust control and fume absorption. The unit is designed to handle 30,000 CFM at 180°F. Polyvinyl dichloride (PVDC) impingement baffle plates and butyl lined shell are employed to resist corrosion. Caustic solutions are recirculated via an integral reservoir in this Scrubber's base.



Round Scrubber - Sealed Power Corp. Vents spin molding machines. Build to operate at 5,000 CFM, 120°F, the scrubber has provisions for increasing capacity to 6,000 CFM. Note that this unit has top horizontal discharge instead of vertical discharge as well as a fan and motor platform.



Impinjet Mist Eliminator - 20 feet in diameter in final stage of fabrication. Installation in customer's concrete stave silo.

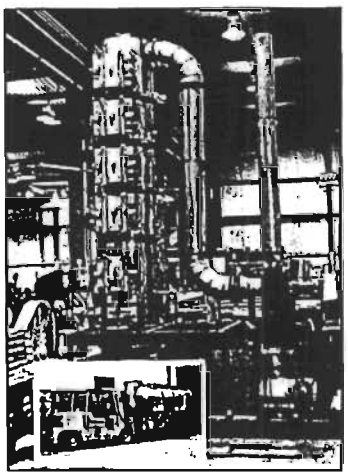
How To Select Your Venturi or Impinjet® Scrubber's Materials of Construction

MAX. USE TEMP-GAS STREAM °F MAX. USE TEMP-SOLUTION °F		400 140	— 200	— 200	— 200	170 140	400 220
Material Collected (5% by Weight)	Mild Steel	Mild Steel Coated	304 S/S	316 S/S	316-L S/S	PVC	FRP
Acetic Acid	N	G	E	E	E	E	E
Alum	N	G	E	E	E	E	E
Aluminum Chloride	N	E	N	N	N	E	E
Aluminum Sulfate	N	E	E	E	E	E	E
Ammonia (Wet)	N	G	E	E	E	N	E
Ammonium Chloride	N	E	G	G	G	E	E
Ammonium Hydroxide	N	N	E	E	E	E	E
Ammonium Nitrate	N	E	E	E	E	E	E
Ammonium Phosphate	N	G	G	G	G	E1	E
Ammonium Sulfate	N	G	G1	E	E	E	E
Black Liquor ($NaOH$, Na_2S, Na_2CO_3)	N	N	N	N	G	E	E
Borax	N	G	E	E	E	E	E
Boric Acid	N	G	E	E	E	E	E
Calcium Chloride	N	G	G	E	E	E	E
Calcium Hypochlorite	N	N	N	N	N	E	E
Carbonic Acid	N	G	E	E	E	E	E
Chlorine	N	N	N	N	N	E	E
Chlorine Dioxide	N	N	N	N	N	E2	E
Chromic Acid	N	N	G	G	G	E3	E
Citric Acid	N	G	E	E	E	E	E
Copper Chloride	N	N	N	N	N	E	E
Copper Sulfate	N	N	E	E	E	E	E
Coal Dust	E	E	E	E	E	E	E
Coal Dust (Dryers—SO_2)	N	G	E	E	E	N	N
Ferric Chloride	N	N	N	N	N	E	E
Ferric Sulfate	N	N	E	E	E	E	E
Ferrous Sulfate	N	N	E	E	E	E	E
Hydrochloric Acid	N	G	N	N	N	E	E
Hydrofluoric Acid	N	N	N	N	N	G	E8
Hydrogen Sulfide	N	N	N	G	G	E	E
Hydrogen Peroxide	N	N	G	G	G	E	E
Magnesium Chloride	N	N	G	G	G	E	E
Magnesium Hydroxide	N	N	G	G	G	E	E
Magnesium Sulfate	N	N	G	G	G	E	E
Mixed Acid (15% Nitric & 4% HF)	N	N	N	N	N	G4	E7
Nitric Acid	N	N	E	E	E	E	E8
Oleic Acid	N	N	G4	G4	G4	N	E
Phosphoric Acid	N	N	G5	G5	G5	E	E
Sodium Carbonate	N	N	E	E	E	E	E7
Sodium Chloride	N	E	G5	E5	E5	E	E
Sodium Hydroxide	E6	E6	E	E	E	E	E
Sodium Hypochlorite	N	N	G4	G4	G4	E	E8
Sodium Nitrate	G	G	E	E	E	E	E
Sodium Sulfate	G	G	E	E	E	E	E
Sodium Sulfite	G	G	E5	E5	E5	E	E
Sulfur Dioxide	N	N	G	E	E	E	E
Sulfuric Acid	N	G	E	E	E	E	E
Sulfurous Acid	N	G	G5	G5	G5	E	E
Zinc Chloride	N	N	N	G	G	E	E
Zinc Sulfate	N	N	N	G	G	E	E

E = Excellent
G = Good
N = Not Suitable for Use

1 Under basic or neutral conditions only
2 At ambient temperature
3 Aqueous solution only

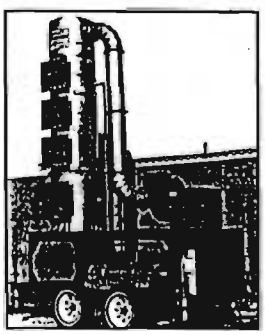
4 to 100°F
5 to 120°F
6 to 135°F
7 to 140°F
8 to 180°F



Field Testing Units & Packaged Systems

As an optional service, we can provide "Package Systems" to include such auxiliaries as fans, pumps, strainers, recirculation tanks, pH controls, flow control and measurement, and interconnecting piping and fittings. A typical such package is the Impinjet test unit shown in photo.

For a quotation on packaged auxiliaries, please furnish a list of items to be included and as much detail on specifications as possible. Quotations on packaged auxiliaries, being custom engineered, will require more lead time in preparation than our standard product line.



For actual field testing at your plant, we can send a portable Impinjet scrubber. The rental cost is nominal.

APPENDIX C

SCREENING THRESHOLD TECHNIQUE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

October 28, 1986

Mr. David Buff
KBN Engineering and Applied
Sciences, Inc.
P. O. Box 14288
Gainesville, Florida 32604

Re: Jefferson Smurfit PSD Permit Application

Dear Dave:

In order to reduce the number of possible disputes with EPA with regard to which sources need to be included in a PSD permit modeling exercise, the department is recommending that you use the EPA-approved North Carolina "Screening Threshold" method. I have included a copy of the paper describing the technique, as well as correspondence between the State of North Carolina and the EPA regarding this method. We further recommend that the screening area boundary be 50 km.

Should you wish to modify this technique or present one of your own, the department will review your proposal and submit it to the EPA for approval.

With regard to your emission inventory, we have included a list of stack parameters for the Container Corporation of America facility (Table 1) as presented to the department by the company on their Annual Operating Report for 1985. Furthermore, we request that you contact the Jacksonville local program in order to verify the SO_2 emissions for the two bark-fired boilers at the Jacksonville Kraft facility. Our records are unclear with regard to these sources.

If you have any questions regarding the proposed screening technique or on the stack parameter data please call me at (904) 488-1344.

Sincerely,

Max A. Linn
Meteorologist
Bureau of Air Quality
Management

ML/ps

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET
ATLANTA, GEORGIA 30365

SEP 5 1985

REF: APT-AP

RECEIVED
SEP 12 1985
AIR QUALITY

Eldewins Haynes
Air Permit Unit
State of North Carolina Department of
Natural Resources & Community Development
512 North Salisbury Street
Raleigh, North Carolina 27611

Subject: A Screening Method for PSD

Dear Mr. Haynes:

This is to acknowledge receipt of your July 22, 1985, letter containing a screening procedure for eliminating sources from the emission inventory for modeling purposes. EPA has reviewed your submittal and has determined that your screening procedure is consistent with the PSD Workshop Manual. Therefore, approval is hereby given to use the screening procedure.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Acting Chief
Air Programs Branch

DER
APR 14 1986
BAQM

State of North Carolina
Department of Natural Resources and Community Development
Division of Environmental Management
512 North Salisbury Street • Raleigh, North Carolina 27611

James G. Martin, Governor
S. Thomas Rhodes, Secretary

R. Paul Wilms
Director

July 22, 1985

Mr. Lewis Nagler
Air Management Branch
EPA Region IV
345 Courtland Street
Atlanta, Georgia 30365

Dear Mr. Nagler:

Subject: A Screening Method for PSD

A simple screening procedure which is applicable to PSD has been developed by the North Carolina Air Quality Section. The "Screening Threshold" method is designed to rapidly and objectively eliminate from the emissions inventory those sources which are beyond the PSD impact area yet within the screening area, but are not likely to have significant interaction with the PSD source. Sources which are flagged by this procedure may then be evaluated with conventional screening techniques, or else be included in refined modeling.

