Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

June 27, 1995

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Tom Hess
Energy Systems
Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

RE: Orlando CoGen L.P.
AC48-206720

Dear Mr. Hess:

The Bureau of Air Regulation received your February 10 request to amend the above referenced permit. Before we can begin processing your request, we will need a $250 processing fee pursuant to Rule 62-4.050(4)(q)5., F.A.C. If you have any questions, please call Patty Adams at (904)488-1344.

Sincerely,

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

CHF/pa

cc: Martin Costello

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:

Tom Hess, Energy Syst.
Air Products + Chemicals
7201 Hamilton Blvd
Allentown, PA 18195-1501

4a. Article Number
Z 392 979 008

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

7. Date of Delivery
7-7-95

5. Signature (Addressee)
Tony Hetrick

6. Signature (Agent)

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

PS Form **3811**, December 1991 ☆U.S. GPO: 1993—352-714 N RECEIPT

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P.O., State and ZIP Code Allentown PA	
Postage	$
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Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Orlando Cosgn AC48-206720 6-28-95	

PS Form **3800**, March 1993

al

HOPPING GREEN SAMS & SMITH
PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS
123 SOUTH CALHOUN STREET
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TALLAHASSEE, FLORIDA 32314
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JULIE R. STEINMEYER

OF COUNSEL
CARLOS ALVAREZ
W. ROBERT FOKES

February 22, 1995

RECEIVED
FEB 23 1995
Bureau of
Air Regulation

VIA HAND DELIVERY

Kenneth Plante, Esquire
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road, Room 654
Tallahassee, FL 32399-2400

Re: Orlando CoGen (I), Inc.
Construction Permit No. AC48-206720, PSD-FL-184
Permit Amendment and Notice of Intent to Deny Requested Permit Revision
Orlando Central Park, Orange County, Florida
OGC Case No.: 94-2845

Dear Mr. Plante:

On August 18, 1994, Orlando CoGen (I), Inc., received the above-referenced notice of Intent to Deny a requested permit revision for its cogeneration facility located in Orange County, Florida. The Intent to Deny was issued by Howard L. Rhodes, Director of the Division of Air Resources Management, Department of Environmental Protection, on August 16, 1994. Subsequently, a Permit Amendment was issued by Mr. Rhodes on February 9, 1995, and received by Orlando CoGen, (I), Inc., on February 15, 1995. Pursuant to Section 120.57, Florida Statutes; Rule 62-103, Florida Administrative Code; and Orders of the Department dated September 21, 1994, November 7, 1994, and December 28, 1994, Orlando CoGen (I), Inc., has until February 28, 1995, to file a petition for administrative proceedings regarding the Intent to Deny and until March 1, 1995, regarding the Permit Amendment.

On behalf of Orlando CoGen (I), Inc., I hereby request, pursuant to Rule 62-103.070, F.A.C., an extension to and including May 1, 1995, in which to file a petition for administrative proceedings regarding the Permit Amendment and the Intent to Deny. As good cause for granting the request for extension of time for filing, Orlando CoGen (I), Inc., states the following:

1. Representatives of Orlando CoGen (I), Inc., have conferred and corresponded with the appropriate representatives of the Department's Bureau of Air Regulation regarding the Intent to Deny and the Permit Amendment in an effort to reach a mutually acceptable resolution of the requested permit revision. Much progress has been made through issuance of the permit amendment; a few issues remain, however. Orlando CoGen (I), Inc., will continue to work with the Department in an effort to resolve these few remaining issues.

2. This request is filed simply as a protective measure to avoid waiver of Orlando CoGen (I), Inc.'s right to challenge the Intent to Deny and the Permit Amendment. Grant of this request will not prejudice either party, but will further their mutual interest and likely avoid the need to initiate formal administrative proceedings.

3. I hereby certify that I have attempted without success to contact Douglas Beason of the Department's Office of General Counsel regarding this request to determine whether he would have an objection.

Accordingly, I hereby request that you formally extend the time for filing a petition for administrative proceedings regarding to the Department's Notice of Intent to Deny and the Permit Amendment for Air Construction Permit No. AC48-206720 and PSD-FL-184, to and including May 1, 1995.

Sincerely,

Angela R. Morrison

cc: Clair H. Fancy, P.E., Chief, BAR, DEP
Douglas Beason, Esquire, OGC, DEP
Ken Kosky, KBN
Tom Hess, Air Products and Chemicals, Inc.
Mark Novotnak, Orlando CoGen (I), Inc.

cc: Syed Arif

Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Telephone (610) 481-4911
Telex: 847416

AIR PRODUCTS

10 February 1995

RECEIVED
FEB 13 1995
Bureau of
Air Regulation

Mr. Bruce Mitchell
Florida Department of Environmental Protection
Air Resources Management
Twin Tours Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Orlando CoGen L.P. (AC48-206720) - particulate matter testing

Dear Mr. Mitchell:

As you requested yesterday in our telephone conversation, I am sending copies of two emission test reports for our Orlando CoGen plant (2-8 September 1994, and 2-3 November 1994 — both in one binder). The data from both reports are summarized in the attached table, which I had previously sent to you. Because one of the September particulate test runs yielded unlikely[1] results, the entire particulate test series was repeated in November.

Tests for NOx and CO were conducted simultaneously using the test ports at the inlet of the heat recovery steam generator, i.e., after the turbine exhaust but ahead of the duct burners, and at the stack (please see the process schematic diagram). However, tests for particulate emissions could only be conducted at the heat recovery steam generator (HRSG) stack. Simultaneous testing for particulate matter at the HRSG inlet and at the stack is not possible since isokinetic sampling conditions do not exist anywhere prior to the duct burners.

Sketch A shows an elevation of the HRSG at the point of turbine exhaust. Approximately six feet downstream of the turbine exhaust is the leading edge of the first of two inclined flow diffusers which extend vertically about three fourths of the height of the HRSG. Approximately two feet downstream of the second set of flow diffusers are the duct burners. As can be seen from the sketch, there is no unobstructed point to insert test probes between the turbine exhaust and the duct burners with the exception of the six feet immediately downstream of the turbine exhaust. This location is only suitable for gas concentration measurements since the required isokinetic sampling conditions for particulate are not present due to the swirling flow of the turbine exhaust. Further, no location upstream of the duct burners meets the minimum requirement of Method 1 that the sampling point be located at least two diameters downstream of the last "flow disturbance," the turbine exhaust into the HRSG. In fact, the only point in the plant where isokinetic sampling is physically possible is the boiler stack. This plant design is consistent will all similar units in the US.

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[1] Particulate run 3, 9/2/94, in Table 2 of the test report yielded 0.0176 lbs/MMBtu$_{HHV}$ while the two prior runs were respectively: 0.0059 and 0.0051 lbs/MMBtu$_{HHV}$ (878 MMBtu/hr$_{HHV}$ turbine and 126 MMBtu/hr$_{HHV}$ duct burners). Also, while firing only the combustion turbine at 878 MMBtu/hr$_{HHV}$, the average of three PM tests was 0.0049 lbs/MMBtu$_{HHV}$. Because 5 of 6 test runs indicated PM emissions in the range of 0.0035 to 0.0072 lbs/MMBtu$_{HHV}$, the one value at 0.0176 lbs/MMBtu$_{HHV}$ was suspect. Consequently three additional particulate test runs were conducted on 11/2-3/1994 (Table 1) which yielded an average of 0.0082 lbs/MMBtu$_{HHV}$ at full combustion turbine and duct burner firing.

Not needed?

Based on the way the BACT determination for PM/PM_{10} was made, we do not believe there is any explicit permit condition or regulation that requires simultaneous testing for particulate. BACT for PM was determined to be good combustion of clean fuels, namely natural gas, the only fuel used at the facility. The emission standard was determined for both the combustion turbine **and** the duct burners to be 0.01 lbs/$MMBtu_{LHV}$. Moreover, the duct burners cannot be operated independently of the combustion turbine. The 0.01 lb/$MMBtu_{LHV}$ standard was then simply multiplied by the maximum heat input to each device to come up with separate emission limits for each device in units of pounds/hour (9 lbs/hr for the combustion turbine and 1.2 lbs/hr for the duct burners). Thus, the proposed emission rate for PM/PM_{10} treated the entire **combustion process** (duct burners and combustion turbine) as a single process. In fact, for ongoing compliance with particulate limits, an opacity standard is established by the permit. The Department concurred with this approval in its final BACT determination.

It must also be kept in mind that the duct burners cannot operate independently of the combustion turbine. The duct burners must be fired in series with the combustion turbine since the combustion turbine exhaust provides the oxygen for combustion of natural gas in the duct burners. There is no other source of combustion air for the duct burners. The plant has only two operating modes: combustion turbine firing alone, and combustion turbine firing with duct burner firing. There is no possible way to operate the duct burners without operation of the combustion turbine.

In interpreting the particulate test results for compliance determination, we believe that prorating the total emissions of particulate[2] between the combustion turbine and duct burners based on heat input is appropriate. This was the method by which the emission limits were established in the permit. We therefore request that the permit special conditions be amended to incorporate the following:

1) require all particulate testing at the stack location

2) require that meeting a total particulate standard of 0.01 lbs/$MMBtu_{LHV}$ is equivalent to 0.01 lbs/$MMBtu_{LHV}$ - duct burners and 0.01 lbs/$MMBtu_{LHV}$ - combustion turbine.

3) require determination of compliance with the specific pound/hr emission limits by prorating the total emissions, pounds/hr, between the combustion turbine and duct burners based on the heat input to each device as observed during the tests.

I hope this additional information will be of help. Please give me a call at 610 481-7620 if you have any questions.

Very truly yours,

Tom Hess

Tom Hess
Energy Systems

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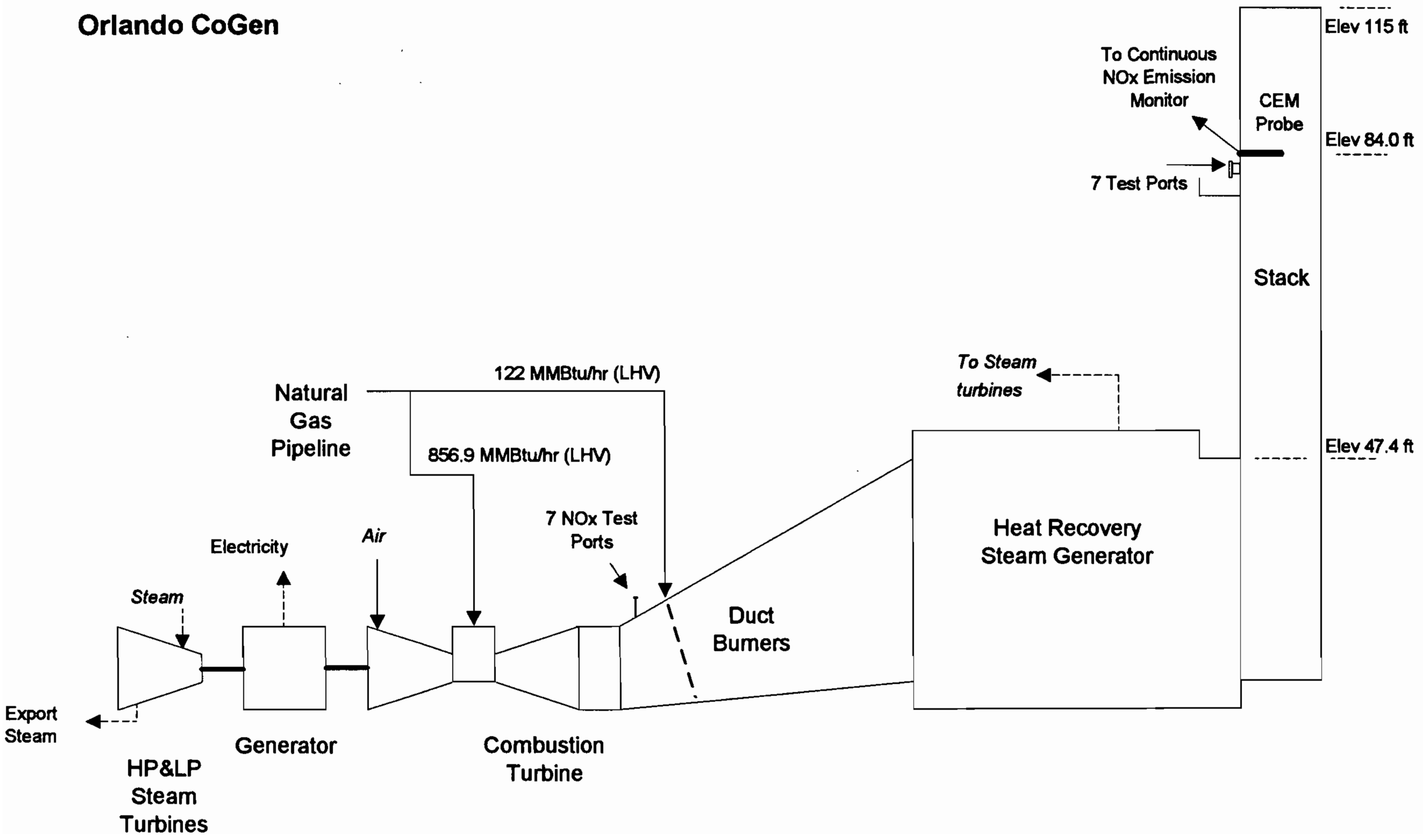
[2] Particulate tests are conducted at the stack of the HRSG with both the combustion turbine and the duct burners at maximum firing.

Orlando CoGen



Orlando CoGen L.P. 128.9 MW Gas-Fired Combined Cycle Power Plant — Summary of Emission Performance Tests (1994)

	BACT Standard (emission limits)	9/2 Test Series, DB & CT full firing (simultaneous testing)	9/6 Test Series, CT only at full firing (Part GG max. load test)	11/2-3 Test Series, DB & CT full firing (simultaneous testing)
CT MMBtu/hr	856.9 LHV (ISO day)	789 LHV (839 ISO), 880 HHV	795 LHV (842 ISO), 887 HHV	822 LHV, 910 HHV
DB MMBtu/hr	122 LHV	113 LHV, 126 HHV	None	114 LHV, 126 HHV
CT NOx	15 ppmvd, 15% O_2 (57.4 lbs/hr)	14.4 ppmvd, 15% O_2 (46.6 lbs/hr)[1] RM 20 at CT exhaust	11.8 ppmvd, 15% O_2 (49.1 lbs/hr)[2] RM 2 & 20 at stack	
CT CO	10 ppmvd (22.3 lbs/hr)	0.33 ppmvd, 15.5% O_2 (0.71 lbs/hr)[3] RM 10 at CT exhaust	0.42 ppmvd, 15.4% O_2 (1.1 lbs/hr) RM 2 & 10 at stack	
CT PM/PM$_{10}$	0.01 lbs/MMBtu LHV (9.0 lbs/hr) ?	*0.0077 lbs/MMBtu LHV* 11.5 *(6.1 lbs/hr)*[4,5] RM 5 & 2 at stack	0.00667 lbs/MMBtu LHV (5.2 lbs/hr)[a] RM 5 & 2 at stack	0.0090 lbs/MMBtu LHV[6] (7.4 lbs/hr) RM 5 & 2 at stack
DB NOx	0.1 lbs/MMBtu LHV (12.2 lbs/hr)	0.0446 lbs/MMBtu LHV[7] (5.0 lbs/hr)[8] RM 20 at stack	None	
DB CO	0.1 lbs/MMBtu LHV (12.2 lbs/hr)	0.0107 lbs/MMBtu LHV[9] (1.2 lbs/hr)[10] RM 10 at stack	None	
DB PM/PM$_{10}$	0.01 lbs/MMBtu LHV (1.2 lbs/hr)	*0.0077 lbs/MMBtu LHV* *(0.87 lbs/hr)*[4,5] RM 5 &2 at stack	None	0.0090 lbs/MMBtu LHV[6] (1.0 lbs/hr) RM 5 & 2 at stack
VE	0%	0%		

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[1] Calculated from heat input to CT and NOx concentration of 0.0530 lbs NOx/MMBtu HHV.

[2] Rate determined by NOx concentration (Method 20) and stack gas flow rate (Method 2).

[3] Calculated from heat input to CT and CT CO concentration, 0.000807 lbs/MMBtu HHV.

[4] Three particulate runs were conducted at the stack (i.e. downstream of the duct burners for total PM emissions — PM from duct burners plus the combustion turbine) with these results: 7.68, 6.33, and 20.53 lbs/hr. Because the last run appeared to be an outlier, the entire test series was repeated on 11/2-3. The values given in italics ignore the third suspect run. The average particulate from the first two runs is prorated between the duct burner and combustion turbine based on their heat input.

[5] Reference Method 5 is specified in the permit, however it is not applicable to this source type nor is it physically possible to conduct a valid Method 5 test in the immediate vicinity of a turbine exhaust.

[a] Average heat input during the particulate test runs was 787 MMBtu/hr LHV

[6] Total particulate (duct burners plus combustion turbine contributing) using Methods 5 and 2 was determined at the stack. The total particulate rate measured was 8.45 lbs/hr (average of 7.58, 8.73, 9.03 lbs/hr). Emissions from the combustion turbine and duct burners were prorated from the total measured rate using the heat input to the duct burners and combustion turbine.

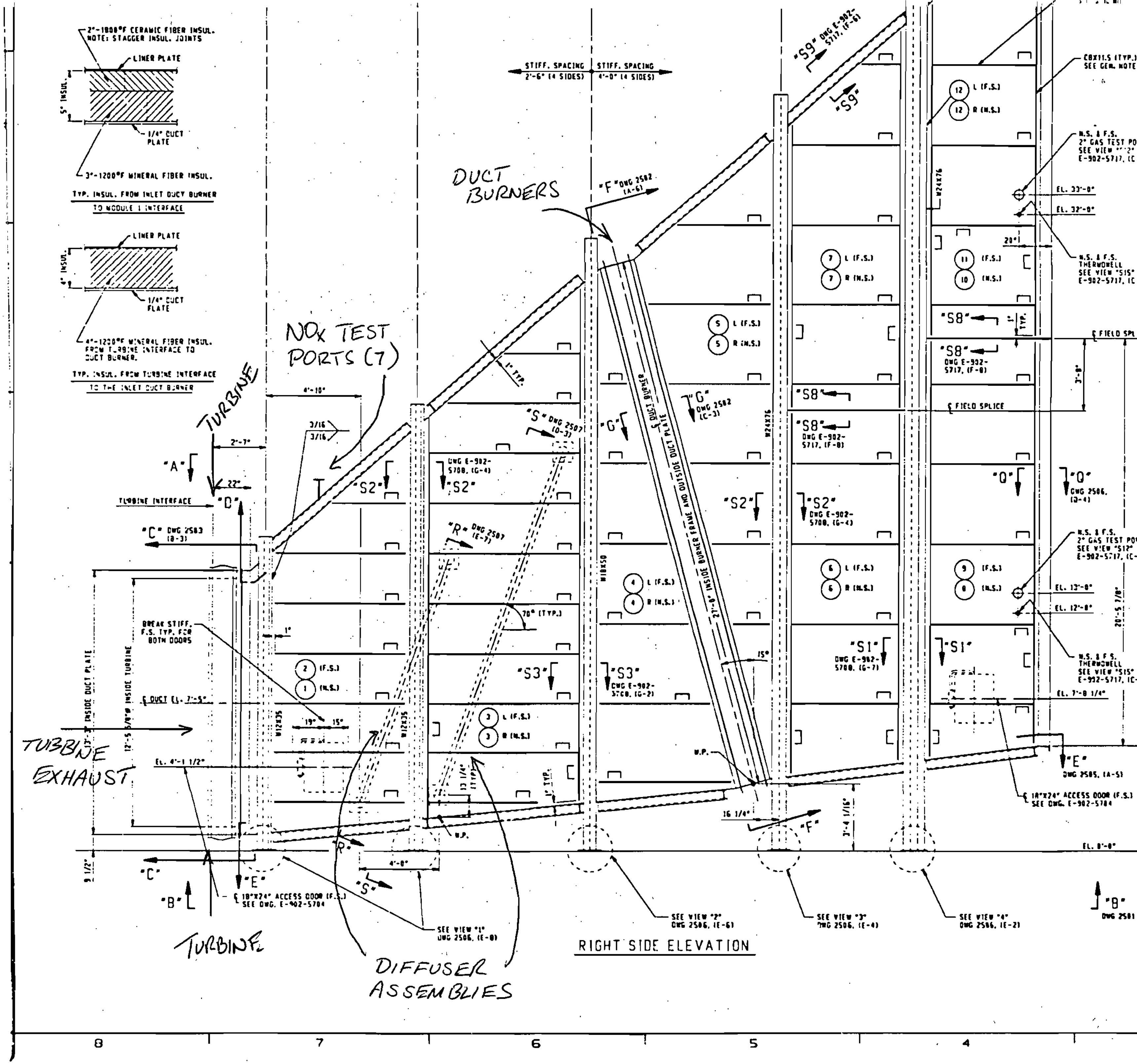
[7] Calculated using Method 19, $E_{Duct\ Burners}=E_{stack}+(CT_{heat\ input}/DB_{heat\ input})\cdot(E_{stack}-E_{turbine})$ = 0.05146 + (880/126)·(0.05146-0.05310) = 0.0400 lbs/MMBtu HHV (0.0446 lbs/MMBtu LHV).

[8] Calculated using (7) $E_{Duct\ Burner}$ and duct burner heat input of 126 MMBtu/hr (LHV).

[9] Calculated using Method 19, $E_{Duct\ Burners}=E_{stack}+(CT_{heat\ input}/DB_{heat\ input})\cdot(E_{stack}-E_{turbine})$ = 0.0019 + (880/126)·(0.001946-0.0008) = 0.009600 lbs/MMBtu HHV (0.0107 lbs/MMBtu LHV).

[10] Calculated from heat input to DB and DB CO concentration from (9), 0.0096 lbs/MMBtu LHV.

A

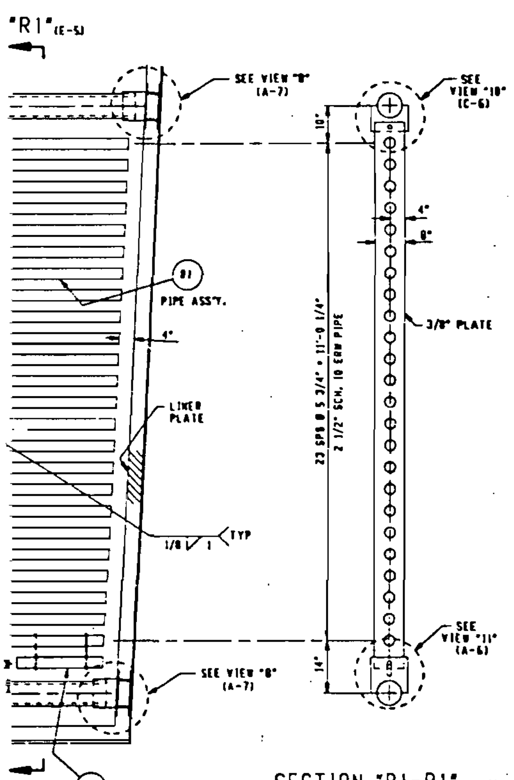


RIGHT SIDE ELEVATION

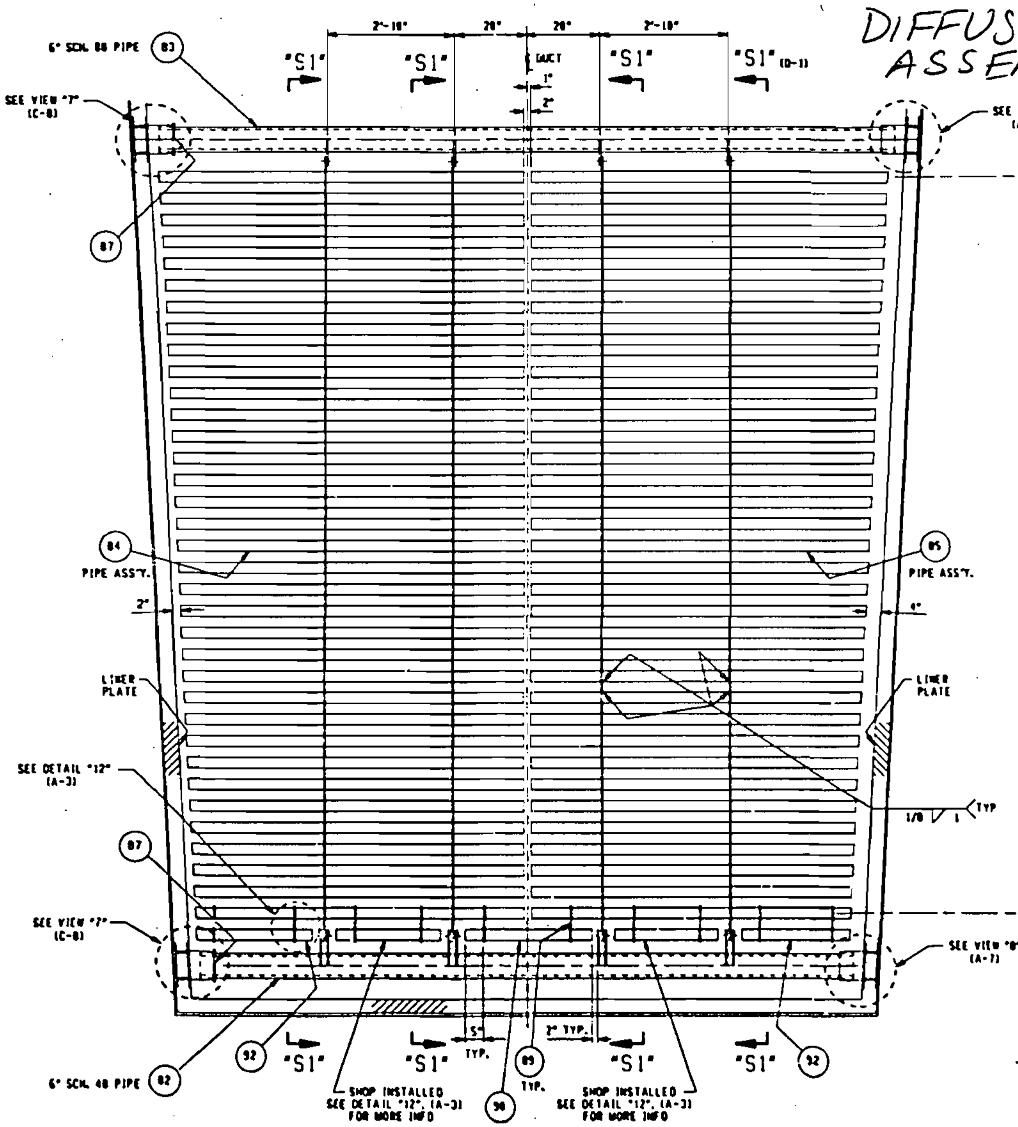
BEST AVAILABLE COPY

6 5 4 3 2 1

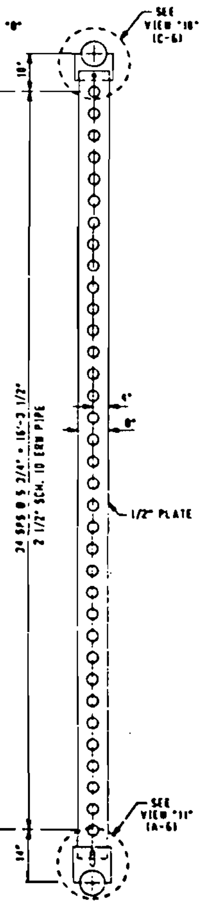
DIFFUSER ASSEMBLY "S"



SECTION "R1-R1" (H-6)
TYP. 4 PLACES

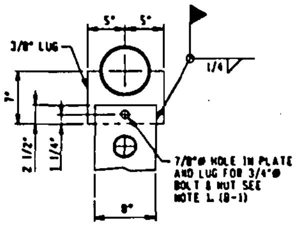


SECTION "S-S" DWG 2508, (D-6)

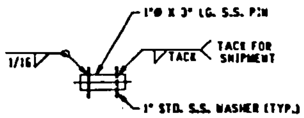


SECTION "S1-S1" (H-2)
TYP. 4 PLACES

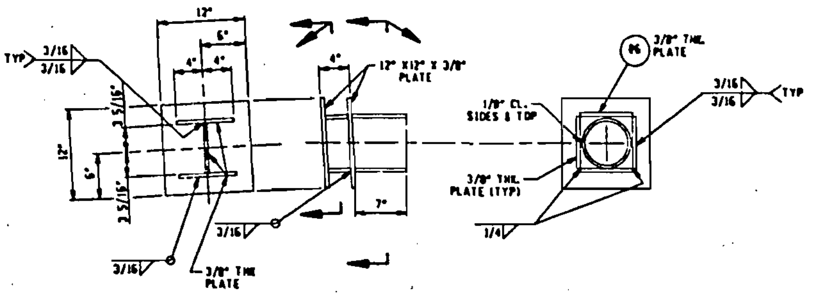
C



VIEW "10" (H-5) & (H-1)



88 TYP PIN



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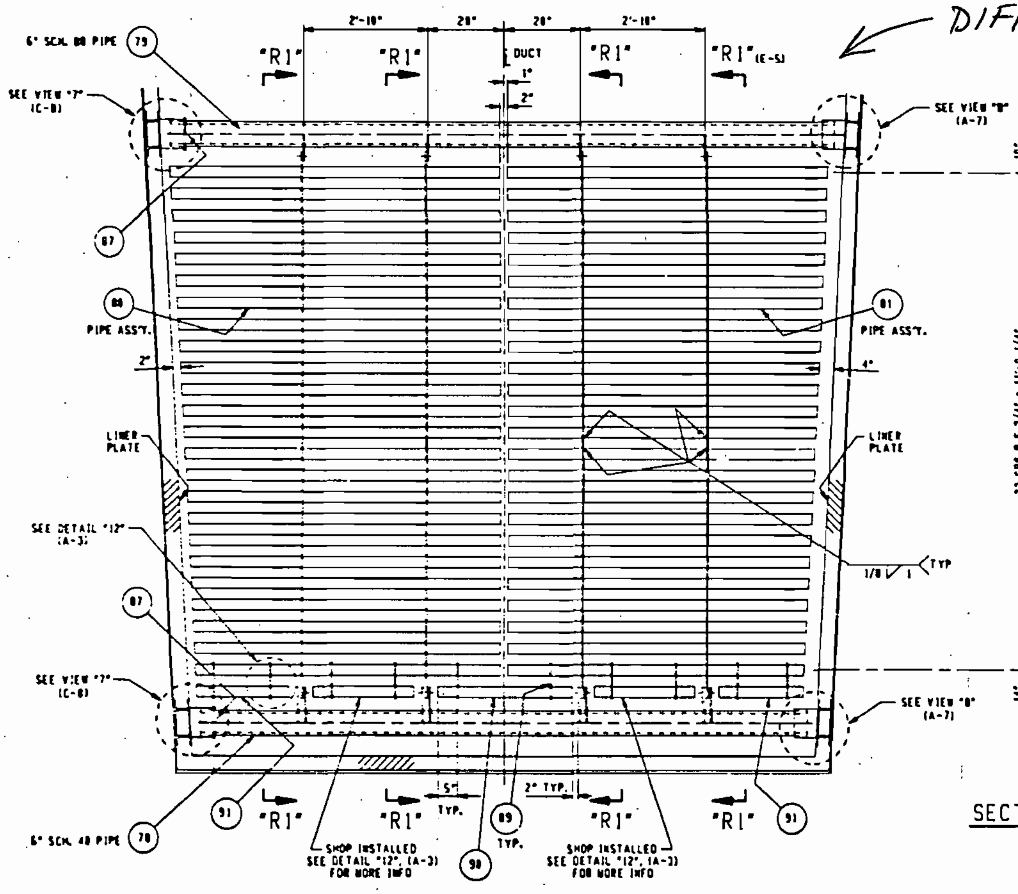
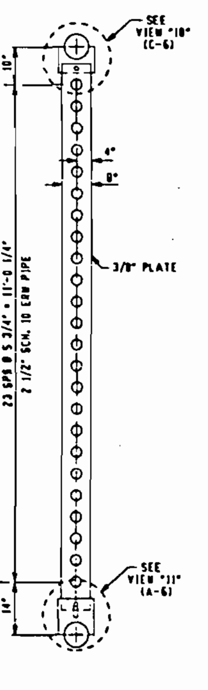
70291-1E2507 REVISION

DIFFUSER ASSEMBLY "R"

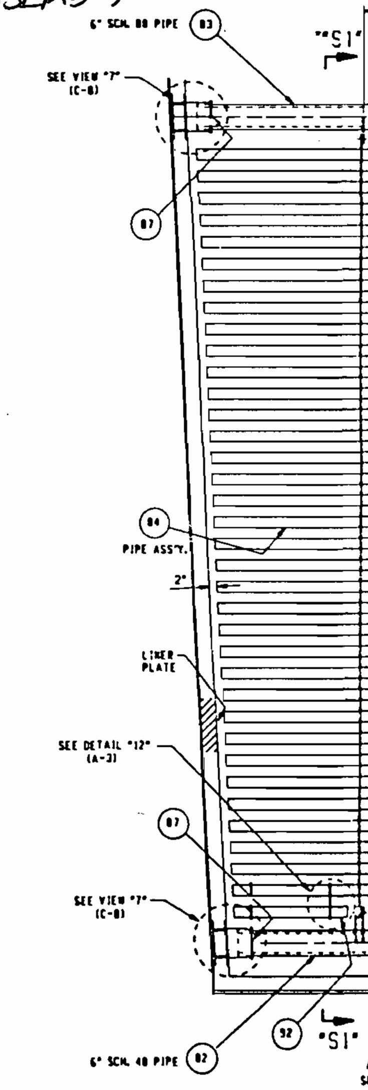
B

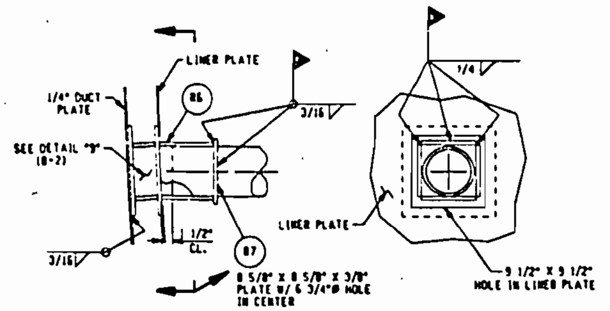


SECTION "R-R" DWG 2500, (D-6)

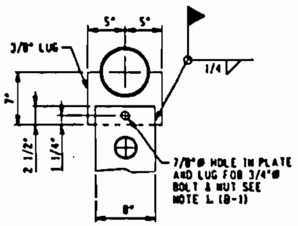


SECTION "R1-R1" (H-6)
TYP. 4 PLACES

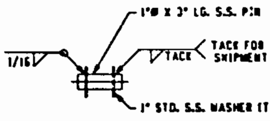




VIEW "7" (E-8), (H-8), (D-4) & (H-4)



VIEW "10" (H-5) & (H-1)



(89) TYP PIN

DEPARTMENT OF ENVIRONMENTAL PROTECTION
FLORIDA

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

February 9, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Dear Mr. Jones:

RE: Request for Construction Permit Amendments
AC 48-206720(A)/PSD-FL-184(A)

The Department has considered Mr. Kennard F. Kosky's request for amendments of the construction permit, referenced above, as outlined in the December 12, 1994 meeting with the Department. Each request will be addressed and the Department's response (R) and any changes will follow:

o <u>Specific Condition 7.b.</u>: Requested that EPA Method 17 be allowed for testing for particulate matter (PM).

R: The request is acceptable and the following will be changed:

FROM: EPA Method 5 for PM.

TO: EPA Method 5 **or 17** for PM **(initial only, unless opacity >10%).**

o <u>Specific Condition 8.</u>: If EPA Method 17 is approved as a testing option in Specific Condition 7.b., then the request is that it also be included as a testing option in this condition.

R: The request is acceptable and the following will be changed:

FROM: EPA Method 5 must be used to determine the initial compliance status of this unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

TO: EPA Method 5 **or 17** must be used to determine the initial compliance status of this unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

o Specific Condition 10.: Requested that the word "proposed", referring to the NO_x standard, be changed to "NSPS".

R: The request is acceptable and the following will be changed:

FROM:

During performance tests, to determine compliance with the proposed NO_x standard, measured NO_x emission at 15 percent oxygen shall be adjusted to ISO ambient atmospheric conditions by the following equation in accordance with 40 CFR 60.335(c)(1):

$$NO_x = (NO_{xo})\ (P_r/P_o)^{0.5}\ e^{19(H_o-0.00633)}\ (288°K/T_a)^{1.53}$$

where:
NO_x = Emission rate of NO_x at 15 percent O_2 and ISO standard ambient conditions, volume percent.
NO_{xo} = Observed NO_x emission at 15 percent oxygen, ppmv.
P_r = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure, mm Hg.
P_o = Measured combustor inlet absolute pressure at test ambient pressure, mm Hg.
H_o = Observed humidity of ambient air at test, g H_2O/g air.
e = Transcendental constant (2.718).
T_a = Temperature of ambient air at test, °K.

TO:

During performance tests, to determine compliance with the **NSPS** NO_x standard, **the** measured NO_x emission at 15 percent oxygen shall be adjusted to ISO ambient atmospheric conditions by the following equation in accordance with 40 CFR 60.335(c)(1):

$$NO_x = (NO_{xo})\ (P_r/P_o)^{0.5}\ e^{19(H_o-0.00633)}\ (288°K/T_a)^{1.53}$$

where:
NO_x = Emission rate of NO_x at 15 percent O_2 and ISO standard ambient conditions, volume percent.
NO_{xo} = Observed NO_x emission at 15 percent oxygen, ppmv.
P_r = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure, mm Hg.
P_o = Measured combustor inlet absolute pressure at test ambient pressure, mm Hg.
H_o = Observed humidity of ambient air at test, g H_2O/g air.
e = Transcendental constant (2.718).
T_a = Temperature of ambient air at test, °K.

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 (F.S.). 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 amendment. 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, F.S.

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, Florida Administrative Code.

A copy of this letter must be attached to the construction permit, No. AC 48-206720(A)/PSD-FL-184(A), and shall become a part of the permit.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes
Director
Division of Air Resources
Management

HLR/SA/bjb

cc: C. Collins, CD
D. Nester, OCEPD
J. Harper, EPA
J. Bunyak, NPS
T. Hess, Orlando CoGen (I), Inc.
K. Kosky, P.E., 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 2/9/95 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 2/9/95

Clerk Date

Z 392 940 715

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

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

PS Form 3800, March 1993

Sent to Mr. John P. Jones	
Street and No. 7201 Hamilton Boulevard	
P.O., State and ZIP Code Allentown, PA 18195-1501	
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: 2/9/95
AC 48-206720(A)/PSD-FL-184(A)

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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.
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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. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

4a. Article Number
Z 392 940 715

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

7. Date of Delivery
FEB 13 1995

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.

Memorandum

Florida Department of
Environmental Protection

TO: Howard L. Rhodes

FROM: Clair Fancy

DATE: February 8, 1995

SUBJECT: Construction Permit Amendments
Orlando CoGen (I), Inc.
AC 48-206720(A)/PSD-FL-184(A)
Orange County

Attached for your approval and signature are amendments to a permit for Orlando CoGen (I), Inc., which is a natural gas fired cogeneration facility. The amendments will allow an alternate testing method for particulate matter (PM), establish the frequency of the PM tests, and clarify the NOx standard ("proposed" to "NSPS"). This action is not controversial.

I recommend your approval and signature.

CF/SA/rbm

Attachment

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

February 8, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Request for Construction Permit Amendments
Orlando CoGen (I), Inc.
AC 48-206720/PSD-FL-184

Dear Mr. Kosky:

The Department has reviewed your requests as outlined in the December 12, 1994 meeting with the Department. The following is a synopsis of the Department's decisions concerning your requests:

1. Clarify that the ISO correction is required only to determine compliance with NSPS NO_x limit.

   The Department agrees with the changes as it relates to the ISO correction for determining compliance with the NSPS standard. Specific Condition 10 will be changed to reflect that. The Department does not agree in making that requirement only for the initial test, but for all annual performance tests, as specified in that condition presently for showing annual compliance with the standard.

2. Revise the CT/Db limit for PM.

   The Department will reconsider this issue after the initial performance test is performed, as required by the construction permit, and the test report is submitted to the Bureau of Air Regulation. The testing should be performed simultaneously at both the combustion turbine (CT) outlet and the heat recovery steam generator (HRSG) stack to determine compliance with the Db limits. The Department will agree to change Specific

Conditions 7a and 8 to include EPA Method 17 as an alternate method for determining PM emissions. Also, the PM emissions test will be required only on an initial basis, and thereafter only if the opacity exceeds 10% and at permit renewal time. The VE test will be required annually.

3. Revise the CT/Db limits for CO and VOC.

   The Department will reconsider this issue after the initial performance test is performed, as required by the construction permit, and the test report is submitted to the Bureau of Air Regulation. The testing should be performed simultaneously at both the CT outlet and the HRSG stack to determine compliance with the Db limits. Compliance with the CO limitation is, by Specific Condition 9 of the permit, an acceptable surrogate method for determining compliance with the VOC emission.

4. The initial NO_X compliance is to be demonstrated using EPA Method 20 and, afterwards, NO_X compliance is to be demonstrated using a CEM; and, annual NO_X tests not be required.

   The Department does not agree with this request because of reasons specified in our previous correspondence of July 8, 1994. 40 CFR 60.8(a) requires the owner or operator to perform an initial performance test; but, it also requires the owner to perform testing at such other times as directed by the Administrator. The Department will reconsider this issue after the initial performance test is performed, as required by the construction permit, and the test report is submitted to the Bureau of Air Regulation. The testing should be performed simultaneously at both the CT outlet and the HRSG stack to determine compliance with the Db limits. If it is determined that the initial Db (i.e., the HRSG) compliance test for the NO_X emissions is demonstrated in accordance with the permit requirements, then the Department will consider changing the annual NO_X compliance testing requirement to once every five years for permit renewal pursuant to Rule 62-297.340(1)(d), F.A.C. The requirement of demonstrating initial and annual NO_X compliance using EPA Method 20 is standard for similar facilities subject to 40 CFR 60, Subpart GG. Since the NO_X CT emissions are greater than 100 TPY, annual EPA Method 20 testing will be required.

The Department will issue a permit amendment on requests that the Department concurred with in the meeting. If there are any questions on the above, please call Syed Arif at (904) 488-1344 or write to me at the above address.

Sincerely,

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

CHF/SA/bjb

cc: C. Collins, CD
J. Harper, EPA
J. Bunyak, NPS
D. Nester, OCEPD
T. Hess, Orlando CoGen (I), Inc.

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.
KBN Engineering & Applied
Sciences, Inc.
1034 N.W. 57th Street
Gainesville, Florida 32605

4a. Article Number
Z 392 940 716

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

7. Date of Delivery
2-13-95

5. Signature (Addressee)
C.M. Reinert

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.

Z 392 940 716

Receipt for Certified Mail

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

UNITED STATES POSTAL SERVICE

PS Form **3800**, March 1993

Sent to Mr. Kennard F. Kosky, P.E.	
Street and No. 1034 N.W. 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: 2/9/95
AC 48-206720/PSD-FL-184

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

November 14, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Amendment of Construction Permit
Orlando CoGen (I), Inc.
AC48-206720; PSD-FL-184

Dear Mr. Kosky:

The Department is in receipt of your letter dated October 10, 1994, requesting reconsideration of the amendment request, and deletion of NSPS ISO correction requirement for NO_x for the above referenced source.

The EPA letter of June 3, 1994 is correct in stating that the emissions limitations must be independently verified for the combustion turbine (CT) and the duct burner (DB) because such limitations result from the applicability of 40 CFR 60, Subparts GG and Db. It follows that PM/PM_{10} and CO must be evaluated in the same manner, since the CT and DB are separate emission units subject to independent emission standards which were established by the BACT determination of August 17, 1992 (date of issuance of the Final Determination). Approval of a combined emission limit for two independent emission units would constitute a "bubble", requiring a SIP revision and EPA approval. Compliance with the CO limitation, is by specific condition 9 of the permit, an acceptable surrogate method for determining compliance with the VOC emission.