Page I-C-18 of the PSD Workshop Manual does state "A simple screening model technique can be used to justify the exclusion of certain emissions...Such exclusions should be justified and documented." The "Screening Threshold" method is documented in the attachment.

We would very much appreciate your comments and ultimate approval. Please feel free to direct any questions or comments to me in writing or by phone at (919) 733-7015.

Sincerely,

Eldewins Haynes

Eldewins Haynes, Meteorologist
Air Permit Unit

Attachment

cc: Mr. Ogden Gerald
Mr. Mike Sewell
Mr. Sammy Amerson
Mr. Jerry Clayton
Mr. Richard Laster
Regional Air Engineers

"Screening Threshold" Method for PSD Modeling
North Carolina Air Quality Section

This method is best suited for situations where a PSD source has several sources outside its impact area, but within its screening area. The object is to find an effective means to minimize the number of such sources in a model, yet to include all sources which are likely to have a significant impact inside the impact area.

As a first-level screening technique, it is suggested to include those sources within the screening area when

$$Q = 20D$$

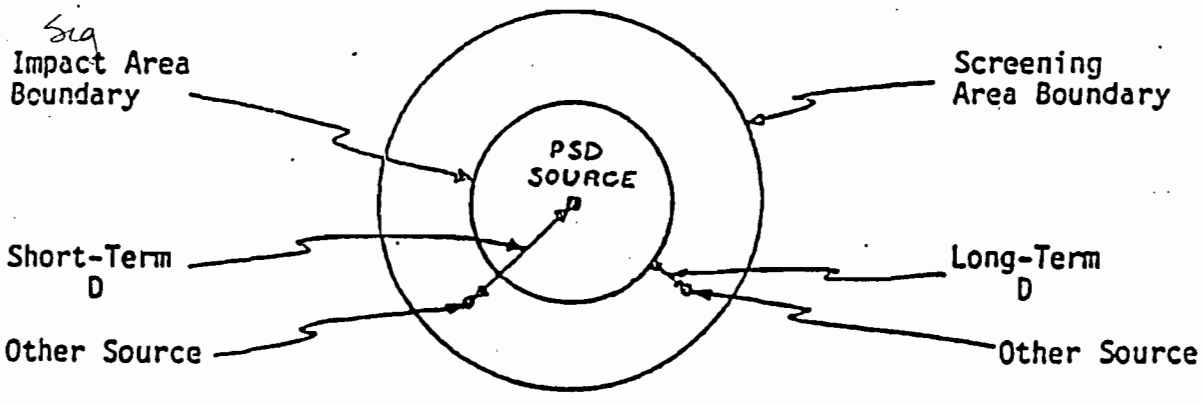
where Q is the maximum emission rate, in tons/year, of the source in the screening area; and D is a distance, in kilometers, from either:

a. the source in the screening area to the nearest edge of the impact area, for long-term analyses

or

b. the source in the screening area to the PSD source defining the impact area, for short-term analyses.

The figure below illustrates the difference between the long-term D and the short-term D.



This method does not preclude the use of alternate screening techniques or of more sophisticated screening techniques given the approval of the review agency. Also, this method does not prevent the review agency from specifying additional sources of interest in the modeling analysis.

The justification for this "Screening Threshold Method" rests upon the following assumptions:

a. effective stack height = 10 meters
b. stability class D (neutral)
c. 2.5 meter/second wind speed
d. mixing height = 300 meters
e. Q = 20D = critical emission rate for a given pollutant
f. one-hour concentrations derived from figure 3-5D in Turner's WADE or from PTDIS.
g. 3-hour and 24-hour concentrations estimated using "Vol. 10R". Annual impacts are 1/7 of 24 hour impacts.

The results, for various distances, are shown in the table below:

D (km)	Q (T/yr)	1-hr Conc. (ug/m^3)	3-hr Conc. (ug/m^3)	24-hr Conc. (ug/m^3)	Annual Conc. (ug/m^3)
0.5	10	47	42	19	2.7
1.0	20	32	29	13	1.9
1.5	30	27	24	10	1.4
2.0	40	23	21	9	1.3
3	60	18	16	7	1.0
4	80	17	15	7	1.0
5	100	14	13	6	1
6	120	13	12	5	1
10	200	10	9	4	1
20	400	7	6	3	1
30	600	6	6	3	1
40	800	6	6	3	1
50	1000	7	6	3	1

The "Screening Threshold" method is conservative. Most sources either have effective stack heights greater than 10 meters; or they have several short stacks spread out over an industrial complex. Thus, actual modeled concentrations will most likely be lower than the "Screening Threshold" would indicate in the table above. One implication of the table is that all major sources within 5 km of the subject PSD source or within 5 km of the PSD source's impact area should be scrutinized before being exempted from the final emissions inventory.

The "Screening Threshold" method is in qualitative agreement with the suggestions on page I-C-18 of the Prevention of Significant Deterioration Workshop Manual (1980). On that page, it is suggested that a 100 T/Y source 10 km outisde the impact area may be excluded from the analysis. The above table would exclude a 100 T/Y source more than 5 km beyond the impact area for long-term analyses or more than 5 km away from the PSD source for short-term analyses; if the source is inside the impact area, it must be included regardless of the "Screening

Threshold". The PSD Workshop Manual also states on page I-C-18 that a 10,000 T/Y source 40 km outside the impact area would probably have to be included in the increment analysis. By the "Screening Threshold" method, the critical distance D = Q/20 = 10,000/20 = 500 km. Thus a 10,000 T/Y source within 500 km would always be included for short-term and long-term analyses if within the screening area.

This "Screening Threshold" method is quick, inexpensive to execute, conservative, and consistent with the intent of the PSD Workshop Manual.

APPENDIX D

SO_2 EMISSION INVENTORY

Table D-1. Summary of SO2 Stack and Operating Parameters for Individual Sources Considered in the AAQS Modeling Analysis (Page 1 of 4)

ARAPDXD1
4/2/92

APIS Number	Facility	APIS Source Number	Source Description	Maximum SO2 Emissions (g/sec)	Location Relative To Proposed* X (m)	Location Relative To Proposed* Y (m)	Stack Data Height (m)	Stack Data Diameter (m)	Operating Data Temperature (K)	Operating Data Velocity (m/sec)	Included in the Modeling Analysis?
40TPA530027	IMC Noralyn Mine Road	01	Dryer #1	1.2	1100	-300	23.16	1.98	394	17.07	Yes
		02	Rock Dryer #2	13.3	1100	-300	16.76	2.83	341	8.53	
40TPA530053	Farmland Industries	03	Sulf Acid Plt #3	33.6	-4100	-500	30.48	2.29	355	9.27	Yes
		04	Sulf Acid Plt #4	33.6	-4100	-500	30.48	2.29	355	9.27	
		05	Sulf Acid Plt #5	42.0	-4100	-500	45.72	2.44	355	9.66	
		28	Therminol Heater	2.3	-4100	-500	28.96	1.68	605	3.35	
40TPA530065	Kaplan Industries	02	Boiler	4.0	4700	-1300	4.27	0.40	422	38.16	Yes
		03	Boiler	5.7	4700	-1300	4.27	0.40	422	38.16	
		04	Boiler	1.7	4700	-1300	4.27	0.40	450	38.16	
40TPA530052	C.F. Industries-Bartow	NA	DAP	4.3	-5600	1800	9.11	0.70	450	22.49	Yes
		NA	Sulf Acid Plt #7	52.9	-5600	1800	67.06	2.41	351	9.81	
40TPA530046	W.R. Grace/Sem. Fert.	08	Sulf Acid Plt #3	58.0	-3800	6100	45.72	2.04	304	9.14	Yes
		12	Sulf Acid Plt #4	40.3	-3800	6100	60.96	1.52	341	24.38	
		13	GTSP	0.2	-3800	6100	30.48	2.04	325	13.11	
		14	GTSP Scrubber	0.1	-3800	6100	16.15	0.67	302	3.96	
		21	DAP #4	4.4	-3800	6100	40.23	2.13	316	26.21	
		30	GTSP	0.03	-3800	6100	24.38	2.01	314	16.46	
		31	Rock Dryer-East	41.1	-3800	6100	15.24	2.04	333	17.07	
		32	Sulf Acid Plt #6	36.0	-3800	6100	60.96	1.52	347	28.35	
		33	Sulf Acid Plt #5	36.0	-3800	6100	60.96	1.52	347	28.35	
		39	Rock Dryer-West	41.1	-3800	6100	15.24	2.04	333	17.07	
40TPA530048	Royster Co.	02	Sulf Acid Plant#2	35.7	-6800	4500	60.96	2.13	360	12.19	Yes
		05	DAP Scrubber	1.1	-6800	4500	31.09	2.68	316	7.92	
		09	Aux Boiler	0.1	-6800	4500	13.72	1.13	300	2.44	
40TPA530054	Agrico Chemical-Pierce	01	Rock Dryer #1	3.8	-9900	-1600	24.38	3.05	316	5.49	Yes
		04	Rock Dryer #3,4	8.2	-9900	-1600	24.38	2.44	321	21.03	
40TPA530055	Agrico Chem.-S. Pierce	01	Aux Boiler	8.0	-6100	-9100	10.67	1.46	494	15.54	Yes
		04	Sulf Acid Plt #10	42.0	-6100	-9100	45.72	1.55	350	28.04	
		05	Sulf Acid Plt #11	42.0	-6100	-9100	45.72	1.55	344	25.91	
		23	GTSP	16.6	-6100	-9100	42.67	2.74	305	10.36	
		NA	Proposed	113.5	-6100	-9100	45.72	1.60	350	39.04	
40TPA530051	U. S. Agri-Chemicals	06	Aux Boiler	6.4	2400	-11600	21.34	1.13	478	14.94	Yes
		16	Sulf Acid-Train #1	63.0	2400	-11600	53.40	2.59	355	15.91	
		17	Sulf Acid-Train #2	63.0	2400	-11600	53.40	2.59	355	15.91	