Additionally, specific condition 18 of the permit required the source to comply with the Stationary Point Source Emission Test Procedures of Rule 17-2.700, requiring the source to provide sampling ports for proper stack sampling for both CT and the DB. Therefore, in order to achieve compliance with the construction permit, the applicant knew or had reason to know that sampling ports with minimum requirements for testing were needed during the engineering phase of the project. Failure to engineer and construct the unit to provide for such testing is not considered grounds for revising the permit, even if bubbling were allowed.

Specific Condition 10 of the permit requires correcting performance test data to ISO conditions. This is a NSPS requirement, and cannot be deleted.

Any further request for an extension to file a petition will not be granted. If there are any questions on the above, please call Syed Arif at (904) 488-1344, or write to me at the above address.

Sincerely,

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

cc: T. Hess, Orlando CoGen (I), Inc.
J. Harper, EPA
C. Collins, CFD
D. Nester, Orange County

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
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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, P.E.
KBN Engineering & Applied
Sciences, Inc.
6241-NW 23rd St.
Gainesville, Fl 32605

4a. Article Number
P 872 562 682

4b. Service Type

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

7. Date of Delivery
11 16 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 872 562 682

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

No Insurance Coverage Provided
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Sent to
Ken Kosky

Street and No.
KBN Engineering

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
11-14-94
Amend - of Const. Pmt.
AC48-206720 -
PSD-Fl-184

PS Form **3800**, JUNE 1991

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

September 8, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Dear Mr. Jones:

The Department received your request to extend the expiration date of the construction permit referenced below. The permit is amended as shown:

Permit No. AC 48-206720, PSD-FL-184, Orlando CoGen (I), Inc., Orlando CoGen Limited, L.P.

Current Expiration Date : December 31, 1994

New Expiration Date : June 2, 1995

This letter shall become an Attachment to Construction Permit No. AC 48-206720.

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 (F.S.). 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, F.S.

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, Florida Administrative Code.

A copy of this letter shall be filed with the referenced permits and will become a part of those permits.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes
Director
Division of Air Resources
Management

HLR/SA/bjb

Attachment

cc: C. Collins, CD
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 9/14/94 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 J. Boutwell 9/14/94
Clerk Date

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SENDER:

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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.

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. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

4a. Article Number
P 872 562 698

4b. Service Type

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

7. Date of Delivery
SEP 19 1994

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.

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UNITED STATES POSTAL SERVICE

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Sent to
Mr. John P. Jones

Street and No.
7201 Hamilton Boulevard

P.O., State and ZIP Code
Allentown, PA 18195-1501

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: 9/14/94
AC48-206720, PSD-FL-184

PS Form 3800, JUNE 1991

0005788

F1

KBN

August 25, 1994

Mr. Clair 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

RE: Request for Extension of Expiration Date
Orlando CoGen (I), Inc.; Orlando CoGen Limited, L.P.
AC 48-206720; PSD-FL-184

Attn: Syed Arif, Permitting Engineer

Dear Syed Arif:

On behalf of Orlando CoGen (I), Inc., an extension to the expiration date of the construction permit for the above referenced source is respectfully requested pursuant to Specific Condition 20 of the air construction permit. An extension until and including July 1, 1995 is requested.

The Orlando CoGen (I), Inc. facility is a Title V source according to FDEP Rule 17-213.100(19) and will be required to submit to the Department a Title V application by April 2, 1995, ([Rule 17-213.420(1)(a)1.a.; PSD source]. The extension of the expiration date of the permit is requested, due to the current time differences between the expiration of the construction permit and when the Title V permit application is due to the Department. This extension will allow representatives of the facility to focus on the preparation of the Title V permit application which is very comprehensive in nature. In addition, the extension will eliminate the Department's need to issue a separate operating permit in the next few months and then issue a Title V permit shortly thereafter. The extension request would also allow additional time to resolve any remaining issues surrounding testing methods for non-NSPS requirements, as discussed in the previous permit amendment request.

1994 AUG 29 PM 3:29
RECEIVED
DER - MAIL ROOM

The Department's consideration in this matter is appreciated. Please call if you have any questions.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

RECEIVED
SEP 01 1994
BAR ASBESTOS

cc: Tom Hess, Orlando CoGen (I), Inc.
S. Arif
C. Collins, C Otal,

91134A1/21

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

1616 'P' Street N.W., Suite 450
Washington, D.C. 20036
202-462-1100
FAX 202-462-2270

EQUAL EMPLOYMENT OPPORTUNITY

AN AFFIRMATIVE ACTION EMPLOYER

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

[redacted] Branch 311

005788

013479

26 August 19 94

PAY ************50*** **DOLLARS AND** 00 **CENTS** **$** *******50.00

TO THE ORDER OF

Florida Department of Environmental Protection
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

PLEASE DETACH AND RETAIN FOR YOUR RECORDS

INVOICE NUMBER	DATE		VOUCHER NO.	AMOUNT
	08/26/94	Air Permit extension		50.00

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
INTENT TO DENY

CERTIFIED MAIL

In the Matter of an Application
for Permit Amendment by:

DEP File No. AC48-206720
PSD-FL-184
Orange County

Mr. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

INTENT TO DENY

The Department of Environmental Protection gives notice of its Intent to Deny the construction permit amendment request for the proposed project as detailed in the application specified above for reasons stated in this Intent.

The applicant, Orlando CoGen (I), Inc., applied on January 6, 1994, for a permit amendment to the construction permit of their 129 megawatt (MW) cogeneration facility in Orlando, Orange County, Florida. The Department has determined that granting such a proposal will constitute approving a "bubble", for which the Department has no authority to approve through a permit amendment process.

PROJECT DESCRIPTION

The source is a 129 MW cogeneration facility located in Orlando, Orange County, Florida. The cogeneration facility consists of a combustion turbine (CT) exhausting through a heat recovery steam generator (HRSG). The transition duct from the CT to the HRSG contains duct burners (DBs) with a maximum heat input of 122 million British thermal units per hour (MMBtu/hr). The two new source performance standards (NSPS) applicable to the facility are 40 CFR 60, Subpart GG, for the combustion turbine and 40 CFR 60, Subpart Db, for the HRSG with the duct burners.

REASON FOR DENIAL

The applicant requested changes to specific conditions 4, 7 and 8 of the construction permit. The requested change to specific condition 4 would imply changing the specific individual limits for the CT and DBs to emission limits applicable to the CT operating alone and the CT/DBs operating together. The request is denied based on EPA's assessment of non-compliance with 40 CFR 60, Subpart Db requirements, and pursuant to Rules 17-296.200(170) and 17-297.100(123), Florida Administrative Code (F.A.C.), and 40 CFR 60.2. The CT and HRSG are separate sources and subject to independent emission limitations. Since the CT and HRSG are, by rule, two separate sources, the request for a combined emission limit is a request for approving a "bubble", which requires a SIP revision and EPA approval. The changes to specific conditions 7 and 8 are denied, as a request of this nature must be processed through an approval of alternate standards and procedures as outlined in Rule 17-297.620, F.A.C.

Pursuant to Section 403.815, Florida Statutes, (F.S.), and DEP Rule 17-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Deny. 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 permit amendment. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department, at the Department of Environmental Protection, 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 amendment.

The Department will deny the permit amendment 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, F.S. 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 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, F.S.

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.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Howard L Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO DENY and all copies were mailed by certified mail before the close of business on [date] 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 8/16/94
(Clerk) (Date)

Copies furnished to:

Charles Collins, Central District
Ken Kosky, KBN
Dennis Nester, Orange County
Jewell Harper, EPA
John Bunyak, NPS

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

1. ☐ Addressee's Address
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3. Article Addressed to:

Mr. John P. Hones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentow, PA 1819501501

4a. Article Number
P 872 563 651

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

7. Date of Delivery
8-23-94

5. Signature (Addressee)

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6. Signature (Agent)

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

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UNITED STATES POSTAL SERVICE

Sent to
Mr. John P. Homes, Orlando CoGen Ltd.

Street and No.
7201 Hamilton Blvd.

P.O., State and ZIP Code
Allentow, PA 18195-1501

Postage	$
Certified Fee	
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Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$

Postmark or Date

Permit: AC48-206720
PSD-FL-184

Mailed: 8-16-94

PS Form **3800**, JUNE 1991

Florida Department of
Environmental Protection

Memorandum

TO: Howard L. Rhodes

FROM: for John Brown Clair Fancy

DATE: August 11, 1994

SUBJECT: Intent to Deny Permit Amendment

Orlando CoGen (I), Inc. submitted a permit amendment request for changes to the construction permit of the 129 megawatt (MW) cogeneration facility located in Orlando, Orange County, Florida, on January 6, 1994. The request included changes to the individual emission limits for the combustion turbine and the duct burner and changes to the test methods specified in the construction permit. Since that time, the focus of the review has been obtaining additional information from the applicant and seeking guidance from EPA for the purpose of making a decision of the requested changes by the facility.

Based on the information on hand, granting the permit amendment would be tantamount to approving a "bubble". The State of Florida has neither adopted nor received federal approval for the review and approval of "bubbles".

It is recommended that the attached "Intent to Deny" be issued.

CF/SA/bjb

Attachment

INTEROFFICE MEMORANDUM

Date: 26-Jul-1994 06:32pm EST
From: Mike Harley TAL
HARLEY_M
Dept: Air Resources Managemen
Tel No: 904/488-1344
SUNCOM:

TO: See Below

Subject: ORLANDO COGEN

Pursuant to your request, Mr. Kosky's latest request concerning Orlando Cogen has been reviewed. The comments are as follows:

1. Pursuant to Rules 62-296.100(168), F.A.C., 62-297.100(123), F.A.C., etc., and 40 CFR 60.2, the combustion turbine and the heat recovery steam generator are separate sources and should be subject to independent emission limitations. Each source of air pollutions should be subject to an independent emission limiting standard.

2. Since the combustion turbine and the heat recovery steam generator are, by rule, two separate sources the request for a combined emission limit is actually a request for a "bubble." The State of Florida has neither adopted nor received federal approval of a generic rule for the review and approval of "bubbles." Therefore, each "bubble" must be adopted as a SIP revision and submitted to EPA for approval on a case-by-case basis regardless of whether the pollutants are regulated on the basis of NSPS, PSD, NA/NSR, or the SIP.

3. The statement that EPA Method 5 particulate testing cannot be performed at the turbine exit due to the difficulty in measuring flow rate is not consistent with information concerning particulate testing of other combustion turbines. Other combustion turbines in Florida have been successfully compliance tested using EPA Method 5--these tests have included successful EPA Method 2 flow measurements. Some of the affected sources are owned by Florida Power and the testing was conducted by Cubix.

4. The request to include PM/PM10 among the pollutants subject to a combined standard is patently unacceptable because the NSPS for Subpart Db sources include emission limiting standards for affected facilities which burn coal, oil, wood, or municipal waste. If neither of the affected sources burn coal, oil, wood, or municipal waste, it may be more appropriate to delete the particulate testing requirement altogether.

5. The application of a combined standard would impair the Department's ability to assign a violation to the specific source of excess emissions.

6. Regardless of the pollutants involved, the creation of a combined standard for a combined cycle system consisting of two NSPS sources through the permitting process would violate federal requirements and establish a precedent that would weaken our position concerning the measurement of the NSPS pollutants.

7. Mr. Kosky needs to specifically identify the specific sources that have already received combined emission limits, so that we can audit the permits to ensure that the issuance neither involved violations of state standards nor federal regulations.

This proposal appears to be based on the erroneous assumption that the Department is in the business of permitting smoke stacks. In fact, the Department is in the business of permitting -- AIR POLLUTION SOURCES. The proposal is contrary to the past practices of the Department. It has the potential to undermine the Department's position with respect to other air pollution sources such as coating lines, printing facilities, kraft pulp mills, and certain power boilers. I recommend rejection of Mr. Kosky's latest proposal.

Distribution:

TO: Syed Arif TAL (ARIF_S)

CC: Clair Fancy TAL (FANCY_C)
CC: John Brown TAL (BROWN_J)
CC: Bruce Mitchell TAL (MITCHELL_B)
CC: Martin Costello TAL (COSTELLO_M)
CC: Ramesh Menon TAL (MENON_R)

DEPARTMENT OF ENVIRONMENTAL PROTECTION
FLORIDA

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

July 8, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Amendment of Construction Permit
Orlando CoGen (I), Inc.
AC48-206720; PSD-FL-184

Dear Mr. Kosky:

The Department is in receipt of your letter dated June 28, 1994, requesting reconsideration of the amendment request for the above referenced source. As stated in our letter of June 17, 1994, the Department concurs with EPA's assessment of the sources compliance with the NSPS requirements of 40 CFR 60 Subpart Db, specifically the testing requirements as outlined in 40 CFR 60.46b(f). A copy of EPA's letter is also attached for your reference.

40 CFR 60.8(a) not only requires the owner or operator to perform an initial compliance test; but, it also requires the owner to perform testing at such other times as directed by the Administrator. The state requirement to conduct annual testing can be found in 17-297.340(1)(d), F.A.C. Also, specific condition 7 of the above referenced permit requires that an initial and subsequent annual compliance tests shall be conducted to demonstrate compliance.

If the source wishes to deviate from the testing requirements of 40 CFR 60 Subpart Db, then it must request approval of alternate standards and procedures as outlined in 17-297.620 F.A.C. from the Department.

The Department will issue an Intent to Deny if it does not receive a request from the source to withdraw the amendment request. However, by copy of this letter we are extending the date until July 22, 1994.

If there are any questions on the above, please call Syed Arif at (904) 488-1344, or write to me at the above address.

Sincerely,

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

CHF/SA/bjb

Attachment

cc: T. Hess, Orlando Cogen (I), Inc.
J. Harper, EPA
C. Collins, CFD
D. Nester, Orange County
M. Harley, BAR
S. Arif, BAR

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3. Article Addressed to:

Mr. Kennard F. Kosdy, P.E.
KBN Engineering & Applied Sciences,
1034 NW 57th Street
Gainesville, FL 32605

4a. Article Number
P 872 563 641

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

7. Date of Delivery
7/14

5. Signature (Addressee)
CM Reinert

6. Signature (Agent)

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

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Sent to
Mr. Kennard F. Kosky, KBN

Street and No.
1034 NW 57th Street

P.O., State and ZIP Code
Gainesville, FL 32605

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Mailed: 7-12-94
Permit: AC48-206720
PSD-FL-184

PS Form **3800**, JUNE 1991

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

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Bureau of
Air Regulation

4APT-AEB

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

SUBJECT: Construction Permit Amendment for Orlando CoGen Limited, L.P.

Dear Mr. Fancy:

This letter is in response to your March 1, 1994, request for clarification regarding the U.S. Environmental Protection Agency (EPA) position on a permit amendment and alternative NO_x compliance demonstration procedure proposed for a gas turbine and a duct burner in a combined cycle system operated by the referenced company. After reviewing the proposed permit amendment and alternative testing procedure, we have determined that we would be opposed to approval of either proposal.

Because of concerns about the difficulty associated with testing the duct burners in the combined cycle system at Orlando CoGen, KBN Engineering and Applied Sciences, Inc. (KBN) proposed revisions to NO_x emission limits and compliance testing procedures for the combined cycle system. The emission standard revision involved establishing two emission limits--a gas turbine emission limit and a combined limit for the gas turbine and duct burner operating together. Under this proposal, there would not be a separate limit for the duct burners, and the basis for this proposal was that the duct burners will never be operated alone.

After considering the KBN proposal for emission standard revisions, we have determined that it is not acceptable because one of the applicable regulations for the duct burners, 40 C.F.R. Part 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), contains a separate NO_x emission standard for duct burners in combined cycle systems. Since Subpart Db contains a NO_x emission limit specifically for duct burners, establishing a combined NO_x emission limit for the gas turbine and duct burner would not relieve Orlando CoGen of the obligation to demonstrate compliance with the applicable duct burner NO_x emission limit in Subpart Db.

The second proposal in the request from KBN involves compliance demonstration procedures for the duct burner. According to Subpart Db, the NO_x emission rate for duct burners is determined by measuring the emission rate at both the inlet

and outlet of the duct burner. As an alternative to performing the test in accordance with Subpart Db, KBN proposed to determine the duct burner emission rate by performing all testing downstream of the duct burner and operating the combined cycle systems in two modes--one with only the turbine running and one with both the turbine and the duct burner operating. Under this scenario, the duct burner emission rate would be calculated by subtracting the turbine emission rate from the emission rate with both facilities operating. In support of this proposed alternative, KBN referenced a previous approval of similar procedures for combined cycle testing that was conducted at the Florida Power and Light (FP&L) Putnam Plant.

After considering the testing alternative proposed by KBN, we do not believe that it should be approved either. The basis for this position is that we are aware of other sources where similar procedures have yielded suspect results (i.e., NO_x mass emission rates with the gas turbine and duct burner operating together were lower than they were with only the turbine operating). The reason for these suspect results is uncertain, but they may have been caused by the inability to achieve and maintain identical operating conditions for the turbine during both sets of tests.

Although procedures similar to those proposed by KBN were approved for the FP&L Putnam Plant, we do not consider this prior approval relevant with respect to Orlando CoGen because of differences in the two facilities. The primary justification for approving alternative testing procedures at the Putnam Plant was that these units were existing units that became subject to Subpart Db due to reconstruction. Although 40 C.F.R. §60.8(e) requires that a source owner or operator provide adequate testing and sampling locations, we did not necessarily consider these requirements applicable to FP&L since the Putnam units were not subject to Subpart Db at the time the units were originally constructed. Since the combined cycle system at Orlando CoGen is new, testing requirements should have been considered during the design of the facility, and failure to take these testing requirements into account during design does not constitute sufficient grounds for approval of an alternative test method.

If you have any questions about the issues addressed in this letter, please contact Mr. David McNeal of my staff at 404/347-5014.

Sincerely yours,

Jewell A. Harper

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

cc: Michael Harley, FL DEP

KBN

PATTY - FILE

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JUL 01 1994

Bureau of
Air Regulation

June 28, 1994

Mr. Preston Lewis
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399

RE: Orlando CoGeneration, Inc.
Amendment to Construction Permit AC48-206720

Dear Preston:

This letter is a following-up of our conversation last week, and provides clarification on the amendment request.

1. Orlando CoGen (I), Inc. has offered to perform initial performance testing of the duct burners (DB) using EPA Method 20 with sampling locations at the turbine exhaust and stack.

2. Such testing would be in conformance with Subpart Db and Method 20. The cost for this testing is estimated to be about $70,000. The applicable standard is 0.2 lb NO_x per million BTU for the DB.

3. The amendment request deals with determining compliance after the initial performance tests.

4. For this purpose, separate combustion turbines (CT) and CT/DB limits are requested.

5. No change in the emissions are proposed, just adding CT/DB emissions together.

6. This request is appropriate because:

   a. DB limit is 1/2 of NSPS limit; therefore meeting CT/DB limit provides reasonable assurance of meeting DB limits.
   b. DB <u>cannot</u> be operated without CT.
   c. Sampling errors could <u>still</u> be in introduced by subtraction using simultaneous testing due to the large flow rates involved.
   d. Simultaneous testing is very costly and difficult to conduct regardless of the plant configuration.
   e. CEM data are more appropriately compared to CT and CT/DB limits and <u>not</u> valid for separate DB limits.

91134A1/18

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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7. We believe the Department has the authority to issue such an amendment since the BACT limits are substantially lower than NSPS limits and there is no specific NSPS requirement to perform simultaneous testing on an annual basis. Moreover, it is not consistent with the monitoring method, i.e. CEM.

I believe the amendment request is a practical solution to a complex issue and will provide both the Department and Orlando Cogen (I), Inc., a straight forward approach of demonstrating and maintaining compliance (i.e., emissions from the stack). It may be appropriate to meet on this issue the week of July 5-8. I'll call you later this week.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

KFK/mlb

cc: Tom Hess, Orlando CoGen (I), Inc.

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

June 28, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Dear Mr. Jones:

The Department received your request to extend the expiration date of the construction permit referenced below. The permit is amended as shown:

Permit No. AC 48-206720, PSD-FL-184, Orlando CoGen (I), Inc., Orlando CoGen Limited, L.P.

Current Expiration Date : August 31, 1994

New Expiration Date : December 31, 1994

This letter shall become an Attachment to Construction Permit No. AC 48-206720.

A 120-day extension is granted to accommodate a revised testing protocol and to provide sufficient time to prepare the facility for testing with the revised testing protocol.

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.

A copy of this letter shall be filed with the referenced permits and will become a part of those permits.

Sincerely,

Howard L. Rhodes

Howard L. Rhodes
Director
Division of Air Resources
Management

HLR/SA/bjb

cc: J. Kissel, 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 5/29/94 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 J. Boutwell 5/29/94
Clerk Date

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Mr. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

4a. Article Number
P 872 562 714

4b. Service Type
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☐ Insured
☒ Certified
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5. Signature (Addressee)

6. Signature (Agent)

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UNITED STATES POSTAL SERVICE

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P.O., State and ZIP Code Allentown, PA 18195-1501	
Postage	$
Certified Fee	
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Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 6/29/94 AC 48-206720	

PS Form **3800**, JUNE 1991

DEPARTMENT OF ENVIRONMENTAL PROTECTION 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 17, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: Amendment of Construction Permit
Orlando CoGen (I), Inc.
AC48-206720; PSD-FL-184

Dear Mr. Kosky:

The Department has received EPA's response for the proposed amendment of the permit for the above referenced source. Enclosed for your review is EPA's June 3, 1994, letter on this subject.

Based on EPA's assessment of the request for the permit amendment, the Department has decided to provide Orlando CoGen (I), Inc., with the opportunity to withdraw the amendment request. If the Department does not receive the request to withdraw by July 8, 1994, then an Intent to Deny the request for permit amendment will be issued.

Please note that in the future, requests for approval of alternate standards and procedures should be directly addressed to Mike Harley of the Emissions Monitoring Section, instead of submitting them as permit amendment requests.

If there are any questions on the above, please call Syed Arif at (904) 488-1344, or write to me at the letterhead address.

Sincerely,

John C Brown, Jr.

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards

JCB/sa

Enclosure

cc: J. Campbell, EPCHC
E. Curran, Cargill
M. Harper, EPA
M. Harley, BAR
B. Thomas, SWD

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JUN 23 1994
Bureau of
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3. Article Addressed to:

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

4a. Article Number
P 872 562 720

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

7. Date of Delivery 6-22

Mary Reinert
5. Signature (Addressee)

6. Signature (Agent)

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

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Street and No. 1034 N.W. 57th Street
P.O., State and ZIP Code Gainesville, FL 32605

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Certified Fee	
Special Delivery Fee	
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Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$

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AC 48-206720; PSD-FL-184

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

RECEIVED
JUN 06 RECD

JUN 0 3 1994

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JUN 06 1994
Bureau of
Air Regulation

4APT-AEB

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

SUBJECT: Construction Permit Amendment for Orlando CoGen Limited, L.P.

Dear Mr. Fancy:

This letter is in response to your March 1, 1994, request for clarification regarding the U.S. Environmental Protection Agency (EPA) position on a permit amendment and alternative NO_x compliance demonstration procedure proposed for a gas turbine and a duct burner in a combined cycle system operated by the referenced company. After reviewing the proposed permit amendment and alternative testing procedure, we have determined that we would be opposed to approval of either proposal.

Because of concerns about the difficulty associated with testing the duct burners in the combined cycle system at Orlando CoGen, KBN Engineering and Applied Sciences, Inc. (KBN) proposed revisions to NO_x emission limits and compliance testing procedures for the combined cycle system. The emission standard revision involved establishing two emission limits--a gas turbine emission limit and a combined limit for the gas turbine and duct burner operating together. Under this proposal, there would not be a separate limit for the duct burners, and the basis for this proposal was that the duct burners will never be operated alone.

After considering the KBN proposal for emission standard revisions, we have determined that it is not acceptable because one of the applicable regulations for the duct burners, 40 C.F.R. Part 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), contains a separate NO_x emission standard for duct burners in combined cycle systems. Since Subpart Db contains a NO_x emission limit specifically for duct burners, establishing a combined NO_x emission limit for the gas turbine and duct burner would not relieve Orlando CoGen of the obligation to demonstrate compliance with the applicable duct burner NO_x emission limit in Subpart Db.

The second proposal in the request from KBN involves compliance demonstration procedures for the duct burner. According to Subpart Db, the NO_x emission rate for duct burners is determined by measuring the emission rate at both the inlet

and outlet of the duct burner. As an alternative to performing the test in accordance with Subpart Db, KBN proposed to determine the duct burner emission rate by performing all testing downstream of the duct burner and operating the combined cycle systems in two modes--one with only the turbine running and one with both the turbine and the duct burner operating. Under this scenario, the duct burner emission rate would be calculated by subtracting the turbine emission rate from the emission rate with both facilities operating. In support of this proposed alternative, KBN referenced a previous approval of similar procedures for combined cycle testing that was conducted at the Florida Power and Light (FP&L) Putnam Plant.

After considering the testing alternative proposed by KBN, we do not believe that it should be approved either. The basis for this position is that we are aware of other sources where similar procedures have yielded suspect results (i.e., NO_x mass emission rates with the gas turbine and duct burner operating together were lower than they were with only the turbine operating). The reason for these suspect results is uncertain, but they may have been caused by the inability to achieve and maintain identical operating conditions for the turbine during both sets of tests.

Although procedures similar to those proposed by KBN were approved for the FP&L Putnam Plant, we do not consider this prior approval relevant with respect to Orlando CoGen because of differences in the two facilities. The primary justification for approving alternative testing procedures at the Putnam Plant was that these units were existing units that became subject to Subpart Db due to reconstruction. Although 40 C.F.R. §60.8(e) requires that a source owner or operator provide adequate testing and sampling locations, we did not necessarily consider these requirements applicable to FP&L since the Putnam units were not subject to Subpart Db at the time the units were originally constructed. Since the combined cycle system at Orlando CoGen is new, testing requirements should have been considered during the design of the facility, and failure to take these testing requirements into account during design does not constitute sufficient grounds for approval of an alternative test method.

If you have any questions about the issues addressed in this letter, please contact Mr. David McNeal of my staff at 404/347-5014.

Sincerely yours,

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

cc: Michael Harley, FL DEP

0004733

KBN

June 15, 1994

252916
PATS updated

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

RECEIVED
DER - MAIL ROOM
1994 JUN 17 PM 2:30

RE: Request for Extension of Permit Expiration
Request for Permit Amendment
Orlando CoGen (I), Inc. Orlando CoGen Limited, L.P.
AC 48-206720; PSD-FL-184

Dear Clair:

This correspondence is submitted on behalf of Orlando CoGen Limited to request an extension of the permit expiration date. In addition, this correspondence modifies the permit amendment request in light of EPA's letter dated June 3, 1994.

Permit Expiration Request

The current construction permit expires on August 31, 1994. A 120-day extension is requested to accommodate a revised testing protocol made necessary by EPA's correspondence of June 3, 1994. In this correspondence, EPA indicates that the required approach to demonstrate compliance with the New Source Performance Standards (NSPS) Subpart Db emission limit (0.2 lb NO_x/MMBtu) is EPA Method 20 performed at both the combustion turbine (CT) outlet and the heat recovery steam generator (HRSG) stack. Subtracting the results of this simultaneous testing would provide information on compliance with the duct burners (DBs) with NSPS limits. In order to provide sufficient time to prepare the facility for testing in this manner, an extension is required. It is anticipated that the tests would be performed in August, 1994; thus, additional time is required to submit the tests and obtain an operating permit. A permit extension fee of $50.00 has been enclosed.

Permit Amendment

The EPA correspondence specifically addressed demonstrating compliance with the NSPS limits. As stated in our correspondence dated January 5, and February 22, 1994, the BACT limit is more stringent than the NSPS limit; thus the requested changes to the construction permit would not in any way affect the NSPS issues. Indeed, Specific Condition 16 separately addresses the requirement for the DBs to meet the NSPS. The requested changes are still appropriate for several reasons. First, there is no NSPS requirement to conduct annual testing to demonstrate compliance with the NSPS limit. Once testing is conducted to demonstrate compliance with the NSPS as indicated above, the facility would have met the obligation under these rules. Second, the proposed amendment (separate CT and CT/DB emission limits)

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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would provide the Department with a clear approach of demonstrating compliance with the BACT limits. Simultaneous Method 20 testing is extremely costly and does not provide any more assurance of meeting the BACT limits. Moreover, the facility has a NO_x CEM that must be used to compare actual stack emissions with express CT and CT/DB limits; Specific Condition 13 of the current permit has this requirement. Thus, the requested changes to Table 1 only make the permit consistent with the Department's intent to regulate total emissions from the stack as provide for NO_x in Specific Condition 13.

Please note that the retesting of the facility using the simultaneous testing approach will cost about $75,000. This cost will not affect the emissions results since the alternate approach produced NO_x emission levels that were clearly in compliance with NSPS.

As always, your consideration in this matter is appreciated.

Sincerely,

Kennard F. Kosky, P.E.
President

cc: Tom Hess, Orlando CoGen (I), Inc.
Syed Arif, FDEP Tallahassee
Charles Collins, FDEP Orlando
Dennis Nester, Orange County EPD

Best Available Copy

3N ENGINEERING AND APPLIED SCIENCES, INC.
INESVILLE, FL 32605

V-3922 012774

PLEASE DETACH AND RETAIN FOR YOUR RECORDS

INVOICE NUMBER	DATE		VOUCHER NO.	AMOUNT
	06/17/94	permit extension fee for Orlando CoGen (AC 48-206720; PSD-FL-184)		50.00

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

[redacted]
Branch 311

012774
0004733

17 June 19 94

PAY *************50*** **DOLLARS AND** 00 **CENTS** **$** ******50.00

TO THE ORDER OF
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee Fl 32399-2400

KBN ENGINEERING AND APPLIED SCIENCES, INC.

AUTHORIZED SIGNATURE

[redacted]

RECEIVED

June 9

Bureau of Air Regulation

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

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

DEPARTMENT OF ENVIRONMENTAL PROTECTION

JUN 08 1994

OFFICE OF THE SECRETARY

JUN 0 3 1994

4APT-AEB

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

SUBJECT: Construction Permit Amendment for Orlando CoGen Limited, L.P.

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After considering the KBN proposal for emission standard revisions, we have determined that it is not acceptable because one of the applicable regulations for the duct burners, 40 C.F.R. Part 60, Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units), contains a separate NO_x emission standard for duct burners in combined cycle systems. Since Subpart Db contains a NO_x emission limit specifically for duct burners, establishing a combined NO_x emission limit for the gas turbine and duct burner would not relieve Orlando CoGen of the obligation to demonstrate compliance with the applicable duct burner NO_x emission limit in Subpart Db.

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If you have any questions about the issues addressed in this letter, please contact Mr. David McNeal of my staff at 404/347-5014.

Sincerely yours,

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

cc: Michael Harley, FL DEP
S. Arif

Florida Department of
Environmental Protection

Lawton Chiles
Governor

Central District
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767

Virginia B. Wetherell
Secretary

COMPLETENESS SUMMARY FOR AIR POLLUTION SOURCES

SOURCE NAME: **Orlando Cogen Limited, L.P.**

DATE RECEIVED: **April 11, 1994**

NAME: **Ronald D. Pettit, Operations Manager**

DATE REVIEWED: **May 9, 1994**

ADDRESS: **7201 Hamilton Boulevard**
Allentown, PA 18195-1501

REVIEWED BY: **Louis Brown**
AC48-206720

Your application for a modification to the operating permit for this referenced project has been received and reviewed for completeness. The following item(s) is/are needed from the professional engineer to complete your application.

1. **A Letter of Authorization designating Ronald D. Pettit, Operations Manager, as an Authorized Representative of Orlando Cogen Limited, L.P., must be submitted to this office.**

2. **This source is not in compliance with the NSPS, 40 CFR 60 Subpart Db, which requires the measurement of NO_X and oxygen at two sampling sites. One sampling site shall be located as close as is practical to the exhaust of the turbine, and the second site at the outlet to the steam generating unit. The source does not have sampling ports at the exhaust of the turbine. The request for modification of Construction Permit No. AC48-206720 must be approved and issued by the Department's Bureau of Air Regulation in Tallahassee before the operating permit for this facility can be processed.**

Pursuant to Section 120.60(2) F.S. , the Department may deny an application if the applicant, after receiving timely notice, fails to correct errors or omissions, or to supply additional information within a reasonable period of time.

If you have any questions, please call Louis Brown at (407)894-7555 or write to the above address.

Sincerely,

Charles M Collins
Charles M. Collins
PE Administrator,
Air Resources Management

5-9-94
Date

CMC/lbl

Copies furnished to:

Kennard F. Kosky
Clair Fancy ✓

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Fancy, Clair H. Chief
2. ARM BAR TL
3. MAGNO 127
4.

RECEIVED
MAY 13 1994
Bureau of
Air Regulation

FROM: Teresa

DATE 5/12

PHONE

08-18 93

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

March 1, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Dear Ms. Harper:

Re: Amendment of Construction Permit
Orlando CoGen (I), Inc.; Orlando CoGen Limited, L.P.
AC48-206720; PSD-FL-184

The Department needs some guidance from the EPA regarding an amendment request by KBN for the above referenced source. The documents enclosed with this letter are as follows:

1. KBN's amendment request dated January 5, 1994.
2. Department's incompleteness letter of January 27, 1994.
3. KBN's response to incompleteness letter dated February 22, 1994.

The issue of concern for the Department is the non-compliance by the source with the New Source Performance Standards (NSPS) requirements of 40 CFR 60, Subpart Db. The source is a 129-megawatt (MW) cogeneration facility consisting of a combustion turbine (CT) with a maximum heat input of 857 MMBtu/hr exhausting through a heat recovery steam generator (HRSG). The transition duct from the CT to the HRSG contains duct burners with a maximum heat input of 122 MMBtu/hr.

The applicable rule for the duct burners, 40 CFR 60.46 (f), Subpart Db, requires the measurement of NO_X and oxygen at two sampling sites. One sampling site shall be located as close as practicable to the exhaust of the turbine and the second site at the outlet to the steam generating unit. The source does not have sampling ports at the exhaust of the turbine.

Since the duct burner cannot be operated independently of the combustion turbine, the source is requesting the specification of individual limits for the CT and duct burners be changed to emission limits applicable to the CT operating alone and the CT and duct burners operating together. This change will not result in an increase in annual emissions. See the attached letter from Mr. Kosky, dated January 5, 1994.

Please indicate EPA's position on this issue of the source's non-compliance with NSPS requirements of testing as cited in Subpart Db. If there are any questions on the above, please call Syed Arif of my staff at (904) 488-1344.

The Department will not be able to take further action on the request for permit amendment until the response from EPA is received.

Sincerely,

CHFancy

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

CHF/SA/bjb

cc: Ken Kosky, KBN w/o attachments
Charles Collins, Central District w/o attachments
Dennis Nester, Orange County w/o attachments

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

4a. Article Number
P 872 562 673

4b. Service Type
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- ☒ Certified
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- ☐ Express Mail
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3-07-94

5. Signature (Addressee)

6. Signature (Agent)

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

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Postmark or Date Mailed: 3/2/94 AC48-206720	

PS Form **3800**, JUNE 1991

KBN

February 22, 1994

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Bureau of
Air Regulation

Mr. John C. Brown, Jr., P.E.
Administrator, Air Permitting and Standards
Bureau of Air Regulation
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: Amendment of Construction Permit
Orlando CoGen (I), Inc.; Orlando CoGen Limited, L.P.
AC48-206720; PSD-FL-184

Attention: Syed Arif

Dear Syed:

This correspondence presents additional information requested in the Department's letter dated January 27, 1994, concerning the request made to amend the above referenced permit. The information and comments are presented in the same order listed in the Department's January 27th letter.

Specific Condition 4

1. The change requested in Specific Condition 4 was made to differentiate the emission limits made for BACT and those applicable for NSPS. The reason this was requested was to distinguish between the applicable limits and provide a clear basis for future compliance. Thus, the issue of testing and location regarding NSPS would only apply to NOx and not the other pollutants. The Department can change this condition without affecting the NSPS or its associated testing issue.

There are no test ports that can meet the requirements to perform an EPA Method 20 in the transition duct between the CT and duct burners. This not only applies to this facility but to all that have been constructed in Florida (and presumably elsewhere to my knowledge). The reasons for this are:

   a. high temperature (1,000°F) and positive pressure of flue gas.

   b. an EPA Method 1 for locating flow rate measurements cannot be performed due to cyclonic flow and obstructions; it would not be possible to determine emissions rates in lbs/hr for NOx, CO and PM.

   c. an EPA Method 20 could not be performed at this location due to the same problems with EPA Method 1.

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
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813-287-1717 FAX 813-287-1716

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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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Historically, all determinations of duct burner emissions were performed using the approach suggested in the testing protocol submitted to the Department for this cogeneration facility and discussed in the results. The test protocol was distributed to both the Central District and the Bureau's Emission Monitoring section and no adverse comments were received. The methodology used presented the "as close as practicable" location as the stack which can meet all EPA and DEP test location criteria. Tests were conducted with and without duct burner operation to determine emission rates. While the test was not conducted at the same time as suggested by the NSPS, the conditions were sufficiently representative to determine if the duct burners were in compliance with the NSPS, i.e., 0.2 lb/mmBtu. Having received no adverse comments on the test plan, testing was conducted, since as you are aware, it was important to perform test within the prescribed NSPS time frames.

I previously contacted EPA, including the author of the NSPS for Subpart Db [Rick Copeland (919)541-5265] and an individual from the EPA Emission Measurement Branch [Terry Harrison (919)541-5233] regarding this issue. Both are aware of the problem of determining compliance and have indicated that it is under review by EPA for change. Both indicated that the testing procedure involving "with and without duct burners" or a combined emission limit (i.e., turbine and duct burners) may be appropriate considerations given the technical problems of testing duct burners.

Again, the requested amendment to Specific Condition would not in any way affect the NSPS testing issue.

2. The cited section of the NSPS [40 CFR 60.46(e)(1)] applies only to sources that are required to have continuous emission monitoring system (CEMS) for NOx as required by Section 60.48b(b). Duct burner systems are exempt under 60.48b(h) from CEMS; please note that this section cites 60.44b(a)(4) which apply to duct burners used in combined cycle systems. The attached EPA letter confirms this observation.

Specific Condition 7

The purpose of requesting this change was for the ease of monitoring after the initial performance tests were conducted. It is recognized that EPA Method 20 is required for the initial compliance tests. However, the NSPS do not require annual compliance tests after the initial performance tests. Thus, the NSPS would not be contradicted if the Department specifies EPA Method 7e for annual compliance after the initial tests. Also, please note that the testing procedure used for determining compliance with the duct burners uses the appropriate methods; the only thing of issue is how the results are interpreted.

Specific Condition 8

There is difficulty using EPA Method 5 due to heated glass probe length and number of test locations. Since EPA Method 17 is equivalent to EPA Method 5 when the temperature is 250°F or greater, it is requested that EPA Method 17 be included in this Specific Condition. The data suggests that the EPA Method 17 criteria can be met at the cogeneration facility.

It is hoped that this information is sufficient to address your questions. However, it may be appropriate to meet with you on these issues to clarify any further questions. I would suggest the week of February 28th as an option. There is some time constraints, since these issues must be address before applying for the operating permit. I'll call in a few days. In the meantime, please call if you have any questions.

Sincerely,

Kennard F. Kosky, P.E.
President

cc: Tom Hess, Orlando CoGen (I), Inc.
Charles Collins, P.E., FDEP Central District
Dennis Nester, Orange County EPD

KFK/mlb

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

January 27, 1994

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

RE: Amendment of Construction Permit
Orlando CoGen (I), Inc.
AC48-206720; PSD-FL-184

Dear Mr. Kosky:

The Department has reviewed the request for changes to the above referenced construction permit. Listed below is the additional information required in order to continue processing this amendment request:

Specific Condition 4

1. Please indicate if there are sampling ports upstream of the duct burner (DB)? The applicable New Source Performance Standards (NSPS) for the DB's in 40 CFR 60.46(f), Subpart Db, require that the measurements of nitrogen oxides (NO_X) and oxygen shall be taken at two sampling sites. One sampling site shall be located as close as practicable to the exhaust of the turbine and the second site at the outlet to the steam generating unit. The NO_X emission rate from the combined cycle system is calculated by taking the difference of the measurements from the two sites. If this condition was not complied with, was a waiver obtained for their locations?

2. For the initial compliance test, 40 CFR 60.46(e)(1), Subpart Db, requires NO_X measurements from the steam generating unit to be continuously monitored for 30 successive steam generating unit operating days. The 30-day average emission rate is used to determine compliance with the NO_X emission standards. Please provide a copy of these test data.

The two requirements above are included in Specific Condition 16 of the air construction permit.

Specific Condition 7

Since the applicable NSPS (Subparts Db and GG) require that EPA Method 20 be used for determining NO_x emissions, the change for this specific condition will require submittal of an alternate sampling procedures request as outlined in 17-297.620.

Specific Condition 8

1. Please explain the reasons for using EPA Method 17 in lieu of EPA Method 5? EPA Method 17 has a stack temperature limitation. Can this condition be met?

We will resume processing the amendment after the requested information is received. Should you have any questions on this matter, please contact Syed Arif at (904) 488-1344.

Sincerely,

John C. Brown

John C. Brown, Jr., P.E.
Administrator
Air Permitting and Standards

JB/SA/bjb

cc: Charles Collins, Central District
Dennis Nester, Orange County

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- Complete items 1 and/or 2 for additional services.
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Consult postmaster for fee.

3. Article Addressed to:

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

4a. Article Number
P 872 562 586

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

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1-31-94

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OM. Reinert

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

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Do not use for International Mail
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Mr. Kennard F. Kosky, P.E.

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1034 N.W. 57th Street

P.O., State and ZIP Code
Gainesville, FL 32605

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
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January 5, 1994

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

RE: Orlando CoGen (I), Inc.; Orlando CoGen Limited, L.P.
AC48-206720; PSD-FL-184; Orange County
Request for Modification of Construction Permit

Dear Clair:

This correspondence is submitted on behalf of Orlando CoGen (I), Inc., to request some minor changes to the construction permit issued for the facility. The source is a 129-megawatt (MW) cogeneration facility located in Orlando Central Park, Orange County, Florida. The cogeneration facility consists of a combustion turbine (CT) exhausting through a heat recovery steam generator (HRSG). The transition duct from the CT to the HRSG contains duct burners (DBs) with a maximum heat input of 122 million British thermal units per hour (MMBtu/hr).

The construction permit was issued August 17, 1992, and expires August 31, 1994. Initial compliance tests were performed on October 12-15, 1993, and revealed some areas where changes to permit conditions are requested. Changes to Specific Conditions 4, 7, and 8 are requested.

Please be advised, however, that this request does not constitute any change in total emissions from the facility. Moreover, the initial tests for the facility demonstrated that the combustion turbine can achieve and nitrogen oxide (NO_x) emission concentration of **15 parts per million (volume) dry** (ppmvd) corrected to 15 percent oxygen (O_2). This extremely low emission rate is currently the **lowest demonstrated** among all cogeneration facilities in the State of Florida.

Specific Condition 4

This condition sets forth the emission limits for the facility (see attached Specific Conditions 4, 7, and 8). The allowable emission standards/limitations are expressed in terms of individual limits for the CT and the DBs. For NO_x, the allowable emission standards are based on 15 ppmvd at 15 percent O_2 for the CT and 0.1 lb/MMBtu heat input for the DBs. The applicable new source performance standards (NSPS) for the CT is Subpart GG which specifies an emission concentration of 75 ppmvd at 15 O_2 and corrected for heat rate (this equates to 94 ppmvd at 15 percent O_2). For the DBs, the applicable NSPS is Subpart Db which specifies an maximum emission rate of 0.2 lb/MMBtu. Emission-limiting standards are also limited for carbon monoxide (CO), particulate matter (PM)/PM10, volatile organic compounds (VOCs), and visible emissions (VE). There are no applicable NSPS for these pollutants. Only natural gas is used as fuel at the facility.

KBN ENGINEERING AND APPLIED SCIENCES, INC.

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EQUAL EMPLOYMENT OPPORTUNITY

AN AFFIRMATIVE ACTION EMPLOYER

It is requested that the Department consider changing the specification of individual limits for the CT and DBs to emission limits applicable to the CT operating alone and the CT/DBs operating together. Attached is the requested terminology for Specific Condition 4. As noted, there will be **no increase in annual emissions** with this requested change to the permit. The reasons for this request are threefold. First, the large volume flow rate of the CT could produce erroneous results when compliance with DB emissions is determined (see attached test report). The combination of large flow rate and smaller emission contribution from the DBs can produce substantial apparent errors when none exist.

Second, determining the emission status of the facility will be much easier for the Department by having specific limits for the CT and CT\DB combination. Since the facility has installed a continuous emission monitoring (CEM) system for NO_x, determining the emission status would be directly evident.

Third, the DBs cannot be operated without the CT; therefore, it is logical to specify emission limits for the combination rather than separately.

It is recognized that the DBs must independently demonstrate compliance with NSPS. It is proposed that this be accomplished separately through requested changes to Specific Condition 7 (see discussion below). The specific reference to NSPS is contained in Specific Condition 16. Please note that the basis of the requested CT/DB emission limit does not change the original basis of 0.1 lb/MMBtu. Indeed, a combined limit must be met during annual compliance tests when both CT and the DBs are at 90 to 100 percent of full load. Therefore, the emissions cannot exceed the original emission basis of 15 ppmvd at 15 percent O_2 for the CT and 0.1 lb/MMBtu for the DBs.

Specific Condition 7
It is requested that this condition be changed to allow the use of EPA Method 7e for determining future compliance with Specific Condition 4. Determining initial compliance with NSPS for the CT has been conducted using EPA Method 20. The results clearly demonstrate that NSPS is achieved by this very low-NO_x emitting machine. Compliance with NSPS for the DBs was determined using EPA Method 20 and demonstrating compliance with the NO_x emission limit of 0.2 lb/MMBtu.

Please note that this approach is consistent with that approved by the Department for the Florida Power & Light Company Putnam Plant. In this case, the Department allowed testing of four HRSGs with DBs using the proposed approach. The DBs for this facility have a higher firing rate that the Orlando CoGen facility and Subpart Db applied.

Specific Condition 8
It is requested that this condition allow the use of EPA Method 17.

PERMIT FEE

A permit fee of $250 as specified by Rule 17-4.050(4)(p)5. F.A.C. is attached to this request.

Please call if you have any questions. If it is necessary to meet on this request, I and representatives of Orlando CoGen would be available at your and your staff's convenience. As always, your consideration in this matter is appreciated.

Sincerely,

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

KFK/mk

cc: Tom Hess, Orlando CoGen (I), Inc.
Bruce Mitchell, FDEP BAR
Charles Collins, P.E., FDEP Central District
Dennis Nester, Orange County EPD
File (2)
C. Holladay
J. Harper, EPA
J. Bunyak, NPS

CURRENT CONDITIONS IN AC 48-206720

Specific Conditions

4. The maximum allowable emissions from this facility shall not exceed the emission rates listed in Table 1.

Table 1

Pollutant	Source	Allowable Emission Standard/Limitation
NO_x	CT	15 ppmvd @ 15% O_2 (57.4 lbs/hr; 251.4 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
	CT/DB	24-hr rolling average
CO	CT	10 ppmvd (22.3 lb/hr; 92.1 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
PM/PM_{10}	CT	0.01 lb/MMBtu (9.0 lbs/hr; 39.4 TPY)
	DB	0.01 lb/MMBtu (1.2 lbs/hr; 2.2 TPY)
VOC	CT	3.0 lbs/hr; 13.0 TPY
	DB	3.7 lbs/hr; 6.8 TPY
VE	CT/DB	≤ 10% opacity

NOTE:
1. CT: combustion turbine
   DB: duct burner
2. Natural gas usage only in the CT and DB.
3. Hours of operation:
   a. CT: 8760 hrs/yr
   b. DB: 3688 hrs/yr (at a maximum heat input of 122.0 x 10^6 Btu/hr)
4. Maximum heat input:
   a. CT: 856.9 x 10^6 Btu/hr
   b. DB: 122.0 x 10^6 Btu/hr; 450,000 x 10^6 Btu/yr
5. DB operation planned when ambient temperature is greater than 59°F.

7. Initial and subsequent annual compliance tests shall be performed within 10 percent of the maximum heat rate input for the tested operating temperature. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1991 version of the 40 CFR 60, Appendix A.

a. EPA Method 5 for PM
b. EPA Method 10 for CO
c. EPA Method 9 for VE
d. EPA Method 20 for NO_x

Note: Other test methods may be used for compliance testing only after prior Department written approval.

8. EPA Method 5 must be used to determine the initial compliance status of this unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

REQUESTED CHANGES IN AC 48-206720

Specific Conditions

4. The maximum allowable emissions from this facility shall not exceed the emission rates listed in Table 1.

Table 1

Pollutant	Source	Allowable Emission Standard/Limitation
NO_x	CT	15 ppmvd @ 15% O_2; 57.4 lbs/hr; 251.4 TPY
	CT/DB	69.6 lbs/hr; 273.9 TPY
	CT/DB	24-hr rolling average
CO	CT	10 ppmvd; 22.3 lbs/hr; 92.1 TPY
	CT/DB	34.5 lbs/hr; 114.6 TPY
PM/PM_{10}	CT	0.01 lb/MMBtu; 9.0 lbs/hr; 39.4 TPY
	CT/DB	10.2 lbs/hr; 41.6 TPY
VOC	CT	3.0 lbs/hr; 13.0 TPY
	CT/DB	6.7 lbs/hr; 19.8 TPY
VE	CT or CT/DB	≤ 10% opacity

NOTE:
1. CT: combustion turbine alone
   CT/DB: CT with duct burner (DB) in operation
2. Natural gas usage only in the CT and DB.
3. Hours of operation:
   a. CT: 8760 hrs/yr
   b. DB: 3688 hrs/yr (at a maximum heat input of 122.0 x 10^6 Btu/hr)
4. Maximum heat input:
   a. CT: 856.9 x 10^6 Btu/hr
   b. DB: 122.0 x 10^6 Btu/hr; 450,000 x 10^6 Btu/yr
5. DB operation planned when ambient temperature is greater than 59°F.

7. Initial and subsequent annual compliance tests shall be performed within 10 percent of the maximum heat rate input for the tested operating temperature. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1993 version of the 40 CFR 60, Appendix A.
a. EPA Method 5 or 17 for PM
b. EPA Method 10 for CO
c. EPA Method 9 for VE
d. EPA Method 20 for NO_x (initial) and EPA Method 7e (annually)

Note: Other test methods may be used for compliance testing only after prior Department written approval.

8. EPA Method 5 or 17 must be used to determine the initial compliance status of this unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

Emissions Performance Test Results

and CEMS Performance Specification Test Results

for

Orlando CoGen Limited

(October 12-15, 1993)

Part A (Results)

Prepared by:

Tom Hess
Air Products and Chemicals, Inc.
1 December 1993

Part A

Contents

Tables

Part B

Contents

Introduction

Emission tests were conducted at Orlando CoGen Limited, "OCL", on a combined-cycle natural gas-fired power plant over the period of 12 October - 15 October. These tests were performed to show compliance with:

- Florida Department of Environmental Regulation Permit No.: AC 48-206720/PSD-FL-184 issued 17 August 1992
- EPA NSPS Subpart GG (combustion turbines)
  EPA NSPS Subpart Db (duct burners)
- EPA Performance Specifications 2 and 6 (NOx continuous emission monitoring system).

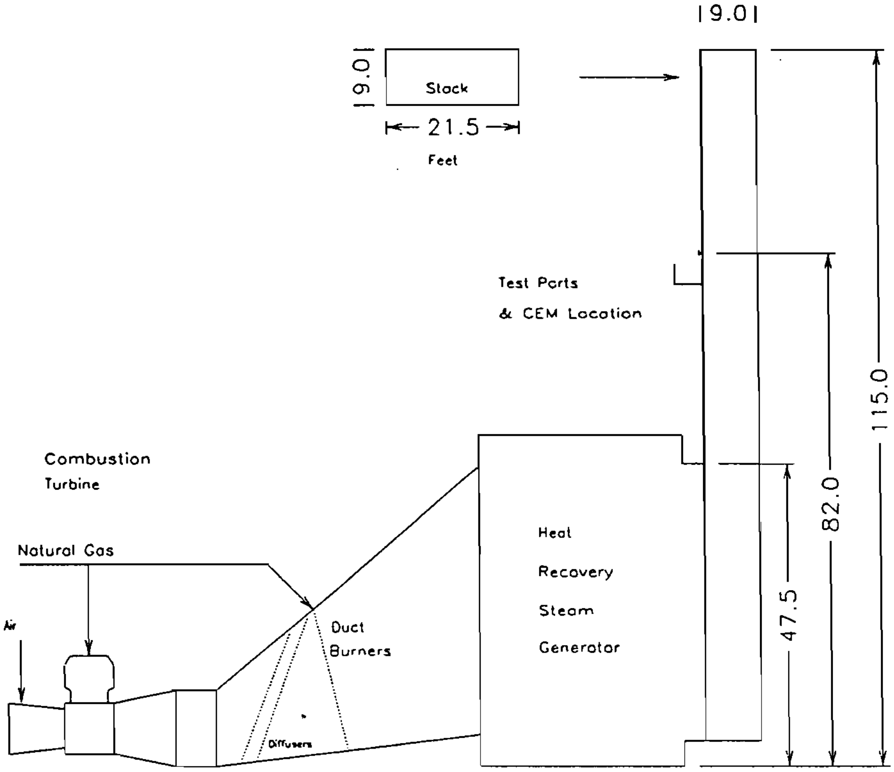
As summarized in Table 1 (page 5), the combined cycle plant meets its total emissions limits for PM, CO, NOx, and visual emissions in its two operating modes: 1)combustion turbine only firing; and 2) combustion turbine firing with auxiliary firing in the duct burners of the heat recovery steam generator.

This report is divided into two parts. Part A, this part, describes the facility, the test program, and gives a summary of all test results compared to emission limitations. Also included are the results of the performance specification tests for the NOx continuous emission monitoring system. Part B contains all raw test data and QA/QC procedures.

Tests were observed by Mr. Dennis Nester of the Orange County Environmental Protection Department and were carried out by Air Consulting and Engineering of Gainesville, Florida.

Facility Description

The OCL facility generates electricity and a small amount of process steam from a single natural gas-fired combustion turbine, "CT", followed by a heat recovery steam generator. Combustion of natural gas occurs primarily in the combustion turbine, but when additional thermal energy is needed, an additional small amount of natural gas is fired in the steam generator portion of the plant in duct burners, "DB". However, no additional combustion air is required for duct burner firing since the turbine exhaust gases have sufficient oxygen to support combustion of gas at the duct burners.



The combustion turbine drives a single generator which is also coupled to low and high pressure steam turbines driven by steam produced in the heat recovery steam generator. During warm weather, when the combustion turbine is limited in its capacity, supplementary firing in the duct burners in the steam generator provides additional steam allowing the plant to maintain its generating capacity.

The duct burners *can not be independently fired*, since the burners rely on the turbine exhaust to provide oxygen for combustion. Therefore, there are only two plant operating modes: 1) combustion turbine (CT) only firing; and 2) combustion turbine plus duct burner firing (CT +DB). Emission tests were conducted to determine emissions for both of these operating modes.

Summary of Results

DER Permit

The following table gives the results of emission tests demonstrating compliance with the DER permit emission limitations. For the maximum firing case (CT +DB) the turbine and duct burners were fired at 95% of the maximum permitted values. All emissions requirements were met. Test data for the case of combustion turbine only (CT) firing, again at 95% of the allowable operating rate, also indicate emissions less than permit values. Complete details of each test run can be found in the section Detailed Summary of Results (page 10).

HHV vs LHV

Table 1. Summary of Emission Test Results

	CT+DB		CT Only		DB Only *	
	Measured	Emission Standard	Measured	Emission Standard	Measured	Emission Standard
	10/12/93 2,3,4-avg		10/13/93 1,2,3-avg		10/12/93 2,3,4-avg	
Gross Power, MW	123.0		115.2		123.0	
MMBtu/hr LHV** CT	778.2		787.3			
MMBtu/hr LHV CT, ISO	812.8	<856.9	811.2	856.9		
Percent of Allowable	94.9		94.7			
MMBtu/hr LHV, DB	116.4	<122.0			116.4	<122.0
Percent of Allowable	95.4				95.4	
NOx, lbs/MMBtu (LHV)	0.06013	n/a	0.05328	n/a	0.1	0.1
NOx, ppmvd ISO 15%O2d	n/a	n/a	13.80	15	n/a	n/a
NOx, lbs/hr	64.8	69.6	49.8	57.4	14.3	12.2
CO, ppmvd	0.0790	n/a	0.014	10	n/a	n/a
CO, lbs/MMBtu (LHV)	0.00019	n/a	0.00004	n/a	0.0012	0.1
CO, lbs/hr	0.20	34.5	0.04	22.3	0.16	12.2
PM, lbs/MMBtu (LHV)	0.00851	n/a	0.00673	0.01	0.02	0.01
PM, lbs/hr	8.96	10.2	6.30	9.0	2.7	1.2
Visible emissions	0	10	0	10	n/a	n/a

HHV

- Is this an emission limit?

* Determined as the difference in emissions with and without duct burners using EPA Method 19 as explained below.

** Lower Heating Value

Also reported are the emissions that may be attributable to the duct burners. However, it must be noted that there is no way to directly determine emissions from duct burners since they cannot be operated independently of the combustion turbine. As a result, estimated emissions of the duct burners must be determined by the difference in emissions between the case of turbine operation with duct burner firing (CT+DB), and the case of combustion turbine operation alone (CT).

From Method 19 of 40 CFR 60, the following equation (19-10) is used to estimate emissions from the duct burners using test results:

$$E_{DB} = E_{(CT+DB)} + \frac{H_{CT}}{H_{DB}} \cdot (E_{(CT+DB)} - E_{CT})$$

where E is lbs of emission/MMBtu and H is the heat input in MMBtu/hr. Care must be taken to consistently use the correct convention for the heat input basis. For all calculations reported here, the lower heating values are used since this is the basis of the permit.

As is evident from the equation, large errors may result in the estimate for E_{DB} from small measurement errors in $E_{(CT+DB)}$ and E_{CT}. It's the classic case of the large error associated with taking the difference in two very small numbers. At the low levels of NOx and PM emitted by this plant, relative errors in measurements are likely to be quite high. Further, any errors in measurement are magnified by the ratio of H_{CT} to H_{DB}. Therefore, because duct firing is a small fraction of total gas firing, large errors in the calculation of NO_X and PM emissions attributable to DB firing will result from small errors in measurement in those variables.

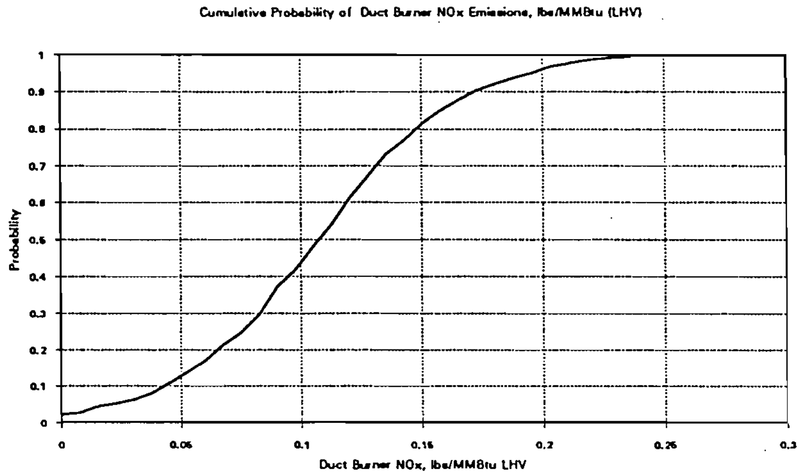
For example, substituting the test results for NO_X from the table above yields

$$E_{DB} = 0.06013 + \frac{778.2}{116.4} \cdot (0.06013 - 0.05328) = 0.1059$$

However, with only a 3% measurement error in $E_{(CT+DB)}$ <u>or</u> E_{CT}, the estimate for E_{DB} becomes (assuming the entire error is in $E_{(CT+DB)}$)

$$E_{DB} = 0.05833 + \frac{778.2}{116.4} \cdot (0.05833 - 0.05328) = 0.09209$$

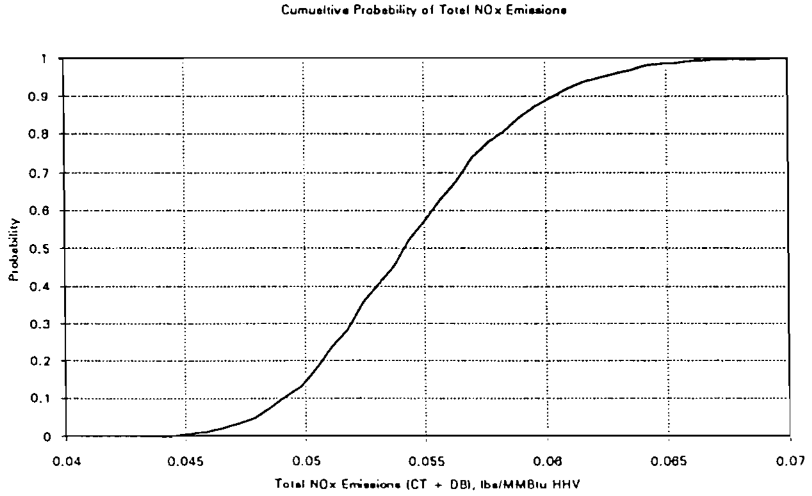
This is over a 13% error in the estimate for E_{DB}. In fact, this calculation understates the uncertainty in the estimate of the duct burner NOx emissions. Four measurements are required to determine E_{DB}: NOx, for DB+CT firing; O_2, for DB+CT firing; NOx, for CT only firing; and O_2 for CT only firing. There is some measurement error associated with all four values, all of which contribute to the error in determining NOx emissions due to the duct burners. To illustrate this more fully, a Monte-Carlo simulation was performed to generate the cumulative probability distribution of E_{DB}. In the simulation it is assumed that measurement error is normally distributed with standard deviation of 3% of the mean of the measurements. For example, the observed value of NOx for the CT was 11.8 ppm, so that the standard deviation for this measurement was assigned a value of 0.35 ppm. Results are shown graphically in the following figure.



The graph shows the effect of these measurement errors in the resulting distribution of calculated values for duct burner NOx, E_{DB}. As shown, the uncertainty in E_{DB} for NOx is very high- the 90th percentile being 65% higher than the mean. For the estimated mean value of 0.106 there is a 40% chance that the true value is actually less than about 0.090 lbs/MMBtu. Another way of thinking about this graph, is that the true emissions performance of the duct burners would have to be less than about 0.04 lbs/MMBtu to have a 90% chance of passing an emission test given the uncertainty in the individual NOx and O_2 measurements.

The accuracy of measurement of particulate matter at these low emission rates is even more of a problem since accurate PM measurements at low emission rates is more difficult than measuring gas concentrations.

However, it should be kept in mind that firing duct burners independently of the combustion turbine is meaningless as well as physically impossible. Again, the combined cycle plant meets the permit's emission limitations under its only two operating modes: combustion turbine operation alone, and combustion turbine operation with gas firing in the duct burners. For total emissions, the uncertainty is much smaller, since the difference in two small numbers does not enter into the calculation of total emissions. As shown below for the simulation of total emissions, the 90th percentile value is only 11% higher than the mean.



New Source Performance Standards

Subpart GG-Stationary Gas Turbines

The following table gives the NSPS emission standards applicable to the combustion turbine compared to observed emissions performance. In all cases observed emissions reported are the average from three runs conducted at a given firing rate. The combustion turbine firing rates were selected to represent the normally expected operating range of the plant.

Table 2. NSPS Subpart GG Performance (Combustion Turbine)

Pollutant	Turbine Firing Rate, Percent of Allowable at ISO conditions (856.9 MMBtu/hr, LHV)	Standard	Observed Emission
NOx	94.7	94 ppmvd, 15% O_2, at a rated heat rate of 11.5 KJ/Watt-hr	13.8 ppmvd, 15% O_2, ISO
	81.9	"	13.5, "
	87.0	"	11.4, "
	92.6	"	12.8, "
SO_2	Average of four fuel samples	Fuel sulfur < 0.8% by weight	0.0035 weight % S

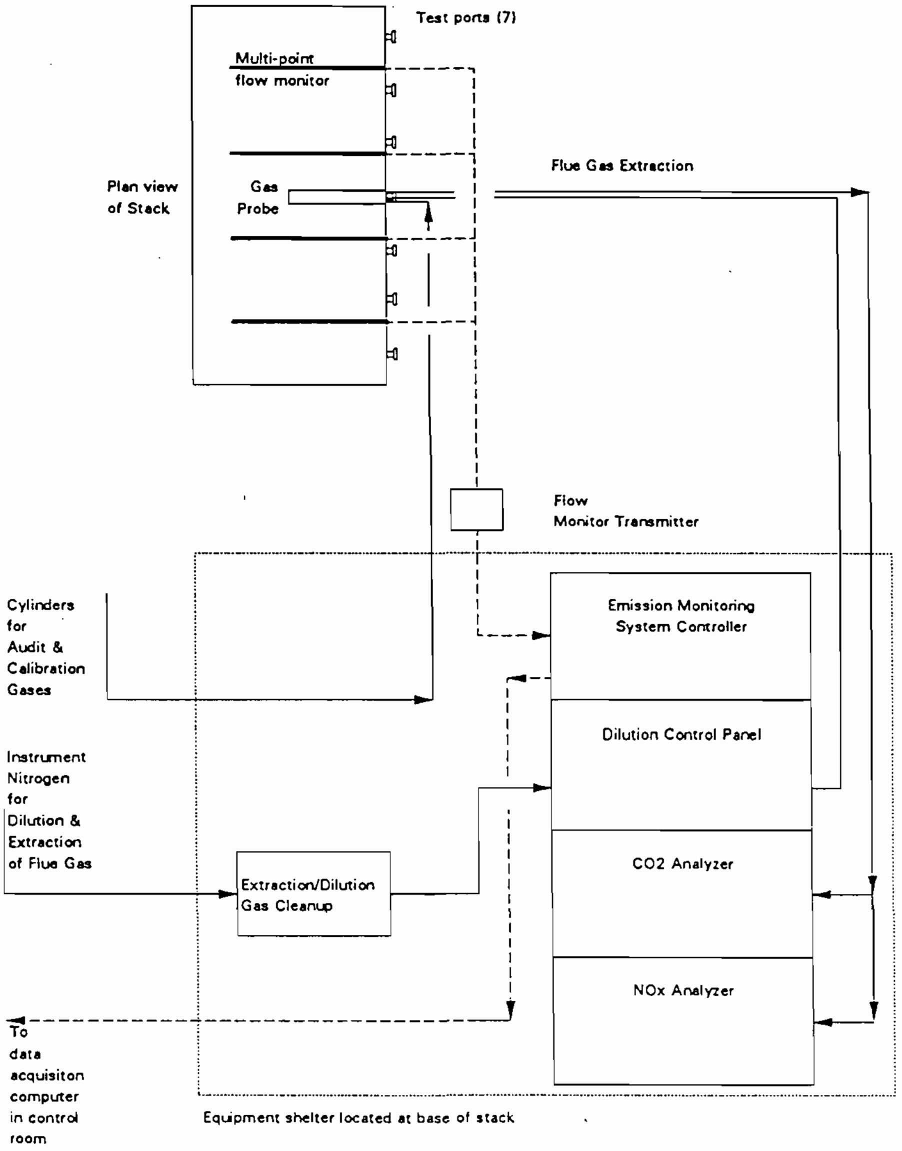
Subpart Db-Duct Burners

The only new source performance standard applicable to natural gas fired duct burners is a limit of 0.2 lbs NOx/MMBtu heat input to the duct burners. The observed NOx emission rate was only 0.1 lbs NOx/MMbtu (see Table 1).

Continuous Emission Monitoring System-Performance Specification Tests

Emission Monitoring System

This plant is equipped with a continuous emission monitoring system to monitor the emission rate of NOx in units of lbs/hr. As shown in the following diagram, the continuous emission monitoring system (CEMS) measures the concentrations of NOx, CO_2, and the flow rate of flue gas leaving the stack following the HRSG. Flue gas is extracted from the stack using purified nitrogen to carry it to CO_2 and NOx analyzers housed in an air conditioned shelter at the base of the stack. The dry nitrogen carrier gas, by diluting the sample, lowers its dew point enough that no moisture removal is necessary prior to passing the gas sample to the analyzers. Because no moisture is removed in the sampling process, all concentrations are therefore on a wet basis.



Flue gas flow rate is monitored at multiple points in the plane of the stack using differential pressure. The multi-point readings are integrated and compensated for temperature and pressure to produce a flow rate in standard cubic feet per minute.

Other components of the system are:

- A system controller which takes instrument readings and converts the analyzer outputs into the correct signal for transmission to the data acquisition computer. The controller also controls the injection of reference gases for system calibration and auditing.

- The dilution control panel controls the flow of extraction gas to the gas sample probe in the stack.

- The extraction gas cleanup module removes moisture, NOx, and CO_2 which may be present in the nitrogen carrier used to extract flue gas from the stack.

Data Acquisition

Data from the analyzers is transmitted via the system controller to a dedicated microcomputer which logs the measurement data (ppm NOx, $\%CO_2$, and SCFM flow) and performs calculations to convert the measurements to other units, such as lbs/hr, and lbs/MMBtu. Additional functions include:

- tracking cumulative emissions,
- recording results of daily and quarterly cylinder gas checks and audits of the CEMS,
- producing alarms if permitted emissions are exceeded or monitor malfunctions are detected,
- recording status of the monitoring system,
- and producing emission reports required by permits and regulations.

Performance Requirements

Performance specifications currently applicable to the monitoring system are contained in 40 CFR 60 App. B Spec. 2 (NOx monitor) and Spec. 6 (NOx rate monitoring). The following table summarizes the results of the performance specification tests for relative accuracy and the 7-day zero and calibration drift tests. Complete results are given in the Detailed Performance Specification Test Results section (page 16).

Table 3. CEMS Performance Specification Test Results

Specification	Standard	Observed Result
Relative accuracy of NOx analyzer	< 20% error at 95% confidence	3.42% in units of ppmw NOx
Relative accuracy of NOx continuous emission rate monitor	< 20% error at 95% confidence	1.63% in units of lbs/hr NOx
Zero Drift NOx analyzer	< 2.5% of span	Max. 0.08%
Span Drift NOx analyzer	< 2.5% of span	Max. 0.80%

Detailed Summary of Results

The following table summarizes the test conditions for each run performed during the emission performance and CEMS performance specification tests. Tables 5, 6, and 7 following give results for each test as well as relevant plant performance data. Part B of the report contains the field data used in preparing the test results given in Tables 5, 6, and 7. Table 4 also indicates in which section of Part B the relevant test data can be found for each test run. Part B also contains all strip charts, field data, laboratory reports, QA/QC data for the emission tests, and NOx CEM RATA/drift data.

The following test methods were used to determine emissions:

EPA Method 20	NOx
EPA Method 10	CO
EPA Method 5	PM
EPA Method 9	Visible Emissions

Table 4. OCL Emission Test Log

Run	Date, Time	Plant Operating Condition	Tests	*Part B Tab*	Remarks
1	10/12, 07:47-10:10	Maximum CT firing, but variable duct burner firing		1	Data for this run is reported in Part B, but operations were not steady and did not represent maximum gas firing. Results not used in evaluation of performance.
2	10/12, 11:23-13:33	Maximum CT & DB firing	PM, NOx, CO, VE x 2, flow, CO_2, O_2		
3	10/12, 14:13-16:18	"	" (VE x 2)		
4	10/12, 16:48-18:53	"	" (no VE)		
1	10/13, 07:48-09:51	Maximum CT firing, no DB firing	PM, NOx, CO, CO_2, O_2, flow	2	Duct burner emissions are determined by difference between PM, NOx, and CO emissions with DB (runs 2-4) and without DB firing (runs 5-7). Slight variations in firing rates are taken into account by weighting emissions on heat input basis using EPA Method 19 (equation 10).
2	10/13, 10:55-13:43	"	"		
3	10/13, 14:31-16:42	"	"		
1	10/14, 08:12-10:04	Nominal 80% firing rate of CT. No DB firing	NOx, CO_2, O_2, flow	3	
2	10/14, 11:04-12:03	"	"		CEMS relative accuracy performance specification test (RATA 1).
3	10/14, 12:23-13:20	"	"		RATA 2
1	10/14, 14:08-15:06	Nominal 87% firing rate of CT. No DB firing	NOx, CO_2, O_2, flow	4	RATA 3
2	10/14, 15:40-16:29				RATA 4
3	10/14, 16:36-17:25				RATA 5
1	10/15, 07:44-08:35	Nominal 94% firing rate of CT. No DB firing	NOx, CO_2, O_2, flow	5	RATA 6
2	10/15, 09:07-9:56				RATA 7
3	10/15, 10:16-11:11				RATA 8
1A	10/15, 11:28-12:27	Nominal 100% CT firing. No DB firing.	NOx, CO_2, O_2, flow	6	RATA 9
2A	10/15, 13:30-14:30	Nominal 100% CT firing. Reduced rate DB firing	NOx, CO_2, O_2, flow	7	RATA 10
3A	10/15, 16:48-17:22	Nominal 100% CT firing. High DB firing.	NOx, CO_2, O_2, flow	8	RATA 11

Table 5. Emission Test Results/Plant Operating Data for 10/12 &13 (Base Cases w & w/o Duct Burners)

OCL Emission Tests	12-Oct	12-Oct	12-Oct		13-Oct	13-Oct	13-Oct	
	CT+DB	CT+DB	CT+DB		CT	CT	CT	
	Run 2	Run3	Run 4	Average	Run 1	Run 2	Run 3	Average
Start Test Run	11:23	14:13	16:48		7:48	10:55	14:31	
Stop Test Run	13:33	16:18	18:53		9:51	13:43	16:42	
MW Generator	123.6	122.6	122.7	123.0	118.0	114.6	113.1	115.2
GT KSCFH nat. gas	852.2	842.3	843.0	845.9	886.0	842.6	841.6	856.7
DB KSCFH nat. gas	126.2	125.2	126.5	126.0	0.0	0.0	0.0	0.0
GT MMBtu/hr HHV	870.1	860.0	860.7	863.6	903.7	859.5	858.4	873.9
GT MMBtu/hr LHV	784.1	775.0	775.6	778.2	814.2	774.4	773.4	787.3
DB MMBtu/hr HHV	128.9	127.9	129.2	128.6	0.0	0.0	0.0	0.0
DB MMBtu/hr LHV	116.1	115.2	116.4	115.9	0.0	0.0	0.0	0.0
Turbine ISO Heat Input LHV	815.1	811.0	812.3	812.8	825.7	800.9	807.1	811.2
Mean Barometric Pressure, inHg	29.95	29.95	29.95		30.02	30.02	30.02	
Mean RH%	55.9	43.3	43.0		86.4	54.9	43.9	
Mean Temp, °F	76.5	81.1	81.5		64.1	75.4	80.8	
Abs. humid (lb water/lb dry air)	0.0108	0.0097	0.0098		0.0110	0.0102	0.0098	
F factor, SCF/MMBtu HHV	8482	8482	8482		8481	8481	8481	
HHV Btu/SCF nat. gas	1021	1021	1021		1020	1020	1020	
LHV Btu/SCF nat. gas	920	920	920		919	919	919	
Stack temperature, °F	242.6	244.4	244.3		252.2	248.1	251.1	
Stack pressure, inHg	29.89	29.89	29.89		29.96	29.95	29.95	
Stack moisture, %	7.68	8.53	7.67		7.11	7.214	7.165	
O_2, %dry	14.90	14.80	14.90		15.80	15.70	15.60	
CO_2, %dry	3.40	3.40	3.40		2.90	3.00	3.00	
Stack actual flow rate, ACFM	834423	807776	851864		862307	856175	843116	
Stack standard flow rate, SCFMD	578347	553309	589058		594584	592966	581780	
Particulate total catch, mg	10.8	11.5	10.1		6.5	5.6	11.2	
Volume sampled, SCFD	94.49	86.56	93.50		101.8	97.05	92.268	
Particulate, lbs/MMBtu, HHV	0.00745	0.00851	0.00704	0.00766	0.00489	0.00434	0.00895	0.00606
Particulate, lbs/MMBtu, LHV	0.00826	0.00945	0.00781	0.00851	0.00543	0.00481	0.00993	0.00673
Particulate, lbs/hr	8.74	9.72	8.42	8.96	5.02	4.53	9.34	6.30
NOx, ppmvd	15.51	15.50	15.36	15.46	11.07	12.06	12.27	11.80
NOx, ppmvd 15%O_2, ISO	n/a	n/a	n/a		13.79	13.92	13.69	13.80
NOx, lbs/MMBtu HHV	0.05471	0.05378	0.05418	0.05422	0.04593	0.04908	0.04899	0.04800
NOx, lbs/MMBtu LHV	0.06072	0.05968	0.06013	0.06018	0.05098	0.05447	0.05438	0.05328
NOx, lbs/hr	64.26	61.43	64.81	63.5	47.15	51.23	51.13	49.8
CO, ppmvd	0.088	0.078	0.071	0.0790	0.043	0	0	0.014
CO, lbs/MMBtu HHV	0.00019	0.00016	0.00015	0.00017	0.00011	0.00000	0.00000	0.00004
CO, lbs/MMBtu LHV	0.00021	0.00018	0.00017	0.00019	0.00012	0.00000	0.00000	0.00004
CO, lbs/hr	0.22	0.19	0.18	0.20	0.11	0.00	0.00	0.04
Visual Emissions, % opacity	0	0	0	0	0	0	0	
Period of Observation	11:25	11:55	14:15	14:45	7:50	10:54	14:35	
	11:55	12:25	14:45	15:15	8:50	11:54	15:35	

Table 6. Emission Test Results/Plant Operating Data for 10/14 (CT Turndown Cases)

OCL Emission Tests	14-Oct CT 80% Run 1	14-Oct CT 80% Run 2 RATA 1	14-Oct CT 80% Run 3 RATA 2	Average	14-Oct CT 87% Run 1 RATA 3	14-Oct CT 87% Run 2 RATA 4	14-Oct CT 87% Run 3 RATA 5	Average
Start Test Run	8:12	11:04	12:23		14:08	15:40	16:36	
Stop Test Run	10:04	12:03	13:20		15:06	16:29	17:25	
MW Generator	96.13	94.59	94.24	95.0	101.40	100.81	100.55	100.9
GT KSCFH nat. gas	736.80	729.35	728.90	731.7	771.83	767.22	768.85	769.3
DB KSCFH nat. gas	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
GT MMBtu/hr HHV	750.1	742.5	742.0	744.9	785.7	781.0	782.7	783.1
GT MMBtu/hr LHV	676.4	669.5	669.1	671.7	708.5	704.3	705.8	706.2
DB MMBtu/hr HHV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DB MMBtu/hr LHV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Turbine ISO Heat Input LHV	700.2	701.6	704.0	701.9	744.4	741.4	750.3	745.4
Mean Barometric Pressure, inHg	30.02	30.13	30.02		30.07	30.07	30.07	
Mean RH%	85.8	78.9	72.1		67.71	60.1	69.6	
Mean Temp, °F	72.2	79.0	80.0		80.71	82.6	84.9	
Abs. humid (lb water/lb dry air)	0.0145	0.0167	0.0158		0.0151	0.0143	0.0179	
F factor, SCF/MMBtu HHV	8480	8480	8480		8480	8480	8480	
HHV Btu/SCF nat. gas	1018	1018	1018		1018	1018	1018	
LHV Btu/SCF nat. gas	918	918	918		918	918	918	
Stack temperature, °F	250	248	247		241	244	243	
Stack pressure, inHg	29.93	29.93	29.93		30.03	30.03	30.03	
Stack moisture, %	8.6	8.6	8.6		7.5	7.5	7.5	
O_2, %dry	15.60	15.70	15.70		15.40	15.30	15.38	
CO_2, %dry	3.00	3.00	3.00		3.20	3.18	3.12	
Stack actual flow rate, ACFM	735697	719720	714460		704532	703977	697879	
Stack standard flow rate, SCFMD	500464	491121	488137		492405	490462	486523	
Particulate total catch, mg	N/A	N/A	N/A		N/A	N/A	N/A	
Volume sampled, SCFD	N/A	N/A	N/A		N/A	N/A	N/A	
Particulate, lbs/MMBtu, HHV	N/A	N/A	N/A		N/A	N/A	N/A	
Particulate, lbs/MMBtu, LHV	N/A	N/A	N/A		N/A	N/A	N/A	
Particulate, lbs/hr	N/A	N/A	N/A		N/A	N/A	N/A	
NOx, ppmvd	9.99	10.01	9.82	9.94	9.69	9.63	9.24	9.52
NOx, ppmvd 15%O_2, ISO	12.54	13.54	14.54	13.54	11.46	11.10	11.50	11.35
NOx, lbs/MMBtu HHV	0.03988	0.04073	0.03996	0.04019	0.03728	0.03639	0.03542	0.03636
NOx, lbs/MMBtu LHV	0.04423	0.04517	0.04431	0.04457	0.04134	0.04035	0.03928	0.04032
NOx, lbs/hr	35.81	35.22	34.34	35.1	34.18	33.83	32.20	33.4
CO, ppmvd	1.41	1.55	1.46	1.4733	0.00	0.00	0.00	0.0000
CO, lbs/MMBtu HHV	0.00343	0.00384	0.00362	0.00363	0.00000	0.00000	0.00000	0.00000
CO, lbs/MMBtu LHV	0.00380	0.00426	0.00401	0.00402	0.00000	0.00000	0.00000	0.00000
CO, lbs/hr	3.08	3.32	3.11	3.17	0.00	0.00	0.00	0.00

Table 7. Emission Test Results/Plant Operating Data for 10/15 (CT Turndown Case)

OCL Emission Tests	15-Oct	15-Oct	15-Oct		15-Oct	15-Oct	15-Oct
	CT 94%	CT 94%	CT 94%		CT	CT+DB	CT+DB
	Run 1	Run 2	Run 3	Average	Run 1A	Run 2A	Run 3A
	RATA 6	RATA 7	RATA 8		RATA 9	RATA 10	RATA 11
Start Test Run	7:44	9:07	10:16		11:28	13:30	16:48
Stop Test Run	8:35	9:56	11:11		12:27	14:30	17:22
MW Generator	109.83	108.99	107.93	108.9	112.43	118.53	123.20
GT KSCFH nat. gas	827.19	825.96	816.70	823.3	849.33	840.67	854.0
DB KSCFH nat. gas	0.00	0.00	0.00	0.0	0.00	103.33	123.73
GT MMBtu/hr HHV	844.6	843.3	833.9	840.6	867.2	858.3	871.9
GT MMBtu/hr LHV	761.0	759.9	751.4	757.4	781.4	773.4	785.7
DB MMBtu/hr HHV	0.0	0.0	0.0	0.0	0.0	105.5	126.3
DB MMBtu/hr LHV	0.0	0.0	0.0	0.0	0.0	95.1	113.8
Turbine ISO Heat Input LHV	792.3	795.1	793.2	793.5	831.7	828.2	823.0
Mean Barometric Pressure, inHg	30.10	30.10	30.10		30.10	30.08	30.08
Mean RH%	84.1	86.6	83.6		76.3	72.0	69.4
Mean Temp, °F	75.6	77.1	80.7		84.7	87.3	79.4
Abs. humid (lb water/lb dryair)							
F factor, SCF/MMBtu HHV	8482	8482	8482		8482	8482	8482
HHV Btu/SCF nat. gas	1021	1021	1021		1021	1021	1021
LHV Btu/SCF nat. gas	920	920	920		920	920	920
Stack temperature, F	242	243	241		247	243	245
Stack pressure, inHg	30.06	30.05	30.05		30.04	30.02	30.02
Stack moisture, %	7.5	7.5	7.5		8.6	8.6	8.6
O_2, %dry	15.20	15.20	15.20		15.36	14.73	14.77
CO_2, %dry	3.25	3.26	3.25		3.15	3.53	3.56
Stack actual flow rate, ACFM	735011	711313	714620		787808	762808	766264
Stack standard flow rate, SCFMD	514105	496453	499778		539741	524887	526348
Particulate total catch, mg	N/A	N/A	N/A		N/A	N/A	N/A
Volume sampled, SCFD	N/A	N/A	N/A		N/A	N/A	N/A
Particulate, lbs/MMBtu, HHV	N/A	N/A	N/A		N/A	N/A	N/A
Particulate, lbs/MMBtu, LHV	N/A	N/A	N/A		N/A	N/A	N/A
Particulate, lbs/hr	N/A	N/A	N/A		N/A	N/A	N/A
NOx, ppmvd	10.95	10.55	10.31	10.60	10.29	12.75	14.34
NOx, ppmvd 15%O_2, ISO	12.99	12.71	12.76	12.82	13.15	N/A	N/A
NOx, lbs/MMBtu HHV	0.04066	0.03917	0.03828	0.0394	0.03931	0.04373	0.04951
NOx, lbs/MMBtu LHV	0.04512	0.04347	0.04248	0.0437	0.04363	0.04854	0.05495
NOx, lbs/hr	40.33	37.52	36.91	38.3	39.78	47.94	54.07
CO, ppmvd	0.07	0.07	0	0.0467	0	0.1	0.09
CO, lbs/MMBtu HHV	0.00016	0.00016	0.00000	0.00011	0.00000	0.00021	0.00019
CO, lbs/MMBtu LHV	0.00018	0.00018	0.00000	0.00012	0.00000	0.00023	0.00021
CO, lbs/hr	0.16	0.15	0.00	0.10	0.00	0.23	0.21

Fuel Analyses

On each of the four test days two grab samples of natural gas entering the plant were taken from the supply pipeline. One sample was analyzed for the main constituents in order to calculate lower and higher heating values as well as F-factors. The second sample was analyzed for sulfur content. The laboratory reported results are given at Tab 12 of Part B. In summary:

Table 8. Pipeline Natural Gas Fuel Constants

Date	Btu/SCF HHV	Btu/SCF LHV	Sulfur wt%	Fd*
10/12	1021	920	0.0051	8482
10/13	1020	919	0.0032	8481
10/14	1018	918	0.0029	8480
10/15	1021	920	0.0026	8482

* DSCF flue gas / MMBtu at 0% excess air

Detailed Performance Specification Test Results for the NOx Continuous Emission Monitoring System

Relative Accuracy

The relative accuracy of the NOx analyzer and NOx continuous emission rate monitoring system were calculated from reference method test results reported in Tables 5, 6, and 7 and the average of the NOx values (ppmw, and lbs/hr) reported by the CEMS during each test run. In the following table the relative accuracy is calculated based on 11 paired runs. The CEMS values are the average of 1-minute values reported by the CEMS over the interval stated in the table (see Part B, Tab 13).