Table D-1. Summary of SO2 Stack and Operating Parameters for Individual Sources Considered in the AAQS Modeling Analysis (Page 2 of 4)

APIS Number	Facility	APIS Source Number	Source Description	Maximum SO2 Emissions (g/sec)	Location Relative To Proposed*		Stack Data		Operating Data		Included in the Modeling Analysis?
					X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
40TPA530056	IMC-Prairie	01	Lime Bucket Elev	3.1	-10700	6400	27.43	0.30	311	12.80	No
40TPA530080	Imperial Phosphate	01	GNSP Dryer	6.9	-8800	-11100	27.43	1.52	333	20.42	Yes
		02	Boiler	1.0	-8800	-11100	27.43	0.61	494	7.01	
40TPA530167	Laidlaw Environ. Serv.	02	Boiler	6.9	10400	11300	6.10	0.67	489	5.79	No
40TPA530057	Conserv. Chemicals	02	DAP Cooler	0.3	-14900	3600	15.85	0.76	322	20.12	Yes
		05	DAP #1	42.0	-14900	3600	45.72	2.29	352	10.30	
		12	Phos Rock Dryer	3.3	-14900	3600	24.69	2.29	328	3.66	
		15	Standby Boiler	0.1	-14900	3600	8.23	0.61	533	13.72	
		16	Boiler	0.2	-14900	3600	11.89	0.98	533	8.84	
40TPA530047	Mobil Chem Co. Nichols	01	Rotary Rk Dryer #1	19.7	-15200	4700	24.38	2.29	344	12.50	Yes
		02	Rotary Rk Dryer #2	19.7	-15200	4700	24.38	2.29	344	12.50	
		03	Rotary Kiln	0.05	-15200	4700	30.48	1.10	339	18.90	
		04	Dryer #4	2.4	-15200	4700	25.91	2.29	339	15.21	
		08	Boiler	1.8	-15200	4700	3.96	0.76	522	1.83	
40TPA530059	IMC - New Wales	02	Sulf Acid Plt #1	61.0	-16900	-1200	60.96	2.59	350	15.30	Yes
		03	Sulf Acid Plt #2	61.0	-16900	-1200	60.96	2.59	350	15.30	
		04	Sulf Acid Plt #3	61.0	-16900	-1200	60.96	2.59	350	15.30	
		09	DAP Plant #1	9.4	-16900	-1200	40.54	2.13	314	14.94	
		10	GTSP	5.6	-16900	-1200	40.54	1.83	316	20.42	
		13	Standby Boiler	71.7	-16900	-1200	28.96	1.71	564	17.07	
		27	Granulation Plant	2.3	-16900	-1200	52.43	2.44	322	13.11	
		42	Sulf Acid Plt #4	61.0	-16900	-1200	60.66	2.59	350	15.30	
		44	Sulf Acid Plt #5	61.0	-16900	-1200	60.66	2.59	350	15.30	
		46	DAP Plant #2	5.6	-16900	-1200	36.58	1.83	319	20.15	
40TPA530044	Gardinier	01	Phos Rock Dryer	33.8	1700	-17300	19.20	2.90	290	7.01	Yes
40HIL290102	Mobil Big Four Mine	01	Phos Rock Dryer	16.4	-18900	-11000	30.48	1.83	333	12.50	Yes
NA	AMAX	NA	NA	0.6	-18800	-12900	8.20	0.41	505	7.57	Yes
		NA	NA	16.4	-18800	-12900	30.48	1.83	334	7.26	
NA	Hardee Power Station	NA	5 CT Units	277.6	-8800	-23200	22.86	4.88	389	23.90	Yes

Table D-1. Summary of SO2 Stack and Operating Parameters for Individual Sources Considered in the AAQS Modeling Analysis (Page 3 of 4)

APIS Number	Facility	APIS Source Number	Source Description	Maximum SO2 Emissions (g/sec)	Location Relative To Proposed*		Stack Data		Operating Data		Included in the Modeling Analysis?
					X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
40HIL290075	Consolidated Minerals	03	Kiln #2	0.003	-19800	15700	46.33	1.77	300	9.45	Yes
		20	Kewanee Boiler	0.1	-19800	15700	6.10	0.37	605	20.12	
		22	Fluid Bed Reac #1	11.6	-19800	15700	46.33	1.77	300	11.89	
		24	Fluid Bed Reac #2	11.6	-19800	15700	46.33	1.77	295	10.97	
		26	Kilns 3,4,5	15.4	-19800	15700	46.33	1.77	298	13.11	
40TPA530004	Lakeland Power/McIntosh	01	Boiler #1	341.3	-4400	25600	45.72	2.74	419	23.77	Yes
		02	Peaking Unit #2	1.5	-4400	25600	6.10	0.79	653	23.47	
		03	Peaking Unit #3	1.5	-4400	25600	6.10	0.79	653	23.47	
		04	Peaking Unit #1	8.3	-4400	25600	10.97	2.80	791	0.30	
		05	Unit #2 Generator	25.7	-4400	25600	47.55	3.17	403	21.03	
		06	Unit #3-Coal	500.1	-4400	25600	76.20	4.88	350	19.69	
40TPA530003	Lakeland Power/Larsen	01	Unit #4	93.3	-4600	25600	50.29	3.05	433	5.49	Yes
		02	Steam Gen #5	0.4	-4600	25600	50.29	3.05	444	6.40	
		03	Steam Gen #6	2.8	-4600	25600	50.29	3.05	444	6.40	
		04	Steam Gen #7	18.7	-4600	25600	50.29	3.05	444	6.71	
		06	Turbine #3	0.2	-4600	25600	9.75	1.52	700	171.30	
		07	Turbine #2	0.01	-4600	25600	9.75	1.52	700	171.30	
		NA	CT	29.1	-4600	25600	30.48	5.79	783	28.22	
40HIL290101	IMC - Fort Lonesome	01	Phos Rk Dryer #1	18.4	-24100	-12700	38.10	2.90	339	10.12	Yes
		02	Phos Rk Dryer #2	21.2	-24100	-12700	38.10	2.44	346	18.41	
		05	Fuel Preheater	0.3	-24100	-12700	6.10	0.30	616	8.23	
40TPA530002	Citrus World	01	Peel Dryer	8.1	27400	6700	22.86	0.98	323	10.67	Yes
		02	Boiler #4	0.003	27400	6700	12.19	1.71	355	8.23	
		03	Boiler #5	0.001	27400	6700	12.19	1.10	505	1.22	
		04	Boiler #3	0.004	27400	6700	12.19	1.10	505	1.22	
		05	Boiler #2	0.004	27400	6700	12.19	0.85	505	2.44	
		07	Peel Dryer	9.1	27400	6700	22.86	0.76	325	12.19	
		13	Peel Dryer	8.1	27400	6700	24.38	0.76	313	21.95	
		17	Boiler #1	0.001	27400	6700	12.19	1.10	505	1.22	
		20	Gas Turbine	0.003	27400	6700	9.14	0.91	558	32.92	
40TPA250009	Wachula City Power	01	Peeking Unit #1	1.0	4800	-33600	10.67	0.55	505	21.95	No
		02	Peeking Unit #2	1.0	4800	-33600	10.67	0.30	589	57.91	
		03	Peeking Unit #3	1.0	4800	-33600	10.67	0.55	505	32.00	
		04	Peeking Unit #4	1.0	4800	-33600	10.67	0.55	505	32.00	
		05	Peeking Unit #5	1.0	4800	-33600	10.67	0.55	505	32.00	

Table D-1. Summary of SO2 Stack and Operating Parameters for Individual Sources Considered in the AAQS Modeling Analysis (Page 4 of 4)

APIS Number	Facility	APIS Source Number	Source Description	Maximum SO2 Emissions (g/sec)	Location Relative To Proposed*		Stack Data		Operating Data		Included in the Modeling Analysis?
					X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
40TPA530019	Citrus Hill Manufacturing	01	Citrus Peel Dryer	11.5	34300	-12300	23.16	0.98	350	20.12	No
		04	Steam Boiler #1	8.3	34300	-12300	20.73	0.98	458	11.28	
		05	Steam Boiler #2	8.0	34300	-12300	18.90	1.07	458	9.45	
		07	Boiler #3	0.003	34300	-12300	21.95	0.91	550	9.14	
40TPA250011	American Orange Corp.	01	Heat Evaporator	6.2	16200	-33300	19.51	0.85	333	10.67	No
		02	Citrus Peel Dryer	6.2	16200	-33300	10.67	3.96	358	1.52	
40TPA530001	Alcoma Packing	01	Oil Fired Boiler	5.8	38000	4900	21.34	0.61	480	21.95	No
		04	Cleaver Boiler	5.3	38000	4900	21.34	0.70	480	15.85	
		05	Citrus Peel Dryer	16.4	38000	4900	27.13	0.98	333	10.06	
NA	C F Industries	NA	Unit C	54.6	-25600	35400	60.35	2.44	353	17.77	Yes
		NA	Unit D	54.6	-25600	35400	60.35	2.44	353	17.77	
40HIL290261	Hillsborough County RRF	01	Unit #1	7.1	-45400	12100	50.00	1.80	491	18.29	No
		02	Unit #2	7.1	-45400	12100	50.00	1.80	491	18.29	
		03	Unit #3	7.1	-45400	12100	50.00	1.80	491	18.29	
52FTM280003	FPL-Avon Park	02	Unit #2	1.7	37800	-30100	59.74	1.46	433	57.00	No
		03	Peaking Unit #1	0.1	37800	-30100	16.76	3.05	728	129.24	
		04	Peaking Unit #2	0.1	37800	-30100	45.42	3.35	728	106.68	
40HIL290076	Delta Asphalt	01	Asphalt Batch	3.8	-41500	24800	8.53	1.16	422	24.38	No

Note: NA = data not available.

* Proposed facility located at 413.6 km east and 3080.6 km north.

Table D-2. Summary of Stack and Operating Parameters for Combined Sources Considered in the AAQS Modeling Analysis (Page 1 of 2)

ARAPDXD2
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APIS Number	Facility	APIS Source Numbers	Maximum SO2 Emissions (g/sec)	Location Relative To Proposed*		Stack Data		Operating Data		ISCST Model ID
				X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
40TPA530027	IMC Noralyn Mine Road	01	1.2	1100	-300	23.16	1.98	394	17.07	1001
		02	13.3	1100	-300	16.76	2.83	341	8.53	1002
40TPA530053	Farmland Industries	03,04	67.2	-4100	-500	30.48	2.29	355	9.27	118
		05	42.0	-4100	-500	45.72	2.44	355	9.66	119
		28	2.3	-4100	-500	28.96	1.68	605	3.35	1101
40TPA530065	Kaplan Industries	02,03,04	11.4	4700	-1300	4.27	0.40	422	38.16	1201
40TPA530052	C.F. Industries-Bartow	NA	4.3	-5600	1800	9.11	0.70	450	22.49	112
		NA	52.9	-5600	1800	67.06	2.41	351	9.81	113
40TPA530046	W.R. Grace/Sem. Fert.	08,13,14,21,30	62.7	-3800	6100	45.72	2.04	304	9.14	1301
		12,32,33	112.3	-3800	6100	60.96	1.52	341	24.38	1302
		31,39	82.2	-3800	6100	15.24	2.04	333	17.07	1303
40TPA530048	Royster Co.	02,05,09	36.9	-6800	4500	60.96	2.13	360	12.19	1401
40TPA530054	Agrico Chemical-Pierce	01,04	12.0	-9900	-1600	24.38	2.44	321	21.03	1501
40TPA530055	Agrico Chem.-S. Pierce	01,04,05,23,NA	222.1	-6100	-9100	45.72	1.60	350	39.04	1601
40TPA530051	U. S. Agri-Chemicals	06,16,17	132.4	2400	-11600	53.40	2.59	355	15.91	1701
40TPA530080	Imperial Phosphate	01,02	7.9	-8800	-11100	27.43	1.52	333	20.42	1801
40TPA530057	Conserv. Chemicals	02,05,12,15,16	45.9	-14900	3600	45.72	2.29	352	10.30	1901
40TPA530047	Mobil Chem Co. Nichols	01,02,03,04,08	43.7	-15200	4700	24.38	2.29	344	12.50	2001
40TPA530059	IMC - New Wales	02,03,04,42,44	305.0	-16900	-1200	60.96	2.59	350	15.30	2101
		09,10,13,27,46	94.6	-16900	-1200	28.96	1.71	564	17.07	2102
40TPA530044	Gardinier	01	33.8	1700	-17300	19.20	2.90	290	7.01	2201
40HIL290102	Mobil Big Four Mine	01	16.4	-18900	-11000	30.48	1.83	333	12.50	2301
NA	AMAX	NA	0.6	-18800	-12900	8.20	0.41	505	7.57	150
		NA	16.4	-18800	-12900	30.48	1.83	334	7.26	151
NA	Hardee Power Station	NA	277.6	-8800	-23200	22.86	4.88	389	23.90	2401

Table D-2. Summary of Stack and Operating Parameters for Combined Sources Considered in the AAQS Modeling Analysis (Page 2 of 2)

APIS Number	Facility	APIS Source Numbers	Maximum SO2 Emissions (g/sec)	Location Relative To Proposed*		Stack Data		Operating Data		ISCST Model ID
				X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
40HIL290075	Consolidated Minerals	03,20,22,24,26	38.7	-19800	15700	46.33	1.77	298	13.11	2501
40TPA530004	Lakeland Power/McIntosh	01,02,03,04,05	378.3	-4400	25600	45.72	2.74	419	23.77	2601
		06	500.1	-4400	25600	76.20	4.88	350	19.69	55
40TPA530003	Lakeland Power/Larsen	01,02,03,04,05 06,07	115.4	-4600	25600	50.29	3.05	433	5.49	2701
		NA	29.1	-4600	25600	30.48	5.79	783	28.22	2702
40HIL290101	IMC - Fort Lonesome	01,02,05	39.9	-24100	-12700	38.10	2.44	346	18.41	2801
40TPA530002	Citrus World	01,02,03,04,05 07,13,17,20	25.3	27400	6700	22.86	0.76	325	12.19	2901
NA	C. F. Industries	NA	109.2	-25600	35400	60.35	2.44	353	17.77	7

Note: NA = data not available.

* Proposed facility located at 413.6 km east and 3080.6 km north.

Table D-3. Summary of SO2 Stack and Operating Parameters for Sources Considered in the PSD Class II Modeling Analysis

Facility	Maximum SO2 Emissions (g/sec)	Location Relative to Proposed*		Stack Data		Operating Data		ISCST Model ID
		X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
CF Ind. Baseline C,D	-100.8	-25600	35400	60.30	2.44	353	16.40	6
CF Ind. Proposed C,D	109.2	-25600	35400	60.30	2.44	353	17.77	7
Hardee Power Station	277.6	-8800	-23200	22.90	4.88	389	23.90	53
Lakeland McIntosh 3	500.1	-5100	25200	76.20	4.88	350	19.70	55
Hillsborough Cty RRF	21.4	-45400	12100	50.00	1.80	491	18.30	56
Lakeland Util CT	29.11	-4400	22200	30.50	5.79	783	28.22	90
IMC SAP 1,2,3 Baseline	-170.1	-17000	-1700	61.00	2.60	350	14.28	91
IMC SAP 1,2,3 Projected	182.85	-17000	-1700	61.00	2.60	350	15.31	92
IMC SAP 4,5 Projected	121.9	-17000	-1700	60.70	2.60	350	15.31	93
IMC DAP	5.54	-17000	-1700	36.60	1.83	319	20.15	94
CF Bartow Retired H2SO4	-110.6	-5100	2400	30.50	1.68	350	14.60	111
CF Bartow DAP	4.3	-5100	2400	9.10	0.70	450	22.50	112
CF Bartow #7 H2SO4	52.9	-5100	2400	67.10	2.40	351	9.80	113
Conserve	-15.2	-15200	3600	30.50	1.80	308	18.90	115
Conserve #1 H2SO4	42	-15200	3600	45.70	2.30	352	10.30	116
Farmland 1,2 H2SO4	-54.56	-4100	-1100	30.50	1.37	311	20.18	117
Farmland 3,4 H2SO4	67.16	-4100	-1100	30.50	2.29	355	9.27	118
Farmland 5 H2SO4	41.96	-4100	-1100	45.70	2.44	355	9.65	119
IMC Lonesome Mine Dryer 1	18.4	-24000	-12700	38.10	2.90	339	10.13	120
IMC Lonesome Mine Dryer 2	21.17	-24000	-12700	38.10	2.44	346	18.40	121
Royster #1	-257.6	-6900	4600	51.00	2.13	356	9.90	136
Royster #2	35.7	-6900	4600	61.00	2.13	360	12.20	137
USSAC Ft Meade H2SO4 1,2	126	2500	-12000	53.40	2.59	355	15.91	140
USSAC Ft Meade H2SO4 X	-78.8	2600	-11900	29.00	3.02	314	6.77	142
WR Grace Retired H2SO4	-216	-3900	5400	45.70	1.40	352	16.50	143
WR Grace 2 46 16	73.6	-3900	5400	61.00	2.80	346	7.30	144
WR Grace 2 46 17	72	-4100	5900	61.00	1.52	347	28.40	145
AMAX	0.6	-18800	-12900	8.20	0.41	505	7.57	150
AMAX	16.35	-18700	-10800	30.50	1.82	334	7.26	151
Mobil	2.44	-15300	3700	25.90	2.29	339	15.20	154
Agrico Baseline	-75.6	-6100	-9300	45.70	1.60	350	26.40	400
Agrico Proposed	113.5	-6100	-9300	45.70	1.60	350	39.06	410