Table 9. Relative Accuracy of NOx CEMS

RATA Run No.	RATA Date,Time	CEM NOx lbs/hr	RM* NOx lbs/hr	Difference	CEM NOx ppmw	RM* NOx ppmw	Difference
1	10/14, 11:03-14:03	35.34	35.22	0.12	8.98	9.15	-0.17
2	10/14, 12:22-13:20	35.93	34.34	1.59	8.87	8.98	-0.11
3	10/14, 14:07-15:06	33.90	34.18	-0.28	8.72	8.96	-0.24
4	10/14, 15:39-16:28	33.13	33.83	-0.70	8.62	8.91	-0.29
5	10/14, 16:26-17:26	32.22	32.20	0.02	8.41	8.55	-0.14
6	10/15, 07:43-08:35	38.82	40.33	-1.51	9.77	10.13	-0.36
7	10/15, 09:06-09:50	37.81	37.52	0.29	9.52	9.76	-0.24
8	10/15, 10:15-11:11	36.35	36.91	-0.56	9.20	9.54	-0.34
9	10/15, 11:28-12:27	40.45	39.78	0.67	9.50	9.41	0.09
10	10/15, 13:29-14:30	47.98	47.94	0.04	11.20	11.65	-0.45
11	10/15, 16:47-17:22	55.08	54.07	1.01	12.76	13.11	-0.35
	*Reference Method Average		38.76	0.0627		9.83	-0.2347
	Standard Deviation			0.8495			0.1511
	$t_{(.975)}$			2.228			2.228
	Confidence Interval			0.571			0.102
	Relative Accuracy%			1.63			3.42

Calibration Drift Test

Calibration drift tests were conducted on the NOx CEMS over a seven day period during which the plant was operating above 50% of its rated capacity. During the drift test period no maintenance was performed or adjustments made to the emission monitoring system. High and low level calibration gases (EPA Protocol No. 1) were injected at 24-hour intervals and the CEMS response recorded (see Part B, Tab 13). The low-level gas used was zero air while the high level gas was NO in a blend of CO_2 and nitrogen. As the results in Table 10 show, the maximum calibration drift was well below the maximum allowable of 2.5% of span.

Table 10. NOx CEMS Calibration Drift Test Results

Date/time	Reference Value (R)	Monitor Response (A)	Absolute Difference $\lvert R-A \rvert$	Calibration Error % $\lvert R-A \rvert \cdot 100/S$ *
10/12, 07:16	23.90 ppm	23.95	0.05	0.20 %
10/13, 05:45	23.90 ppm	23.91	0.01	0.04 %
10/14, 05:45	23.90 ppm	23.90	0.00	0.00 %
10/15, 05:45	23.90 ppm	23.84	0.06	0.24 %
10/16, 05:45	23.90 ppm	23.70	0.20	0.80 %
10/17, 05:45	23.90 ppm	23.70	0.20	0.80 %
10/18, 05:45	23.90 ppm	23.85	0.05	0.20 %
10/19, 05:45	23.90 ppm	23.84	0.06	0.24 %
			Maximum	0.80 %
10/12, 07:30	0.00 ppm	0.01	0.01	0.04 %
10/13, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/14, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/15, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/16, 06:00	0.00 ppm	0.02	0.02	0.08 %
10/17, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/18, 06:00	0.00 ppm	0.01	0.01	0.04 %
10/19, 06:00	0.00 ppm	0.01	0.01	0.04 %
			Maximum	0.08 %

* The NOx analyzer span (S) is 25 ppm NOx.

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

PLEASE DETACH AND RETAIN FOR YOUR RECORDS

INVOICE NUMBER	DATE		VOUCHER NO.	AMOUNT
	January 5, 1994			$250.00

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

[redacted]
Branch 311

010925

January 5 1994

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

TO THE ORDER OF Florida Department of Environmental Protection

KBN ENGINEERING AND APPLIED SCIENCES, INC.

AUTHORIZED SIGNATURE

[redacted]

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

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SEP 21 1993
Division of Air
Resources Management

DEPARTMENT OF
ENVIRONMENTAL PROTECTION
SEP 20 1993
OFFICE OF THE SECRETARY

SEP 17 1993

4APT-AE

Mr. Clair H. Fancy, Chief
Air Resources Management Division
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Fl 32399-2400

RE: Orlando CoGen Limited, L.P. (OCL)
Stationary Gas Turbines, AC 48-206720, PSD-FL-184
Customized Fuel Monitoring Schedule

Dear Mr. Fancy:

This letter is in response to OCL's July 26, 1993, request for approval of a customized fuel monitoring schedule for the above referenced project. This request was sent to the Environmental Protection Agency (EPA), and a copy was forwarded to you. Since the authority for approving alternatives to the monitoring requirements in § 60.334(b) of 40 CFR Part 60, Subpart GG, was not delegated to the State of Florida, we have reviewed OCL's custom fuel monitoring schedule. Based on our review, we have determined that it is acceptable because it conforms to custom fuel monitoring guidance (a copy of this guidance memo is enclosed) issued by EPA Headquarters in 1987. Therefore, you may modify OCL's permit accordingly. Please note that the approved reference methods are cited in 40 CFR §60.335(d), and not in 40 CFR §60.335(b)(2) as referenced in OCL's July 26, 1993, letter.

If you have any questions regarding the determination provided in 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, and Toxics
Management Division

Enclosure

cc: Mr. Tom Hess, Orlando CoGen Limited, L.P.

10/13

John Brown —

~~[illegible] He's let Harley know~~

Colin

I presume we have to submit to them on a case-by case basis.

Preston

(1) Region III can approve customized fuel mon..

(2) Make sure that Eng for ~~[illegible]~~ OCL knows about this.

(3) Make cy for Mike H. JB

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

AUG 14 1987

OFFICE OF
AIR AND RADIATI

MEMORANDUM

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

FROM: John B. Rasnic, Chief John B Rasnic
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 these 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

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 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. 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.

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 SSCD 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

CM: P 649 682 993
7-27-93
Lehigh Valley, PA

Orlando CoGen Limited, L.P.

7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

26 July 1993

RECEIVED
JUL 30 1993
Division of Air
Resources Management

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

Subject: Orlando CoGen (I), Inc.
129-MW Combined Cycle Gas Turbine, Orange County
AC 48-206720
PSD-FL-184

Dear Mr. Fancy:

We would like to inform the Department that in accordance with Rule 17-2.660, F.A.C., that the anticipated date of initial startup of this facility is 1 September 1993. We will notify the Department of the date of actual startup within 15 days after that date. For your information, at this time we tentatively plan to perform the emission testing required by the referenced permit beginning on or about 15 September, however we will notify the department 30 days prior to the actual anticipated date.

Please call me at (215) 481-7620 with any questions or comments.

Very truly yours,

Tom Hess

Tom Hess
Energy Systems

cc: Mr. Charles Collins, P.E.
Central District

Mr. Dennis J. Nester
Orange County Environmental
Protection Department
J. Harper, EPA
J. Bunyak, NPS

Fed Ex# 0181-0342-7
7-7-93
Allentown, PA

Orlando
CoGen
Limited, L.P.

7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

7 July 1993

Mr. Dennis J. Nester
Environmental Engineer
Orange County Environmental Protection Department
2002 E. Michigan St.
Orlando, FL 32806

RECEIVED
JUL 08 1993
Division of Air
Resources Management

Subject: Orlando CoGen Limited, L.P. (OCL)
AC 48-206720
PSD-FL-184
Emission testing

Dear Mr. Nester:

I was happy to get a chance to talk to you last week about the impending startup of our plant in September. As we discussed, fairly extensive emission testing will be conducted to meet the specific requirements of the referenced construction permit, other Florida DER regulations, and new source performance standards. Also, because this plant is equipped with a continuous emission monitoring system, a number of emission monitoring system performance specification tests, including relative accuracy, will be conducted. The monitoring system performance tests will have to meet both 40 CFR 60 and 40 CFR 75 specifications.

As promised, I have enclosed a few attachments that may be of help to you prior to our meeting next Thursday in understanding the plant and our proposed program to conduct needed emissions testing . These are:

A) A brief description of the combined cycle power plant combustion equipment and the continuous emission monitoring system.

B) A proposed plan for emission testing to demonstrate both emission compliance and to confirm that the emission monitoring system meets performance specifications. The table on page B-6 summarizes the tests and the number runs that we believe will be needed at different plant operating conditions.

C) This attachment shows three detailed sections of mechanical drawings locating the point of emission testing and test port configuration.

Stack Testing

As noted in the draft test plan (Attachment B) we are proposing some very minor modifications to the sampling points suggested by Method 20 (NOx). Method 20 requires a sampling site as close to the turbine exhaust as practical considering turbine geometry, baffling, and point of introduction of dilution air. Referring to the figure on page A-1, at this facility the exhaust of the gas turbine enters a transition duct containing duct burners before it enters the steam generator. Testing in the transition duct or in the steam generator is not practical or meaningful for the following reasons (many of which Method 20 recognizes):

- In the transition duct it is highly likely that cyclonic flow is present from the turbine exhaust and at the same time the duct cross section is continually changing. This would likely lead to errors in flow measurement (the DER permit is based on mass flow rate of NOx and therefore velocity traverses are needed).

- Duct burners immediately following the turbine would interfere with test probe traverses here and the location presents potential danger to the test team because of the high temperature exhaust (no dilution air is used in this plant).

- In the steam generator, the multitude of tube bundles for heat transfer would again interfere with test probe traverses and also again would interfere with accurate determination of gas velocity. Also the size of the cross sectional area would represent difficulty in testing (roughly 22 by 48 feet)

- The proposed test location, at the stack, is more accessible and more likely to be representative. Because the only air entering the process is combustion air in the turbine (no dilution air down stream of the exhaust is injected) the flue gas at the proposed stack test location is the same composition as the turbine exhaust. The flue gas velocity should be more uniform and the stack cross section more manageable to test (9 x 21.5 feet).

- Continuous emission compliance for the facility is based on meeting a total emission rate of 69.6 lbs/hr (combined duct burner and combustion turbine firing) leaving the stack (DER condition 13) . On a continuous basis there is no separate emission requirement for the duct burner and the combustion turbine. Thus the emission point of concern is the stack not the turbine or duct burners individually.

- For the purposes of initial and annual compliance testing, the stack location can meet DER permit requirement for determining turbine and duct burner emissions separately by simply performing the tests with and without duct burner firing. This is proposed in the draft test plan.

- The proposed test location and facilities meet the requirements of EPA Method 1 and DER 17-2.700 (4)(c) relating to test facilities. It is problematic that any other location in the plant would meet these criteria. Further, the turbulent mixing that the flue gas experiences in the steam generator should minimize the chances for stratification at this test point compared to others.

- Actual traverse points for gas emissions (CO, NOx, etc.) would be selected based on the criteria of Method 20 (i.e. 8 points having the lowest O_2 or highest CO_2) unless there are no significant differences among the points. In that case we would propose to use fewer points for each traverse.

We would also like to review with you the county's reporting and notification requirements. This includes items such as:

- frequency, content, and format of routine reports, both emissions and process data
- notification procedures: for excess emission incidents, monitoring system out of service periods, annual compliance tests
- requirements for stack test contractors such as registration or certification.

I appreciate your time in reviewing the enclosed material and would be happy to answer any questions or provide additional information that would be helpful to you. Please call me at (215) 481-7620 (fax: 5444). I look forward to meeting you next Thursday (15 July) at your office at 8:00 AM.

Very truly yours,

Tom Hess

Tom Hess
Energy Systems

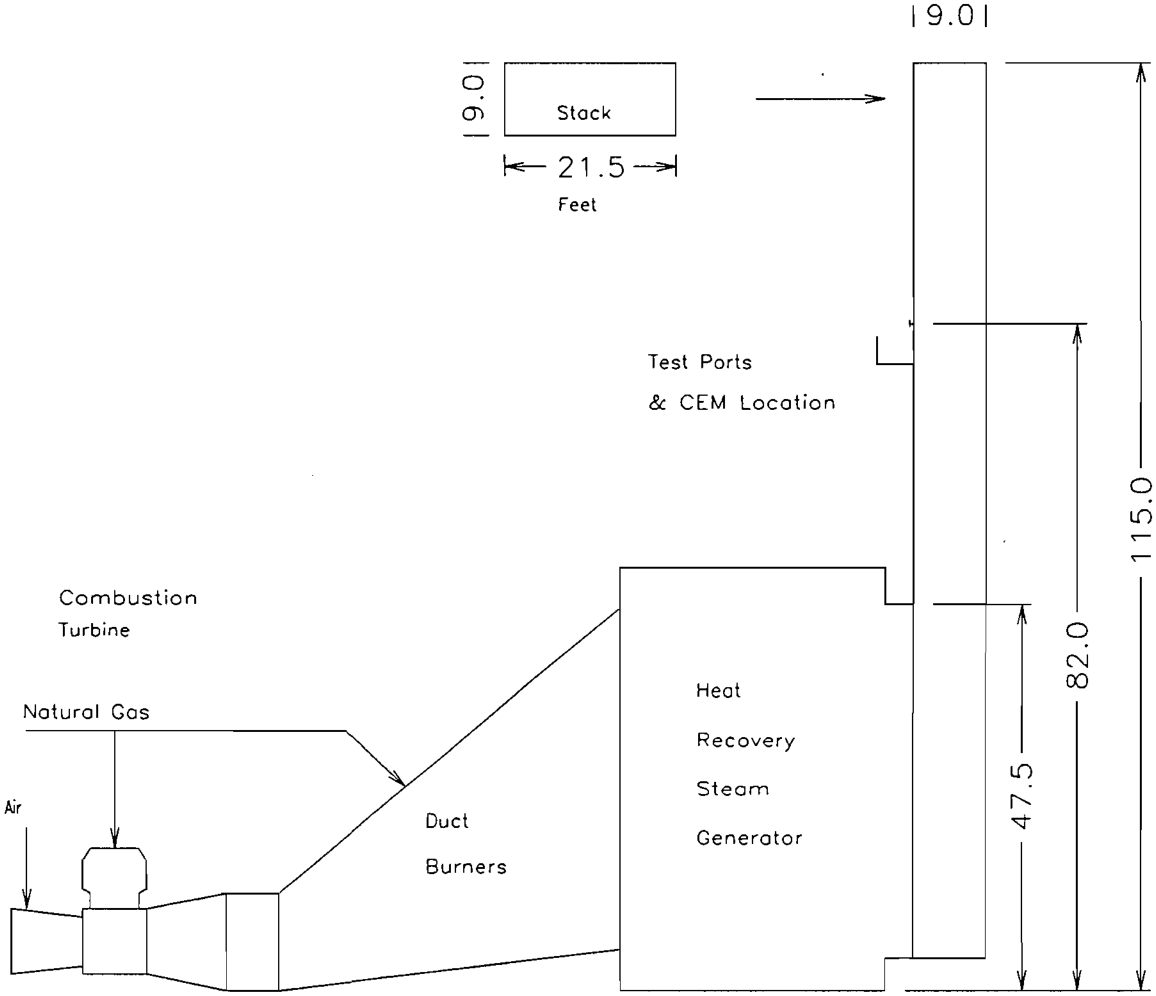
cc: Mr. Gary Kuberski
Central District Office, Florida DER

Mr. Bruce Mitchell
Permitting and Standards, Florida DER

Orlando CoGen Limited-Continuous Emission Monitoring System

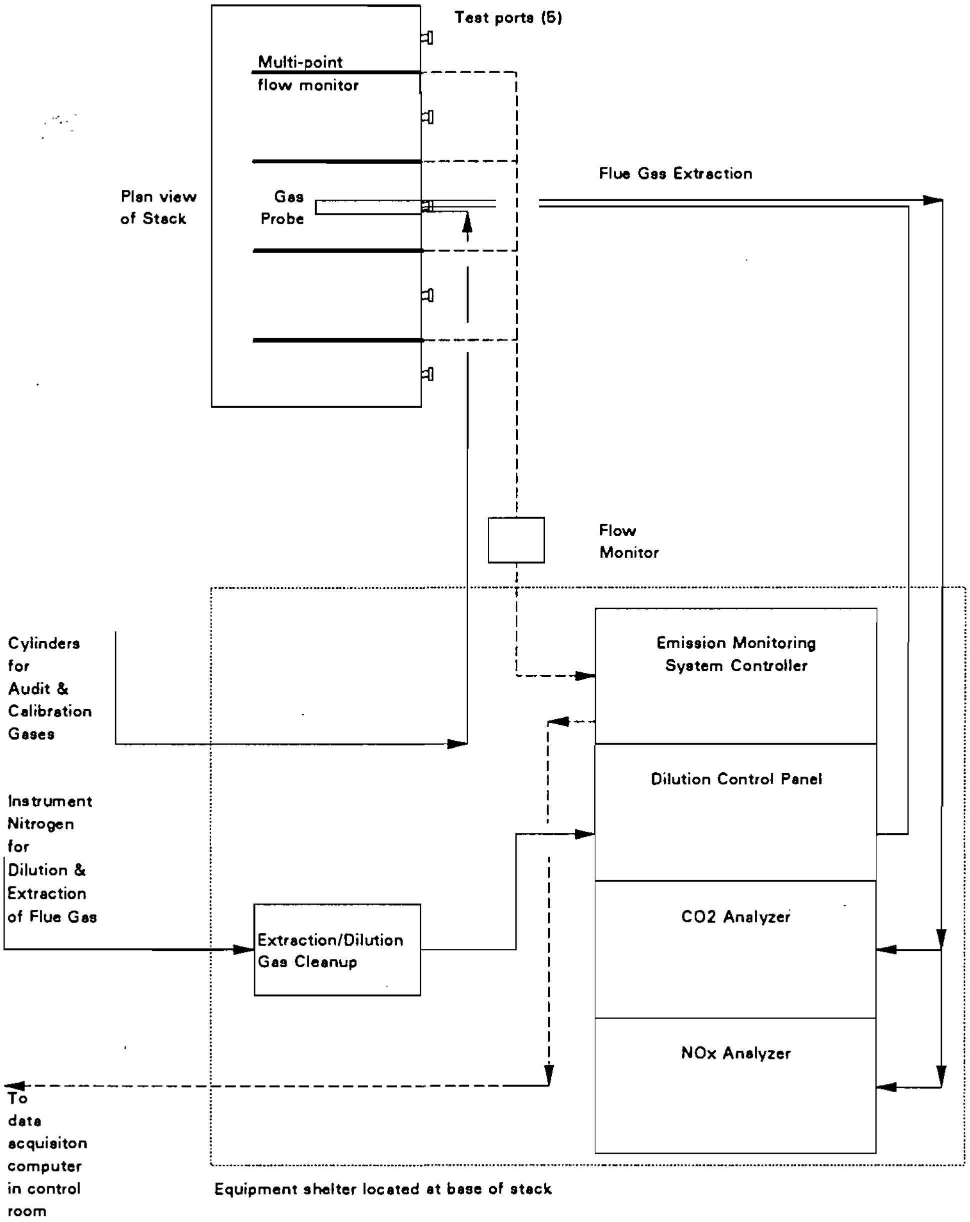
Process Description

The Orlando CoGen Limited facility generates process steam and electricity in a combined cycle power plant consisting of a combustion turbine (CT) followed by a heat recovery steam generator (HRSG) as shown in the figure below. Additional gas may be fired in duct burners (DB) when additional steam is needed. However, even with DB firing, the only point of combustion air addition is at the combustion turbine. When there is no DB firing, the flue gas monitored at the stack is at the same concentration as at the outlet of the combustion turbine. When firing additional fuel in the duct burners, the stack gas emissions are the combination of those produced by the CT and the duct burners. Again, no additional combustion air is needed at the duct burners when they are fired. The turbine exhaust, because of the high excess air fired in the turbine, contains more than enough oxygen (on the order of 15%) to supply that needed to cleanly burn the supplementary fuel fired in the duct burners.



Emission Monitoring System

As shown in the following diagram, the continuous emission monitoring system (CEMS) measures the concentrations of NOx, CO_2, and the flow rate of flue gas leaving the stack following the HRSG. Flue gas is extracted from the stack using purified nitrogen to carry it to CO_2 and NOx analyzers housed in an air conditioned shelter at the base of the stack. The dry nitrogen carrier gas, by diluting the sample, lowers its dew point enough that no moisture removal is necessary prior to passing the gas sample to the analyzers. Because no moisture is removed in the sampling process, all concentrations are therefore on a wet basis.



Flue gas flow rate is monitored at multiple points in the plane of the stack using differential pressure. The multi-point readings are integrated and compensated for temperature and pressure to produce a flow rate in standard cubic feet per minute.

Other components of the system are:

- A system controller which takes instrument readings and converts the analyzer outputs into the correct signal for transmission to the data acquisition computer. The controller also controls the injection of reference gases for system calibration and auditing.

- The dilution control panel controls the flow of extraction gas to the gas sample probe in the stack.

- The extraction gas cleanup module removes moisture, NOx, and CO_2 which may be present in the nitrogen carrier used to extract flue gas from the stack.

Data Acquisition

Data from the analyzers is transmitted via the system controller to a dedicated microcomputer which logs the measurement data (ppm NOx, %CO_2, and SCFM flow) and performs calculations to convert the measurements to other units, such as lbs/hr, and lbs/MMBtu. Additional functions include:

- tracking cumulative emissions,
- recording results of daily and quarterly cylinder gas checks and audits of the CEMS,
- producing alarms if permitted emissions are exceeded or monitor malfunctions are detected,
- recording status of the monitoring system,
- and producing emission reports required by permits and regulations.

Orlando CoGen Limited

DRAFT Plan for Atmospheric Emission Testing and Performance Testing of the Continuous Emission Monitoring System

I. Term definitions

DER	Florida Department of Environmental Regulation
CEMS	Flue gas continuous emission monitoring system including all gas analyzers, computer data acquisition system, and gas sampling components
CT	Combustion turbine
DB	Duct burner
PST	Performance specification test (for CEMS)
PM	Particulate matter
RA	Relative accuracy, deviation of a CEMS measured value from a reference method measured value
RM	Reference method, a test method approved by EPA or DER
CD/CE	Calibration drift/calibration error, change over a time in a CEMS monitor's response to a reference gas
Part 52/60/75	Refers to Title 40 of the Code of Federal Regulations; Parts 52, 60, 75
Bias	Test for systematic error in CEM measurements with respect to the RM measurements
HRSG	Heat recovery steam generator
Db	EPA new source performance standards relating to the duct burner
GG	EPA new source performance standards relating to the combustion turbine
ISO	ISO standard day refers to ambient atmospheric conditions of 59°F, 60% RH, and 1 atm pressure
Protocol Gas	A calibration gas meeting EPA traceability requirements to a reference material
DAS	Data acquisition system component of the CEMS

II. Purpose of test program

1) To demonstrate compliance with the emission limitations contained in the following:

a) Florida DER Permit

NOx	CT	15 ppmvd @ 15% O_2 (at ISO**)	57.4 lbs/hr
	DB	0.1 lb/MMBtu *	12.2 lbs/hr
CO	CT	10 ppmvd @ 15% O_2	22.3 lbs/hr
	DB	0.1 lb/MMBtu *	12.2 lbs/hr
PM/PM-10	CT	0.01 lb/MMBtu *	9.0 lbs/hr
	DB	0.01 lb/MMBtu *	1.2 lbs/hr
VOC	VOC is deemed to meet permit conditions if CO emission limitations are met		
Visual emissions	CT/DB	<10% opacity	

* lower heating value basis
maximum heat input to the CT 856.9 MMBtu/hr (**LHV**) (ISO day){**see Appendix**}
maximum heat input to the DB 122.0 MMBtu/hr (**LHV**) (3688 hour annual average)

b) 40 CFR 60 Subpart Db (duct burner emissions) NOx - 0.20 lbs/MMBtu (**HHV**)

c) 40 CFR 60 Subpart GG (combustion turbine emissions) NOx - 93 ppmvd @ 15% O_2 (ISO)[60.332]
SO_2 - either <150 ppmvd @ 15% O_2 or fire fuel containing <0.8% sulfur by weight [60.335 (d)(e)]

**NOx measurement correction equation to ISO standard day conditions:

$$NOx_{(ISO-ppmvd-15\%O_2)} = NOx_{(obsv'd-ppmvd-15\%O_2)} \cdot \left(\frac{P_r}{P_o}\right)^{0.5} \cdot e^{19\cdot(H_o-0.00633)} \cdot \left(\frac{288^\circ K}{T_a}\right)^{1.53}$$

P_r-reference combustor inlet absolute pressure at 101.3 KPa ambient pressure
P_o-observed combustor inlet absolute pressure at test

H_o-observed humidity of ambient air
T_a-ambient temperature, °K

2) To demonstrate that the CEMS meets the performance specifications contained in:

a) 40 CFR 60 Appendix B:
Specification 2 for NOx monitoring
Specification 3 for CO_2 monitoring
Specification 6 for continuous emission rate monitoring

b) 40 CFR 75 Appendix A
NOx, CO_2, and flow monitoring specifications

III. Test Location and Number of Tests

All emission testing will take place at the stack serving the heat recovery steam generator. The stack is rectangular with dimensions of 9 by 21.5 feet with the long side containing five 4-inch test ports. Testing facilities including platforms, platform access, electrical power, and test equipment supports meeting DER requirements will be provided.

The equivalent diameter of this stack is 12.7 feet. Using this equivalent diameter the test ports are 2.72 diameters downstream of the last flow disturbance and more than two diameters upstream of the stack exit. Based on RM 1, the minimum number of traverse points for particulate tests is 25 on a 5 x 5 grid. For flow rate determinations, the number of traverse points may be reduced to 16. However, given the 5 ports, in practice a minimum of 20 points will be needed for all tests requiring flow rate determinations.

With respect to combustion turbine tests required by subpart GG, this location is the closest practical point to conduct required emission tests. The transition from the CT exhaust to the HRSG varies continuously in cross section and contains the duct burners making it impractical to conduct tests between the combustion turbine and duct burners. Instead of simultaneously testing the combustion turbine exhaust and stack (Db), test runs will be conducted at the stack without duct burner firing and then with duct burner firing while maintaining combustion turbine operation constant. Because no dilution air is added in the HRSG, measurements at the stack should be representative of the conditions at the CT outlet when the DB is not being fired.

Summary of On Site Tests

Test	Number of Test Runs
Particulate Matter	6
NOx	15
CO_2	15
CO	6
Visual Emissions	6
Flow	27
Additional required for CEMS	Drift/Linearity/Response

IV. Reference Method Test Requirements for Emission Compliance Determination and CEMS Performance Specification Testing.

Emis-sion	Reg.	Ref. Method	Plant Condition During Test	Traverse Pts/No. Runs	Sampling Time	Other Requirements & Exceptions
PM	DER Permit only	EPA-5 [Permit condition 7.a.]	within 10% of maximum heat rate input at ambient conditions (interpreted to mean maximum CT firing at ambient conditions with and without maximum DB firing) [Permit Condition 11].	Minimum of 6 valid tests. Number of traverse points from EPA-1 (i.e., 25 points) each test run).	Minimum of 2 minutes per traverse point with sample time per run ≥ 1 hr & gas volume of >25 SCF [DER 17-2.700 (1)(d)1.a.].	Will perform 3 test runs with and 3 test runs without DB firing while maintaining CT at maximum operating rate.
NOx	DER Permit	EPA-20 [Permit condition 7.d.]	as for particulate	Minimum of 6 valid tests. At the 8 traverse points having the highest CO_2 at the low CT operating rate.	as above.	For determination of 8 sample points, method requires diluent sampling at 49 points on 7 x 7 grid [60, App. A, RM 20, 6.1.2.1] at turbine exhaust.Propose use RM 1 grid for initial diluent sampling to select 8 traverse points at stack.
	Db	EPA-20	as for particulate	6 tests (see last column), otherwise as above.	Minimum of 1-minute plus RM response time at each of the 8 points.[60 App. A. 6.2.2]	Db requires simultaneous measurement at outlet of CT and HRSG stack[60.46b(f)]. Propose 3 test runs with and 3 test runs without maximum DB firing while maintaining CT at maximum operating rate.
	GG	EPA-20	Test at 4 CT operating rates required. Operating points are minimum, maximum and 2 intermediate points. [60.335(c)(2&3)]	3 valid tests at each of the 4 operating points. Traverse points for each test as above [60, App. A, RM 20,6.2]	Minimum of 1-minute plus RM response time at each of the 8 points.[60 App. A. 6.2.2]	Maximum operating rate point tests are satisfied by above tests. Require an additional 9 tests at intermediate and low operating rates without DB firing.
	PST (for RA of CEM)	EPA-20	Operating rate >50% [60, App.B, Spec.2,5.3]	Minimum of 9 valid tests required. 15 tests should be available provided requirements at right are met.	Requires at least 3 traverse points sampled for 7 minutes each (21 minutes total/run)[60,App.B,Spec.2,7.1.1]	Will conduct RM 20 for Db and GG tests above such that a minimum of 21 minutes of sampling occurs for each test run. Provided this requirement is met, the data from those tests may be used to satisfy this requirement.
CO_2	PST only	EPA-20	as above	as above	as above	as above
CO	DER Permit only	EPA-10 [Permit condition 7.b.]	same as for PM tests	6 valid tests using the 8 NOx sample points above for each test.	Minimum of 2 minutes per traverse point with sample time per run ≥ 1 hr & gas volume of >25 SCF [DER 17-2.700 (1)(d)1.a.].	Will perform 3 test runs with and 3 test runs without DB firing while maintaining CT at maximum operating rate.
Opac-ity	DER Permit only	EPA-9	same as for PM tests	6 valid observations	60 min/per observation period [DER 17-2.700 (1)(d)1.b]	as above

In addition to the pollutant reference method tests above, EPA RM 2, 3, and 4 will be used to determine flue gas flow rates, dry molecular weight, and flue gas moisture as needed.

V. CEMS Performance Specifications and Test Requirements *

	40 CFR Part 60		40 CFR Part 75	
	Standard	Test Method	Standard	Test Method
Linearity: NOx CO_2	N/A N/A		NOx-measured deviations from calibration gases must be <5% of the calibration gas value or 5 ppm absolute difference. CO_2-all measurements, less restrictive of 5% of: the calibration gas value, absolute difference of 0.5% CO_2	Challenge system by introducing calibration gases at point of sample acquisition at three concentration levels (low-, mid- high-). Repeat three times with no concentration used twice in succession [75,App.A,6.2]
Calibration error (drift): NOx CO_2 flow	NOx-deviations from zero and high-level calibration gases must be <2.5% of instrument span.[60,App.B,Spec.2,4.2] CO_2-same as Part 75 [60,App.B,Spec.2,2.2] Flow-same as Part 75 [Part 52 App.E ,4]	NOx-same as Part 75 CO_2-same as Part 75 Flow-same as Part 75	NOx-deviations from the zero and high-level calibration gases must be <2.5% of instrument span or <5 ppm absolute deviation. CO_2-deviation from the zero and high-level calibration gases, absolute difference must be <0.5% CO_2. Flow-deviation must be <3% of monitor span at two reference points: 0-20% of span and 50-70% of span	NOx, CO_2-over a 7 consecutive operating day period, measure the calibration error for each monitor at approximately 24-hr intervals for the zero-level and high-level. Challenge each monitor with the zero and high-level gas once by injecting the gas at the point of sample acquisition.[75, App.A,6.3.1] Flow-inject reference signal to the flow transducer at two test points once each day over the 7-day period.[75, App.A,6.3.2]
Cycle time /response test: NOx/CO_2 combined	N/A	N/A	Time to reach 95% of final response to a step change in CO_2 and NOx concentration must be <15 minutes[75, App.A,3.5]	While the CEMS is monitoring emissions, simultaneously challenge the CO_2 monitor and NOx monitor at two points (low level, high level) and record the time for the monitors to reach 95% of their final values. The system should be returned to normal operation between tests. Because this test is to observe responses to step changes in lbs NOx/MMBtu, the low level CO_2 calibration gas should be used simultaneously with the high level NOx calibration gas for one test and vice versa for the second test.[75, App.A,6.4]

Relative accuracy and bias: NOx CO_2 Flow	NOx-error in CEM measured relative to the RM measurements must be <20% (95% confidence) of the RM measurements or 10% of the applicable standard (whichever is greater) in units of the standards: lbs/MMBtu, ppm, lbs/hr. [60,App.B, Spec.2,4.3]	NOx, CO_2-same as Part 75 [60,App.B, Spec.2,7]	NOx-error in CEM measured lbs/MMBtu relative to the RM measurements must be <10% at 95% confidence of the RM measurements in lbs/MMBtu or if CEM mean value is <0.2 lb/MMBtu must be within ±0.02 lb/MMBtu of average RM. [75,App. A 3.3.2]	NOx, CO_2-at a normal operating rate perform a minimum of 9 valid RM tests (per PST 2 of Part 60) while simultaneously recording the CEM output during each test run. Calculate the relative accuracy at the 95% confidence level. [75,App. A 6.5.9]
	CO_2-error in CEM measured relative to the RM measurements must be <20% (95% confidence) of the RM measurements or 1% CO_2 (whichever is greater) [60,App.B, Spec.2,2.3]		CO_2-error in CEM measured %CO_2 relative to the RM measurements must be <10% of the RM at 95% confidence, or the difference between the average of the RM and the average of the CEM must be <±1% CO_2. [75,App.A,3.3.3]	
	Flow-N/A (Though 40 CFR Part 52 does contain flow monitor performance specifications, this part is not applicable to either a Subpart Db, or Subpart GG source)	Flow-N/A	Flow-error in SCFH measured must be <10% of the RM at 95% confidence for each operating level.	Flow-as above but perform at 3 plant operating rates with minimum of 9 RM flow tests at each plant operating level.
	Bias-N/A	Bias-N/A	Bias-shall not be biased low. For flow monitors, applies to only at intermediate operating rate.[75,App.A,3.4.]	Bias-use test results above in this calculation. The mean difference of the RM tests and the CEMS measurements must be less than the confidence coefficient.[75,App.A,7.6.4]

*Requirements for calibration gas ranges [Part 75, App. A, 5.2], all gases will be EPA Protocol 1 gases.

Zero-level concentration:	0-20% of instrument span
Low-level concentration	20-40% of instrument span
Mid-level concentration	50-60% of instrument span
High-level concentration	80-100% of instrument span

VI. Plant Data

During each emission test the following minimum process data will be recorded every 15 minutes (15 minute averages):

Natural gas flow to the combustion turbine
Natural gas flow to the duct burners
Steam production
Electric power generated
Combustion turbine-combustor inlet pressure

At least once during each test series the following ambient data will be recorded:

Barometric pressure
Temperature
Relative humidity

At least one fuel sample will be taken on each day of emission testing for analysis of sulfur and nitrogen and determination of lower and higher heating value using ASTM methods.

The CEMS DAS will record and report CEMS responses during tests for system RA, CD/zero drift, linearity, and response time.

VII. Tests Required at Each Plant Operating Level

The exact number and sequence of tests will be coordinated with the stack testing contractor and is subject to the availability of testing personnel and equipment. The CT operating points are to be determined prior to the submission of the the test plan to the Florida DER. This plan must be submitted at least 30 days prior to beginning emission and CEMS performance testing [DER Permit Cond. 11]. The final report of test results must be submitted to the DER within 45 days of completion of testing [DER Permit Cond. 11].

Test	Minimum CT Firing	CT Firing at Point 2	CT Firing at Point 3	Maximum CT Firing	Maximum CT & DB Firing
O_2 & CO_2	3 (PST)*	3 (PST)	3 (PST)	3 (PST)	3 (PST)
NOx	3(GG, PST)*	3 (GG, PST)	3 (GG, PST)	3 (DER 1-hr)	3 (DER 1-hr)
CO				3 (DER 1-hr)	3 (DER 1-hr)
PM				3 (DER1-hr)	3 (DER 1-hr)
Stack flow	9			9 (3 from PM)	9 (3 from PM)
Moisture	1	1	1	from PM	from PM
Dry MW	1	1	1	1	1
Visible emissions				3	3

* GG, PST means minimum sample time per run set by the longer of the two requirements

The number of test runs above should also be sufficient for the determination of CEMS RA. The CEMS drift test, linearity test, and response time test are performed using cylinder gases over a seven day period and do not require the presence of the test contractor.

Appendix

Correction of observed combustion turbine firing rate at actual ambient conditions to firing rate at ISO ambient conditions.

$$Q_{iso} = \frac{Q_{obs}}{0.0253700 + \frac{12.8672}{v}}$$

where Q_{obs} is the natural gas firing rate in the combustion turbine in MMBtu/hr (LHV) and Q_{iso} is the value that would be observed under ISO conditions.

v is the moist volume of ambient air, ft^3 ambient air/lb dry air and is given by

$$v = \frac{\frac{29.92}{P} \cdot \left(\frac{379.4}{520} \cdot (T + 460) \right)}{28.97 \cdot \left(1 - \frac{P_w \cdot RH}{P} \right)}$$

and P_w is the vapor pressure of water given by

$$P_w = \exp \frac{37.2264 - 0.0691698 \cdot (T + 460)}{1 - 0.00578492 \cdot (T + 460)}$$

where **RH** is the ambient relative humidity (decimal fraction), T is ambient temperature (°F), and **P** is ambient pressure (inHg).

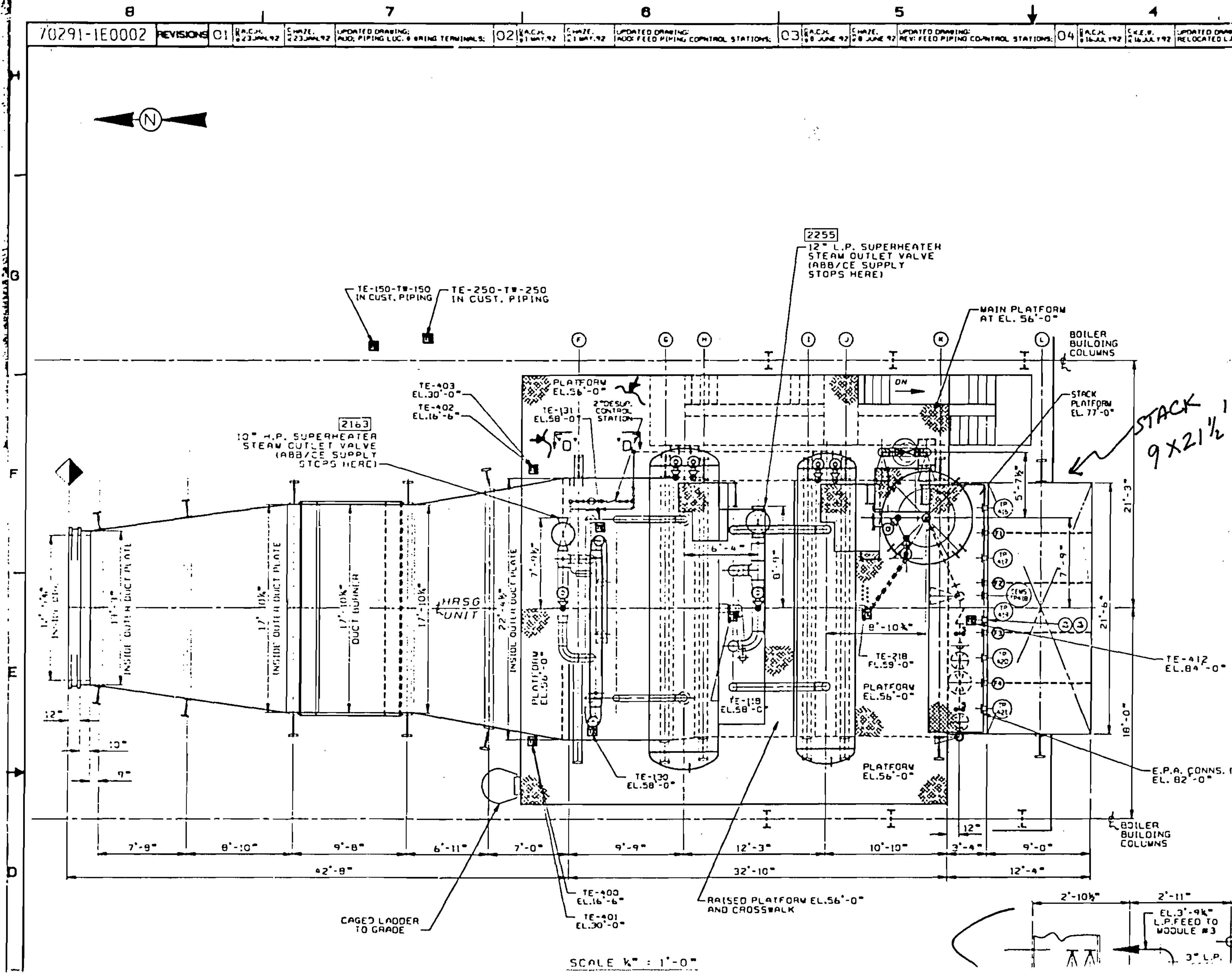
Orlando CoGen Limited

Attachment C

Plan view - heat recovery steam generator from turbine exhaust inlet to stack outlet
Partial elevation-heat recovery steam generator and stack
Detail of stack test ports and CEMS ports

BEST AVAILABLE COPY

70291-1E0002 REVISIONS 01 R.A.C.H. 23JAN.92 C.HAZE. 23JAN.92 UPDATED DRAWING: ADD: PIPING LOC. & WIRING TERMINALS; 02 R.A.C.H. 1 MAY.92 C.HAZE. 1 MAY.92 UPDATED DRAWING: ADD: FEED PIPING CONTROL STATIONS; 03 R.A.C.H. 8 JUNE 92 C.HAZE. 8 JUNE 92 UPDATED DRAWING: REV: FEED PIPING CONTROL STATIONS; 04 R.A.C.H. 16 JULY 92 C.K.E.B. 16 JULY 92 UPDATED DRA RELOCATED L



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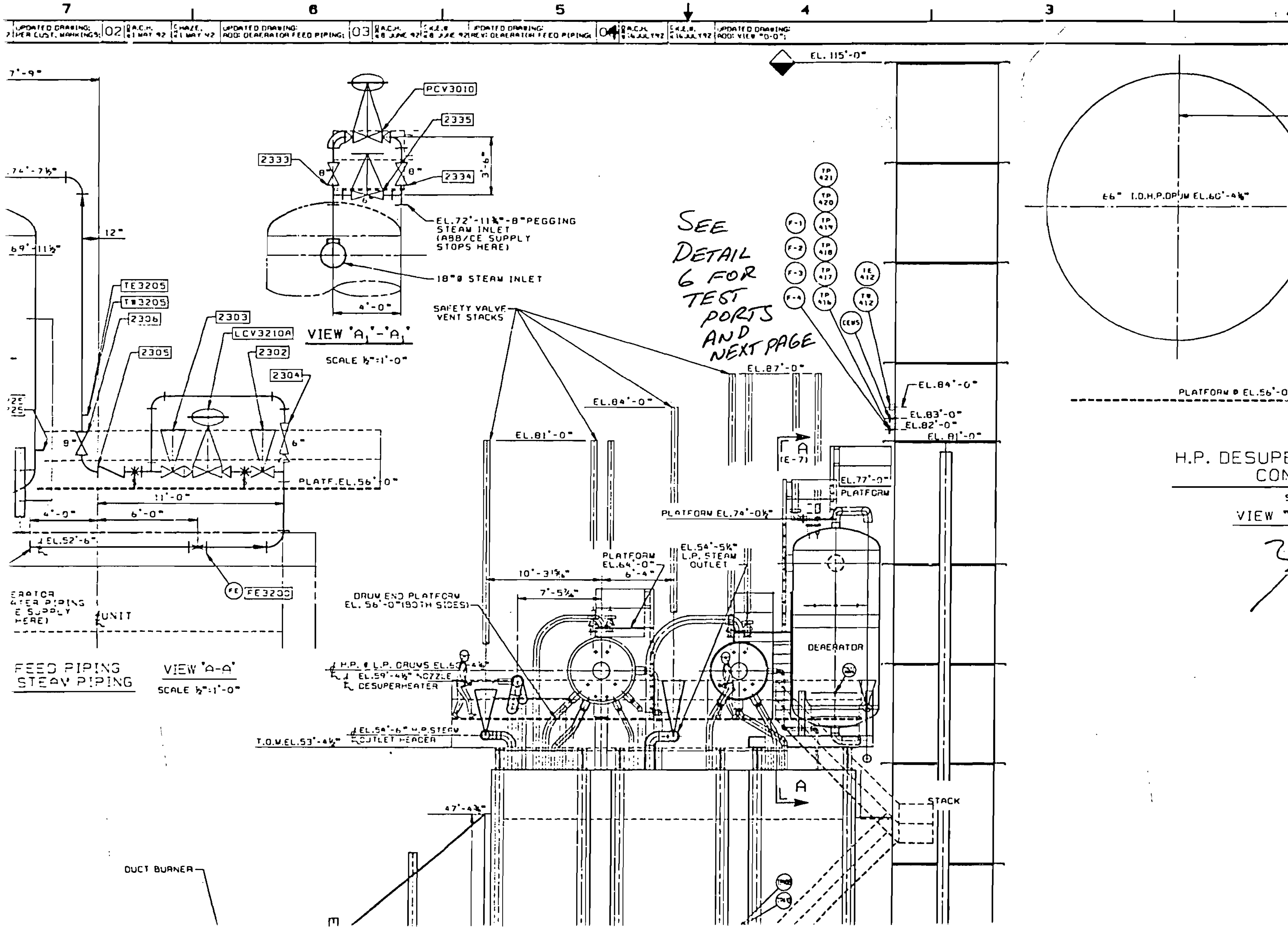
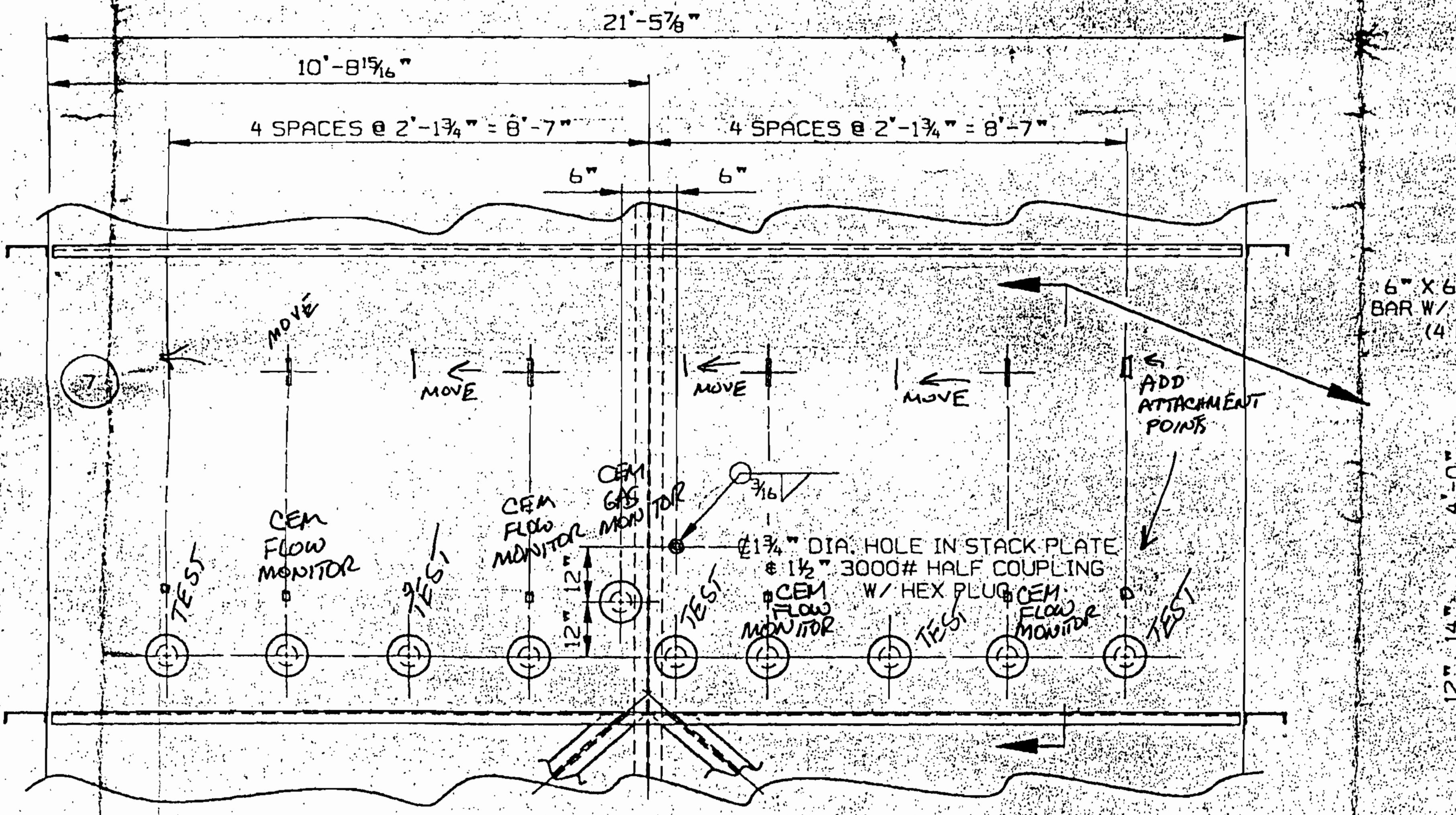


SEE DETAIL 6 FOR TEST PORTS AND NEXT PAGE

DETAIL "3"

(SHT.#1,D-6)



DETAIL "6"

(SHT. #1,F-7)

STACK PLATE

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 4, 1993

Mr. Tom Hess
Energy Systems
Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Dear Mr. Hess:

Re: Orlando CoGen, Inc.
AC 48-206720 and PSD-FL-184

Thank you for the updated information regarding the Orlando CoGen project. I have been able to complete my assignment because of the data you sent. Again, many thanks for the response.

Sincerely,

R Bruce Mitchell

R. Bruce Mitchell
Engineer IV
Bureau of Air Regulation

Reading File
C. Collins, CD } 1-4-93 BRM

Environmental/Energy Division
Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501
Telephone (215) 481-4911

AIR PRODUCTS

18 December 1992

Mr. Bruce Mitchell
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Bldg.
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED
DEC 2 2 1992
Division of Air
Resources Management

Subject: Orlando CoGen (I), Inc.
129-MW Combined Cycle Gas Turbine, Orange County
AC 48-206720
PSD-FL-184

Dear Mr. Mitchell:

Enclosed is the process information we discussed in our telephone conversation this morning. Included are

1) An overall process flow diagram
2) Material balance keyed to the diagram
3) An elevation drawing of the ABB supplied heat recovery steam generator

I also wanted to confirm the information I gave you over the phone with regard to power production and steam production.

Electric Power Production (ISO conditions)

	Power Attributable to Combustion Turbine	Power Attributable to Steam Turbine	Total Electric Power Generated
with no supplemental firing in the HSRG	78.8 MW	35.7 MW	114.5 MW
with supplemental firing in the HSRG	78.8 MW	50.1 MW	128.9 MW

Gross Steam Production from the Heat Recovery Steam Generator

	High Pressure Steam	Low Pressure Steam
with no supplemental firing in the HSRG	274,000 lb/hr 1140 psi, 930°F	79,100 lb/hr 80 psi, 536°F
with supplemental firing in the HSRG	368,200 lb/hr 1290 psi, 932°F	66,500 lb/hr 100 psi, 563°F

I hope this material will be helpful. Please call me at (215) 481-7620 if you have any questions or require additional information.

Very truly yours,

Tom Hess

Tom Hess
Energy Systems

cc'd:
C. Collins, CD 1-4-93

Air Products and Chemicals, Inc.
Orlando Cogen Project

Orlando, Florida

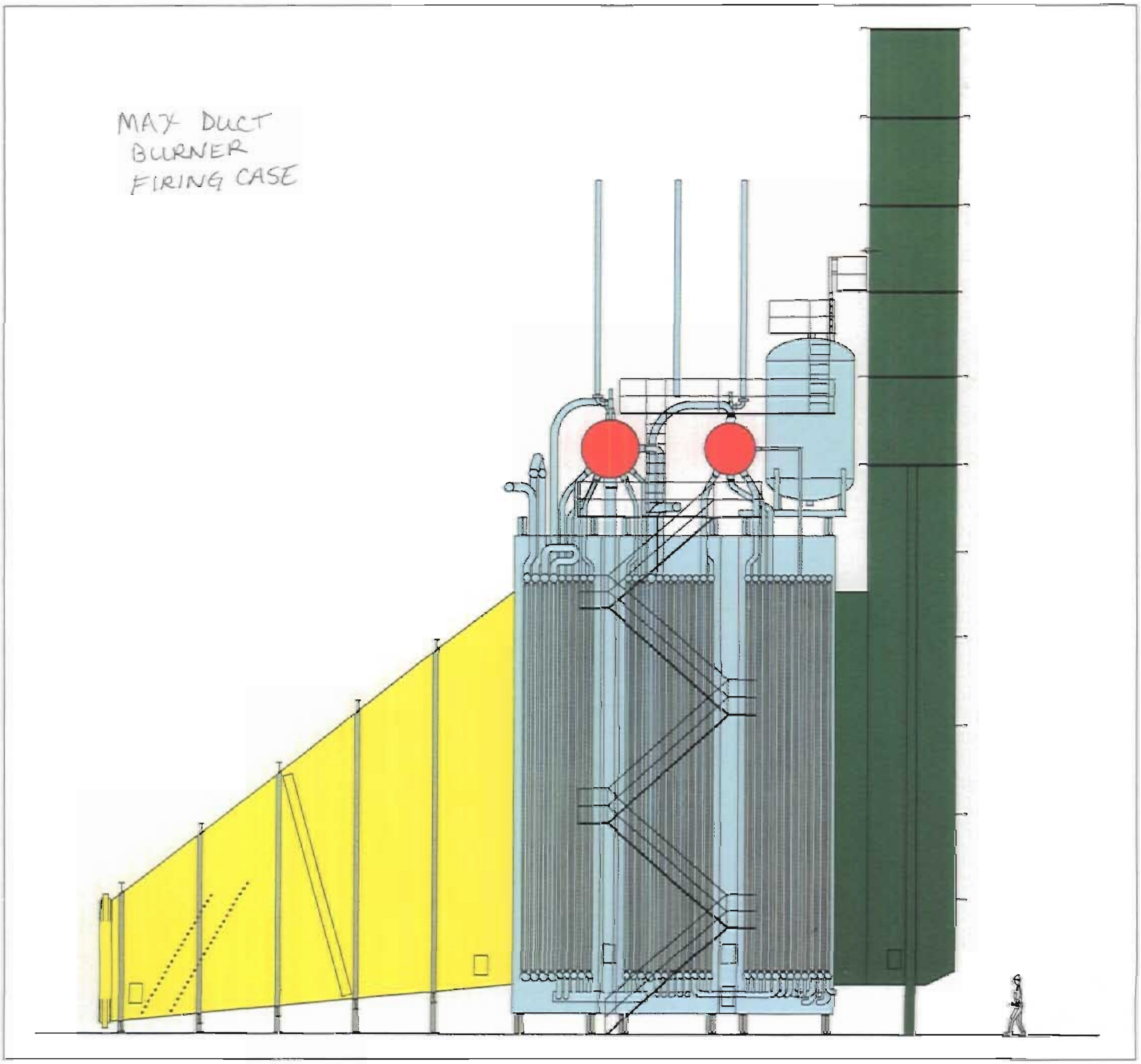
ASEA BROWN BOVERI

ABB Combustion Engineering Systems
Combustion Engineering, Inc.
1000 Prospect Hill Road
Windsor, CT 06095-0500

HRSG Steam Conditions

	Capacity lb/hr	Pressure psig	Temperature degrees F
HP	368,200	1140	930
LP	66,500	100	563

MAX DUCT
BURNER
FIRING CASE



CAMBRIA COGEN
03-1-8011

MATERIAL BALANCE
REFER TO PROCESS FLOW DIAGRAM 03-1-8011-55.10

J.T.KINDT
25 FEB 92

STREAM NUMBER	LOCATION	FLUID	UNFIRED PSIA	UNFIRED degF	UNFIRED LB/HR	SUPP FIRED PSIA	SUPP FIRED degF	SUPP FIRED LB/HR	
100	INLET AIR FILTER	AIR	14.7	-72	ABB-PGI	14.7	72	ABB-PGI	
105	INLET OF FUEL PREHEATER	NATURAL GAS	414.7	60	39.476	414.7	60	44.741	@ 20.896 BTU/LB LHV
110	FUEL TO DUCT BURNER	NATURAL GAS	414.7	60	0	414.7	60	5.264	@ 20.896 BTU/LB LHV
115	FUEL TO COMBUSTOR	NATURAL GAS	404.7	293	39.476	404.7	293	39.476	@ 20.896 BTU/LB LHV
120	GT EXHAUST	FLUE GAS	15.1	965	2.420.000	15.1	965	2.420.000	12"WC HRSG dP
122	DUCT BURNER OUTLET	FLUE GAS	ABB-CE	965	2.420.000	ABB-CE	1117	2.425.241	
125	HRSG STACK	FLUE GAS	14.7	220	2.420.000	14.7	220	2.425.241	
200	HP SUPERHEATER OUTLET	HP STEAM	1152.8	930	✓274.000	1301.2	932	✓368.200	ABB-CE GUARANTEE
202	HP TURBINE INLET	HP STEAM	1106.6	924.4	270.870	1225.5	925.5	368.200	ABB-PGI REQUIREMENT
204	HP TURBINE INLET	HP STEAM	1106.6	924.4	274.000	1225.5	925.5	368.200	USED IN MAT'L BAL
204	TO GLAND STEAM SYSTEM	HP STEAM	1106.6	924.4	0	1225.5	925.5	0	
206	LP SUPERHEATER OUTLET	LP STEAM	95	536	✓79.100	115.2	563	✓66.500	ABB-CE GUARANTEE
208	LP TURBINE INLET	LP STEAM	87.4	532.4	78.840	112.1	568.8	✓63.200	ABB-PGI REQUIREMENT
210	LP TURBINE INLET	LP STEAM	87.4	532.4	79.100	112.1	568.8	66.500	USED IN MAT'L BAL
210	PEGGING STEAM TO DA	LP STEAM	103.7	330	0	122.7	343	0	
212	LP TURBINE PROCESS EXTR.	LP STEAM	35	324	32.600	35	324	32.600	
214	ABSORP SYS. CONCENTRATOR INLET	LP STEAM	26.7	243	32.600	26.7	243	32.600	TRANE GUARANTEE
216	LP TURBINE EXTR. TO DA	LP STEAM			4.950			7.100	ABB TO CONFIRM P/T
218	EXTR. STEAM AT DA	LP STEAM	2.9	140	4.950	2.9	140	7.100	
220	STEAM TO DA	LP STEAM	2.9	140	4.950	2.9	140	7.100	
222	HP TURBINE BYPASS	HP STEAM	1106.6	924.4	0	1225.5	925.5	0	
224	EXIT OF BYPASS VALVE	LP STEAM	1.37		0	1.37		0	
226	LP TURBINE EXHAUST	LP STEAM	1.37	113	314.830	1.37	113	394.070	
228	INLET OF MAIN CONDENSER	LP STEAM	1.37	113	314.830	1.37	113	394.070	
230	DEAERATOR VENT	NON CONDENS	2.9	140	0.2	2.9	140	0.2	
232	CONDENSER VENT	NON CONDENS	1.37	113	22.5	1.37	113	22.5	
234	INLET OF VACUUM PUMPS	NON CONDENS	1.37	113	22.7	1.37	113	22.7	
300	DEMIN MAKE-UP TO COND. STORAGE	DEMIN WATER			25.000			25.000	50 GPM DEMIN CAPACITY
302	COND XFER PUMP DISCH	DEMIN WATER			3.819			4.641	1% OF MAKE:PUMP @ MIN
304	OUTLET OF MAIN CONDENSER	CONDENSATE	1.37	113	319.369	1.37	113	399.641	
306	CONDENSATE PUMP DISCH	CONDENSATE	75.6	113	319.369	76.3	113	399.641	
308	GLAND CNDNSR EXIT	CONDENSATE		113	319.369		113	399.641	DUTY IGNORED
310	MAIN CONDENSATE TO DA	CONDENSATE	2.9	113	319.369	2.9	113	399.641	
312	ABSORP SYS. CONDENSATE RETURN	CONDENSATE	14.7	212	32.600	14.7	212	32.600	
314	ABSORP SYS CONDENSATE AT DA	CONDENSATE	2.9	212	32.600	2.9	212	32.600	
316	HP FW TO FUEL PREHEATER	HP FEEDWATER	1236	324	28.807	1394	320 ~~324~~	29.443	
318	HP FW FROM FUEL PREHEATER	HP FEEDWATER	1226	130	28.807	1384	130	29.443	
320	FW FROM DA AT BFW PUMP INLET	FEEDWATER	23.7	140	385.726	23.7	140	468.784	
322	BFW PUMP LP FW DISCH	LP FEEDWATER	225.7	140	79.891	244.7	140	67.165	PUMP ENERGY NOT ADDED
324	BFW PUMP HP FW DISCH	HP FEEDWATER	1368.7	140	305.835	1548.7	140	401.619	PUMP ENERGY NOT ADDED
326	LP FW TO GLAND SYSTEM	LP FEEDWATER	225.7	140	?	244.7	140	?	ABB-PGI TO CONFIRM
328	HP FW TO BYPASS ATTEMPORATOR	HP FEEDWATER	1368.7	140	0	1548.7	140	0	
330	GLAND SEAL LEAKAGE	LP STEAM			720			930	ABB-PGI TO CONFIRM
332	GLAND CONDENSER DRAIN	CONDENSATE	1.37		720	1.37		930	

CAMBRIA COGEN
03-1-8011

MATERIAL BALANCE
REFER TO PROCESS FLOW DIAGRAM 03-1-8011-55.10

J.T.KINDT
25 FEB 92

STREAM NUMBER	LOCATION	FLUID	UNFIRED			SUPP FIRED			
			PSIA	degF	GPM	PSIA	degF	GPM	
400	CW CIRC PUMP DISCH	COOLING WATER		84	37,969		84	45,673	
402	INLET OF SIDESTREAM FILTERS	COOLING WATER		84	743		84	893	2% OF CIRC RATE
404	EXIT OF SIDESTREAM FILTERS	COOLING WATER		84	743		84	893	
406	SIDESTREAM FILTER BACKWASH	COOLING WATER		84	0		84	0	NOT CONTINUOUS
408	CW BLOWDOWN	COOLING WATER		84	93		84	112	0.251% OF CIRC RATE
410	MAIN CONDENSER INLET	COOLING WATER		84	29,067		84	36,434	
412	MAIN CONDENSER OUTLET	COOLING WATER		106	29,067		106	36,434	
414	CHILLER CW BOOSTER PUMP SUCTION	COOLING WATER		84	5,850		84	5,850	
416	CHILLER CW BOOSTER PUMP DISCH	COOLING WATER		84	5,850		84	5,850	
418	CHILLER CONDENSER EXIT	COOLING WATER		102	5,850		102	5,850	
420	BOP CW BOOSTER PUMP SUCTION	COOLING WATER		84	2,216		84	2,384	
422	BOP CW BOOSTER PUMP DISCH	COOLING WATER		84	2,216		84	2,384	
424	TO VAC PUMPS & ST OIL COOLER	COOLING WATER		84	399		84	479	
426	VACUUM PUMP COOLER INLET	COOLING WATER		84	? 14 ~~[illegible]~~ 40		84	14 40	~~[illegible]~~ GPM ?
428	VACUUM PUMP COOLER OUTLET	COOLING WATER		106	14		106	14	
430	ST OIL COOLER INLET	COOLING WATER		84	385		84	465	
432	ST OIL COOLER OUTLET	COOLING WATER		106	385		106	465	
434	FROM VAC PUMPS & ST OIL COOLER	COOLING WATER		106	399		106	479	
436	TO GT & BFW OIL & GEN COOLERS	COOLING WATER		84	1817		84	1905	
438	GAS TURBINE OIL COOLER INLET	COOLING WATER		84	705		84	705	
440	GAS TURBINE OIL COOLER EXIT	COOLING WATER		106	705		106	705	
442	BFW PUMP OIL COOLERS INLET	COOLING WATER		84	22		84	28	
444	BFW PUMP OIL COOLERS OUTLET	COOLING WATER		106	22		106	28	
446	GENERATOR COOLERS INLET	COOLING WATER		84	1,090		84	1,172	
448	GENERATOR COOLERS OUTLET	COOLING WATER		106	1,090		106	1,172	
450	FROM GT & BFW OIL & GEN COOLERS	COOLING WATER		106	1,817		106	1,905	
452	BOP CW OUTLET	COOLING WATER		106	2,216		106	2,384	
454	RETURN TO COOLING TOWER	COOLING WATER		106	37,133		106	44,668	
456	COOLING TOWER EVAPORATION	COOLING WATER			654			786	1.76% OF RETURN
458	COOLING TOWER MAKE-UP	COOLING WATER		72	739		72	889	
460	BOILER BLOWDOWN	COOLING WATER			8			9	
470	ASU CW BOOSTER PUMP SUCTION	COOLING WATER		76	1,660		76	1,660	
472	ASU CW BOOSTER PUMP DISCH	COOLING WATER		76	1,660		76	1,660	
474	CHILLED ASU COOLING WATER	COOLING WATER		52	1,660		52	1,660	

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. AC 48-206720
PSD-FL-184
Orange County

Mr. John P. Jones, President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

______________________________/

Enclosed is Permit Number AC 48-206720 to construct a 128.9 megawatt cogeneration facility located in the Orlando Central Park, Orange County, Florida. This permit is 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

CH Fancy

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 August 17, 1992 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 8/17/92
(Clerk) (Date)

Copies furnished to:

C. Collins, CD
K. Kosky, P.E., KBN
J. Harper, EPA
C. Shaver, NPS
D. Nester, OCEPD
P. Cunningham, Esq. HBG&S

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. John P. Jones, President
Orlando CoGen (I), Inc.
7201 Hamilton Blvd.
Allentown, PA 18195-1501

4a. Article Number
P 062 921 987

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

7. Date of Delivery AUG 20 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, November 1990 ☆U.S. GPO: 1991—287-066 **DOMESTIC RETURN RECEIPT**

P 062 921 987

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

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

Sent to Mr. John P. Jones, Orlando	
Street and No. CoGen.Limited 7201 Hamilton Blvd.	
P.O., State and ZIP Code Allentow, PA 18195-1501	
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: 8-17-92 Permit: AC 48-206720 PSD-FL-184	

PS Form **3800**, June 1991

Final Determination

Orlando CoGen Limited, L.P.
Orange County, Florida

Construction Permit No.
AC 48-206720
(PSD-FL-184)

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

August 17, 1992

Final Determination

Orlando CoGen Limited, L.P.

AC 48-206720 (PSD-FL-184)

The construction permit application package and supplementary material have been reviewed by the Department. Public Notice of the Department's Intent to Issue was published in The Orlando Sentinel on June 12, 1992. The Technical Evaluation and Preliminary Determination (TE&PD) was distributed on June 8, 1992, and was available for public inspection at the Department's Central District office and the Department's Bureau of Air Regulation office.

Comments were received from the applicant during the public notice period. The comments were received on July 7, 1992. The Department's response to the comments are as follows (note: each response is numbered to correspond to each comment):

1. The Department will change the permittee's name to read "Orlando CoGen Limited, L.P." instead of "Orlando Cogen Limited, L.P."

2. Since the requested change does not affect the potential emissions, a revised TE&PD will not be required. However, the comment is acknowledged.

3. Permit No. AC 48-206720 (PSD-FL-184)

a. The request is acceptable, but the specific language will be slightly different than what was requested:

<u>SPECIFIC CONDITION No. 1</u>:

From: The CT (combustion turbine) is allowed to operate continuously (8,760 hours per year). The HRSG-DB (heat recovery steam generator-duct burner) is permitted to operate 3688 hrs/yr at a maximum heat input of 122 x 10^6 Btu/hr.

To: The CT (combustion turbine) is allowed to operate continuously (8,760 hours per year). The HRSG-DB (heat recovery steam generator-duct burner) is permitted to operate 3688 hrs/yr at a maximum heat input of 122.0 x 10^6 Btu/hr for a maximum heat input of 450,000 x 10^6 Btu/yr (note: The unit may operate at lower rates for more hours within the annual heat input limit).

b. The request is acceptable to add a clarifier to the hours of operation.

SPECIFIC CONDITION No. 4: Table 1, Note 3b:

From: DB: 3688 hrs/yr

To: DB: 3688 hrs/yr (at a maximum heat input of 122 x 10^6 Btu/hr)

c. Except for minor particulate sources equipped with a baghouse control system, the Department does not have the authority, by rule, to substitute a visible emission standard for a mass emissions standard in accordance with Florida Administrative Code (F.A.C.) Rule 17-2.700(3)(d). However, the owner or operator of any source may request approval of alternate procedures and requirements in accordance with F.A.C. Rule 17-2.700(3)(a). Therefore, the request is not acceptable and SPECIFIC CONDITION No. 8 will not be altered.

d. The request is acceptable, which alters the original wording, but not the intent.

SPECIFIC CONDITION No. 12:

From: The permittee shall leave sufficient space suitable for future installation of SCR equipment.

To: The permittee shall design the facility to allow for future installation of SCR equipment.

e. The request is acceptable.

SPECIFIC CONDITION No. 13:

From: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2, (July 1, 1991).

To: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor (CEM) in the stack to measure and record the nitrogen oxides (NOx) emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1991 version).

For the purpose of demonstrating ongoing compliance with the applicable NOx emissions limitation in Table 1, using the stack CEM, compliance is considered to occur when the NOx emissions are less than or equal to 57.4 lbs/hr when only the CT is operating and less than or equal to 69.6 lbs/hr when both the CT and DB are operating. The 24-hour rolling average compliance level is calculated based on the proportion of hours in any 24-hour period that the CT only or CT/DB are operating. Any portion of an hour that the DB operates is recognized as an hour period on the rolling average.

For example, in a given 24-hour period, with 20 hours of CT operation only and 4 hours of CT/DB operation:

Calculated Emission Limitation =

[(57.4 lbs/hr x 20 hrs) + (69.6 lbs/hr x 4 hrs)]/24 hrs =

24-hour rolling average-compliance NOx level = 59.4 lbs/hr

Compliance with the permitted NOx emission limitation is considered satisfied as long as the NOx emissions from the stack CEM are less than or equal to the calculated NOx emissions, averaged over the same 24-hour period.

f. The request is acceptable, which alters the original wording, but not the intent.

<u>SPECIFIC CONDITION No. 14</u>:

From: Combustion control shall be utilized for CO control. The permittee shall leave a sufficient space suitable for future installation of an oxidation catalyst. Once performance testing has been completed, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

To: Combustion control shall be utilized to minimize CO emissions. The permittee shall design the facility to allow for the future installation of an oxidation catalyst. Once the performance test is completed and if the facility demonstrates compliance with the CO emission limits in Table 1, then an oxidation catalyst will not be required. Otherwise, the decision to require an oxidation catalyst will be based on a cost/ benefit analysis of using such control.

4. BACT Determination to Permit No. AC 48-206720 (PSD-FL-184)

a. The request is acceptable and the BACT will be revised on page 1, 1st paragraph, to reflect the product output of the combustion turbine (CT) to be 78.8 MW and the steam turbine (ST) to be 50.1 MW. Originally, the CT's output was listed as 79 MW and the ST's output as 50 MW.

b. The request is acceptable and the sentence (i.e., page 3, 2nd paragraph under "Products of Incomplete Combustion", 2nd sentence) will be deleted. The rationale is that the applicant attests that the proposed unit is a proven operation and is being permitted for a CO level lower than other recently permitted sources. Data has been submitted to substantiate CO levels from currently operating and similar units.

c. The request is acceptable, but the proposed language will be slightly different than what was requested. Therefore, the 2nd sentence, 1st paragraph, page 8-"BACT Determination by DER": NOx Control, will be revised to read:

Duct firing will be used for supplying steam and limited to operate at a full load equivalent of 3688 hrs/yr at a maximum heat input of 122.0 x 10^6 Btu/hr for a maximum heat input of 450,000 x 10^6 Btu/yr (note: The unit may operate at lower rates for more hours within the annual heat input limit).

d. The request is acceptable, but the proposed language will be slightly different than what was requested. Therefore, the 2nd sentence, 2nd paragraph, page 8-"BACT Determination by DER": CO Control, will be revised to read:

The permittee shall design the facility to allow for the future installation of an oxidation catalyst. Once the performance test is completed and if the facility demonstrates compliance with the CO emission limits, then an oxidation catalyst will not be required. Otherwise, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

e. The "Note" associated with the table "Emission Standards/ Limitations", located on page 8 of the proposed BACT Determination, will be revised to read:

Note: Natural gas firing will be used only for supplemental firing the DB for a full load equivalent of 3688 hrs/yr at 122.0 x 10^6 Btu/hr maximum heat input for a maximum heat input of 450,000 x 10^6 Btu/yr (note: The unit may operate at lower rates for more hours within the annual heat input limit).

5. Attachment to be Incorporated:

o Mr. Gary D. Kinsey's letter with enclosure received July 7, 1992.

Therefore, it is recommended that the construction permit, No. AC 48-206720 (PSD-FL-184), and associated BACT Determination, be issued as drafted, with the above referenced revisions incorporated.

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:

Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Permit Number: AC 48-206720
PSD-FL-184
Expiration Date: August 31, 1994
County: Orange
Latitude/Longitude: 28°26'23"N
81°24'28"W
Project: 128.9-MW Combined Cycle Gas Turbine

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4, and 40 CFR (July, 1991 version). 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 128.9 MW (megawatt) combined cycle gas turbine cogeneration facility to be located in the Orlando Central Park, Orange County, Florida, and will supply steam to the adjacent Air Products and Chemicals Plant. The UTM coordinates are Zone 17, 459.5 km East and 3,146.1 km North.

4911 - Electric Generation/Distribution

The Standard Industrial Code: ~~4931 Electric and Other Services Combined~~

2-02-002-31 Industrial e- gen.; Natural Gas Turbine; cogeneration 10^6 ft^3 burned

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. Orlando Cogen Limited, L.P.'s application received December 30, 1991.
2. Mr. C. H. Fancy's letter dated January 28, 1992.
3. Mr. Kennard F. Kosky's letter with enclosures received March 2, 1992.
4. Mr. Wayne A. Hinman's letter received via FAX May 27, 1992.
5. Mr. Kennard F. Kosky's letter with enclosure received May 27, 1992 (hand delivered).
6. Document (Table 1) received June 1, 1992, from Mr. Peter Cunningham (hand delivered).
7. 40 CFR (July, 1991 version).
8. Technical Evaluation and Preliminary Determination dated June 5, 1992.
9. Mr. Gary D. Kinsey's letter with enclosure received July 7, 1992.

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, F.S. 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), F.S., 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, F.S. 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 F.A.C. Rules 17-4.120 and 17-30.300, 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.

GENERAL CONDITIONS:

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. The CT (combustion turbine) is allowed to operate continuously (8,760 hours per year). The HRSG-DB (heat recovery steam generator-duct burner) is permitted to operate 3688 hrs/yr at a maximum heat input of 122.0 x 10^6 Btu/hr for a maximum heat input of 450,000 x 10^6 Btu/yr (note: The unit may operate at lower rates for more hours within the annual heat input limit).

2. The CT and HRSG-DB are only allowed to use natural gas.

3. The permitted materials and utilization rates for the combined cycle gas turbine shall not exceed the values as follows:

- Maximum heat input to the CT shall not exceed 856.9 MMBtu/hr at ISO conditions.
- Maximum heat input to the HRSG-DB shall not exceed 122.0 MMBtu/hr; 450,000 MMBtu/yr.

4. The maximum allowable emissions from this facility shall not exceed the emission rates listed in Table 1.

Table 1

Pollutant	Source	Allowable Emission Standard/Limitation
NOx	CT	15 ppmvd @ 15% O_2 (57.4 lbs/hr; 251.4 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
	CT/DB	24-hr rolling average

To
Toli

From
Marty

SPECIFIC CONDITIONS:

Table 1 cont.:

CO	CT	10 ppmvd (22.3 lbs/hr; 92.1 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
PM/PM_{10}	CT	0.01 lb/MMBtu (9.0 lbs/hr; 39.4 TPY)
	DB	0.01 lb/MMBtu (1.2 lbs/hr; 2.2 TPY)
VOC	CT	3.0 lbs/hr; 13.0 TPY
	DB	3.7 lbs/hr; 6.8 TPY
VE	CT/DB	$\leq$ 10 % opacity

NOTE:
1. CT: combustion turbine
   DB: duct burner
2. Natural gas usage only in the CT and DB.
3. Hours of operation:
   a. CT: 8760 hrs/yr
   b. DB: 3688 hrs/yr (at a maximum heat input of 122.0 x 10^6 Btu/hr)
4. Maximum heat input:
   a. CT: 856.9 x 10^6 Btu/hr
   b. DB: 122.0 x 10^6 Btu/hr; 450,000 x 10^6 Btu/yr
5. DB operation planned when ambient temperature is greater than 59°F.

5. Any change in the method of operation, equipment or operating hours, pursuant to F.A.C. Rule 17-2.100, Definitions-Modification, shall be submitted to the Department's Bureau of Air Regulation and Central District offices.

6. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility shall be included in the operating permit.

7. Initial and subsequent annual compliance tests shall be performed within 10 percent of the maximum heat rate input for the tested operating temperature. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1991 version of the 40 CFR 60, Appendix A.
a. EPA Method 5 for PM
b. EPA Method 10 for CO
c. EPA Method 9 for VE
d. EPA Method 20 for NOx

Note: Other test methods may be used for compliance testing only after prior Department written approval.

SPECIFIC CONDITIONS:

8. EPA Method 5 must be used to determine the initial compliance status of this unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

9. Compliance with the total volatile organic compound emission limits will be assumed, provided the CO allowable emission rate is achieved. Specific VOC compliance testing is not required.

10. During performance tests, to determine compliance with the proposed NOx standard, measured NOx emission at 15 percent oxygen shall be adjusted to ISO ambient atmospheric conditions by the following equation in accordance with 40 CFR 60.335(c)(1):

$$NO_x = (NO_{xo})\ (P_r/P_o)^{0.5}\ e^{19(H_o-0.00633)}\ (288°K/T_a)^{1.53}$$

where:

NO_x = Emission rate of NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent.

NO_{xo} = Observed NOx emission at 15 percent oxygen, ppmv.

P_r = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure, mm Hg.

P_o = Measured combustor inlet absolute pressure at test ambient pressure, mm Hg.

H_o = Observed humidity of ambient air at test, g H_2O/g air.

e = Transcendental constant (2.718).

T_a = Temperature of ambient air at test, °K.

11. Test results will be the average of 3 valid runs. The Department's Central District office shall be notified at least 30 days in advance of the compliance test in accordance with 40 CFR 60.8(c). The source shall operate between 90% and 100% of permitted capacity as adjusted for ambient temperature during the compliance test. Compliance test results shall be submitted to the Department's Central District office no later than 45 days after completion in accordance with F.A.C. Rule 17-2.700(8)(b).

12. The permittee shall design the facility to allow for future installation of SCR equipment.

13. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor (CEM) in the stack to measure and record the nitrogen oxides (NOx) emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2, (July 1, 1991 version).

SPECIFIC CONDITIONS:

For the purpose of demonstrating ongoing compliance with the applicable NOx emissions limitation in Table 1, using the stack CEM, compliance is considered to occur when the NOx emissions are less than or equal to 57.4 lbs/hr when only the CT is operating and less than or equal to 69.6 lbs/hr when both the CT and DB are operating. The 24-hour rolling average compliance level is calculated based on the proportion of hours in any 24-hour period that the CT only or CT/DB are operating. Any portion of an hour that the DB operates is recognized as an hour period on the rolling average.

For example, in a given contiguous 24-hour period, with 20 hours of CT operation only and 4 hours of CT/DB operation:

Calculated Emission Limitation =

[(57.4 lbs/hr x 20 hrs) + (69.6 lbs/hr x 4 hrs)]/24 hrs =

24-hour rolling average-compliance NOx level = 59.4 lbs/hr

Compliance with the permitted NOx emission limitation is considered satisfied as long as the NOx emissions from the stack CEM are less than or equal to the calculated NOx emissions, averaged over the same 24-hour period.

14. Combustion control shall be utilized for CO control. The permittee shall design the facility to allow for future installation of an oxidation catalyst. Once performance testing has been completed, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

15. This source shall be in compliance with all applicable provisions of Chapter 403, F.S., F.A.C. Chapters 17-2 and 17-4, and the 40 CFR (July, 1991 version).

16. This source shall be in compliance with all applicable requirements of 40 CFR 60, Subparts GG and Db, in accordance with F.A.C. Rule 17-2.660(2)(a), Standards of Performance for Stationary Gas Turbines and Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units.

17. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-2.210(1)).

SPECIFIC CONDITIONS:

18. This source shall be in compliance with all applicable provisions of F.A.C. Rules 17-2.240: Circumvention; 17-2.250: Excess Emissions; 17-2.660: Standards of Performance for New Stationary Sources (NSPS); 17-2.700: Stationary Point Source Emission Test Procedures; and, 17-4.130: Plant Operation-Problems.

19. Pursuant to F.A.C. Rule 17-2.210(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: fuel usage, hours of operation, air emissions limits, etc. Annual reports shall be sent to the Department's Central District office by March 1 of each year.

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

21. An application for an operation permit must be submitted to the Department's Central 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 17th day
of August, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Carol M. Browner, Secretary

Best Available Control Technology (BACT) Determination
Orlando CoGen Limited, L.P.
Orange County

The applicant proposes to install a combustion turbine generator at their facility in Orange County. The generator system will consist of one nominal 78.8 megawatt (MW) combustion turbine (CT), with exhaust through a heat recovery steam generator (HRSG), which will be used to power a nominal 50.1 MW steam turbine.

The combustion turbine will be capable of combined cycle operation. The applicant requested that the combustion turbine use only natural gas. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity and type of fuel fired at ISO conditions to be as follows:

Pollutant	Emissions (TPY)	PSD Significant Emission Rate (TPY)
NO_x	273.9	40
SO_2	12.0	40
PM/PM_{10}	41.7	25/15
CO	114.6	100
VOC	19.8	40
H_2SO_4	0.9	7
Be	Neg.	0.0004
Hg	Neg.	0.1
Pb	Neg.	0.6

Florida Administrative Code (F.A.C.) Rule 17-2.500(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

December 30, 1991

BACT Determination Requested by the Applicant

Pollutant	Determination
NO_x	15 ppmvd @ 15% O_2 (natural gas burning)--CT 0.1 lb/10^6 Btu--duct burner
CO	Combustion Control
PM/PM_{10}	Combustion Control

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.

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

o Combustion Products (e.g., particulates). Controlled generally by efficient combustion of clean fuels.

o Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.

o Acid Gases (e.g., NO_X). Controlled generally by gaseous control devices.

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

Combustion Products

The projected emissions of particulate matter and PM_{10} from the Orlando CoGen Limited, L.P. facility surpass the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2.

A PM/PM_{10} emissions limitations of 0.01 lb/MMBtu from the CT when firing natural gas is reasonable as BACT for the Orlando CoGen Limited, L.P. facility. The duct burner PM/PM_{10} emission rate of 0.01 lb/MMBtu is reasonable as BACT.

Products of Incomplete Combustion

The projected emissions of carbon monoxide exceed the PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emissions from the proposed turbine is based on exhaust concentrations of 10 ppmvd for natural gas firing.

A review of the BACT/LAER clearinghouse indicates that several of the combustion turbines using dry low-NOx combustion technology to control NOx to 15 ppmvd (corrected to 15 percent O_2) have been permitted with CO limitations that are higher than those proposed by the applicant. The majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds. Additional 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. The existing gas turbine applications have been limited to smaller cogeneration facilities burning natural gas.

Given the applicant's proposed BACT level for carbon monoxide of 10 ppm, a lower emission rate as BACT would not produce a significant reduction in emissions or impacts. Also, this CO concentration level is near the lowest established as BACT even with catalytic oxidation. For these reasons, it appears that the limit proposed by the applicant is reasonable as BACT.

Emission of volatile organic compounds are below the significant level and therefore do not require a BACT analysis.

Acid Gases

The applicant has stated that BACT for nitrogen oxides will be met by using dry low-NOx combustors to limit emissions to 15 ppmvd (corrected to 15% O_2) when burning natural gas.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NOx emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. 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 NOx emissions. The SCR process combines vaporized ammonia with NOx in the presence of a catalyst to form nitrogen and water. Vaporized ammonia is injected into the exhaust gases prior to passage through a catalyst bed. The SCR process can achieve up to 90% reduction of NOx with a new catalyst. As the catalyst ages, the maximum NOx reduction will decrease to approximately 86 percent.

A review of the combined cycle facilities in which SCR has been established as a BACT requirement indicates that the majority of these facilities are also intended to operate at high capacity factors. As this is the case, the proposed project is similar to other facilities in which SCR has been established as BACT.

Given the applicant's proposed BACT level for nitrogen oxides control stated above, an evaluation can be made of the cost and associated benefit of using SCR as follows:

The applicant has indicated that the total levelized annual cost (operating plus amortized capital cost) to install SCR for natural gas firing at a 100 percent capacity factor is $1,903,000. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can be developed.

Based on the information supplied by the applicant, it is estimated that the maximum annual NOx emissions with dry low-NOx combustors from the Orlando CoGen Limited, L.P. facility will be 274 tons/ year. Assuming that SCR would reduce the NOx emissions to a level of 9 ppmvd when firing natural gas, about 141 tons of NOx would be emitted annually. When this reduction is taken into consideration with the total levelized annual cost of $1,900,300, the cost per ton of controlling NOx is $14,308. This calculated cost is higher than has previously been approved as BACT.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics.

In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement was made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

For fuel oil firing, the cost associated with controlling NOx emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the 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. As this the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NOx injection ratio. For natural gas firing operation NOx 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 NOx 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.

Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NOx emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

The Orlando CoGen Limited, L.P. facility has proposed not to utilize fuel oil; therefore, those consequences of SCR attributed to fuel oil firing will not likely occur. However, the small amount of sulfur in natural gas would likely form ammonium salts.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NOx control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NOx control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental impact. Although the use of SCR does have some positive environmental benefits, the disadvantages may outweigh the benefits which would be provided by reducing nitrogen oxide emissions by 80 percent or greater. The benefit of NOx control by using SCR is substantiated by the fact that nearly one half of all BACT determinations have established SCR as the control measure for nitrogen oxides over the last five years.

From the evaluation of natural gas combustion, toxics are projected to be emitted in very small amounts, with the total combined emissions to be less than 0.1 tons per year. Although the emissions of toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber system, the amount of emission reductions would not warrent the added expense. Consequently, the Department does not believe that the BACT determination would be affected by the emissions of the toxic polutants associated with the firing of natural gas.

Potentially Sensitive Concerns

With regard to controlling NOx emissions with SCR, the applicant has identified the following technical limitations:

1. SCR would reduce the output of the combustion turbines by one-half percent.

2. SCR could result in the release of unreacted ammonia to the atmosphere.

3. SCR would require handling of ammonia by plant operators. Since it is a hazardous material, there is a concern about safety and productivity of operators.

4. SCR results in contaminated catalyst from flue gas trace elements which could be considered hazardous. Safety of operators and disposal of spent catalyst is a concern.

The combustion turbines proposed for the project (ABB 11N-EV) is a heavy-frame that is highly efficient and uses advanced dry low-NOx combustion technology. Information supplied by the applicant indicates that actual emissions will be 15 ppmvd (corrected to 15% O_2) or lower on a continuous basis.

BACT Determination by DER

NOx Control

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, capacity factors ranging from low to high). However, the cost and other concerns expressed by the applicant are valid, and advanced NOx combustion controls have been accepted as BACT on similar projects.

The information that the applicant presented and Department calculations indicates that the incremental cost of controlling NOx ($14,308/ton) is high compared to other BACT determinations which require SCR. Furthermore, actual NOx levels are expected to be less than the 15 ppmvd (corrected to 15% O_2), which would increase the cost of SCR. Based on the information presented by the applicant and the evaluation conducted, the Department believes that the use of SCR for NOx control is not justifiable as BACT. Therefore, the Department will accept dry low-NOx combustors as NOx control when firing natural gas for this project.

The emissions of NOx from the duct burner will be limited to 0.1 lb/MMBtu, which has been the BACT limit established for similar facilities. Duct firing will be used for supplying steam and limited to operate at a full load equivalent of 3,688 hours/year at a maximum heat input of 122.0 x 10^6 Btu/hr for a maximum heat input of 450,000 x 10^6 Btu/yr (note: The unit may operate at lower rates for more hours within the annual heat input limit).