* Proposed facility located at 413.6 km east to 3080.6 km north.

APPENDIX E

AIR TOXIC MODELING ANALYSIS

Table E-1. Summary of Maximum Pollutant Emission Rates and Concentrations for the Air Toxic Modeling Analysis (Page 1 of 2)

ARAPDXE1
4/2/92

Pollutant	Emission Rate at 20° Design Temp (lb/hr)		Emission Rate at 100° Design Temp (lb/hr)		Averaging Period	Maximum Concentration (µg/m³) (20° Design Temperature)			Maximum Concentration (µg/m³) (100° Design Temperature)		
	CT	CO2	CT	CO2		CT (A)	CO2 (B)	Total (A+B)	CT (C)	CO2 (D)	Total (C+D)
Antimony	0.0215	0.0010	0.0167	0.0010	8-hour	0.0058	0.0000	0.0058	0.0063	0.0000	0.0063
					24-hour	0.0029	0.0000	0.0029	0.0033	0.0000	0.0033
					Annual	0.000043	0.000016	0.000059	0.000042	0.000015	0.000057
Arsenic	0.0041	0.0002	0.0032	0.0002	8-hour	0.0011	0.0000	0.0011	0.0012	0.0000	0.0012
					24-hour	0.00056	0.0000	0.00056	0.00063	0.0000	0.00063
					Annual	0.000008	0.000003	0.000011	0.000008	0.000003	0.000011
Barium	0.0192	0.0009	0.0149	0.0009	8-hour	0.0052	0.0000	0.0052	0.0056	0.0000	0.0056
					24-hour	0.0026	0.0000	0.0026	0.0030	0.0000	0.0030
					Annual	0.000038	0.000014	0.000052	0.000037	0.000013	0.000051
Beryllium	0.0025	0.0001	0.0019	0.0001	8-hour	0.00066	0.00000	0.00066	0.00072	0.00000	0.00072
					24-hour	0.00033	0.00000	0.00033	0.00038	0.00000	0.00038
					Annual	0.000005	0.000002	0.000007	0.000005	0.000002	0.000007
Cadmium	0.0103	0.0005	0.0080	0.0005	8-hour	0.0028	0.0000	0.0028	0.0030	0.0000	0.0030
					24-hour	0.0014	0.0000	0.0014	0.0016	0.0000	0.0016
					Annual	0.000021	0.000008	0.000028	0.000020	0.000007	0.000027
Chlorine	0.0265	0.0013	0.0206	0.0012	8-hour	0.0071	0.0000	0.0071	0.0078	0.0000	0.0078
					24-hour	0.0036	0.0000	0.0036	0.0041	0.0000	0.0041
					Annual	0.000053	0.000019	0.000072	0.000052	0.000018	0.000070
Chromium	0.0467	0.0023	0.0363	0.0022	8-hour	0.013	0.000	0.013	0.014	0.000	0.014
					24-hour	0.0063	0.0000	0.0063	0.0072	0.0000	0.0072
					Annual	0.000093	0.000034	0.00013	0.000091	0.000032	0.00012
Cobalt	0.0089	0.0004	0.0069	0.0004	8-hour	0.0024	0.0000	0.0024	0.0026	0.0000	0.0026
					24-hour	0.0012	0.0000	0.0012	0.0014	0.0000	0.0014
					Annual	0.000018	0.000007	0.000024	0.000017	0.000006	0.000024
Copper	0.2755	0.0133	0.2137	0.0127	8-hour	0.074	0.000	0.074	0.081	0.000	0.081
					24-hour	0.037	0.000	0.037	0.043	0.000	0.043
					Annual	0.00055	0.00020	0.00075	0.00054	0.00019	0.00073
Ethanolamine	0.0	37.5	0.0	37.5	8-hour	0.0	31.2	31.2	0.0	31.2	31.2
					24-hour	0.0	12.4	12.4	0.0	12.4	12.4
					Annual	0.00	1.19	1.19	0.00	1.19	1.19
Fluoride	0.0320	0.0015	0.0248	0.0015	8-hour	0.0086	0.0000	0.0086	0.0094	0.0000	0.0094
					24-hour	0.0043	0.0000	0.0043	0.0049	0.0000	0.0049
					Annual	0.000064	0.000023	0.000087	0.000062	0.000022	0.000085

Table E-1. Summary of Maximum Pollutant Emission Rates and Concentrations for the Air Toxic Modeling Analysis (Page 2 of 2)

Pollutant	Emission Rate at 20° Design Temp (lb/hr)		Emission Rate at 100° Design Temp (lb/hr)		Averaging Period	Maximum Concentration (μg/m³) (20° Design Temperature)			Maximum Concentration (μg/m³) (100° Design Temperature)		
	CT	CO2	CT	CO2		CT (A)	CO2 (B)	Total (A+B)	CT (C)	CO2 (D)	Total (C+D)
Formaldehyde	0.3985	0.0230	0.3091	0.0222	8-hour	0.11	0.00	0.11	0.12	0.00	0.12
					24-hour	0.053	0.000	0.053	0.062	0.000	0.062
					Annual	0.00079	0.00035	0.00114	0.00078	0.00033	0.00111
Lead	0.0088	0.0004	0.0068	0.0004	8-hour	0.0023	0.0000	0.0023	0.0026	0.0000	0.0026
					24-hour	0.0012	0.0000	0.0012	0.0014	0.0000	0.0014
					Annual	0.000017	0.000006	0.000024	0.000017	0.000006	0.000023
Manganese	0.0063	0.0003	0.0049	0.0003	8-hour	0.0017	0.0000	0.0017	0.0019	0.0000	0.0019
					24-hour	0.0009	0.0000	0.0009	0.0010	0.0000	0.0010
					Annual	0.000013	0.000005	0.000017	0.000012	0.000004	0.000017
Mercury	0.0030	0.0001	0.0023	0.0001	8-hour	0.0008	0.0000	0.0008	0.0009	0.0000	0.0009
					24-hour	0.0004	0.0000	0.0004	0.0005	0.0000	0.0005
					Annual	0.000006	0.000002	0.000008	0.000006	0.000002	0.000008
Nickel	0.1673	0.0081	0.1297	0.0077	8-hour	0.045	0.000	0.045	0.049	0.000	0.049
					24-hour	0.022	0.000	0.022	0.026	0.000	0.026
					Annual	0.00033	0.00012	0.00046	0.00033	0.00012	0.00044
Polyorganic Matter	0.0003	0.0001	0.0002	0.0001	8-hour	0.000074	0.000000	0.000074	0.000080	0.000000	0.000080
					24-hour	0.000037	0.000000	0.000037	0.000042	0.000000	0.000042
					Annual	0.000001	0.000002	0.000002	0.000001	0.000002	0.000002
Selenium	0.0231	0.0011	0.0179	0.0011	8-hour	0.0062	0.0000	0.0062	0.0068	0.0000	0.0068
					24-hour	0.0031	0.0000	0.0031	0.0036	0.0000	0.0036
					Annual	0.000046	0.000017	0.000063	0.000045	0.000016	0.000061
Sulfuric Acid Mist	8.1221	0.4162	6.3001	0.3994	8-hour	2.17	0.00	2.17	2.35	0.00	2.35
					24-hour	1.09	0.00	1.09	1.24	0.00	1.24
					Annual	0.016	0.006	0.022	0.016	0.006	0.022
Vanadium	0.0686	0.0033	0.0532	0.0032	8-hour	0.018	0.000	0.018	0.020	0.000	0.020
					24-hour	0.0092	0.0000	0.0092	0.0106	0.0000	0.0106
					Annual	0.00014	0.00005	0.00019	0.00013	0.00005	0.00018
Zinc	0.6723	0.0325	0.5215	0.0311	8-hour	0.18	0.00	0.18	0.20	0.00	0.20
					24-hour	0.090	0.000	0.090	0.10	0.000	0.10
					Annual	0.0013	0.0005	0.0018	0.0013	0.0005	0.0018

Note: Impacts for arsenic, beryllium, ethanolamine, and sulfuric acid mist were predicted by modeling these pollutants at their actual emission rates. All other impacts presented were derived by using a ratio method based on the impacts predicted for beryllium.