CO Control

Combustion control will be considered as BACT for CO when firing natural gas. The permittee shall design the facility to allow for the future installation of an oxidation catalyst. Once the performance test is completed and if the facility demonstrates compliance with the CO emission limits, then an oxidation catalyst will not be required. Otherwise, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

Other Emissions Control

The emission limitations for PM and PM_{10} are based on previous BACT determinations for similar facilities.

The emission limits for the Orlando CoGen Limited, L.P. project are thereby established as follows:

	Emission Standards/Limitations	
Pollutant	CT (Natural Gas Firing)	DB (Natural Gas Firing)
NOx	15 ppmvd @ 15% O2	0.1 lb/MMBtu
CO	10 ppmvd	0.1 lb/MMBtu
PM & PM10	0.01 lb/MMBtu	0.01 lb/MMBtu

Note: Natural gas will be used only for supplemental firing the DB for a full load equivalent of 3688 hrs/yr at 122.0 x 10^6 Btu/hr maximum heat input for a maximum heat input of 450,000 x 10^6 Btu/yr (note: The unit may operate at lower rates for more hours within the annual heat input limit).

Details of the Analysis May be Obtained by Contacting:

Bruce Mitchell, Engineer IV
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

August 14 1992
Date

Approved by:

Carol M. Browner, Secretary
Dept. of Environmental Regulation

August 17 1992
Date

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State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

Interoffice Memorandum

TO: Carol M. Browner

for FROM: Howard L. Rhodes

DATE: August 17, 1992

SUBJ: Approval of Construction Permit No. AC 48-206720 (PSD-FL-184)
Orlando CoGen Limited, L.P.

Attached for your approval and signature is a construction permit and associated BACT Determination prepared by the Bureau of Air Regulation for the above referenced company to construct a 128.9 megawatt (MW) cogeneration facility. A combustion turbine and a steam turbine will drive an electrical generator to produce 78.8 MW and 50.1 MW, respectively. This was not a power plant siting review because the electrical steam generation will be less than 75 MW. Electricity will be generated for sale to the electrical grid and steam will be supplied to the Air Products and Chemical Plant located adjacent to the proposed facility's site.

The combustion turbine will fire natural gas and exhaust through a heat recovery steam generator, which will also fire natural gas within its duct work as necessary for heat and steam generation. Dry low-NOx combustors will be used to minimize NOx emissions. Combustion control will be used to minimize CO emissions.

The proposed facility will be located in the Orlando Central Park, Orange County, Florida. Comments were received during the public notice period from the applicant and the changes made had no adverse affect on the Department's Intent.

I recommend your approval and signature.

HLR/BM/rbm

LOWNDES, DROSDICK, DOSTER, KANTOR & REED
PROFESSIONAL ASSOCIATION
ATTORNEYS AT LAW
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FROM:: Bill Bird

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August 10, 1992

VIA TELECOPY

Office of the General Counsel
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention Douglas Beason, Esquire

Re: OGC File No. 92-1210/Orlando Cogen Limited, L.P./Air Construction Permit No. AC48-206720/PSD-187/Orange County

Dear Mr. Beason:

Please be advised on behalf of my client, State of Wisconsin Investment Board, that the petition for Administrative Proceeding filed by this law firm on behalf of State of Wisconsin Investment Board and its agent, Jones Lang Wootton Realty Advisers, on August 6, 1992 with respect to the referenced matter is hereby withdrawn. Please return the original Petition to me at your earliest opportunity.

We are most grateful for your gracious cooperation in this matter.

Very truly yours,

Bill Bird

William R. Bird, Jr.

WRB:gr
50-M2716R

c: Mr. Bruce Mitchell, DER (via telecopy)
Orlando Cogen Limited, L.P. (via telecopy)
Peter Cunningham, Esquire (via telecopy)
Mr. Steve McCarthy (via telecopy)

OPTIONAL FORM 99 (7-90)
FAX TRANSMITTAL
# of pages ▶
To Bruce Mitchell
From Bud Rolofson
Dept/Agency FDER
Phone # 303-969-2804
Fax # 904-922-6979
Fax # 303-969-2822
NSN 7540-01-317-7368 5099-101 GENERAL SERVICES ADMINISTRATION

DRAFT

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 completed our review of the material that you sent us regarding Orlando CoGen Limited's proposal to construct a 129 MW cogeneration facility at the Orlando Central Park, Orange County, Florida. The facility would be located approximately 121 km southeast of the Chassahowitzka Wilderness Area (WA), a Class I area administered by the U.S. Fish and Wildlife Service. The proposed project would be a significant emitter of nitrogen oxides (NO_x), carbon monoxide, and particulate matter.

Orlando CoGen failed to assess potential effects on biological resources at the Class I area from the proposed emissions. However, given the low modeled concentrations at Chassahowitzka WA, we do not anticipate that this facility will adversely affect air quality or related resources at the wilderness area. Regarding the best available control technology (BACT) analysis, we agree that firing natural gas and installing dry low-NO_x combustors represents BACT to minimize emissions from the proposed turbine.

We appreciate the opportunity to comment on Orlando CoGen Limited's permit application. If you have any questions regarding this matter, please contact Bud Rolofson of our Air Quality office in Denver at (303) 969-2804.

Sincerely yours,

James W. Pulliam, Jr.
Regional Director

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

C. Holladay
CHF/PL

INTEROFFICE MEMORANDUM

Date: 13-Aug-1992 11:05am EST
From: Doug Beason TAL
BEASON_D
Dept: Office General Counsel
Tel No: 904/488-9730
SUNCOM:

TO: Bruce Mitchell TAL (MITCHELL_B)

Subject: air products

The petition for administrative hearing has been withdrawn and there is no legal obstacle to the issuance of the permit.

BEST AVAILABLE 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

FAX TRANSMITTAL SHEET

NAME(S): Mr. Todd Solodar, Esq.

DEPARTMENT/COMPANY: Air Products

DATE: 8-7-92

PHONE: 215-481-2558 FAX: 215-481-7572

TOTAL NUMBER OF PAGES, INCLUDING COVER PAGE: 7

****

FROM: Bruce Mitchell

DIVISION OF AIR RESOURCES MANAGEMENT

BUREAU: of Air Regulation

OFFICE PHONE: 904-488-1344 FAX PHONE: (904)922-6979

SENDER: Same

COMMENTS: Draft FD: Orlando CoGen Limited, L.P.

HAVE A NICE DAY!

8-7-92
@ 4:00 p.m. confirmed receipt [illegible] Mr. Solodar.

MESSAGE CONFIRMATION AUG-07-'92 FRI 17:48

TERM ID: DIV OF AIR RES MGMT F-9999

TEL NO: 904-922-6979

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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

FAX TRANSMITTAL SHEET

NAME(S): Mr. Bill Bird, Esq.

DEPARTMENT/COMPANY: Lowndes Brosdick

DATE: 8-10-92

PHONE: 407-843-4600 FAX: 407-423-4495

TOTAL NUMBER OF PAGES, INCLUDING COVER PAGE: 6

****

FROM: Bruce Mitchell

DIVISION OF AIR RESOURCES MANAGEMENT

BUREAU: of Air Regulation

OFFICE PHONE: 904-488-1344 FAX PHONE: (904)922-6979

SENDER: Jan

COMMENTS: Draft Final Determination
Orlando Cogen Limited, L.P.

HAVE A NICE DAY!

Recycled Paper
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MESSAGE CONFIRMATION

AUG-10-'92 MON 13:15

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TEL NO: 904-922-6979

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DRAFT

Final Determination

Orlando CoGen Limited, L.P.
Orange County, Florida

Construction Permit No.
AC 48-206720
(PSD-FL-184)

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

August 17, 1992

DRAFT

Final Determination

Orlando CoGen Limited, L.P.

AC 48-206720 (PSD-FL-184)

The construction permit application package and supplementary material have been reviewed by the Department. Public Notice of the Department's Intent to Issue was published in The Orlando Sentinel on June 12, 1992. The Technical Evaluation and Preliminary Determination (TE&PD) was distributed on June 8, 1992, and available for public inspection at the Department's Central District office and the Department's Bureau of Air Regulation office.

Comments were received from the applicant during the public notice period. The comments were received on July 7, 1992. The Department's response to the comments are as follows (note: each response will be numbered so as to correspond to each comment):

1. The Department will change the permittee's name to read "Orlando CoGen Limited, L.P." instead of "Orlando Cogen Limited, L.P."

2. Since the requested change does not affect the potential emissions, a revised TE&PD will not be required. However, the comment is acknowledged.

3. Permit No. AC 48-206720 (PSD-FL-184)

a. The request is acceptable, but the specific language will be slightly different than what was requested:

<u>SPECIFIC CONDITION No. 1</u>:

From: The CT (combustion turbine) is allowed to operate continuously (8,760 hours per year). The HRSG-DB (heat recovery steam generator-duct burner) is permitted to operate 3688 hrs/yr at a maximum heat input of 122 x 10^6 Btu/hr.

To: The CT (combustion turbine) is allowed to operate continuously (8,760 hours per year). The HRSG-DB (heat recovery steam generator-duct burner) is permitted to operate 3688 hrs/yr at a maximum heat input of 122 x 10^6 Btu/hr for a maximum heat input of 450,000 x 10^6 Btu/yr (note: The unit may operate at lower rates for more hours within the annual heat input limit).

b. The request is acceptable to add a clarifier to the hours of operation.

<u>SPECIFIC CONDITION No. 4: Table 1, Note 3b</u>:

From: DB: 3688 hrs/yr

To: DB: 3688 hrs/yr (at a maximum heat input of 122 x 10^6 Btu/hr)

c. Except for minor particulate sources equipped with a baghouse control system, the Department does not have the authority, by rule, to substitute a visible emission standard for a mass emissions standard in accordance with Florida Administrative Code (F.A.C.) Rule 17-2.700(3)(d). However, the owner or operator of any source may request approval of alternate procedures and requirements in accordance with F.A.C. Rule 17-2.700(3)(a). Therefore, the request is not acceptable and SPECIFIC CONDITION No. 8 will not be altered.

d. The request is acceptable, which alters the original verbiage, but not the intent.

<u>SPECIFIC CONDITION No. 12</u>:

From: The permittee shall leave sufficient space suitable for future installation of SCR equipment.

To: The permittee shall design the facility to allow for future installation of SCR equipment.

e. The request is acceptable.

<u>SPECIFIC CONDITION No. 13</u>:

From: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2, (July 1, 1991).

To: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1991 version).

For the purpose of demonstrating ongoing compliance with the applicable NOx emissions limitation in Table 1, using the stack CEM, compliance is considered to occur when the NOx emissions are less than or equal to 57.4 lbs/hr when only the CT is operating and less than or equal to 69.6 lbs/hr when both the CT and DB are operating. The 24-hour rolling average compliance level is calculated based on the proportion of hours in any 24-hour period that the CT only or CT/DB are operating. Any portion of an hour that the DB operates is recognized as an hour period on the rolling average.

For example, in a given contiguous 24-hour period, with 20 hours of CT operation only and 4 hours of CT/DB operation:

Emission Limitation =

[(57.4 lbs/hr x 20 hrs) + (69.6 lbs/hr x 4 hrs)]/24 hrs =

24-hour rolling average-compliance NOx level = 59.4 lbs/hr

Actual hourly NOx emissions levels from the stack CEM will be averaged over the same 24-hour rolling period to determine the facility's actual NOx emissions level. At all times, the 24-hour rolling average-actual NOx emissions level must be less than or equal to the 24-hour rolling average-compliance NOx emissions level.

f. The request is acceptable, which alters the original verbiage, but not the intent.

SPECIFIC CONDITION No. 14:

From: Combustion control shall be utilized for CO control. The permittee shall leave a sufficient space suitable for future installation of an oxidation catalyst. Once performance testing has been completed, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

To: Combustion control shall be utilized for CO control. The permittee shall design the facility to allow for the future installation of an oxidation catalyst. Once the performance test is completed and the facility demonstrates compliance with the CO emission limits in Table 1, then an oxidation catalyst will not be required. Otherwise, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

4. BACT Determination to Permit No. AC 48-206720 (PSD-FL-184)

a. The request is acceptable and the BACT will be revised on page 1, 1st paragraph, to reflect the product output of the combustion turbine (CT) to be 78.8 MW and the steam turbine (ST) to be 50.1 MW. Originally, the CT's output was listed as 79 MW and the ST's output as 50 MW.

b. The request is acceptable and the sentence (i.e., page 3, 2nd paragraph under "Products of Incomplete Combustion", 2nd sentence) will be deleted. The rationale is that the applicant attests that the proposed unit is a proven operation and is being permitted for a CO level lower than other recently permitted sources. Data has been submitted to substantiate CO levels from currently operating and similar units.

c. The request is acceptable, but the proposed language will be slightly different than what was requested. Therefore, the 2nd sentence, 1st paragraph, page 8-"BACT Determination by DER": NOx Control, will be revised to read:

Duct firing will be used for supplying steam and limited to operate at a full load equivalent of 3688 hrs/yr at a maximum heat input of 122 x 10^6 Btu/hr for a maximum heat input of 450,000 x 10^6 Btu/yr (note: The unit may operate at lower rates for more hours within the annual heat input limit).

d. The request is acceptable, but the proposed language will be slightly different than what was requested. Therefore, the 2nd sentence, 2nd paragraph, page 8-"BACT Determination by DER": CO Control, will be revised to read:

The permittee shall design the facility to allow for the future installation of an oxidation catalyst. Once the performance test is completed and the facility demonstrates compliance with the CO emission limits, then an oxidation catalyst will not be required. Otherwise, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

e. The "Note" associated with the table "Emission Standards/ Limitations", located on page 8 of the proposed BACT Determination, will be revised to read:

Note: Natural gas firing will be used only for supplemental firing the DB for a full load equivalent of 3688 hrs/yr at 122 x 10^6 Btu/hr maximum heat input for a maximum heat input of 450,000 x 10^6 Btu/yr (note: The unit may operate at lower rates for more hours within the annual heat input limit).

5. <u>Attachment to be Incorporated</u>:

o Mr. Gary D. Kinsey's letter with enclosure received July 7, 1992.

Therefore, it is recommended that the construction permit, No. AC 48-206720 (PSD-FL-184), and associated BACT Determination, be issued as drafted, with the above referenced revisions incorporated.

meeting @ 10:00 am @ BAR/DARM conference room

Orlando CoGen Limited, L.P.

Attendee List: 7/31/92

Bruce Mitchell	FDER/DARM/BAR	904-488-1344
Peter Cunningham	HBG-S / Atty for Air Products	904-222-7500
DOUGLAS BEASON	DER/OGC	4889730
Todd Solodar	Air Products & Chemicals	(215) 481-2558
BRUCE METRICK	Air Products & Chemicals	(215/481-7304)

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

CARLOS ALVAREZ
JAMES S. ALVES
BRIAN H. BIBEAU
KATHLEEN BLIZZARD
ELIZABETH C. BOWMAN
WILLIAM L. BOYD, IV
RICHARD S. BRIGHTMAN
PETER C. CUNNINGHAM
THOMAS M. DeROSE
WILLIAM H. GREEN
WADE L. HOPPING
FRANK E. MATTHEWS
RICHARD D. MELSON
WILLIAM D. PRESTON
CAROLYN S. RAEPPLE
GARY P. SAMS
ROBERT P. SMITH
CHERYL G. STUART

C. ALLEN CULP, JR.
RALPH A. DeMEO
JAMES C. GOODLETT
RICHARD W. MOORE
ANGELA R. MORRISON
MARIBEL N. NICHOLSON
LAURA BOYD PEARCE
GARY V. PERKO
MICHAEL P. PETROVICH
DOUGLAS S. ROBERTS
JULIE B. ROME
KRISTIN C. RUBIN
CECELIA C. SMITH

OF COUNSEL
W. ROBERT FOKES

RECEIVED
JUL 21 1992
Division of Air
Resources Management

July 20, 1992

W. Douglas Beason, Esquire
Office of General Counsel
Florida Department of Environmental
Regulation
2600 Blair Stone Road, Room 654
Tallahassee, Florida 32399-2400

Re: Orlando CoGen Limited, L.P.
Air Construction Permit No. AC 48-206720;
PSD-FL-187; Orange County

Dear Doug:

By my letter to Dan Thompson dated June 22, 1992, Orlando CoGen Limited, L.P. ("Orlando CoGen") requested an extension of time to file a petition for administrative proceedings regarding the Department's proposed action on the referenced air permit. No action on that request has been taken by the Department as of today, and I am now writing on behalf of Orlando CoGen to withdraw the pending request, which was filed solely as a protective measure to avoid waiver of my client's right to initiate administrative proceedings in this matter. The extension no longer appears necessary, in view of discussions with permitting staff of the Bureau of Air Regulation that indicate the Department agrees that certain technical and clarifying changes to the proposed permit are appropriate. We further understand that no comments have been received from either the public or other regulatory agencies in the 30 days following publication of notice of the Department's proposed permit action that would warrant other changes in the Department's final permit action. Under these circumstances no purpose would be served by the extension of time previously requested by Orlando CoGen.

We are aware that another request for extension of time regarding this matter, dated June 25, 1992 and signed by Casey M. Cavanaugh, Esquire, representing Jones Lang Wootton

Realty Advisers as agents for an unidentified "adjacent property owner", was filed with the Department. While neither that letter nor Mr. Cavanaugh's letter dated June 26, 1992 amending the original request contained a certificate of service stating that service had been made on Orlando CoGen or this firm as its counsel of record, we have obtained copies of both letters from your office.

Please be advised that Orlando CoGen strongly objects to the grant of any extension of time to the unidentified entity referred to in Mr. Cavanaugh's request. Mr. Cavanaugh's letters failed to show any good cause for an extension in this case, and the amended request in fact merely states that:

> If the DER grants the Applicant an extension, our client would like to monitor this matter during said extension period and to review the changes, if any, which are made to the documents filed by the Applicant and to the conditions imposed on the Applicant by the DER, before our client decides whether or not to file a petition.

With Orlando CoGen's withdrawal of its request for extension, the predicate and sole reason for the unidentified entity's extension request has been eliminated, and thus the request is now moot. I would also emphasize that statements in Mr. Cavanaugh's letter regarding his attempts to contact me are less than complete insofar as: (1) I was not on vacation on June 25 or 26, 1992 and he was not so advised by anyone at my office; and (2) Mr. Cavanaugh in fact spoke with my law partner, Gary Sams, on June 26, 1992, and Mr. Sams initially indicated he could not concur in the grant of any extension request without talking with me, and after speaking with me by phone, he attempted without success to reach Mr. Cavanaugh and, ultimately, before close of business on June 26, 1992 left a message for Mr. Cavanaugh stating that Orlando CoGen could not consent to his extension request. Orlando CoGen also has reason to believe that Mr. Cavanaugh's client or other local real estate agents representing the adjacent property owner did have the telephone number of representatives of Orlando CoGen in Allentown, Pennsylvania, contrary to the statement in his letter of June 26, 1992.

Given these circumstances, and the fact that neither the unidentified property owner nor any of its agents or attorneys has stated any substantive objection or concern about the referenced permit whatsoever, either in the extension request or by filing written comments during the 30 day public comment period that expired July 13, 1992, there is no justification for granting Mr. Cavanaugh's request for extension. Moreover, Orlando CoGen is clearly prejudiced by Mr. Cavanaugh's request, as it is now causing delay in issuance of the final air construction permit for my client's project, with direct and substantial scheduling and financial consequences to Orlando CoGen.

For the reasons stated herein, Orlando CoGen objects to the grant of Mr. Cavanaugh's extension request and respectfully urges that the Department exercise its discretion under Florida Administrative Code Rule 17-103.070 to deny said request.

Sincerely,

HOPPING BOYD GREEN & SAMS

Peter C. Cunningham

Attorneys for Orlando CoGen
Limited, L.P.

Beason:PCC/gbb

cc: Casey M. Cavanaugh, Esquire
William R. Bird, Jr., Esquire
B. Mitchell

KBN

July 16, 1992

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

Subject: Orlando CoGen Limited, L.P., Proposed Cogeneration Facility, Orlando Central Park

Dear Clair:

Air quality impact analyses that showed the proposed facility's maximum predicted concentrations at the Prevention of Significant Deterioration (PSD) Class I area of the Chassahowitzka National Wilderness Area were submitted with the PSD permit application for this project. These results demonstrated that the proposed facility's impacts were low and well below the National Park Service's significant impact levels for particulate matter (PM) and nitrogen dioxide (NO_2) for Class I areas. Given that the best available control technology (BACT) evaluation established the NO_2 emission limit to be 15 ppm instead of the 25 ppm considered in the modeling, the project's maximum NO_2 concentration in the Class I area will be even lower than that reported in the PSD permit application.

Based on these results, the proposed facility's impacts are not expected to adversely affect air quality related values, including biological resources, at the Class I area.

If you have further questions or comments, please call me at your earliest convenience.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
Project Manager

RECEIVED
JUL 17 1992
Division of Air
Resources Management

cc: Bruce Mitchell, DER
Cleve Holladay, DER
Gary Kinsey, Air Products

91134A1/7

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

MARCH 3, 1849

United States Department of the Interior

TAKE PRIDE IN AMERICA

FISH AND WILDLIFE SERVICE
75 Spring Street, S.W.
Atlanta, Georgia
30303

July 15, 1992

RECEIVED
JUL 20 1992
Division of Air
Resources Management

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 completed our review of the material that you sent us regarding Orlando CoGen Limited's proposal to construct a 129 MW cogeneration facility at the Orlando Central Park, Orange County, Florida. The facility would be located approximately 121 km southeast of the Chassahowitzka Wilderness Area (WA), a Class I area administered by the Fish and Wildlife Service. The proposed project would be a significant emitter of nitrogen oxides (NO_x), carbon monoxide, and particulate matter.

Orlando CoGen failed to assess potential effects on biological resources in the Class I area from the proposed emissions. However, given the low modeled concentrations at Chassahowitzka WA, we do not anticipate that this facility will adversely affect air quality or related resources at the wilderness area. Regarding the best available control technology (BACT) analysis, we agree that firing natural gas and installing dry low-NO_x combustors represents BACT to minimize emissions from the proposed turbine.

We appreciate the opportunity to comment on Orlando CoGen Limited's permit application. If you have any questions regarding this matter, please contact Mr. Bud Rolofson of our Air Quality office in Denver at 303/969-2071.

Sincerely yours,

John R. Eadie

John R. Eadie
Acting 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

cc: B. Mitchell
C. Holladay
C. Collins, C Dist.
D. Nester, OCEPD
K. Kosky, KBN
CHF/PL

Florida Department of Environmental Regulati
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-
Lawton Chiles, Governor
Carol M. Browner, Sec

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FAX TRANSMITTAL COVER

DATE: 10 July 1992

TO: Ken Kosky
KBN Engineering
Gainesville, FL

PHONE: 904-331-9000

FAX: 904-332-4189

NUMBER OF PAGES TRANSMITTED (INCLUDING COVER SHEET) 2

* * * * * *

FROM: Steve Holladay
FDER/DARM

PHONE: SUNCOM 278-1344 OR (904) 488-1344

FAX: (904) 922-6979

PLEASE CONTACT AT ABOVE NUMBER IF TRANSMISSION IS INCOMPLETE OR UNREADABLE.

COMMENTS:

Draft Comments on Orlando C Gen

Recycled Paper

JUL-10-'92 FRI 16:17

MESSAGE CONFIRMATION

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TEL NO: 904-922-6979

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OPTIONAL FORM 99 (7-90)
FAX TRANSMITTAL
# of pages ▶

To Bruce Mitchell	From Bud Rolofson
Dept./Agency FDER	Phone # 303-969-2804
Fax # 904-922-6979	Fax # 303-969-2822

NSN 7540-01-317-7368 5099-101 GENERAL SERVICES ADMINISTRATION

DRAFT

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 completed our review of the material that you sent us regarding Orlando CoGen Limited's proposal to construct a 129 MW cogeneration facility at the Orlando Central Park, Orange County, Florida. The facility would be located approximately 121 km southeast of the Chassahowitzka Wilderness Area (WA), a Class I area administered by the U.S. Fish and Wildlife Service. The proposed project would be a significant emitter of nitrogen oxides (NO_x), carbon monoxide, and particulate matter.

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We appreciate the opportunity to comment on Orlando CoGen Limited's permit application. If you have any questions regarding this matter, please contact Bud Rolofson of our Air Quality office in Denver at (303) 969-2071.

Sincerely yours,

James W. Pulliam, Jr.
Regional Director

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

Florida Department of Environmental Regulati

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

Lawton Chiles, Governor

Carol M. Browner, Sec

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FAX TRANSMITTAL COVER

DATE: 7-8-92

TO: Bud Rolofson

NPS - Air

PHONE: 303-969-2804

FAX: 303-969-2822

NUMBER OF PAGES TRANSMITTED (INCLUDING COVER SHEET) 6

* * * * * *

FROM: Bruce Mitchell

FDER/DARM/BAR

PHONE: SUNCOM 278-1344 OR (904) 488-1344

FAX: (904) 922-6979

PLEASE CONTACT AT ABOVE NUMBER IF TRANSMISSION IS INCOMPLETE OR UNREADABLE.

COMMENTS:

Orlando Cogen

PSD-FL-184

Comments from the permittee regarding to Intent package. We are not in total agreement with the points made. Please give me a call to discuss.

Recycled Paper

JUL-08-'92 WED 15:31

MESSAGE CONFIRMATION

TERM ID: DIV OF AIR RES MGMT P-9999

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Florida Department of Environmental Regulati
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-
Lawton Chiles, Governor
Carol M. Browner, Sec

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FAX TRANSMITTAL COVER

DATE: 7-8-92

TO: Gregg Worley
U.S. EPA, Region IV

PHONE: 404-347-5104

FAX: 404-347-2130

NUMBER OF PAGES TRANSMITTED (INCLUDING COVER SHEET) 6

* * * * * *

FROM: Bruce Mitchell
FDER/DARM/BAR

PHONE: SUNCOM 278-1344 OR (904) 488-1344

FAX: (904) 922-6979

PLEASE CONTACT AT ABOVE NUMBER IF TRANSMISSION IS INCOMPLETE OR UNREADABLE.

COMMENTS:

Orlando Cogen
PSD-FL-184

Day 30 of the comment period is 7/12/92; also, the enclosed comments on the Department's Intent pkg. are from the permittee. We are not in total agreement with the points made. Please give me a call to discuss.

Recycled Paper

Thanks,
Bruce Mitchell

MESSAGE CONFIRMATION JUL-08-'92 WED 15:45

TERM ID: DIV OF AIR RES MGMT P-3999

TEL NO: 904-922-6979

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Orlando CoGen Limited, L.P.

7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

6 July 1992

RECEIVED
JUL 07 1992
Division of Air
Resources Management

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Subject: Written Comments on Preliminary Determination and Proposed PSD permit - Orlando CoGen Limited, L.P. Project, Orange County; DER File No. AC 48-206720; PSD-FL-184

Attention: Mr. Preston Lewis

Please find enclosed Orlando CoGen Limited's written comments to the Department Preliminary Determination and Proposed PSD Permit for the subject project. Please consider these comments when the Department finalizes the proposed permit.

As we discussed on Tuesday, 30 June, Orlando CoGen Limited will include provisions in the CEM data acquisition system which will allow for the comparison of actual NO_x emissions measured in the stack with an emissions limitation determined each hour taking into account duct burner firing status. Per conversation with our engineering group, this tracking can be done by obtaining an electrical signal from the duct burner system main natural gas control valve and integrating it into the logic of the CEM computer program. As noted in our requested changes to Special Condition #13, this provision will be incorporated into the permit.

Orlando CoGen Limited, L.P. greatly appreciated the opportunity to meet with the Department to discuss the proposed PSD permit. If you should have any questions or would need additional information, please call me.

Sincerely,

Gary D. Kinsey, P.E.
Environmental Engineer

cc: P. Cunningham, HBG&S
K. Kosky, KBN
B. Mitchell
C. Holladay
C. Collins. C Dist
D. Nester, OCEPD
G. Harper, EPA
C. Shaver, NPS
CHF/PL

ORLANDO COGEN LIMITED, L.P.
DER FILE NO. AC 48-206720; PSD-FL-184

WRITTEN COMMENTS ON PROPOSED PSD PERMIT ISSUED BY FDER BUREAU OF AIR REGULATION ON JUNE 5, 1992

PREPARED BY: ORLANDO COGEN LIMITED, L.P.
6 JULY 1992

1. The permittee name shall be Orlando CoGen Limited, L.P. There is a capital "G" in CoGen. This change should be made throughout the documents.

2. Technical Evaluation and Preliminary Determination Document:

a. Section III.A, Table 1:

- Note 3b: Request to read: DB: 3688 hrs/yr (at full load equivalent of 122 MMBTU/hr)

3. Proposed Permit Draft Document:

a. Page 5 of 9, Specific Condition #1:

Please change second sentence to read: "The HRSG-DB (heat recovery steam generator-duct burner) is permitted to operate at 3688 hrs/yr at a full load equivalent of 122 MMBTU/hr for a maximum heat duty of 450,000 MMBTU/yr (e.g. 4500 hrs/yr at 100 MMBTU/hr).

b. Page 6 of 9, Specific Condition #4, Table 1:

- Note 3b: Request to read: DB: 3688 hrs/yr (at full load equivalent of 122 MMBTU/hr)

c. Page 7 of 9, Specific Condition #8: (Request to read)

EPA Method 5 must be used to determine the initial compliance status of this unit. During the initial compliance testing, compliance with the PM/PM-10 emissions limits will be assumed provided that the PM test of the CT and DB operating together shows emissions less than or equal to 10.2 lbs/hr. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

d. Page 8 of 9, Specific Condition #12: (Request to read)

The permittee shall design the facility to allow for future installation of SCR equipment.

e. Page 8 of 9, Specific Condition #13: (Please add the following to the existing paragraph)

For purpose of demonstrating ongoing compliance with the applicable NO_x emissions limitations in Table 1, using the stack CEM, compliance is considered to occur when the NO_x emissions are less than or equal to 57.4 lbs/hr when only the CT is operating and less than or equal to 69.6 lbs/hr when both the CT and DB are operating. The 24 hour rolling average compliance level is calculated based on the proportion of hours in any rolling 24 hour period that the CT only or CT/DB are operating. Any portion of an hour that the DB operates is recognized as an hour period on the rolling average.

For example, in a given contiguous 24-hour period, with 20 hours operation of CT only and 4 hour of CT with any DB operation in each hour;

Emissions Limitations =

[(57.4 lbs/hr x 20 hours) + (69.6 lbs/hr x 4 hours)]/24 hours =

24 hour rolling average - compliance NO_x level = 59.4 lbs/hr

Actual hourly NO_x emissions levels from the stack CEM will be averaged over the same 24 hour rolling period to determine the facility actual NO_x emissions level. At all times, the 24 hour rolling average - actual NO_x emissions level must be less than or equal to the 24 hour rolling average - compliance NO_x emissions level.

f. Page 8 of 9, Specific Condition #14: (Request to read)

Combustion control shall be utilized for CO control. The permittee shall design the facility to allow for the future installation of an oxidation catalyst. Once the performance test is completed and the facility demonstrates compliance with the CO emissions limits in Table 1, then an oxidation catalyst will not be required. Otherwise, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

4. BACT Determination Document:

a. Page 1, 1st paragraph: The combustion turbine should be listed as 78.8 MW and the steam turbine as 50.1 MW.

b. Page 3, Products of Incomplete Combustion: The sentence "the applicant has stated that the CT is a new design, and CO margins must be higher" should be deleted. The proposed unit is a proven operation and is being permitted for a CO level lower than other recently permitted sources.

c. Page 7, BACT Determination by DER, NO_x Control: Please change the last sentence in this section to read: Duct firing will be used for supplying steam and limited to a full load equivalent of 3,688 hrs/yr at 122 MMBTU/hr maximum heat input up to 450,000 MMBTU/yr (e.g., 4500 hrs/yr at 100 MMBTU/hr).

d. Page 8, BACT Determination by DER, CO Control: Please reword this section to match the language in the proposed PSD permit for CO control (i.e., proposed permit Specific Condition #14).

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

RECEIVED
JUL 08 1992
Division of Air
Resources Management

JUL - 1 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: Orlando Cogen, Inc. (PSD-FL-184)

Dear Mr. Fancy:

This is to acknowledge receipt of your preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility by letter dated June 5, 1992. The proposed project involves the construction of a combined cycle combustion turbine (ABB 11N-EV model) rated at 129 MW. The project is subject to PSD for emissions of NO_x, PM & PM_{10}, and CO.

We have reviewed the package as requested and have no adverse comments. Emissions will be limited through combustion controls and the firing of natural gas to 15 ppm NO_x, 10 ppm CO, and 0.011 lb/mmBTU PM for the combustion turbine; and 0.1 lb/mmBTU NO_x, 0.1 lb/mmBTU CO, and 0.1 lb/mmBTU PM for the duct burner. If you have any questions or comments on this project, please contact Mr. Gregg Worley of my staff at (404) 347-5014.

Sincerely yours,

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

cc: B. Mitchell
C. Holladay
C. Collins, C Dist.
D. Nester, OC EPD
C. Shaver, NPS
D. Buff, KBN
CHF/PL

Printed on Recycled Paper

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

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RICHARD S. BRIGHTMAN
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DOUGLAS S. ROBERTS
JULIE B. ROME
KRISTIN C. RUBIN
CECELIA C. SMITH

OF COUNSEL
W. ROBERT FOKES

RECEIVED
JUN 23 1992
Division of Air
Resources Management

June 22, 1992

Daniel H. Thompson, Esquire
Office of General Counsel
Florida Department of Environmental
Regulation
2600 Blair Stone Road, Room 654
Tallahassee, Florida 32399-2400

Re: Orlando CoGen Limited, L.P.
Air Construction Permit No. AC 48-206720;
PSD-FL-187; Orange County

Dear Mr. Thompson:

On June 8, 1992, Orlando CoGen Limited, L.P. ("Orlando CoGen") received the Department's notice of "Intent to Issue" the referenced air construction permit, with the associated "Technical Evaluation and Preliminary Determination" and proposed permit for a 129 megawatt combined cycle cogeneration project to be located in Orange County, Florida. These documents were transmitted by letter dated June 5, 1992 and signed by Clair Fancy, Chief of the Department's Bureau of Air Regulation. Pursuant to Florida Administrative Code Rule 17-103.155 and the "Intent to Issue", Orlando CoGen has until June 22, 1992 in which to file a petition for administrative proceedings regarding the Department's proposed action.

I am writing on behalf of Orlando CoGen to request, pursuant to Florida Administrative Code Rule 17-103.070, an extension of sixty (60) days, to and including August 21, 1992, in which to file a petition for administrative proceedings regarding the Department's proposed action in this matter. As good cause for granting this request for extension of time, Orlando CoGen states the following:

1. The proposed permit contains 21 Specific Conditions, several of which appear to warrant clarification or correction.

2. After completing review of the proposed permit, Orlando CoGen representatives intend to meet with staff of the Department's Bureau of Air Regulation to discuss their concerns and recommended revisions to the proposed permit.

3. This request is filed simply as a protective measure to avoid waiver of Orlando CoGen's right to challenge the Department's proposed action through initiation of administrative proceedings.

4. Grant of this request will not prejudice either party, but will further their mutual interests by affording an opportunity to resolve all issues regarding the proposed permit without resort to formal administrative proceedings.

I hereby certify that I have discussed this request with Bruce Mitchell of the Department's Bureau of Air, Regulation and that he is in agreement with the grant of this request.

Accordingly, I hereby respectfully request an order extending the time for filing of a petition for administrative proceedings regarding the Department's proposed action on the referenced air construction permit to and including August 21, 1992.

Respectfully submitted,

Peter C.

Peter C. Cunningham
Counsel for Orlando CoGen
Limited, L.P.

OrlandoLtr:PCC/gbb

cc: Preston Lewis
Bruce Mitchell
Pat Comer, Esquire
Gary Kinsey
Ken Kosky
C. Holladay
C. Collins, C. Dist
D. Nester, OC EPD
J. Harper, EPA
C. Shaver, NPS
CHF/PL

**Orlando
CoGen
Limited, L.P.**

7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

RECEIVED

JUN 29 1992

Division of Air
Resources Management

17 June 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Subject: Proof of Publication for Notice of Intent to Issue Permit
Orlando CoGen Limited, L.P. Project, Orange County
DER File No. AC 48-206720; PSD-FL-184

Attention: Mr. Preston Lewis

Please find enclosed the original copy of the proof of publication for the Notice of Intent to Issue Permit for the subject project. This notice was published in the Friday, 12 June 1992 edition of the Orlando Sentinel newspaper. Please include this document in the DER project file.

If you have any questions or need additional information, please call me at (215) 481-4029.

Sincerely,

Gary D. Kinsey, P.E.
Environmental Engineer

cc: P. Cunningham, Esq., HBG&S
K. Kosky, P.E., KBN

Best Available Copy

The Orlando Sentinel

Published Daily
$219.19

State of Florida } S.S.
COUNTY OF ORANGE

Before the undersigned authority personally appeared ______________________________, who on oath says that he/she is the Legal Advertising Representative of The Orlando Sentinel, a daily newspaper published at ORLANDO in ORANGE County, Florida; that the attached copy of advertisement, being a NOTICE OF INTENT in the matter of AC 48-206720

in the ORANGE Court, was published in said newspaper in the issue; of 06/12/92

Affiant further says that the said Orlando Sentinel is a newspaper published at ORLANDO, in said ORANGE County, Florida, and that the said newspaper has heretofore been continuously published in said ORANGE County, Florida, each Week Day and has been entered as second-class mail matter at the post office in ORLANDO in said ORANGE County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he/she 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 the said newspaper.

Juanita Rosado

The foregoing instrument was acknowledged before me this 12th day of June, 19 92, by JUANITA ROSADO, who is personally known to me and who did take an oath.

Noemi R. Lucero

NOEMI R. LUCERO
(SEAL)

Noemi R Lucero
Notary Public, State of Florida
My commission expires August 28, 1994
Commission # CC042971

NOTICE OF INTENT
STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION NOTICE OF INTENT TO ISSUE PERMIT
AC 48-206720
PSD-FL-184

The Department of Environmental Regulation gives notice of its intent to issue a permit to Orlando Cogen Limited, L.P., 7201 Hamilton Boulevard, Allentown, PA 18195-1501, to construct a 129 MW cogeneration facility consisting of one combined cycle gas turbine generators and associated steam cycle; also, steam will be supplied to the Air Products and Chemical Plant located adjacent to the proposed site. The proposed facility will be located in the Orlando Central Park, Orange County, Florida. A determination of Best Available Control Technology (BACT) was required. The Class I PM10 PSD increment consumed is 0.02 vs. 8 allowable 24-hour average and 0.001 vs. 4 allowable annual average, in micrograms per cubic meter. The Class I nitrogen dioxide increment consumed is 0.01 vs. 2.5 allowable annual average, in micrograms per cubic meter. The maximum predicted increases in ambient concentrations for the above three pollutants for all averaging times are less than significant in the Class II area surrounding the plant, thus no increment consumption was calculated. 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 (F.S.). 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, F.S.

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 petitoner 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, FL 32399-2400

Department of Environmental Regulation
Central District
3319 Maguire Blvd., Suite 232
Orlando, FL 32803-3767

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.

COR6B61004 Jun.12,1992

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

June 5, 1992

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. John P. Jones, President
Orlando Cogen (I), Inc.
Orlando Cogen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Dear Mr. Jones:

Attached is one copy of the Technical Evaluation and Preliminary Determination and proposed permit to construct a 129 MW cogeneration facility consisting of one combined cycle gas turbine generator and associated steam cycle.

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/BM/rbm

Attachments

c: C. Collins, CD
K. Kosky, P.E., KBN
J. Harper, EPA
C. Shaver, NPS
D. Nester, OCEPD
P. Cunningham, Esq., HBG&S

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. John P. Jones, President
Orlando Cogen (I), Inc.
7201 Hamilton Boulevard
Allentow, PA 18195-1501

4a. Article Number
P 710 058 541

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

7. Date of Delivery
JUN 11 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

P 710 058 541

Certified Mail Receipt

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

UNITED STATES POSTAL SERVICE

Sent to Mr. John P. Jones, Orlando Cogen Limited	
Street & No. 7201 Hamilton Blvd.	
P.O., State & ZIP Code Allentow, PA 18195-1501	
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: 6-8-92 Permit: ACP48-206720 PSD-FL-184	

PS Form **3800**, June 1990

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DER File No. AC 48-206720
PSD-FL-184
Orange County

Orlando Cogen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

______________________________/

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, Orlando Cogen Limited, L.P., applied on December 30, 1991, to the Department of Environmental Regulation for a permit to construct a 129 MW cogeneration facility consisting of one combined cycle gas turbine generator and associated steam cycle; also, steam will be provided to the Air Products and Chemicals Plant located adjacent to the proposed site. The proposed facility will be located in the Orlando Central Park, Orange County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.) 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, F.S., 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 the one with significant circulation in the area that may be affected by the permitting action. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 (904-488-1344), 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, F.S.

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

c: C. Collins, CD
K. Kosky, P.E., KBN
J. Harper, EPA
C. Shaver, NPS
D. Nester, OCEPD
P. Cunningham, Esq., HBG&S

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 6-8-92 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.

6-8-92
Clerk Date

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

AC 48-206720
PSD-FL-184

The Department of Environmental Regulation gives notice of its intent to issue a permit to Orlando Cogen Limited, L.P., 7201 Hamilton Boulevard, Allentown, PA 18195-1501, to construct a 129 MW cogeneration facility consisting of one combined cycle gas turbine generators and associated steam cycle; also, steam will be supplied to the Air Products and Chemical Plant located adjacent to the proposed site. The proposed facility will be located in the Orlando Central Park, Orange County, Florida. A determination of Best Available Control Technology (BACT) was required. The Class I PM_{10} PSD increment consumed is 0.02 vs. 8 allowable 24-hour average and 0.001 vs. 4 allowable annual average, in micrograms per cubic meter. The Class I nitrogen dioxide increment consumed is 0.01 vs. 2.5 allowable annual average, in micrograms per cubic meter. The maximum predicted increases in ambient concentrations for the above three pollutants for all averaging times are less than significant in the Class II area surrounding the plant, thus no increment consumption was calculated. 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 (F.S.). 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, F.S.

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.

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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
Central District
3319 Maguire Blvd., Suite 232
Orlando, Florida 32803-3767

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

Orlando Cogen Limited, L.P.
Orange County, Florida

129 MW Combined Cycle Gas Turbine Cogeneration Facility

Permit Number: AC 48-206720
PSD-FL-184

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

June 5, 1992

I. Application

A. Applicant

Orlando Cogen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

B. Project Description and Location

The applicant proposes to construct a 129 MW (megawatt) cogeneration facility consisting of one combined cycle gas turbine generator and associated steam cycle; also, steam will be supplied to the Air Products and Chemical Plant located adjacent to the proposed site. The proposed facility will be located in the Orlando Central Park, Orange County, Florida. The UTM coordinates are Zone 17, 459.5 km East and 3,146.1 km North.

C. Process and Controls

The proposed project will consist of one CT (combustion turbine) that will exhaust through one HRSG (heat recovery steam generator). The CT will be an Asea Brown Boveri (ABB) 11N-EV machine. The ABB 11N-EV is a heavy frame industrial gas turbine that uses a single dry low-NOx combustion chamber. The CT will be served by a single HRSG, exhausting to an individual stack. There will be no bypass stacks on the CT for simple cycle operation. There will be an electrical generator, which will be driven directly by the CT and a steam turbine.

Only natural gas will be used to fuel the CT; distillate oil will not be used. Supplementary firing of only natural gas in the HRSG will occur only when the ambient temperature is 59°F or greater. The supplementary firing is expected to occur during "on-peak" power demand time periods. Maximum heat input to the CT and HRSG are 856.9 x 10^6 Btu/hr and 122 x 10^6 Btu/hr, respectively. Maximum net capacities for the CT and HRSG are 78.83 MW and 50.1 MW, respectively (~129 MW, total).

Air emission sources associated with the proposed project consist of the CT and supplemental firing in the HRSG. Dry low-NOx combustion will be used to control emissions of NOx from the CT; low-NOx burners will minimize NOx emissions when duct firing. The use of natural gas will minimize the emissions of sulfur dioxide (SO_2) and other pollutants.