Attachments are listed below: (Cont'd)
12. EPA letter dated December 16, 1992.
13. KBN letter dated February 19, 1993.
14. DER letter dated March 19, 1993.
15. KBN letter dated August 17, 1993.
16. DER letter dated August 19, 1993.
17. KBN letter dated August 27, 1993.
18. HBG&S letter dated November 16, 1993.
19. DEP letter dated November 18, 1993.
20. HBG&S letter dated December 20, 1993.
21. PPP letter dated December 17, 1993.
22. GECC letter dated December 16, 1993.
23. HBG&S letter dated December 22, 1993.

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.

GENERAL CONDITIONS:

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.

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

GENERAL CONDITIONS:

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 prescribed 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, 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 (NSPS)

GENERAL CONDITIONS:

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.

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. This permit supersedes the initial permit issued on November 24, 1992. Unless otherwise indicated, the construction and operation of the subject facilities shall be in accordance with the capacities and specifications stated in the application and subsequent submittals by the permittee.

SPECIFIC CONDITIONS:

2. Emissions from the facility shall not exceed the limits listed below based on operation at 59°F and 60% relative humidity (ISO conditions):

Pollutant	Source	Fuel	Through 12/31/97 lbs/hr	Through 12/31/97 tons/yr	After 12/31/97 (See notes) lbs/hr	After 12/31/97 (See notes) tons/yr
NOx	HRSG Stack 1	Gas	87.8	384.5	52.7	230.7
	HRSG Stack 2	Gas	19.9	87.1	18.3	80.0
	HRSG Stack 1	Oil	164.0	718.2	164.0	59.0
	HRSG Stack 2	Oil	23.4	102.4	23.4	8.4
SO2	HRSG Stack 1	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
	HRSG Stack 2	Oil	0.1% Sulfur Max.		0.1% Sulfur Max.	
VE	HRSG Stack 1	Gas	10% Opacity		10% Opacity	
	HRSG Stack 2	Gas	10% Opacity		10% Opacity	
	HRSG Stack 1	Oil	20% Opacity		20% Opacity	
	HRSG Stack 2	Oil	20% Opacity		20% Opacity	
VOC	HRSG Stack 1	Oil	9.2	40.4	--	--
CO	HRSG Stack 1	Gas	42.9	187.8	53.0	232.0
	HRSG Stack 2	Gas	11.9	52.0	12.6	55.2
	HRSG Stack 1	Oil	75.3	329.9	75.3	27.1
	HRSG Stack 2	Oil	13.4	58.5	13.4	4.8

Notes:
(1) NO_x limits for turbine after 12/31/97 based on 15 ppmvd (gas firing) achievable by 4/30/97 but not effective until after 12/31/97.
(2) CO limits for turbine after 12/31/97 based on 25 ppmvd (gas firing).
(3) Opacity limit will allow one 6-minute period per hour of not more than 27% opacity.
(4) Oil may be used as backup fuel for up to 30 days per year.
(5) HRSG Stack 1 = primary; HRSG Stack 2 = secondary (portion of exhaust from combustion turbine is vented through secondary stack along with exhaust from gas-fired duct burner).

3. The cogeneration facility shall be permitted to fire natural gas and No. 2 fuel oil until December 31, 1997, after which the primary fuel will be natural gas. Fuel consumption rates (based on operation at 20°F) and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr	MM ft3/yr	hrs/yr	M lb/hr	MM lb/yr	hrs/yr
Turbine	1013.4	8877.4	8760	55.6	379.9	6833(1)
Duct Burner	104.2	450.2(2)	8760	0	0	0

(1) After December 31, 1997, fuel oil can be used permanently as backup fuel for no more than 720 hours per year.
(2) Based on maximum firing rate for 4,320 hours per year.

SPECIFIC CONDITIONS:

4. Before this construction permit expires, the cogeneration facility stack and secondary HRSG stack shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96% to 100% of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_X: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10
VOC: EPA Method 25A

5. The Southwest District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the Southwest District office in Tampa and the Bureau of Air Regulation office in Tallahassee (third annual compliance test only) within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and water injection flows to the cogeneration turbine along with the power output of the generators shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DEP upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent NOx control systems. The Bureau of Air Regulation shall, if NO_X emission limits are not met, review the need for making a revised determination of Best Available Control Technology. If test results show that it is unlikely that NO_X limits can be met, a revised BACT determination shall be made. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. The retrofit costs associated with not making provisions for such technology initially shall not be considered by the Department in the retrofit cost analysis.

SPECIFIC CONDITIONS:

8. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

9. An application for an operation permit must be submitted to the Southwest District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this _____ day
of _____, 1994

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

_____
Virginia B. Wetherell, Secretary

REVISED DRAFT

Best Available Control Technology (BACT) Determination
Mulberry Cogeneration Project
Polk County

The applicant proposes to install a 126 MW combined cycle cogeneration unit. The Polk County facility will consist of a General Electric PG7111EA Gas Turbine Generator exhausting through a primary heat recovery steam generator which will produce steam for the steam-electric cycle. Initially, the turbine will be fired by natural gas and No. 2 fuel oil, with natural gas becoming the permanent fuel after December 31, 1997. A secondary heat recovery steam generator will be auxiliary-fired by natural gas.

BACT Determination Requested by Applicant

NO_x - Dry Low NO_x Combustion
CO - Combustion Design
H_2SO_4/SO_2 - Low Sulfur Fuel Oil (0.1%S)
PM/PM_{10} - Combustion Design/Clean Fuel
VOC - Combustion Design

BACT Determination by the Department

NO_x - Dry Low NO_x Combustion with potential future SCR capability
CO - Combustion Design
H_2SO_4/SO_2 - Low Sulfur Fuel Oil (0.1%S)
PM/PM_{10} - Combustion Design/Clean Fuel
VOC - Combustion Design

Proposed Emissions (tons per year)

	Through 12/31/97 (22% Gas/78% Oil)			After 12/31/97 (100% Gas)			PSD
	HRSG	Secondary HRSG	Total	HRSG	Secondary HRSG	Total	
NO_x	644.8	99.1	743.9	230.7	80.0	310.7	40.0
SO_2	327.4	16.4	343.8	11.4	1.8	13.2	40.0
PM/PM_{10}	58.0	28.9	86.9	30.7	27.7	58.4	25/15
CO	298.6	57.1	355.7	232.0	55.2	287.2	100.0
VOC	37.7	--	37.7*	28.2	--	28.2	40.0
H_2SO_4	26.4	1.3	27.7	0.9	0.1	1.0	7.0
Be	.008	--	.008	--	--	--	0.0004
As	0.13	--	.013	--	--	--	0.0

*Would be 40.4 TPY at 100% oil firing

Emissions after December 31, 1997, are based on firing only natural gas at 868.8 MMBtu/hr. Turbine performance under natural gas firing is based on NOx emissions of 25 ppm (corrected to 15 percent O_2) through December 31, 1997 and 15 ppm thereafter. Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O_2). SO_2 emissions are based on 0.1 percent sulfur.

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-212, 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.

BACT Determination Rationale

Particulate Matter (PM/PM_{10})

Particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbine when burning natural gas and fuel oil will not cause visible emissions to exceed 10% and 20% opacity, respectively.

Arsenic and Beryllium (As, Be)

The Department agrees that there are no feasible methods to control beryllium and arsenic except by specifying the quality of the fuel.

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The majority of BACT emissions limitations have been based on controlling carbon monoxide and volatile organic compounds through efficient combustion. Advanced control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalyst systems are not considered to be technically feasible for gas turbines fired with fuel oil. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for a natural gas-fired unit; however, the cost effectiveness of over $6,000 per ton of CO removed will have a significant economic impact on this project. Therefore, efficient combustion will be the control method for CO and VOC.

Nitrogen Oxides (NO_x)

The applicant requested that BACT for nitrogen oxides through December 31, 1997, be water injection and Low NO_x Burners. This would limit emissions to 25 ppmvd when burning natural gas and 42 ppmvd when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest emission limit established to date for a combustion turbine is 4.5 ppmvd (corrected to 15% O_2). This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

Although feasible, the applicant rejected using SCR because of economic, energy, and environmental impacts. The following factors were considered in the decision not to propose SCR:

a) Disposal of hazardous waste generated (spent catalyst).
b) An energy penalty of $0.05/KWH due to back pressure from the catalyst bed.
c) A power loss penalty based on lost capacity.
d) Potential for public exposure to high concentrations from ammonia storage and handling leaks and ammonia slip.
e) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
f) Cost effectiveness for SCR technology was determined to be in the range of $6,000 per ton of NO_x removed.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate which can be formed by reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. The latest information available indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing, NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 75 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. SCR has been established as BACT for oil fired combined cycle facilities with NO_x emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control.

The applicant determined that the total annual cost of SCR for this project is $1,957,700 with an average cost effectiveness in the range of $6,000 to $7,000 per ton of NO_x removed. The maximum annual NO_x emissions using water injection and Low NO_x combustor design will be 744 tons/year through December 31, 1997. Assuming that SCR would reduce the NO_x emissions by 65%, about 484 tons/year of NO_x would be removed initially followed by 200 tons/year thereafter. When this reduction is factored into the total annual cost, the cost per ton of controlling NO_x is in the range of $6,000

to $6,500. This calculated cost is higher than has previously been approved as BACT.

The latest DEP BACT determinations have a NO_x limit of 15 ppmvd (natural gas) using Low-NO_x burner technology. Although the turbine manufacturer does not presently guarantee this limit, they have agreed to lower NO_x to 15 ppm by April 30, 1997. This lower NO_x limit will be achieved by application of low-NO_x burners or SCR.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

In accordance with "top down" BACT review, only two alternatives exist that would result in stringent SO_2 emissions; using low sulfur content fuel oil or flue gas desulfurization (FGD). EPA has recognized that FGD technology is inappropriate to apply to these combustion units due to negative environmental, economic and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

This leaves the use of low sulfur fuel oil as the best option. The Department accepts the use of No. 2 fuel oil with a 0.1% sulfur by weight as BACT for this project.

Details of the Analysis May be Obtained by Contacting:

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

Recommended by:	Approved by:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Virginia B. Wetherell, Secretary Dept. of Environmental Protection
_____, 1994 Date	_____, 1994 Date

Revised
Technical Evaluation
and
Preliminary Determination

Polk Power Partners
Mulberry Cogeneration Project
Polk County, Florida

Permit No. AC 53-211670
PSD-FL-187

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

December 29, 1993

I. Application Information

A. Applicant

Polk Power Partners
23293 South Pointe Drive
Laguna Hills, Florida 92653

B. Request

The permittee, Polk Power Partners, applied on April 6, 1992, to the Department of Environmental Protection for a permit to construct a cogeneration and CO_2 recovery facility 3.7 miles southwest of Bartow in Polk County, Florida. The Department issued the permit initially on November 24, 1992. Since that time, the permittee submitted new information justifying revised gas turbine emission limits for carbon monoxide (CO) and a deletion of the carbon dioxide (CO_2) recovery facility. Therefore, the Department is reissuing the permit to include these changes and provide additional time to accomplish the revised objectives. The only increase in allowable emissions for this reissued permit is 47.4 tons of CO per year.

C. Classification/Location

The proposed facility (SIC Codes 4911 and 2813) will be located on County Road 555 approximately 3.7 miles southwest of Bartow, Polk County, Florida. Latitude and longitude are 27°50'56"N and 81°52'38.9"W, respectively. The UTM coordinates of the site are: Zone 17, 413.6 km E and 3,080.6 km N.

II. Project Description/Emissions

The applicant originally proposed and was permitted to construct a 126 MW combined cycle cogeneration power plant along with a 150 ton per day carbon dioxide (CO_2) plant recovering CO_2 from the power plant flue gas. The CO_2 plant has been deleted and replaced by an ethanol plant to be constructed by different owners under separate permits. Cogeneration equipment includes a General Electric combustion turbine (CT), a non-auxiliary fired primary and an auxiliary-fired secondary heat recovery steam generator (HRSG), and a steam turbine generator.

The permanent fuel for the power plant will be natural gas, although the plant will not have a firm contract for natural gas until the fourth year of operation. During the first three years, natural gas will provide a minimum of 22% of fuel requirements with the balance supplied by distillate fuel oil. About two-thirds of the facility's power output will come from the gas turbine generator. Steam from the primary and secondary HRSG will drive a steam turbine to generate the other third of the power output.

Combustion gases from the turbine will be routed to the primary HRSG which provides steam for additional power generation. Part of the turbine exhaust will go to the secondary HRSG and vented through the secondary HRSG stack along with the exhaust from the gas-fired duct burner.

Emission estimates below are based on the initial operation through December 31, 1997, using a 22% gas/78% oil fuel mix followed by natural gas as the permanent fuel. Annual estimates are based on full load operation at 59°F and 0.1% sulfur content of the fuel oil.

	Projected Emissions (TPY)					
	Through 12/31/97 (22% Gas/78% Oil)(1)			After 12/31/97 (100% Gas)(2)		
	HRSG Stack	Sec. HRSG Stack	Total	HRSG Stack	Sec. HRSG Stack	Total
NO_x	644.8	99.1	743.9	230.7	80.0	310.7
SO_2	327.4	16.4	343.8	11.4	1.8	13.2
PM/PM_{10}	58.0	28.9	86.9	30.7	27.7	58.4
CO	298.6	57.1	355.7	232.0	55.2	287.2
VOC	37.7	--	37.7	28.2	--	28.2
H_2SO_4	26.4	1.3	27.7	0.9	0.1	1.0
Be	.008	--	.008	--	--	--
As	.013	--	.013	--	--	--

(1) Based on 25 ppm NO_x (gas) and 42 ppm NO_x (oil).
(2) Based on 15 ppm NO_x (gas).

III. Rule Applicability

The construction permit application is subject to review under Chapter 403, Florida Statutes, and Florida Administrative Code (F.A.C.) Chapters 17-212, 17-296 and 17-4. The proposed facility is subject to the provisions of F.A.C. Rule 17-212.400, Prevention of Significant Deterioration (PSD). The facility is located in an area classified as attainment for all regulated air pollutants. The proposed emissions exceed the significant levels set forth in Table 212.400-2 of F.A.C. Rule 17-212. Preconstruction review must include a determination of Best Available Control Technology (BACT), good-engineering practice stack height, ambient impact analysis, impact on soils, vegetation and visibility. Applicable emission limit rules are F.A.C. Rules 17-296.800, Table 296.800-1, Section 60.330, New Source Performance Standards (NSPS) for Stationary Gas Turbines, Subpart GG, and F.A.C. Rule 17-296.406, Fossil Fuel Steam Generators with Less than 250 Million Btu per Hour Heat Input. Contrary to the applicant's analysis, the emission limits under Subpart Dc of the federal NSPS do not apply to the duct burner since this rule requires only recordkeeping and reporting for natural gas applications. BACT limits will be based on the turbine manufacturer's performance guarantees since they are more stringent than the NSPS limits.

IV. Air Quality Analysis

a. Introduction

The operation of the proposed facility will result in emissions increases which are projected to be greater than the PSD significant emission rates for the following pollutants: NO_x, SO_2, PM, PM_{10}, Be, CO, VOC (based on oil firing), inorganic arsenic, and H_2SO_4 mist. Therefore, the project is subject to the PSD NSR requirements contained in F.A.C. Rule 17-212.400 for these pollutants. Part of these requirements is an air quality impact analysis for these pollutants, which includes:

- An analysis of existing air quality;
- A PSD increment analysis (for SO_2, PM, PM_{10}, and NO_2);
- An ambient Air Quality Standards analysis (AAQS);
- An analysis of impacts on soils, vegetation, visibility and growth-related air quality impacts; and,
- A Good Engineering Practice (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The PSD increment and AAQS analyses are based on air quality dispersion modeling completed in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the proposed project, 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. A brief description of the modeling methods used and results of the required analyses follow. A more complete description is contained in the permit application on file.

b. Analysis of the Existing Air Quality

Preconstruction ambient air quality monitoring may be required for pollutants subject to PSD review. However, an exemption to the monitoring requirement can be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined through air quality modeling, is less than a pollutant-specific de minimus concentration. The predicted maximum concentration increase for each pollutant subject to PSD (NSR) is given below:

	SO_2	TSP & PM_{10}	NO_2	CO	Be
PSD de minimus Concentration (ug/m^3)	13	10	14	575	.001
Averaging Time	24-hr	24-hr	Annual	8-hr	24-hr
Maximum Predicted Impact (ug/m^3)	15.5	2.8	0.85	23.6	0.00038

There are no monitoring de minimus concentrations for H_2SO_4 mist and inorganic arsenic. As shown above, the predicted impacts for TSP/PM_{10}, NO_2, CO, and Be are all less than the corresponding de minimus concentrations; therefore, no preconstruction monitoring is required for these pollutants. However, since the predicted SO_2 impact is greater than the de minimus concentration, a preconstruction ambient monitoring analysis is required for SO_2. The Department determined that the use of existing FDEP air quality monitoring data collected in 1991 from the Mulberry SO_2 monitoring site in Polk County would be appropriate to satisfy the ambient monitoring analysis requirement. Background SO_2 values of 176 ug/m^3, 3-hr average; 40 ug/m^3, 24-hr average; and 12 ug/m^3, annual average, were based on these data. This site is located 9.7 km away from the project.

c. Modeling Method

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used by the applicant to predict the impact of the proposed project on the surrounding ambient air. All recommended EPA default options were used. Downwash parameters were used. Five years of sequential hourly surface and mixing depth data from the Tampa, Florida National Weather Service (NWS) station collected during 1982 through 1986 were used in the model. Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations are compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards.

d. Modeling Results

The applicant first evaluated the potential increase in ambient ground-level concentrations associated with the project to determine if these predicted ambient concentration increases would be greater than specified PSD significant impact levels for SO_2, CO, NO_x, PM and PM_{10}. This evaluation was based on the proposed facility operating at maximum load conditions and 20°F and 100°F design temperatures. Maximum load conditions along with these two design temperatures were used because the highest emissions and flow rate occur at the 20°F design condition while the lowest emissions and flow rate occur at the 100°F design condition. This approach ensured that the maximum impacts from the proposed facility were obtained either for the maximum emission condition or minimum flow rate condition. The applicant modeled emissions based on the use of fuel oil with a maximum sulfur content of 0.1%. Dispersion modeling was performed with receptors placed along the 36 standard radial directions (10 degrees apart) surrounding the proposed units at the following downwind distances: (1) the first 36 receptors were located at the plant property boundaries; (2) subsequent receptors were located at distances of 0.3, 0.5, 0.7, 1.0, 1.5, 2.0, 3.0, 4.0 and 5.0 km from the facility, all of which

are off plant property. The results of this modeling presented below show that the increases in ambient ground-level concentrations for all averaging times are less than the PSD significant impact levels for CO, NO_x, PM and PM_{10}.

	SO_2			NO_2	CO		PM and PM_{10}	
Avg. Time	Annual	3-hr	24-hr	Annual	1-hr	8-hr	Ann.	24-hr
PSD Signifi. Level (ug/m^3)	1.0	25.0	5.0	1.0	2000	800	1.0	5.0
Ambient Concen. Increase (ug/m^3)	0.3	42.5	15.5	0.9	68.6	27.5	0.2	2.8

Therefore, further dispersion modeling for comparison with AAQS and PSD increment consumption were not required for CO, NOx, PM and PM_{10}. However, the results also show that the increases in maximum ambient ground level concentrations for the 3-hr and 24-hr averaging times for SO_2 were greater than the PSD significant impact levels, thus requiring the applicant to do a full impact analysis for SO_2. The significant impact area for the facility was determined to be 0.7 km; therefore, all sources within 51 km of the facility were evaluated by the applicant. Screening analyses were performed to predict maximum SO_2 concentrations for comparison to the PSD Class II increments and the AAQS using the same receptor grid described above. Refined AAQS and PSD Class II analyses were based on modeling the years during which the overall HSH 3-hour and HSH 24-hour concentrations were predicted in the screening analyses. The refined 3-hr and 24-hr modeling was conducted using a receptor grid centered on the receptor which had the HSH 3-hr or 24-hr concentration determined from the screening analysis. These receptors were located at intervals of 200m between the distances considered in the screening phase, along 9 radials spaced at 2-degree increments centered on the radial along which the maximum concentration was predicted. The results of these analyses for SO_2 and their comparison with the appropriate standards and increments are summarized in the following tables. The tables show that the maximum predicted SO_2 concentrations are all less than the appropriate AAQS and PSD increments.

AAQS Analysis (all values in ug/m^3)

Avg. Time	Annual	3-hr	24-hr
Maximum Predicted Concentration	42	837	234
Includes Background Value	12	176	40
AAQS	60	1300	260

Cumulative PSD Class II
Increment Analysis (all values in ug/m^3)

Avg. Time	Annual	3-hr	24-hr
Max. Predicted Consumption Concen.	-0.42	139	39
Increment	20	512	91

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area located 120 km from the facility. The predicted impact of the proposed project on this area was evaluated by first using the ISCST model to predict maximum increment consumptions by the source alone and by comparing these predicted values to the appropriate recommended significance levels to determine whether further modeling was necessary. The significance levels used by the Department were the more stringent National Park Service (NPS) recommended levels. The predicted maximum PM/PM_{10} and NO_2 increment consumptions for all applicable averaging times were less than these significance levels. Therefore, no further modeling for PM/PM_{10} and NO_2 was required. In addition, the predicted maximum SO_2 annual average increment consumption by the source alone was also below the NPS significance level. However, the predicted maximum SO_2 24-hour and 3-hour concentrations were predicted to be greater than the NPS levels. The Department and the NPS directed the applicant to further evaluate the SO_2 short term impacts on the Class I area. The applicant used ISCST and modeled the inventory of all PSD increment consuming and expanding sources using 1982-1986 Tampa meteorological data. The applicant also modeled the proposed facility's impacts during this time period and compared the results to the NPS significance levels. Results of this evaluation show that on the days and at the location of significant impacts due to the proposed facility, total 3-hour and 24-hour SO_2 impacts at Chassahowitzka were predicted to be less than the allowable 3-hour and 24-hour PSD Class I increments except for one case. In that case, the total 24-hour concentration was predicted to be 5.22 ug/m^3 with the proposed source contributing 0.09 ug/m^3. The allowable 24-hour Class I increment is 5.0 ug/m^3 and the NPS significance level is 0.07 ug/m^3. However, the NPS has stated by verbal communication that they do not expect the proposed facility to adversely impact the Class I area since the maximum predicted impacts were based on the use of fuel oil and the applicant is committed to using and will be limited by the Department to using natural gas as the permanent fuel after the first three years.

Sulfuric acid mist, beryllium and inorganic arsenic are noncriteria pollutants, which means that neither national AAQS nor PSD Significant Impacts have been defined for these pollutants. However, the Department does have a draft Air Toxics Permitting Strategy, which defines acceptable ambient concentrations for these pollutants. The Department and the applicant have used the same

modeling procedure described above for the screening analysis to evaluate the maximum increase in ground level concentration of these pollutants for comparison with the acceptable ambient concentrations. The results of this analysis are shown below:

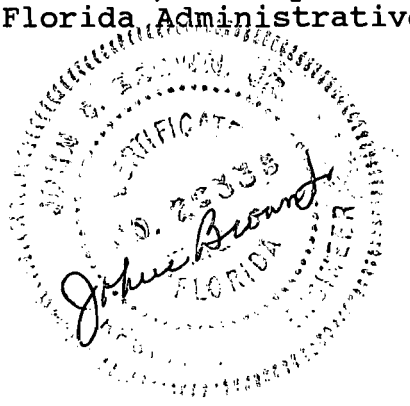
Avg. Time	H_2SO_4 Mist 24-hr	Beryllium Annual	Arsenic Annual
Acceptable Ambient Concentrations (ug/m^3)	2.38	0.00042	0.00023
Max. Concen. Increase	1.24	0.00001	0.00001

All of these values are less than their respective acceptable ambient concentrations.

e. Additional Impacts Analysis

A Level-1 screening analysis using the EPA model, VISCREEN was used to determine any potential adverse visibility impacts on the Class I Chassahowitzka National Wilderness Area located about 120 km away. Based on this analysis, the maximum predicted visual impacts due to the proposed project are less than the screening criteria both inside and outside the Class I area. A comprehensive air quality related values (AQRV) analysis for this Class I area was performed by the applicant.

In addition, the maximum predicted concentrations from NOx, CO, SO_2, PM and PM_{10} are predicted to be less than the AAQS, including the national secondary standards designed to protect public welfare-related values. As such, no harmful effects on soil and vegetation are expected in the area of the project. Also, the proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

VI. Conclusion

Based on the information provided by Polk Power Partners, L.P., the Department has reasonable assurance that the proposed installation, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapter 17-200 of the Florida Administrative Code.