D. The Standard Industrial Codes are:

Major Group No. 49 - Electric, Gas and Sanitary Services.
~~Industry Group No. 493 - Combination Electric, Gas and Other Utility Services.~~
Industry Group No. ~~4931 - Electric and Other Services Combined~~.
4911 - Electric Generation / Distribution

SCC:
2-02-002-31 Industrial e- gen.: Natural Gas - Turbine: cogeneration 10^6 ft^3 burned

II. Rule Applicability

The proposed project is subject to preconstruction review in accordance with Chapter 403, Florida Statutes, Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4, and the 40 CFR (July, 1991 version).

The plant is located in an area designated as an air quality maintenance area for the air pollutant ozone in accordance with F.A.C. Rule 17-2.460(1)(b) and attainment for all other criteria pollutants.

The proposed facility will be classified as a major emitting facility. The proposed project will emit approximately 274 tons per year (TPY) of nitrogen oxides (NOx), 12 TPY of sulfur dioxide (SO2), 42 TPY of particulate matter (PM/PM_{10}), 115 TPY of carbon monoxide, 20 TPY of volatile organic compounds (VOC), and 0.1 TPY of sulfuric acid mist.

The proposed project will be reviewed under F.A.C. Rule 17-2.500(5), new source review for Prevention of Significant Deterioration (PSD), because it will be a new major facility. This review consists of a determination of Best Available Control Technology (BACT) pursuant to F.A.C. Rule 17-2.630; and, unless otherwise exempted, an analysis of the air quality impact of the increased emissions. No air quality impact analysis is required for ozone, even though there will be an increase in VOC emissions, because this increase is less than 40 tons per year. The review also includes an analysis of the project's impacts on soils, vegetation and visibility, along with air quality impacts resulting from associated commercial, residential and industrial growth.

The proposed source shall be in compliance with all applicable provisions of F.A.C. Chapters 17-2 and 17-4 and the 40 CFR (July, 1991 version). The proposed source shall be in compliance with all applicable provisions of F.A.C. Rules 17-2.240: Circumvention; 17-2.250: Excess Emissions; 17-2.660: Standards of Performance for New Stationary Sources (NSPS); 17-2.700: Stationary Point Source Emission Test Procedures; and, 17-4.130: Plant Operation-Problems.

This source shall be in compliance with the NSPS for Gas Turbines, Subpart GG, and NSPS for Industrial Steam-Generating Units, Subpart Db, which are contained in the 40 CFR 60, Appendix A, and adopted by reference in F.A.C. Rule 17-2.660.

III. Emission Limitations and Impact Analysis

A. Emission Limitations

The proposed source is subject to emission limitations for the pollutants NOx, SO2, CO, VOC, sulfuric acid mist, and PM/PM10. The proposed source will also be subject to a visible emission (VE) limitation. The impact of these pollutant emissions are below the Florida ambient air quality standards (AAQS) and/or the acceptable ambient concentration levels (AAC). The following Table 1 lists each contaminant and its maximum allowable emission rate:

Table 1

Pollutant	Source	Allowable Emission Standard/Limitation
NOx	CT	15 ppmvd @ 15% O_2 (57.4 lbs/hr; 251.4 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
	CT/DB	24-hr rolling average
CO	CT	10 ppmvd (22.3 lbs/hr; 92.1 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
PM/PM_{10}	CT	0.011 lb/MMBtu (9.0 lbs/hr; 39.4 TPY)
	DB	0.01 lb/MMBtu (1.2 lbs/hr; 2.2 TPY)
VOC	CT	3.0 lbs/hr; 13.0 TPY
	DB	3.7 lbs/hr; 6.8 TPY
VE	CT/DB	≤ 10 % opacity

NOTE:
1. CT: combustion turbine
   DB: duct burner
2. Natural gas usage only in the CT and DB.
3. Hours of operation:
   a. CT: 8760 hrs/yr
   b. DB: 3688 hrs/yr
4. Maximum heat input:
   a. CT: 856.9 x 10^6 Btu/hr
   b. DB: 122.0 x 10^6 Btu/hr; 450,000 x 10^6 Btu/yr
5. Pollutant basis:
   a. NOx: BACT-see Table 1 received June 2, 1992
   b. CO: BACT-see Table A-2 received March 2, 1992
   c. PM/PM_{10}: BACT-see Table A-2 received March 2, 1992
   d. VOC: applicant request-see Table A-2 received March 2, 1992
      1) CT: 3 ppm corrected to dry conditions
      2) DB: 0.03 lb/MMBtu
   e. VE: BACT
6. DB operation planned when ambient temperature is greater than 59°F.

B. Air Toxics Evaluation

The operation of this source will produce emissions of chemical compounds that may be toxic in high concentrations. The emission rates of these chemicals shall not create ambient concentrations greater than the acceptable ambient concentrations (AAC) as shown below. Determination of the AAC for these organic compounds shall be determined by Department approved dispersion modeling or ambient monitoring.

$$AAC = \frac{OEL}{\text{Safety Factor}}$$

Where,

AAC = acceptable ambient concentration

Safety Factor = 50 for category B substances and 8 hrs/day
100 for category A substances and 8 hrs/day
210 for category B substances and 24 hrs/day
420 for category A substances and 24 hrs/day

OEL = Occupational exposure level such as ACGIH, ASHA and NIOSH published standards for toxic materials.

MSDS = Material Safety Data Sheets

C. Air Quality Analysis

1. Introduction

The operation of the proposed natural gas-fired 129 MW cogeneration facility will result in emissions increases which are projected to be greater than the PSD significant emission rates for the following pollutants: CO, NOx, PM/PM10. Therefore, the project is subject to the PSD new source review requirements contained in F.A.C. Rule 17-2.500 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 PM, PM10, and NOx);
- 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 combined cycle gas turbine cogeneration facility, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any PSD increment or ambient air quality standard. 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.

2. 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 review is given below:

	CO	TSP and PM10	NOx
PSD de minimus Concentration (ug/m3)	575	10	14
Averaging Time	8-hr	24-hr	Annual
Maximum Predicted Impact (ug/m3)	12	2.4	0.37

As shown above, the predicted impacts are all less than the corresponding de minimus concentrations; therefore, no preconstruction monitoring is required for any pollutant.

3. 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. The potential for building downwash was also assessed because the stack height will be less than the good engineering practice (GEP) stack height. Five years of sequential hourly surface and mixing depth data from the Orlando/Tampa Florida National Weather Service (NWS) stations collected during 1982 through 1986 were used in the model. Since five years of data were used, the highest-second-high short-term predicted concentrations were 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.

All modeling impacts presented herein were based on firing natural gas.

4. 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 CO, NO_x, PM and PM_{10}. Dispersion modeling was performed with receptors placed along the 36 standard radial directions (10 degrees apart) surrounding the proposed source at the following downwind distances: (1) the first 36 receptors were located at the plant property boundaries with an additional near field grid of 35 receptors located 100 meters from the proposed source off of the plant property; and, (2) subsequent receptors were located at distances of 500; 1,000; 1,500; 2,000; 3,000; 3,500; 4,000; and, 5,000 meters. Refined analyses were then performed to determine maximum impacts. 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}.

Pollutant	Averaging Time	PSD Significance Level (ug/m^3)	Ambient Concentration Increase (ug/m^3)
CO	8-hour	500	12
	1-hour	2000	47
NO_2	Annual	1.0	0.37
PM/PM_{10}	Annual	1.0	0.07
	24-hour	5.0	2.44

Therefore, further dispersion modeling for comparison with AAQS and PSD increment consumption was not required in this case.

The applicant performed dispersion modeling to determine the predicted ambient concentration increases in the Class I Chassahowitzka National Wilderness Area located 121 km away for the pollutants with Class I increments. The maximum predicted PM increases are 0.001 ug/m^3 for the annual averaging time and 0.02 ug/m^3 for the 24-hr averaging time. These values are less than the National Park Service's (NPS) proposed significance levels for PM of 0.08 ug/m^3, annual average, and 0.27 ug/m^3, 24-hour average. The maximum predicted NO_2 increase is 0.01 ug/m^3 for the annual averaging time. This value is less than the NPS's proposed significance value for NO_2 of 0.025 ug/m^3, annual average. Since the maximum predicted increases are less than corresponding significance levels, no further Class I increment modeling is required.

5. 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 121 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. Because the impacts from the proposed pollutants are predicted to be less than PSD significance levels, no harmful effects on soils and vegetation is expected. In addition, 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.

IV. CONCLUSION

Based on the information provided by Orlando Cogen Limited, L.P., the Department has reasonable assurance that the proposed installation of the 129 MW combined cycle gas turbine system, 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.

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IV. CONCLUSION

Based on the information provided by Orlando Cogen Limited, L.P., the Department has reasonable assurance that the proposed installation of the 129 MW combined cycle gas turbine system, 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.

#41755

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:

Orlando Cogen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Permit Number: AC 48-206720
PSD-FL-184
Expiration Date: June 30, 1994
County: Orange
Latitude/Longitude: 28°26'23"N
81°24'28"W
Project: 129-MW Combined Cycle Gas Turbine

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4, and 40 CFR (July, 1991 version). 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 129 MW (megawatt) combined cycle gas turbine cogeneration facility to be located in the Orlando Central Park, Orange County, Florida, and will supply steam to the adjacent Air Products and Chemicals Plant. The UTM coordinates are Zone 17, 459.5 km East and 3,146.1 km North.

4911 - Electric Generation / Distribution
The Standard Industrial Code: ~~4931-Electric and Other Services Combined~~

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. Orlando Cogen Limited, L.P.'s application received December 30, 1991.
2. Mr. C. H. Fancy's letter dated January 28, 1992.
3. Mr. Kennard F. Kosky's letter with enclosures received March 2, 1992.
4. Mr. Wayne A. Hinman's letter received via FAX May 27, 1992.
5. Mr. Kennard F. Kosky's letter with enclosure received May 27, 1992 (hand delivered).
6. Document (Table 1) received June 1, 1992, from Mr. Peter Cunningham (hand delivered).
7. 40 CFR (July, 1991 version).
8. Technical Evaluation and Preliminary Determination dated June 5, 1992.

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, F.S. 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), F.S., 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.

GENERAL CONDITIONS:

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,

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.

GENERAL CONDITIONS:

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, F.S. 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 F.A.C. Rules 17-4.120 and 17-30.300, 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

GENERAL CONDITIONS:

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. The CT (combustion turbine) is allowed to operate continuously (8,760 hours per year). The HRSG-DB (heat recovery steam generator-duct burner) is permitted to operate 3688 hrs/yr at a maximum heat input of 122 x 10^6 Btu/hr.

2. The CT and HRSG-DB are only allowed to use natural gas.

3. The permitted materials and utilization rates for the combined cycle gas turbine shall not exceed the values as follows:

- Maximum heat input to the CT shall not exceed 856.9 MMBtu/hr at ISO conditions.
- Maximum heat input to the HRSG-DB shall not exceed 122 MMBtu/hr; 450,000 MMBtu/yr.

SPECIFIC CONDITIONS:

4. The maximum allowable emissions from this facility shall not exceed the emission rates listed in Table 1.

Table 1

Pollutant	Source	Allowable Emission Standard/Limitation
NOx	CT	15 ppmvd @ 15% O_2 (57.4 lbs/hr; 251.4 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
	CT/DB	24-hr rolling average
CO	CT	10 ppmvd (22.3 lbs/hr; 92.1 TPY)
	DB	0.1 lb/MMBtu (12.2 lbs/hr; 22.5 TPY)
PM/PM_{10}	CT	0.011 lb/MMBtu (9.0 lbs/hr; 39.4 TPY)
	DB	0.01 lb/MMBtu (1.2 lbs/hr; 2.2 TPY)
VOC	CT	3.0 lbs/hr; 13.0 TPY
	DB	3.7 lbs/hr; 6.8 TPY
VE	CT/DB	$\leq$ 10 % opacity

NOTE:
1. CT: combustion turbine
   DB: duct burner
2. Natural gas usage only in the CT and DB.
3. Hours of operation:
   a. CT: 8760 hrs/yr
   b. DB: 3688 hrs/yr
4. Maximum heat input:
   a. CT: 856.9 x 10^6 Btu/hr
   b. DB: 122.0 x 10^6 Btu/hr; 450,000 x 10^6 Btu/yr
5. DB operation planned when ambient temperature is greater than 59°F.

5. Any change in the method of operation, equipment or operating hours, pursuant to F.A.C. Rule 17-2.100, Definitions-Modification, shall be submitted to the Department's Bureau of Air Regulation and Central District offices.

6. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility shall be included in the operating permit.

SPECIFIC CONDITIONS:

7. Initial and subsequent annual compliance tests shall be performed within 10 percent of the maximum heat rate input for the tested operating temperature. Tests shall be conducted using EPA reference methods in accordance with the July 1, 1991 version of the 40 CFR 60, Appendix A.

a. 5 for PM
b. 10 for CO
c. 9 for VE
d. 20 for NOx

Note: Other test methods may be used for compliance testing after prior Departmental approval has been received in writing.

8. EPA Method 5 must be used to determine the initial compliance status of this unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

9. Compliance with the total volatile organic compound emission limits will be assumed, provided the CO allowable emission rate is achieved; specific VOC compliance testing is not required.

10. During performance tests,, to determine compliance with the proposed NOx standard, measured NOx emission at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NOx = (NOx_{obs}) \left[\frac{(P_{ref})}{P_{obs}}\right] 0.5 \quad e^{19} (H_{obs} - 0.00633) \quad \left[\frac{(288°K)}{T_{AMB}}\right] 1.53$$

where:

NOx = Emissions of NOx at 15 percent oxygen and ISO standard ambient conditions.

NOx obs = Measured NOx emission at 15 percent oxygen, ppmv.

Pref = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

Pobs = Measured combustor inlet absolute pressure at test ambient pressure.

Hobs = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

TAMB = Temperature of ambient air at test.

SPECIFIC CONDITIONS:

11. Test results will be the average of 3 valid runs. The Department's Central District office shall be notified at least 30 days in advance of the compliance test. The source shall operate between 90% and 100% of permitted capacity as adjusted for ambient temperature during the compliance test. Compliance test results shall be submitted to the Department's Central District office no later than 45 days after completion.

12. The permittee shall leave sufficient space suitable for future installation of SCR equipment.

13. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2, (July 1, 1991).

14. Combustion control shall be utilized for CO control. The permittee shall leave a sufficient space suitable for future installation of an oxidation catalyst. Once performance testing has been completed, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

15. This source shall be in compliance with all applicable provisions of Chapter 403, F.S., F.A.C. Chapters 17-2 and 17-4, and the 40 CFR (July, 1991 version).

16. This source shall be in compliance with all applicable requirements of 40 CFR 60, Subparts GG and Db, in accordance with F.A.C. Rule 17-2.660(2)(a), Standards of Performance for Stationary Gas Turbines and Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units.

17. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-2.210(1)).

18. This source shall be in compliance with all applicable provisions of F.A.C. Rules 17-2.240: Circumvention; 17-2.250: Excess Emissions; 17-2.660: Standards of Performance for New Stationary Sources (NSPS); 17-2.700: Stationary Point Source Emission Test Procedures; and, 17-4.130: Plant Operation-Problems.

SPECIFIC CONDITIONS:

19. Pursuant to F.A.C. Rule 17-2.210(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: fuel usage, hours of operation, air emissions limits, etc. Annual reports shall be sent to the Department's Central District office by March 1 of each calendar year.

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

21. An application for an operation permit must be submitted to the Department's Central 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
Orlando Cogen Limited, L.P.
Orange County

The applicant proposes to install a combustion turbine generator at their facility in Orange County. The generator system will consist of one nominal 79 megawatt (MW) combustion turbine (CT), with exhaust through heat recovery steam generator (HRSG), which will be used to power a nominal 50 MW steam turbine.

The combustion turbine will be capable of combined cycle operation. The applicant requested that the combustion turbine use only natural gas. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity and type of fuel fired at ISO conditions to be as follows:

Pollutant	Emissions (TPY)	PSD Significant Emission Rate (TPY)
NO_x	273.9	40
SO_2	12.0	40
PM/PM_{10}	41.7	25/15
CO	114.6	100
VOC	19.8	40
H_2SO_4	0.9	7
Be	Neg.	0.0004
Hg	Neg.	0.1
Pb	Neg.	0.6

Florida Administrative Code (F.A.C.) Rule 17-2.500(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

December 30, 1991

BACT Determination Requested by the Applicant

Pollutant	Determination
NO_x	15 ppmvd @ 15% O_2 (natural gas burning)--CT 0.1 lb/106 Btu--duct burner
CO	Combustion Control
PM/PM_{10}	Combustion Control

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.

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

- Combustion Products (e.g., particulates). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.
- Acid Gases (e.g., NO_X). Controlled generally by gaseous control devices.

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

Combustion Products

The projected emissions of particulate matter and PM_{10} from the Orlando Cogen Limited, L.P. facility surpass the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2.

A PM/PM_{10} emissions limitations of 0.0011 lb/MMBtu from the CT when firing natural gas is reasonable as BACT for the Orlando Cogen Limited, L.P. facility. The duct burner PM/PM_{10} emission rate of 0.01 lb/MMBtu is reasonable as BACT.

Products of Incomplete Combustion

The emissions of carbon monoxide exceed the PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emissions from the proposed turbine is on exhaust concentrations of 10 ppmvd for natural gas firing.

A review of the BACT/LAER clearinghouse indicates that several of the combustion turbines using dry low-Nox combustion technology to control NOx to 15 ppmvd (corrected to 15 percent O_2) have been permitted with CO limitations that are higher than those proposed by the applicant. The applicant has stated that the CT is a new design, and CO margins must be higher. The majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, additional 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. The existing gas turbine applications have been limited to smaller cogeneration facilities burning natural gas.

Given the applicant's proposed BACT level for carbon monoxide of 10 ppm, a lower emission rate as BACT would not produce a significant reduction in emissions or impacts. Also, this CO concentration level is near the lowest established as BACT even with catalytic oxidation. For these reasons, it appears that the limit proposed by the applicant is reasonable as BACT.

Emission of volatile organic compounds are each below the significant level and therefore do not require a BACT analysis.

Acid Gases

The emissions of nitrogen oxides represent a significant proportion of the total emissions and need to be controlled if deemed appropriate.

The applicant has stated that BACT for nitrogen oxides will be met by using dry low-NOx combustion to limit emissions to 15 ppmvd (corrected to 15% O_2) when burning natural gas.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NOx emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. 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 NOx emissions. The SCR process combines vaporized ammonia with NOx 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 NOx with a new catalyst. As the catalyst ages, the maximum NOx reduction will decrease to approximately 86 percent.

A review of the combined cycle facilities in which SCR has been established as a BACT requirement indicates that the majority of these facilities are also intended to operate at high capacity factors. As this is the case, the proposed project is similar to other facilities in which SCR has been established as BACT.

Given the applicant's proposed BACT level for nitrogen oxides control stated above, an evaluation can be made of the cost and associated benefit of using SCR as follows:

The applicant has indicated that the total levelized annual cost (operating plus amortized capital cost) to install SCR for natural gas firing at 100 percent capacity factor is $1,903,000. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

Based on the information supplied by the applicant, it is estimated that the maximum annual NOx emissions with dry low-NOx combustion from the Orlando Cogen Limited, L.P. facility will be 274 tons/year. Assuming that SCR would reduce the NOx emissions to a level of 9 ppmvd when firing natural gas, about 141 tons of NOx would be emitted annually. When this reduction is taken into consideration with the total levelized annual cost of $1,900,300, the cost per ton of controlling NOx is $14,308. This calculated cost is higher than has previously been approved as BACT.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics.

In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement was made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

For fuel oil firing, the cost associated with controlling NOx emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NOx injection ratio. For natural gas firing operation NOx 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 NOx 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.

Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NOx emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

The Orlando Cogen Limited, L.P. facility has proposed not to utilize fuel oil; therefore, those consequences of SCR attributed to fuel oil firing will not likely occur. However, the small amount of sulfur in natural gas would likely form ammonium salts.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NOx control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NOx control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Also, air emissions result from the lost generations that must be replaced. The lost generation is due to the back pressure on the turbine covered by the catalyst. Although the use of SCR does have some environmental impacts, the disadvantages may outweigh the benefit which would be provided by reducing nitrogen oxide emissions by 80 percent or greater. The benefit of NOx control by using SCR is substantiated by the fact that nearly one half of all BACT determinations have established SCR as the control measure for nitrogen oxides over the last five years.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of natural gas and No. 2 fuel oil have been evaluated. Toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than 0.1 tons per year.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of natural gas.

Potentially Sensitive Concerns

With regard to controlling NOx emissions with SCR, the applicant has identified the following technical limitations:

1. SCR would reduce output of combustion turbines by one-half percent.
2. SCR could result in the release of unreacted quantities of ammonia to the atmosphere.
3. SCR would require handling of ammonia by plant operators. Since it is a hazardous material, there is a concern about safety and productivity of operators.
4. SCR results in contaminated catalyst from flue gas trace elements which could be considered hazardous. Safety of operators and disposal of spent catalyst is a concern.

The combustion turbines proposed for the project (ABB 11N-EV) is a heavy-frame that is highly efficient and uses advanced dry low-NOx combustion technology. Information supplied by the applicant indicates that actual emissions will be 15 ppmvd (corrected to 15% O_2) or lower on a continuous basis.

BACT Determination by DER

NOx Control

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, capacity factors ranging from low to high). However, the cost and other concerns expressed by the applicant are valid, and advanced NOx combustion controls have been accepted as BACT on similar projects.

The information that the applicant presented and Department calculations indicates that the incremental cost of controlling NOx ($14,308/ton) is high compared to other BACT determinations which require SCR. Furthermore, actual NOx levels are expected to be less than the 15 ppmvd (corrected to 15% O_2), which would increase the cost effectiveness of SCR. Based on the information presented by the applicant and the studies conducted, the Department believes that the use of SCR for NOx control is not justifiable as BACT. Therefore, the Department is willing to accept dry low-NOx combustion as NOx control when firing natural gas.

The emissions of NOx from the duct burner will be limited to 0.1 lb/MMBtu, which has been the BACT limit established for similar facilities. Duct firing will be used for supplying steam and limited to an equivalent of 3,688 hours/year at 122 MMBtu/hr heat input (maximum).

CO Control

Combustion control will be considered as BACT for CO when firing natural gas. Also, due to the lack of operational experience with the ABB 11N-EV and the uncertainty of actual CO emissions, the permittee shall install a duct module suitable for future installation of oxidation catalyst.

Other Emissions Control

The emission limitations for PM and PM_{10} are based on previous BACT determinations for similar facilities.

The emission limits for the Orlando Cogen Limited, L.P. project are thereby established as follows:

	Emission Standards/Limitations	
Pollutant	CT (Natural Gas Firing)	DB (Natural Gas Firing)
NOx	15 ppmvd @ 15% O2	0.1 lb/MMBtu
CO	10 ppmvd	0.1 lb/MMBtu
PM & PM10	0.011 lb/MMBtu	0.1 lb/MMBtu

Note: Natural gas will be used only for supplemental firing for no greater than 3688 full-load equivalent hours at 122 MMBtu/hr heat input on a total annual basis (maximum of 450,000 MMBtu/yr heat input annually).

Details of the Analysis May be Obtained by Contacting:

Bruce Mitchell, 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

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Orlando Cogen Limited, L.P. File Copy

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Peter Cunningham

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03/18/92

Table 1. Allowable Emission Limits Combined Cycle Combustion Turbine Cogeneration Facility

Pollutant	Source[a]	Fuel[b]	Basis of Limit	Allowable Emission Limits	
				lb/hr/source	tons/year/facility
NO_x	CT	NG	BACT: ~~2~~15 ppmvd at 15% O_2	~~95.7~~ 57.4[c]	~~400.9~~ 273.9
	DB	NG	BACT: 0.1 lb/MMBtu	12.2[c]	
CO	CT	NG	BACT: 10 ppmvd	22.3	114.6
	DB	NG	BACT: 0.1 lb/MMBtu	12.2	
PM/PM_{10}	CT	NG	BACT: 0.011 lb/MMBtu	11.0	41.67
	DB	NG	BACT: 0.01 lb/MMBtu	1.22	
VOC	CT	NG	Proposed by Applicant	3.18	19.75
	DB	NG	Proposed by Applicant	3.7	

[a] CT = combustion turbine
DB = duct burner

[b] NG = natural gas

[c] COMPLIANCE WITH ALLOWABLE EMISSION LIMIT IS BASED ON A 24-HOUR AVERAGE OF BOTH LIMITS; i.e. 69.6 lb/hr.

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To Peter Cunningham	From Ken Kosky
Co. HBG&S	Co. KBN
Dept. 90115	Phone #
Fax # C	Fax #

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KBN

May 27, 1992

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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

RE: Orange County--A.P.
Orlando CoGen Limited, L.P.
Combustion Turbine and Heat Recovery Steam Generator
AC 48-206720 and PSD-FL-184

Attention: Mr. Preston Lewis and Mr. Bruce Mitchell

Dear Preston and Bruce:

As discussed yesterday, the applicant for the above-referenced project, after discussions with the combustion turbine (CT) vendor (i.e., ABB), will agree to a nitrogen oxide (NO_x) emission limit for the CT based on 18 parts per million volume dry (ppmvd) corrected to 15 percent oxygen. On this basis, the maximum NO_x emission rate proposed as Best Available Control Technology (BACT) for the project will be 68.9 lb/hr for the CT at an ambient temperature of 20°F. The maximum NO_x emission rate at 59°F is proposed as 62.2 lb/hr. The maximum annual emission rate is proposed as 301.8 tons per year (TPY) at 20°F. Table 2-1 from the application has been revised to reflect the proposed BACT emission limit.

This proposed change in the emission limit for NO_x has considerable ramifications for the economic and environmental considerations in the BACT analysis. The cost effectiveness for installing and operating selective catalytic reduction (SCR) on the project at 18 ppmvd (corrected to 15 percent oxygen) is estimated at $12,300 per ton of NO_x removed (annualized cost of $1,903,000 divided by a net NO_x reduction of 154 TPY). This cost effectiveness exceeds the cost effectiveness found unreasonable for other similar projects by about $5,000 per ton of NO_x removed (or about 75 percent). At 18 ppmvd (corrected), the costs for SCR are clearly unreasonable and should be rejected as BACT.

The proposed BACT emission limit for NO_x emissions reduces the maximum potential emissions for the project by 106 TPY or by 26 percent from that originally proposed for the project. At the proposed emission level, the net reduction with SCR when all pollutants except carbon dioxide (CO_2) are considered will be only 29 TPY (see revised Table 4-7). Indeed, the amount of increased CO_2 emissions with SCR is estimated to be two orders of magnitude larger than the net emission reduction with SCR. Taking together the low overall environmental benefit and the potential hazards of handling ammonia in an urban area, application of SCR as BACT for this project appears environmentally unreasonable. As

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

discussed in the PSD application, the proposed technology (i.e., dry low-NO_x combustion) is truly "pollution prevention" and must be taken into account.

The proposed emission limit, if established as BACT, will be the lowest in Florida at 0.07 lb NO_x per million Btu heat input. This limit is about 25 percent lower than other similar natural gas fired combined cycle cogeneration projects and about 60 percent lower than other power generation projects that have been required to install NO_x reduction technologies [i.e., SCR and selective non-catalytic reduction (SNCR)].

I hope this information is helpful. Please call if you have any questions.

Sincerely,

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

KFK/tyf

Enclosure

cc: Gary Kinsey, Air Products
John P. Jones, Orlando CoGen Limited, L.P.
File (2)
B. Mitchell
C. Holladay
C. Collins, C Dist.
J. Harper, EPA
C. Shaver, NPS

Table 2-1. Stack, Operating, and Emission Data for the Proposed Cogeneration Facility

	Maximum Emissions			
		CT/Duct Burner		
Parameter	CT Only[a]	CT[b]	Duct Burner[c]	Total
Stack Data (ft)				
Height	115			115
Diameter	15.7			15.7
Operating Data				
Temperature (°F)	250			220
Velocity (ft/sec)	69.9			58.14
Building Data (ft)				
Height	76			76
Length	60			60
Width	43			43
Maximum Hourly Emissions (lb/hr)				
SO_2	2.82	2.59	0.37	2.96
PM/PM10	11.0	9.0	1.22	10.22
NO_x	68.9	62.2	12.2	74.4
CO	23.3	21.0	12.2	33.2
VOC	3.18	2.98	3.7	6.7
Sulfuric Acid Mist	0.02	0.02	0.003	0.02
Annual Potential Emissions (TPY)				
SO_2	12.35	11.34	0.68	12.02
PM/PM10	48.18	39.42	2.25	41.67
NO_x	301.8	272.5	22.5	295.0
CO	102.1	92.1	22.5	114.6
VOC	13.9	13.0	6.75	19.75
Sulfuric Acid Mist	0.95	0.87	0.05	0.92

Note: 10^6 Btu/hr = million British thermal units per hour.
CO = carbon monoxide.
CT = combustion turbine.
°F = degrees Fahrenheit.
ft = feet.
ft/sec = feet per second.
HRSG = heat recovery steam generator.
lb/hr = pounds per hour.
Neg = negative.
NO_x = nitrogen oxides.
O_2 = oxygen molecule.
PM = particulate matter.
PM10 = particulate matter less than or equal to 10 micrometers.
ppmvd = parts per million by volume dry.
SO_2 = sulfur dioxide.
TPY = tons per year.
VOC = volatile organic compound.

[a] Performance based on 20°F with NO_x emissions at 18 ppmvd (corrected to 15 percent O_2); 8,760 hr/yr operation.

[b] Performance based on 59°F with NO_x emissions of 18 ppmvd (corrected to 15 percent O_2), 8,760 hr/yr operation; stack parameters based on 90°F ambient temperature.

[c] Performance based on 122 x 10^6 Btu/hr heat input for HRSG; annual emissions based on 4,500 hours per year operation at an average heat input of 100 x 10^6 Btu/hr.

Table 4-7. Maximum Potential Emission Differentials TPY With and Without Selective Catalytic Reduction

	Project With SCR			Project Without SCR	
Pollutants	Primary	Secondary[a]	Total	CT/DB	Difference[b]
Particulate	24 [c]	2.06	26	0	26
Sulfur Dioxide	0	22.64	23	0	23
Nitrogen Oxides	141 [d]	11.32	152	295	(143)
Carbon Monoxide	0	0.68	1	0	1
Volatile Organic Compounds	0	0.10	0	0	0
Ammonia	64 [e]	0.00	64	0	64
Total	229	36.81	266	295	(29)
Carbon Dioxide[f]	--	3,535	3,535	--	3,535

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 0.47 MW from heat rate penalty and electrical for 8,760 hours per year operation (0.5% of 78.83 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 - 0.47 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 = 2.06 TPY.

[b] Difference = Total with SCR minus project without SCR.

[c] Assume sulfur reacts with ammonia; 11.65 TPY SO_2 x 132 (MW of ammonia salt) ÷ 64 (MW of SO_2).

[d] 9 ppm NO_x emissions.

[e] 10 ppm ammonia slip (ideal gas law at actual flow rate from stack): 726,343 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., 0.47 MW CO_2 calculated based on 85.7% carbon in fuel oil and 18,300 BTU/lb).

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COMPANY: FLORIDA DEPT OF ENVIRONMENTAL REGULATION.

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FROM: ORLANDO COGEN LIMITED, L.P.

DATE: 26 MAY 1992

COMMENTS:

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Thank you
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**Orlando
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Limited, L.P.**

26 May 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

Subject: Orange County - A.P.
Orlando CoGen Limited, L.P. Cogeneration Project
Combustion Turbine and Heat Recovery Steam Generator
AC 48-206720 and PSD-FL-184

Attention: Preston Lewis

Dear Mr. Lewis:

This letter is to confirm your conversation earlier today with Mr. Kennard F. Kosky, President, KBN Engineering and Applied Sciences, Inc.

1. Orlando CoGen Limited has reviewed the technical capabilities of the proposed dry-low NO_x combustor with ABB, the gas turbine manufacturer. The equipment manufacturer is willing to guarantee the NO_x emissions levels from the gas turbine unit at a level of 18 PPM (corrected to 15% O_2). This equipment guarantee will become the basis for the emissions levels for the proposed facility's gas turbine.

2. Orlando CoGen Limited with the help of KBN Engineering and Applied Sciences, Inc. will provide the updated emissions data which corresponds to the 18 PPM NO_x emissions level. This information will be provided to the Department later this week.

Orlando CoGen Limited looks forward to finalizing this PSD permit application review with the Department. The facility is planning to start construction around mid-summer of this year to support a scheduled on-stream date of 1 January 1994.

Sincerely,

Wayne A Hinman

Wayne A. Hinman
President
Orlando CoGen (I), Inc.
General Partner of Orlando
CoGen Limited, L.P.

cc: Mr. Kennard F. Kosky, KBN

Orlando CoGen Limited, L.P.

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26 May 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

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Orlando CoGen Limited, L.P.

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26 May 1992

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Sincerely,

Wayne A Hinman

Wayne A. Hinman
President
Orlando CoGen (I), Inc.
General Partner of Orlando
CoGen Limited, L.P.

cc: Mr. Kennard F. Kosky, KBN
B. Mitchell
P. Lewis

KBN

April 13, 1992

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Subject: Orange County - A.P.
Orlando CoGen Limited, L.P. Cogeneration Project
AC 48-206720 and PSD-FL-184

Attention: Bruce Mitchell

Dear Bruce:

This correspondence and attachments presents information requested by the Department's March 31, 1991 letter. Please find attached the following:

1. The equations contained in Notes A, B and C have been further annotated to reference the equations from the Code of Federal Regulations (CFR) for which NOx, CO and VOC emissions are calculated from parts per million (ppm) with corrections to lb/hr. Also attached is a copy of the relevant CFR (i.e., 40 CFR Part 60 Appendix A, Method 20). Please recognize that the notes contained in the application were not titled as Notes-1 as indicated in the March 31, 1992 letter but as Notes A, B and C.

2. A computer disk containing the spreadsheet used to develop Tables A-1 through A-4 is enclosed with this correspondence. Please note that this spreadsheet is a work product of KBN Engineering and Applied Sciences, Inc. (KBN) and must be considered as confidential business information.

Submittal of this information clarifies 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,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

cc: Mr. John P. Jones
Mr. Gary Kinsey, P.E.
B. Mitchell
C. Holladay
C. Collins, C. Oest
D. Nester, Orange Co.
J. Harper, EPA
C. Shaver, NPS

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EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

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 (K)

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:

1. $$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

[see Equation 20-4, EPA Method 20]

2. $V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$

3. $\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$

[see Equation 20-1, EPA Method 20]

4. $V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$

[see Equation 20-1, EPA Method 20]

Substituting:

5. $V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9$

[Substitute Equation 2 in Equation 4]

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9$$

[Substitute in Equation 3]

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)]\ /\ 5.9$$

6. $m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)] * P * M_{NOx} / (RT * 5.9)$

[Ideal Gas Law]

CO is calculated the same as NOx. JSG

NOTE C

~~CO and~~ VOC ~~are~~ is calculated by correcting to dry conditions:
JSG

7. $V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$

[see Equation 3 above]

8. $m_{CO} = PV_{CO\ Act}M_{CO} / RT$
$= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO} / RT$

[Ideal Gas Law]

device, the following equation may be used to adjust the emission rate for sulfur retention credits (no credits are allowed for oil-fired systems) (E_{di}) for each sampling period using the following equation:

$$E_{di}=0.97\ K\ (\%S/GCV)$$

Eq. 19-25

where:

E_{di}=average inlet SO_2 rate for each sampling period d, ng/J (lb/million Btu)

%S=sulfur content of as-fired fuel lot, dry basis, weight percent.

GCV=gross calorific value of the fuel lot consistent with the sulfur analysis, kJ/kg (Btu/lb).

$K=2\times10^7[(kg)(ng)/(\%)(J)]\ \{2\times10^4(lb)(Btu/(\%))(million\ Btu)\}$

After calculating E_{di} use the procedures in Section 4-2 to determine the average SO_2 emission rate to the atmosphere for the performance test period (E_{ao}).

7. *Determination of Compliance When Minimum Data Requirement Is Not Met*

7.1 Adjusted Emission Rates and Control Device Removal Efficiency. When the minimum data requirement is not met, the Administrator may use the following adjusted emission rates or control device removal efficiencies to determine compliance with the applicable standards.

Eq. 19-27

7.1.1 Emission Rate. Compliance with the emission rate standard may be determined by using the lower confidence limit of the emission rate (E_{ao}^{*}) as follows:

$$E_{ao}^{*}=E_{ao}-t_{0.95}\ S_o$$

Eq. 19-26

where:

S_o=standard deviation of the hourly average emission rates for each performance test period, ng/J (lb/million Btu).

$t_{0.95}$=values shown in Table 19-2 for the indicated number of data points n.

7.1.2 Control Device Removal Efficiency. Compliance with the overall emission reduction (%R_o) may be determined by using the lower confidence limit of the emission rate (E_{ao}^{*}) and the upper confidence limit of the inlet pollutant rate (E_{ai}^{*}) in calculating the control device removal efficiency (%R_g) as follows:

$$\%R_g=100\ [1.0-E_{ao}^{*}/E_{ai}^{*}]$$

$$E_{ai}^{*}=E_{ai}+t_{0.95}\ S_i$$

Eq. 19-28

where:

S_i=standard deviation of the hourly average inlet pollutant rates for each performance test period, ng/J (lb/million Btu).

TABLE 19-2—VALUES FOR $T_{0.95}$

n[1]	$t_{0.95}$	n[1]	$t_{0.95}$	n[1]	$t_{0.95}$
2	6.31	8	1.89	22-26	1.71
3	2.42	9	1.86	27-31	1.70
4	2.35	10	1.83	32-51	1.68
5	2.13	11	1.81	59-91	1.67
6	2.02	12-16	1.77	92-151	1.66
7	1.94	17-21	1.73	152 or more	1.65

[1] The values of this table are corrected for n-1 degrees of freedom. Use n equal to the number (H) of hourly average data points.

7.2 Standard Deviation of Hourly Average Pollutant Rates. Compute the standard deviation (S_e) of the hourly average pollutant rates using the following equation:

$$S_e = \sqrt{(1/H) - (1/H_r)}\ \ (\sqrt{[\sum_{j=1}^{H}(E_{hj} - E_a)^2]/(H - 1)}\ )$$

Eq. 19-29

where:

S=standard deviation of the hourly average pollutant rates for each performance test period, ng/J (lb/million Btu).

H_r=total numbers of hours in the performance test period (e.g., 720 hours for 30-day performance test period).

Equation 19-29 may be used to compute the standard deviation for both the outlet (S_o) and, if applicable, inlet (S_i) pollutant rates.

METHOD 20—DETERMINATION OF NITROGEN OXIDES, SULFUR DIOXIDE, AND DILUENT EMISSIONS FROM STATIONARY GAS TURBINES

1. *Principle and Applicability*

1.1 Applicability. This method is applicable for the determination of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and a diluent gas, either oxygen (O_2) or carbon dioxide (CO_2), emissions from stationary gas turbines. For the NO_x and diluent concentration determinations, this method includes:

(1) Measurement system design criteria; (2) Analyzer performance specifications and performance test procedures; and (3) Procedures for emission testing.

1.2 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of NO_x and diluent content. During each NO_x and diluent determination, a separate measurement of SO_2 emissions is made, using Method 6, or its equivalent. The diluent determination is used to adjust the NO_x and SO_2 concentrations to a reference condition.

2. *Definitions*

2.1 Measurement System. The total equipment required for the determination of a gas concentration or a gas emission rate. The system consists of the following major subsystems:

2.1.1 Sample Interface. That portion of a system that is used for one or more of the following: sample acquisition, sample transportation, sample conditioning, or protection of the analyzers from the effects of the stack effluent.

2.1.2 NO_x Analyzer. That portion of the system that senses NO_x and generates an output proportional to the gas concentration.

2.1.3 O_2 Analyzer. That portion of the system that senses O_2 and generates an output proportional to the gas concentration.

2.1.4 CO_2 Analyzer. That portion of the system that senses CO_2 and generates an output proportional to the gas concentration.

2.1.5 Data Recorder. That portion of the measurement system that provides a permanent record of the analyzer(s) output. The data recorder may include automatic data reduction capabilities.

2.2 Span Value. The upper limit of a gas concentration measurement range that is specified for affected source categories in the applicable part of the regulations.

2.3 Calibration Gas. A known concentration of a gas in an appropriate diluent gas.

2.4 Calibration Error. The difference between the gas concentration indicated by the measurement system and the known concentration of the calibration gas.

2.5 Zero Drift. The difference in the measurement system output readings from zero after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input concentration at the time of the measurements was zero.

2.6 Calibration Drift. The difference in the measurement system output readings from the known concentration of the calibration gas after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input at the time of the measurements was a high-level value.

2.7 Response Time. The amount of time required for the measurement system to display on the data output 95 percent of a step change in pollutant concentration.

2.8 Interference Response. The output response of the measurement system to a component in the sample gas, other than the gas component being measured.

3. *Measurement System Performance Specifications*

3.1 NO_2 to NO Converter. Greater than 90 percent conversion efficiency of NO_2 to NO.

3.2 Interference Response. Less than ± 2 percent of the span value.

3.3 Response Time. No greater than 30 seconds.

3.4 Zero Drift. Less than ± 2 percent of the span value over the period of each test run.

3.5 Calibration Drift. Less than ± 2 percent of the span value over the period of each test run.

4. *Apparatus and Reagents*

4.1 Measurement System. Use any measurement system for NO_x and diluent that is expected to meet the specifications in this method. A schematic of an acceptable measurement system is shown in Figure 20-1. The essential components of the measurement system are described below:

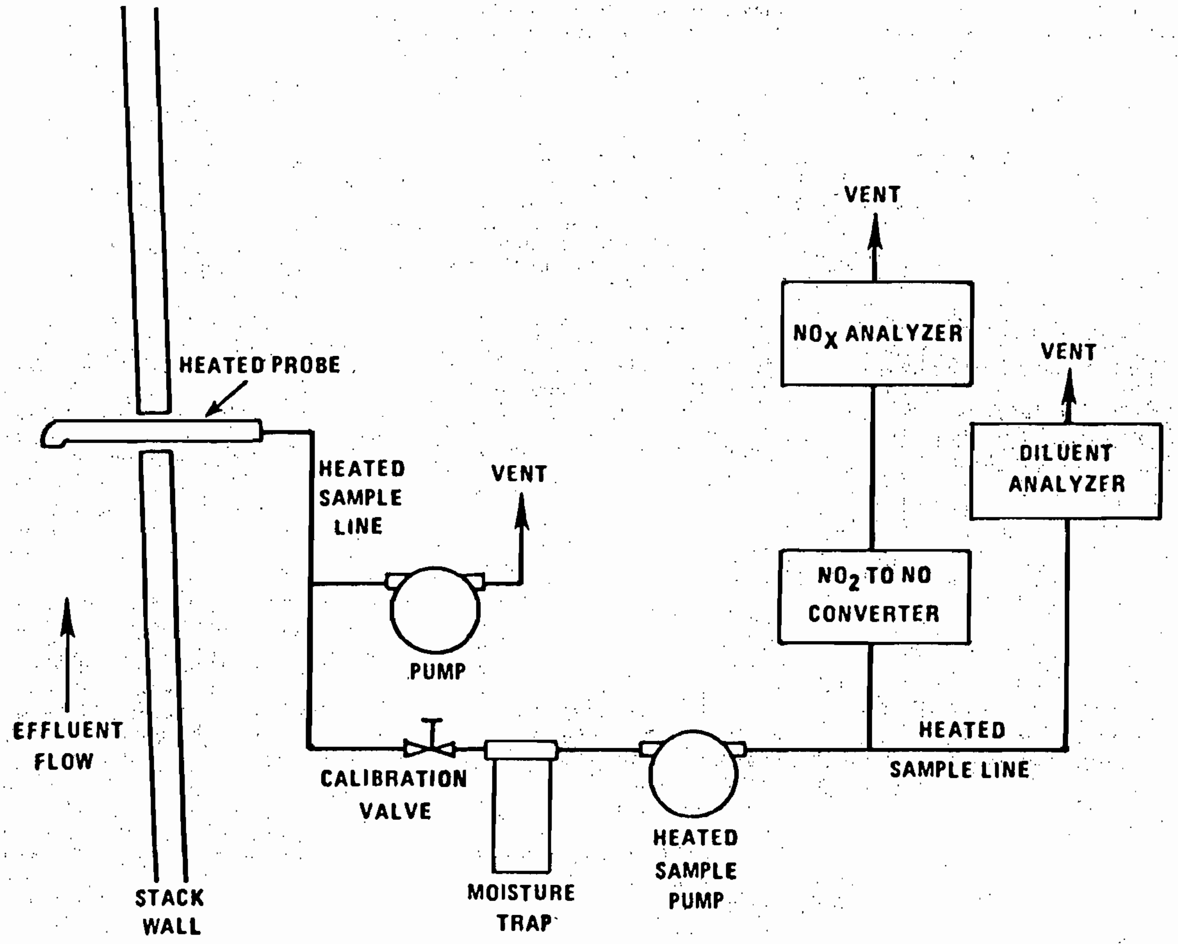

Figure 20-1. Measurement system design.
[Figure 20-1 revised by 51 FR 32455, September 12, 1986]

[Appendix A, Method 20]

4.1.2 Sample Line. Heated (>95°C) stainless steel or Teflon tubing to transport the sample gas to the sample conditioners and analyzers.

4.1.3 Calibration Valve Assembly. A three-way valve assembly to direct the zero and calibration gases to the sample conditioners and to the analyzers. The calibration valve assembly shall be capable of blocking the sample gas flow and of introducing calibration gases to the measurement system when in the calibration mode.

4.1.4 NO_2 to NO Converter. That portion of the system that converts the nitrogen dioxide (NO_2) in the sample gas to nitrogen oxide (NO). Some analyzers are designed to measure NO_x as NO_2 on a wet basis and can be used without an NO_2 to NO converter or a moisture removal trap provided the sample line to the analyzer is heated (>95°C) to the inlet of the analyzer. In addition, an NO_2 to NO converter is not necessary if the NO_2 portion of the exhaust gas is less than 5 percent of the total NO_x concentration. As a guideline, an NO_2 to NO converter is not necessary if the gas turbine is operated at 90 percent or more of peak load capacity. A converter is necessary under lower load conditions.

4.1.5 Moisture Removal Trap. A refrigerator-type condenser or other type device designed to continuously remove condensate from the sample gas while maintaining minimal contact between any condensate and the sample gas. The moisture removal trap is not necessary for analyzers that can measure NO_x concentrations on a wet basis; for these analyzers, (a) heat the sample line up to the inlet of the analyzers, (b) determine the moisture content using methods subject to the approval of the Administrator, and (c) correct the NO_X and diluent concentrations to a dry basis.

[4.1.5 amended by 51 FR 32455, September 12, 1986]

4.1.6 Particulate Filter. An in-stack or an out-of-stack glass fiber filter, of the type specified in EPA Method 5; however, an out-of-stack filter is recommended when the stack gas temperature exceeds 250 to 300°C.

[4.1.6. amended by 55 FR 47472, November 14, 1990]

4.1.7 Sample Pump. A nonreactive leak-free sample pump to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from stainless steel or coated with Teflon or equivalent.

4.1.8 Sample Gas Manifold. A sample gas manifold to divert portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, Teflon, stainless steel, or equivalent.

4.1.9 Diluent Gas Analyzer. An analyzer to determine the percent O_2 or CO_2 concentration of the sample gas.

[4.1.9 amended by 51 FR 32455, September 12, 1986]

4.1.10 Nitrogen Oxides Analyzer. An analyzer to determine the ppm NO_x concentration in the sample gas stream.

4.1.11 Data Recorder. A strip-chart recorder, analog computer, or digital recorder for recording measurement data.

[4.1.11 amended by 51 FR 32455 September 12, 1986]

4.2 Sulfur Dioxide Analysis. EPA Method 6 apparatus and reagents.

[4.2 amended by 55 FR 47472, November 14, 1990]

4.3 NO_x Calibration Gases. The calibration gases for the NO_x analyzer shall be NO in N_2. Use four calibration gas mixtures as specified below:

4.3.1 High-level Gas. A gas concentration that is equivalent to 80 to 90 percent of the span value.

4.3.2 Mid-level Gas. A gas concentration that is equivalent to 45 to 55 percent of the span value.

4.3.3 Low-level Gas. A gas concentration that is equivalent to 20 to 30 percent of the span value.

4.3.4 Zero Gas. A gas concentration of less than 0.25 percent of the span value. Ambient air may be used for the NO_x zero gas.

4.4 Diluent Calibration Gases.

[4.4 revised, 4.4.1 and .2 added by 51 FR 32455, September 12, 1986]

4.4.1 For O_2 calibration gases, use purified air at 20.9 percent O_2 as the high-level O_2 gas. Use a gas concentration between 11 and 15 percent O_2 in nitrogen for the mid-level gas, and use purified nitrogen for the zero gas.

4.4.2 For CO_2 calibration gases, use a gas concentration between 8 and 12 percent CO_2 in air for the high-level calibration gas. Use a gas concentration between 2 and 5 percent CO_2 in air for the mid-level calibration gas, and use purified air (<100 ppm CO_2) as the zero level calibration gas.

5. Measurement System Performance Test Procedures

Perform the following procedures prior to measurement of emissions (Section 6) and only once for each test program, i.e., the series of all test runs for a given gas turbine engine.

5.1 Calibration Gas Checks. There are two alternatives for checking the concentrations of the calibration gases. (a) The first is to use calibration gases that are documented traceable to National Bureau of Standards Reference Materials. Use *Traceability Protocol for Establishing True Concentrations of Gases Used for Calibrations and Audits of Continuous Source Emission Monitors* (Protocol Number 1) that is available from the Environmental Monitoring Systems Laboratory, Quality Assurance Branch, Mail Drop 77, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. Obtain a certification from the gas manufacturer that the protocol was followed. These calibration gases are not to be analyzed with the Reference Methods. (b) The second alternative is to use calibration gases not prepared according to the protocol. If this alternative is chosen, within 1 month prior to the emission test, analyze each of the calibration gas mixtures in triplicate using Method 7 or the procedure outlined in Citation 1. for NO_X and use Method 3. for O_2 or CO_2. Record the results on a data sheet (example is shown in Figure 20-2). For the low-level, mid-level, or high-level has mixtures, each of the individual NO_X analytical results must be within 10 percent (or 10 ppm, whichever is greater) of the triplicate set average (O_2 or CO_2 test results must be within 0.5 percent O_2 pr CO_2); otherwise, discard the entire set and repeat the triplicate analyses. If the average of the triplicate reference method test results is within 5 percent for NO_X gas or 0.5 percent O_2 or CO_2 for the O_2 or CO_2 gas of the calibration gas manufacturer's tag value, use the tag value; otherwise, conduct at least three additional reference method test analyses until the results of six individual NO_X runs (the three original plus three additional) agree within 10 percent (or 10 ppm, whichever is greater) of the average (O_2 or CO_2 test results must be within 0.5 percent O_2 or CO_2). Then use this average for the cylinder value.

[5.1 amended by 51 FR 32455, September 12, 1986; 52 FR 34639, September 14, 1987; 55 FR 47472, November 14, 1990]

5.2 Measurement System Preparation. Prior to the emission test, assemble the measurement system following the manufacturer's written instructions in preparing and operating the NO_2 to NO converter, the NO_X analyzer, the diluent analyzer, and other components.

[5.2 amended by 51 FR 32455, September 12, 1986]

FIGURE 20-2—ANALYSIS OF CALIBRATION GASES

Date ——— (Must be within 1 month prior to the test period)

Reference method used ————————

Sample run	Gas concentration, ppm		
	Low level[a]	Mid level[b]	High level[c]
1			
2			
3			
Average			
Maximum % deviation[d].			

[a] Average must be 20 to 30% of span value.

[b] Average must be 45 to 55% of span value.

[c] Average must be 80 to 90% of span value.

[d] Must be <±10% of applicable average or 10 ppm, whichever is greater.

[Appendix A, Method 20]

5.3 Calibration Check. Conduct the calibration checks for both the NO_x and the diluent analyzers as follows:

[5.3 amended by 51 FR 32455, September 12, 1986]

5.3.1 After the measurement system has been prepared for use (Section 5.2), introduce zero gases and the mid-level calibration gases; set the analyzer output responses to the appropriate levels. Then introduce each of the remainder of the calibration gases described in Sections 4.3 or 4.4, one at a time, to the measurement system. Record the responses on a form similar to Figure 20-3.

5.3.2 If the linear curve determined from the zero and mid-level calibration gas responses does not predict the actual response of the low-level (not applicable for the diluent analyzer) and high-level gases within 2 percent of the span value, the calibration shall be considered invalid. Take corrective measures on the measurement system before proceeding with the test.

[5.3.2 amended by 51 FR 32455 September 12, 1986]

5.4 Interference Response. Introduce the gaseous components listed in Table 20-1 into the measurement system separately, or as gas mixtures. Determine the total interference output response of the system to these components in concentration units; record the values on a form similar to Figure 20-4. If the sum of the interference responses of the test gases for either the NO_x or diluent analyzers is greater than 2 percent of the applicable span value, take corrective measure on the measurement system.

[5.4 amended by 51 FR 32455, September 12, 1986]

FIGURE 20-3—ZERO AND CALIBRATION DATA

Turbine type ....

Date ....

Analyzer type ....

Identification number ....

Test number ....

Identification number ....

	Cylinder value, ppm or %	Initial analyzer response, ppm or %	Final analyzer responses, ppm or %	Difference: initial-final, ppm or %
Zero gas				
Low-level gas				
Mid-level gas				
High-level gas				

$$\text{Percent drift} = \frac{\text{Absolute difference}}{\text{Span value}} \times 100$$

TABLE 20-1—INTERFERENCE TEST GAS CONCENTRATION

CO.....	500±50 ppm	CO_2....................	10±1 percent.
SO_2.....	200±20 ppm	O_2....................	20.9±1 percent.

FIGURE 20-4—INTERFERENCE RESPONSE

Date of test ———————

Analyzer type ———————————————

Serial No. ———————————————

Test gas type	Concentration, ppm	Analyzer output response	% of span

$$\% \text{ of span} = \frac{\text{Analyzer output response}}{\text{Instrument span}} \times 100.$$

Conduct an interference response test of each analyzer prior to its initial use in the field. Thereafter, recheck the measurement system if changes are made in the instrumentation that could alter the interference response, e.g., changes in the type of gas detector.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20-1 the interference performance specification is not exceeded, are acceptable.

5.5 Response time. To determine response time, first introduce zero gas into the system at the calibration valve until all readings are stable; then, switch to monitor the stack effluent until a stable reading can be obtained. Record the upscale response time. Next, introduce high-level calibration gas into the system. Once the system has stabilized at the high-level concentration, switch to monitor the stack effluent and wait until a stable value is reached. Record the downscale response time. Repeat the procedure three times. A stable value is equivalent to a change of less than 1 percent of span value for 30 seconds or less than 5 percent of the measured average concentration for 2 minutes. Record the response time data on a form similar to Figure 20-5, the readings of the upscale or downscale reponse time, and report the greater time as the "response time" for the analyzer. Conduct a response time test prior to the initial field use of the measurement system, and repeat if changes are made in the measurement system.

FIGURE 20-5—RESPONSE TIME

Date of test ———————

Analyzer type ———————————————

S/N ———————————————

Span gas concentration: ——— ppm.

Analyzer span setting: ——— ppm.

Upscale:

1 ——— seconds.
2 ——— seconds.
3 ——— seconds.

Average upscale response ——— seconds.

Downscale:

1 ——— seconds.
2 ——— seconds.
3 ——— seconds.

Average downscale response ——— seconds.

System response time = slower average time = ——— seconds.

5.6 NO_2 to NO Conversion Efficiency.

5.6.1 Add gas from the mid-level NO in N_2 calibration gas cylinder to a clean, evacuated, leak-tight Tedlar bag. Dilute this gas approximately 1:1 with 20.9 percent O_2, purified air. Immediately attach the bag outlet to the calibration valve assembly and begin operation of the sampling system. Operate the sampling system, recording the NO_x response, for at least 30 minutes. If the NO_2 to

[Appendix A, Method 20]

NO conversion is 100 percent, the instrument response will be stable at the hightest peak valve observed. If the response at the end of 30 minutes decreases more than 2.0 percent of the highest peak value, the system is not acceptable and corrections must be made before repeating the check.

5.6.2 Alternatively, the NO_2 to NO converter check described in Title 40, Part 86: Certification and Test Procedures for Heavy-duty Engines for 1979 and Later Model Years may be used. Other alternative procedures may be used with approval of the Administrator.

6. Emission Measurement Test Procedure

6.1 Preliminaries.

6.1.1 Selection of a Sampling Site. Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling, and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler. The diameter of the sample ports shall be sufficient to allow entry of the sample probe.

6.1.2 A preliminary O_2 or CO_2 traverse is made for the purpose of selecting sampling points of low O_2 or high CO_2 concentrations, as appropriate for the measurement system. Conduct this test at the turbine operating condition that is the lowest percentage of peak load operation included in the test program. Follow the procedure below, or use an alternative procedure subject to the approval of the Administrator.

[6.1.2 revised by 51 FR 32455, September 12, 1986]

6.1.2.1 Minimum Number of Points. Select a minimum number of points as follows: (1) Eight, for stacks having cross-sectional areas less than 1.5 m² (16.1 ft²); (2) eight plus one additional sample point for each 0.2 M² (2.2 ft² of areas, for stacks of 1.5 m² to 10.0 m² (16.1-107.6 ft²) in cross-sectional area; and (3) 49 sample points (48 for circular stacks) for stacks greater than 10.0 m ² (107.6 ft ²) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20-2; therefore, round off the number of points (upward), when appropriate.

[6.1.2.2 and 6.1.2.3 amended by 51 FR 32455, September 12, 1986]

6.1.2.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary diluent sampling has been determined, use Method 1 to locate the traverse points.

6.1.2.3 Preliminary Diluent Measurement. While the gas turbine is operating at the lowest percent of peak load, conduct a preliminary diluent measurement as follows: Position the probe at the first traverse point and begin sampling. The minimum sampling time at each point shall be 1 minute plus the average system response time. Determine the average steady-state concentration of diluent at each point and record the data on Figure 20-6.

6.1.2.4 Selection of Emission Test Sampling Points. Select the eight sampling points at which the lowest O_2 concentrations or highest CO_2 concentrations were obtained. Sample at each of these selected points during each run at the different turbine load conditions. More than eight points may be used, if desired, providing that the points selected as described above are included.

[6.1.2.4 revised by 51 FR 32455, September 12, 1986]

TABLE 20-2—CROSS-SECTIONAL LAYOUT FOR RECTANGULAR STACKS

	Matrix layout
No. of traverse points:	
9	3 x 3
12	4 x 3
16	4 x 4
20	5 x 4
25	5 x 5
30	6 x 5
36	6 x 6
42	7 x 6
49	7 x 7

FIGURE 20-6—PRELIMINARY DILUENT TRAVERSE

Date ________

Location:
Plant ________
City, State ________

Turbine identification:
Manufacturer ________
Model, serial number ________

Sample point	Oxygen concentration, ppm

[Figure 20-6 amended by 51 FR 32455, September 12, 1986]

6.2 NO_x and Diluent Measurement. This test is to be conducted at each of the specified load conditions. Three test runs at each load condition constitute a complete test.

[6.2 amended by 51 FR 32455, September 12, 1986]

6.2.1 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20-7. Also, record the location and number of the traverse points on a diagram.

6.2.2 Position the probe at the first point determined in the preceding section and begin sampling. The minimum sampling time at each point shall be at least 1 minute plus the average system response time. Determine the average steady-state concentration of diluent and NO_x at each point and record the data on Figure 20-8.

[6.2.2 amended by 51 FR 32455, September 12, 1986]

FIGURE 20-7—STATIONARY GAS TURBINE DATA

TURBINE OPERATION RECORD

Test operator ________ Date ____

Turbine identification:
Type ________
Serial No. ________

Location:
Plant ________
City ________

Ambient temperature ________
Ambient humidity ________
Test time start ________
Test time finish ________
Fuel flow rate[a] ________
Water or steam Flow rate[a] ________
Ambient Pressure ________
Ultimate fuel Analysis:
C ________
H ________
O ________
N ________
S ________
Ash ________
H_2O ________
Trace Metals:
Na ________
Va ________
K ________
etc[b] ________
Operating load ________

---

[a] Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.

[b] i.e., additional elements added for smoke suppression.

FIGURE 20-8—STATIONARY GAS TURBINE SAMPLE POINT RECORD

Turbine identification:
Manufacturer ________
Model, serial No. ________

Location:
Plant ________
City, State ________

Ambient temperature ________
Ambient pressure ________
Date ______
Test time: start ________
Test time: finish ________
Test operator name ________
Diluent instrument type ________
Serial No ________

NO_x instrument type—————————

Serial No. —————————

Sample point	Time, min.	O_2*, %	NO_x*, ppm

*Average steady-state value from recorder or instrument readout.

[Figure 20-8 amended by 51 FR 32455, September 12, 1986]

6.2.3 After sampling the last point, conclude the test run by recording the final turbine operating parameters and by determining the zero and calibration drift, as follows:

Immediately following the test run at each load condition, or if adjustments are necessary for the measurement system during the tests, reintroduce the zero and mid-level calibration gases as described in Sections 4.3. and 4.4, one at a time, to the measurement system at the calibration valve assembly. (Make no adjustments to the measurement system until after the drift checks are made). Record the analyzers' responses on a form similar to Figure 20-3. If the drift values exceed the specified limits, the test run preceding the check is considered invalid and will be repeated following corrections to the measurement system. Alternatively, recalibrate the measurement system and recalculate the measurement data. Report the test results based on both the initial calibration and the recalibration data.

6.3 SO_2 Measurement. This test is conducted only at the 100 percent peak load condition. Determine SO_2 using Method 6, or equivalent, during the test. Select a minimum of six total points from those required for the NO_x measurements; use two points for each sample run. The sample time at each point shall be at least *10 minutes. Average the O_2 readings taken during the NO_x test runs at sample points corresponding to the SO_2 traverse points (see Section 6.2.2) and use this average O_2 concentration to correct the integrated SO_2 concentration obtained by Method 6 to 15 percent O_2 (see Equation 20-1).

If the applicable regulation allows fuel sampling and analysis for fuel sulfur content to demonstrate compliance with sulfur emission unit emission sampling with Method 6 is not required, provided the fuel sulfur content meets the limits of the regulation.

* 6.3 amended by 55 FR 47472, November 14, 1990]

7. Emission Calculations

[7. revised by 51 FR 32455, September 12, 1986]

7.1 Moisture Correction. Measurement data used in most of these calculations must be on a dry basis. If measurements must be corrected to dry conditions, use the following equation:

$$C_d = \frac{C_w}{1 - B_{ws}} \qquad \text{Eq. 20-1}$$

Where:

C_d = Pollutant or dilujent concentration adjusted to dry conditions, ppm or percent.

C_w = Pollutant or diluent concentrations measured under moist sample conditions, ppm or percent.

B_w= Moisture content of sample gas as measured with Method 4, reference method, or other approved method percent/100.

7.2 CO_2 Correction Factor. If pollutant concentrations are to be corrected to 15 percent O_2 and O_2 concentration is measured in lieu of O_2 concentratin measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as follows:

7.2.1 Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2 and the following equation.

$$F_o = \frac{0.209\ F_d}{F_c} \qquad \text{Eq. 20-2}$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air, dimensionless.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/10⁶ Btu).

F_c = Ratio of the volume of carbon dioxide produced to the gross calorific value of the fuel from Method 19, dsm³/J (dscf⁶ Btu).

7.2.2. Calculate the CO_2 correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{Eq. 20-3}$$

where:

X_{co} = CO_2 Correction factor, percent.

5.9 = 20.9 percent O_2 — 15 percent O_2, the defined O_2 correction value, percent.

7.3 Correction of Pollutant Concentrations to 15 percent O_2. Calculate the NO_x and SO_2 gas concentrations adjusted to 15 percent O_2 using Equation 20-4 or 20-5, as appropriate. The correction to 15 percent O_2 is very sensitive to the accuracy of the O_2 or CO_2 concentration measurement. At the level of the analyzer drift specified in Section 3, the O_2 or CO_2 correction can exceed 5 percent at the concentration levels expected in gas turbine exhaust gases. Therefore, O_2 or CO_2 analyzer stability and careful calibration are necessary.

7.3.1 Correction of Pollutant Concentration Using O_2 Concentration. Calculate the O_2 corrected pollutant concentration, as follows:

$$C_{adj} = C_d \frac{5.9}{20.9 - \%O_2} \qquad \text{Eq. 20-4}$$

where:

C_{adj} = Pollutant concentration corrected to 15 percent O_2 ppm.

C_d = Pollutant concentration measured, dry basis, ppm.

$\%O_2$ = Measured O2 concentration dry basis, percent.

7.3.2 Correction of Pollutant Concentration Using CO_2 corrected pollutant concentration, as follows.

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{Eq. 20-5}$$

where:

CO_2 = Measured CO_2 concentration measured, dry basis, percent.

7.4 Average Adjusted NO_x Concentration. Calculate the average adjusted NO_x concentration by summing the adjusted values for each sample point and dividing by the number of points for each run.

7.5 NO_x and SO_2 Emission Rate Calculations. The emission rates for NO_x and SO_2 in units of pollutant mass per quantity of heat input can be calculated using the pollutants and diluent concentrations and fuel specific F-factors based on the fuel combustion characteristics. The measured concentrations of pollutant in units of parts per million by volume (ppm) must be converted to mass per unit volume concentration units for these calculations. Use the following table for such conversions:

CONVERSION FACTORS FOR CONCENTRATION

From	To	Multiply by
g/sm^3	ng/sm^3	10^9
mg/sm^3	ng/sm^3	10^6
lb/scf	ng/sm^3	1.602×10^{13}
ppm (SO_2)	ng/sm^3	2.660×10^6
ppm (NO_x)	ng/sm^3	1.912×10^6
ppm (SO_2)	lb/scf	$1.660 \times 10-^7$
ppm (NO_x)	lb/scf	$1.194 \times 10-^7$

7.5.1 Calculation of Emission Rate Using Oxygen Correction. Both the O_2 concentration and the pollutant concentration must be on a dry basis. Calculate the pollutant emission rate, as follows:

$$E=C_dF_d \frac{20.9}{20.9-\%O_2} \qquad \text{Eq. 20-6}$$

where:

E=Mass emission rate of pollutant, ng/J ($lb/10^6$ Btu).

7.5.2 Calculation of Emission Rate Using Carbon Dioxide Correction. The CO_2 concentration and the pollutant concentration may be on either a dry basis or a wet basis, but both concentrations must be on the same basis for the calculations. Calculate the pollutant emission rate using Equation 20-7 or 20-8:

$$E=C_dF_c \frac{100}{\%CO_2} \qquad \text{Eq. 20-7}$$

$$E=C_wF_c \frac{100}{\%CO_{2w}} \qquad \text{Eq. 20-8}$$

where:

C_w=Pollutant concentration measured on a moist sample basis, ng/sm^3 (lb/scf).

$\%CO_{2w}$=Measured CO_2 concentration measured on a moist sample basis, percent.

8. *Bibliography*

1. Curtis, F. A Method for Analyzing NO_x Cylinder Gases-Specific Ion Electrode Procedure, Monograph available from Emission Measurement Laboratory, ESED, Research Triangle Park, NC 27711, October 1978.

2. Sigsby, John E., F. M. Black, T. A. Bellar, and D. L Klosterman. Chemiluminescent Method for Analysis of Nitrogen Compounds in Mobile Source Emissions (NO, NO_2, and NH_3). "Environmental Science and Technology," 7:51-54. January 1973.

3. Shigehara, R.T., R.M. Neulicht, and W.S. Smith. Validating Orsat Analysis Data from Fossil Fuel-Fired Units. Emission Measurement Branch, Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC 27711. June 1975.

METHOD 21—DETERMINATION OF VOLATILE ORGANIC COMPOUNDS LEAKS

1. *Applicability and Principle*

1.1 Applicability. This method applies to the determination of volatile organic compound (VOC) leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

1.2 Principle. A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in Section 3. A leak definition concentration based on a reference compound is specified in each applicable regulation. This procedure is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rates from individual sources.

2. *Definitions*

2.1 Leak Definition Concentration. The local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound.

2.2 Reference Compound. The VOC species selected as an instrument calibration basis for specification of the leak definition concentration. (For example: If a leak definition concentration is 10,000 ppmv as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument calibrated with methane would be classified as a leak. In this example, the leak definition is 10,000 ppmv, and the reference compound is methane.)

2.3 Calibration Gas. The VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a concentration approximately equal to the leak definition concentration.

2.4 No Detectable Emission. Any VOC concentration at a potential leak source (adjusted for local VOC ambient concentration) that is less than a value corresponding to the instrument readability specification of section 3.1.1(c) indicates that a leak is not present.

[Revised by 55 FR 25604, June 22, 1990]

2.5 Response Factor. The ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the application regulation.

2.6 Calibration Precision. The degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

2.7 Response Time. The time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

3. *Apparatus*

3.1 Monitoring Instrument.

3.1.1 Specifications.

a. The VOC instrument detector shall respond to the compounds being processed. Detector types which may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infrared absorption, and photoionization.

b. — e. revised and f. added by 55 FR 25604, June 22,1990]

b. Both the linear response range and the measurable range of the instrument for each of the VOC to be measured, and for the VOC calibration gas that is used for calibration, shall encompass the leak definition concentration specified in the regulation. A dilution probe assembly may be used to bring the VOC concentration within both ranges; however, the specifications for instrument response time and sample probe diameter shall still be met.

c. The scale of the instrument meter shall be readable to ±2.5 percent of the specified leak definition concentration when performing a no detectable emission survey.

d. The instrument shall be equipped with an electrically driven pump to insure that a sample is provided to the detector at a constant flow rate. The nominal sample flow rate, as measured at the sample probe tip, shall be 0.10 to 3.0 liters per minute when the probe is fitted with a glass wool plug or filter that may be used to prevent plugging of the instrument.

e. The instrument shall be intrinsically safe as defined by the applicable U.S.A. standards (e.g., National Electric Code by the National Fire Prevention Association) for operation in any explosive atmospheres that may be encountered in its use. The instrument shall, at a minimum, be intrinsically safe for Class 1, Division 1 conditions, and Class 2, Division 1 conditions, as defined by the example Code. The instrument shall not be operated with any safety device, such as an exhaust flame arrestor, removed.

f. The instrument shall be equipped with a probe or probe extension for sampling not to exceed ¼ in. in outside diameter, with a single end opening for admission of sample.

3.1.2 Performance Criteria.

[(a) and (b) revised by 55 FR 25604, June 22, 1990]

(a) The instrument response factors for each of the VOC to be measured shall be less than 10. When no instrument is available that meets this specification when calibrated with the reference VOC specified in the applicable regulation, the available instrument may be calibrated with one of the VOC to be measured, or any other VOC, so long as the instrument then has a response factor of less than 10 for each of the VOC to be measured.

(b) The instrument response time shall be equal to or less than 30 seconds. The instrument pump, dilution probe (if any), sample probe, and probe filter, that will be used during testing, shall all be in place during the response time determination.

c. The calibration precision must be equal to or less than 10 percent of the calibration gas value.

d. The evaluation procedure for each parameter is given in Section 4.4.

3.1.3 Performance Evaluation Requirements.

a. A response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated at subsequent intervals.

b. The calibration precision test must be completed prior to placing the analyzer into service, and at subsequent 3-month intervals or at the next use whichever is later.

c. The response time test is required prior to placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required prior to further use.

3.2 Calibration Gases. The monitoring instrument is calibrated in terms of parts per million by volume (ppmv) of the reference compound specified in the applicable regulation. The calibration gases required for monitoring and instrument performance evaluation are a zero gas (air, less than 10 ppmv VOC) and a calibration gas in air mixture approximately equal to the leak definition specified in the regulation. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within ±2 percent accuracy, and a shelf life must be specified. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life. Alternately, calibration gases may be prepared by the user according to any accepted gaseous standards preparation procedure that will yield a mixture accurate to within ±2 percent. Prepared standards must be replaced each day of use unless it can be demonstrated that degradation does not occur during storage.

Calibrations may be performed using a compound other than the reference compound if a conversion factor is determined for that alternative compound so that the resulting meter readings during source surveys can be converted to reference compound results.

4. *Procedures*

4.1 Pretest Preparations. Perform the instrument evaluation procedures given in Section 4.4 if the evaluation requirements of Section 3.1.3 have not been met.

4.2 Calibration Procedures. Assemble and start up the VOC analyzer according to the manufacturer's instructions. After the appropriate warmup period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value.

NOTE: If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated and corrective actions are necessary before use.

4.3 Individual Source Surveys.

4.3.1 Type I—Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

a. Valves—The most common source of leaks from valves is at the seal between the stem and housing. Place the probe at the interface where the stem exits the packing gland and sample the stem circumference. Also, place the probe at the interface of the packing gland take-up flange seat and sample the periphery. In addition, survey valve housings of multipart assembly at the surface of all interfaces where a leak could occur.

b. Flanges and Other Connections—For welded flanges, place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange. Sample other types of nonpermanent joints (such as threaded connections) with a similar traverse.

c. Pumps and Compressors—Conduct a circumferential traverse at the outer surface of the pump or compressor shaft and seal interface. If the source is a rotating shaft, position the probe inlet within 1 cm of the shaft-seal interface for the survey. If the housing configuration prevents a complete traverse of the shaft periphery, sample all accessible portions. Sample all other joints on the pump or compressor housing where leakage could occur.

d. Pressure Relief Devices—The configuration of most pressure relief devices prevents sampling at the sealing seat interface. For those devices equipped with an enclosed ex-

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

March 31, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John P. Jones, President
Orlando CoGen Inc.
7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

Dear Mr. Jones:

Re: Completeness Review for Application to Construct a Combustion Turbine and Associated Heat Recovery Steam Generator
AC 48-206720 and PSD-FL-184

The Department has reviewed the supplementary information received on March 2, 1992. Based on a technical evaluation of the material, the application package is deemed incomplete. Therefore, please submit to the Department's Bureau of Air Regulation the following information, including all calculations, assumptions and reference material, and the status will, again, be ascertained:

1. Please provide additional clarification and completed calculations for items on the page numbered as Notes-1, which were discussed in a meeting held on March 11 between Messrs. Ken Kosky (KBN) and Bruce Mitchell (FDER/BAR).

2. Please provide a floppy disk containing the data that was used to calculate and generate the information found in Tables A-1 thru A-4.

Sincerely,

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

CHF/BM/plm

cc: C. Collins, CD
D. Nester, OCEPD
G. Smallridge, Esq., DER
C. Shaver, NPS
J. Harper, EPA
D. Buff, P.E., KBN

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. John P. Jones, President
Orlando CoGen Inc.
7201 Hamilton Blvd.
Allentown, PA 18195-1501

4a. Article Number
P 617 884 161

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

7. Date of Delivery
4-6-92

5. Signature (Addressee)
Tony Hetrick

6. Signature (Agent)

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

PS Form **3811**, November 1990 ☆U.S. GPO: 1991—287-066 **DOMESTIC RETURN RECEIPT**

P 617 884 161

Certified Mail Receipt

No Insurance Coverage Provided
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(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to
Mr. John P. Jones, Orlando CoGen Inc.

Street & No.
7201 Hamilton Blvd.

P.O., State & ZIP Code
Allentown, PA 18195-1501

Postage	$
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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: 3-31-92
Permit: AC 48-206720
PSD-FL-184

PS Form **3800**, June 1990

KBN

RECEIVED

MAR 25 1992

Bureau of
Air Regulation

March 24, 1992

Bruce Mitchell
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Bruce:

Please find attached for your consideration and use a proposed permit package for the Orlando CoGen project. I have tailored this after the recently issued Pasco and Lake Cogen permits. I have also enclosed a copy of the text on disk, both 3½ and 5¼, in both WordPerfect 5.1 and DOS files.

Sincerely,

Ken

Kennard F. Kosky
President

KFK/dmm
cc: File (2)

91134B1/R2/1

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

Technical Evaluation
and
Preliminary Determination

Orlando CoGen Limited, L.P.
Orange County, Florida

128-MW Combined Cycle Gas Turbine Cogeneration Facility

Permit Number: AC 48-206720
PSD-FL-184

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

April 1992

SYNOPSIS OF APPLICATION

I. NAME AND ADDRESS OF APPLICANT

Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

II. REVIEWING AND PROCESS SCHEDULE

Date of Receipt of Application: December 30, 1991.

III. FACILITY INFORMATION

III.1 Facility Location

This facility is located in Orlando Central Park in Orange County, Florida. The UTM coordinates are 459.5 km East and 3,146.1 km North.

III.2 Facility Identification Code (SIC)

Major Group No. 49 - Electric, Gas and Sanitary Services.

Industry Group No. 493 - Combination Electric, Gas and Other Utility Services.

Industry Group No. 4931 - Electric and Other Services Combined.

III.3 Facility Category

The proposed facility will be classified as a major emitting facility. The proposed project will emit approximately 401 tons per year (TPY) of nitrogen oxides (NO_x), 12 TPY of sulfur dioxide (SO_2), 42 TPY of particulate matter (PM), 115 TPY of carbon monoxide, 20 TPY of volatile organic compounds (VOC), and 0.9 TPY of sulfuric acid mist.

IV. PROJECT DESCRIPTION

Orlando CoGen Limited, L.P. proposes to construct and operate a nominal 128-MW combined cycle gas turbine cogeneration facility. The unit will be located adjacent to the Air Products and Chemicals plant. The project will consist of one combustion turbine (CT), a heat recovery steam generator (HRSG) with duct burner, and a steam cycle. The combustion turbine will be capable of generating approximately 78 MW while operating in simple cycle and 128 MW when in combined cycle operation. The combined cycle HRSG will power a 50-MW steam turbine-generator. The HRSG with supplemental firing of duct burner will supply steam to an absorption chiller system which will supply chilled water to the Air Products and Chemicals Plant located adjacent to the site. The fuel will be natural gas.

V. RULE APPLICABILITY

The proposed project is subject to preconstruction review under the provisions of Chapter 403, Florida Statutes, and Chapter 17-2, Florida Administrative Code (F.A.C.).

The plant is located in an area designated attainment for all criteria pollutants in accordance with F.A.C. Rule 17-2.420.

The proposed project will be reviewed under F.A.C. Rule 17-2.500, Prevention of Significant Deterioration (PSD), because it will be a major facility. This review consists of a determination of Best Available Control Technology (BACT) and unless otherwise exempted, an analysis of the air quality impact of the increased emissions. No air quality impact analysis is required for ozone and there will not be a significant increase in VOC emissions. The review also includes an analysis of the project's impacts on soils, vegetation and visibility; along with air quality impacts resulting from associated commercial, residential and industrial growth.

This source shall be required to comply with the New Source Performance Standards (NSPS) for Gas Turbines, Subpart GG, and NSPS for Industrial Steam-Generating Units, Subpart Db, which are contained in 40 CFR 60, Appendix A and is adopted by reference in F.A.C. Rule 17-2.660. The proposed source shall also comply with applicable provisions of F.A.C. Rule 17-2.700, Stack Test Procedures, and F.A.C. Rule 17-2.630, Best Available Control Technology.

VI. SOURCE IMPACT ANALYSIS

VI.1 Emission Limitations

The operation of the combined cycle plant will produce emissions of NO_x, SO_2, CO, VOC, sulfuric acid mist, PM, and PM_{10}. The impact of these pollutant emissions are below the Florida ambient air quality standards (AAQS) and/or the acceptable ambient concentration levels (AAC). Table 1 lists each contaminant and its maximum expected emission rate, along with the proposed increase of emissions.

VI.2 Air Toxics Evaluation

The operation of this source will produce emissions of chemical compounds that may be toxic in high concentrations. The emission rates of these chemicals shall not create ambient concentrations greater than the acceptable ambient concentrations (AAC) as shown below. Determination of the AAC for these organic compounds shall be determined by Department approved dispersion modeling or ambient monitoring.

$$AAC = \frac{OEL}{\text{Safety Factor}}$$

Where,

AAC = acceptable ambient concentration

Safety Factor = 50 for category B substances and 8 hrs/day
100 for category A substances and 8 hrs/day
210 for category B substances and 24 hrs/day
420 for category A substances and 24 hrs/day

OEL = Occupational exposure level such as ACGIH, ASHA and NIOSH published standards for toxic materials.

MSDS = Material Safety Data Sheets

VI.3 Air Quality Analysis

a. Introduction

The operation of the proposed 128 MW combined cycle gas turbine system will result in emissions increases which are projected to be greater than the PSD significant emission rates for the following pollutants: CO, NO_x, PM, and PM_{10}. Therefore, the project is subject to the PSD review requirements contained in F.A.C. Rule 17-2.500 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_x);
- 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 combined cycle gas turbine cogeneration facility, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any PSD increment or ambient air quality standard. 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 review is given below:

	CO	TSP and PM_{10}	NO_x
PSD de minimus Concentration ($\mu g/m^3$)	575	10	14
Averaging Time	8-hr	24-hr	Annual
Maximum Predicted Impact ($\mu g/m^3$)	12.0	2.4	0.6

As shown above, the predicted impacts are all less than the corresponding de minimus concentrations; therefore, no preconstruction monitoring is required for any pollutant.

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. Direction-specific downwash parameters were used because the stack was less than the good engineering practice (GEP) stack height. Five years of sequential hourly surface and mixing depth data from the Orlando, Florida National Weather Service (NWS) station collected during 1982 through 1986 were used in the model. Since five years for data were used, the highest-second-high 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 CO, NO_x, PM and PM_{10}. Dispersion modeling was performed with receptors placed along the 36 standard radial directions (10 degrees apart) surrounding the proposed source at the following downwind distances: 47; 100; 300; 600; 900; 1,200; 1,600; 2,000; 2,500; 3,000; 4,000; and 5,000 meters. Refined analyses were then performed to determine maximum impacts. 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}.

Pollutant	Averaging Time	PSD Significance Level ($\mu g/m^3$)	Ambient Concentration Increase ($\mu g/m^3$)
CO	8-hour	500	47.0
	1-hour	2000	12.0
NO_2	Annual	1.0	0.61
PM/PM_{10}	Annual	1.0	0.07
	24-hour	5.0	2.44

Therefore, further dispersion modeling for comparison with AAQS and PSD increment consumption were not required in this case.

The applicant performed dispersion modeling to determine the predicted ambient concentration increases in the Class I Chassahowitzka National Wilderness Area located 121 km away for the pollutants with Class I increments. The maximum predicted PM increases are 0.001 $\mu g/m^3$ for the annual averaging time and 0.02 for the 24-hr averaging time. The maximum predicted NO_2 increase is 0.01 $\mu g/m^3$ for the annual averaging time. These predicted values are all much less than the corresponding Class I increments and the EPA Class I significant impact levels.

e. Additional Impacts Analysis

The emissions from the Orlando CoGen Limited, L.P., facility are not expected to affect the visibility in the Chassahowitzka National Wilderness area located 121 km away because of the very small maximum predicted impacts. Because the impacts from the proposed pollutants are predicted to be less than PSD significance levels, no harmful effects on soils and vegetation is expected. In addition, 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.

VII. CONCLUSION

Based on the information provided by Orlando CoGen Limited, L.P., the Department has reasonable assurance that the proposed installation of the 128 MW combined cycle gas turbine system, 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.

State of Florida
Department of Environmental Regulation
Notice of Intent to Issue

The Florida Department of Environmental Regulation hereby gives notice of its intent to issue a permit to Orlando CoGen Limited, L.P., 7201 Hamilton Boulevard, Allentown, PA 18195-1501, to construct and operate a nominal 128-MW combined cycle gas turbine cogeneration facility located in Orange County, Florida. A determination of Best Available Control Technology (BACT) was required. The Class I PM_{10} PSD increment consumed is 0.02 vs. 8 allowable 24-hour average and 0.001 vs. 4 allowable annual average, in micrograms per cubic meter. The Class I nitrogen dioxide increment consumed is 0.01 vs. 2.5 allowable annual average, in micrograms per cubic meter. The maximum predicted increases in ambient concentrations for the above three pollutants for all averaging times are less than significant in the Class II area surrounding the plant, thus no increment consumption was calculated. 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 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 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 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
Central District
3319 Maguire Blvd.
Orlando, Florida 32803-3767

Any person may send written comments on the proposed action to Mr. Barry Andrews at the Department's Tallahassee address. All comments mailed 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.

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

In the Matter of
Application for Permit by:

Orlando CoGen Limited, L.P.
7201 Hamilton Blvd.
Allentown, PA 18195-1501

DER File No. AC 48-206720
PSD-FL-184

INTENT TO ISSUE

The Department of Environmental Regulation hereby gives notice of its intent to issue an air construction permit (copy attached) for the proposed project as detailed in the application specified above. The Department is issuing this Intent to Issue for the reasons stated in the attached Technical Evaluation and Preliminary Determination.

The applicant, Orlando CoGen Limited, L.P., applied on December 30, 1991, to the Department of Environmental Regulation for a permit to construct and operate a nominal 128-MW cogeneration facility consisting of one combined cycle gas turbine generator and associated steam cycle.

The Department has permitting jurisdiction under Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. The project is not exempt from permitting procedures. The Department has determined that an air construction permit is required for the proposed work.

Pursuant to Section 403.815, F.S. and DER 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. The applicant shall provide proof of publication to the Department, at the address specified 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 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 notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the application(s) 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 in 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

Copies furnished to:

Charles Collins, CD
Jewell Harper, EPA

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this NOTICE OF INTENT TO ISSUE and all copies were mailed before the close of business on ________________.

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

__________________ __________
Clerk Date

Best Available Control Technology (BACT) Determination
Orlando CoGen Limited, L.P.
Orange County

The applicant proposes to install a combustion turbine generator at its facility in Orange County. The generator system will consist of one nominal 78-megawatt (MW) combustion turbine, with exhaust through heat recovery steam generator (HRSG) which will be used to power nominal 50-MW steam turbine. The HRSG will be supplementary fired to produce sufficient steam at higher operating temperatures.

The combustion turbine will be capable of combined cycle operation. The applicant requested that the combustion turbine use only natural gas. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity and type of fuel fired at ISO conditions to be as follows:

Pollutant	Potential Emissions (TPY)	PSD Significant Emission Rate (TPY)
NO_x	400.9	40
SO_2	12.02	40
PM	41.67	25
PM_{10}	41.67	15
CO	114.6	100
VOC	19.8	40
H_2SO_4	0.92	7
Be	Neg.	0.0004
Hg	Neg.	0.1
Pb	Neg.	0.6

Florida Administrative Code Rule 17-2.500(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

December 30, 1991

BACT Determination Requested by the Applicant

Pollutant	Determination
NO_x	25 ppmvd @ 15% O_2 (natural gas burning)--CT 0.1 lb/10^6 Btu--duct burner
CO	Combustion control
PM and PM_{10}	Combustion control

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.

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

- Combustion Products (e.g., particulates). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (e.g., CO). Control is achieved largely by proper combustion techniques.
- Acid Gases (e.g., NO_x). Controlled generally by gaseous control devices.

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

Combustion Products

The projected emissions of particulate matter and PM_{10} from the Orlando CoGen Limited, L.P. facility surpass the significant emission rates given in Florida Administrative Code Rule 17-2.500, Table 500-2.

A PM/PM_{10} emissions limitations of 0.011 lb/MMBtu from the CT when firing natural gas is reasonable as BACT for the Orlando CoGen facility. The duct burner PM/PM_{10} emission rate of 0.01 lb/MMBtu is reasonable as BACT.

Products of Incomplete Combustion

The emissions of carbon monoxide emissions exceed PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emission rate from the proposal turbine is based on exhaust concentrations of 10 ppmvd for natural gas firing.

A review of the BACT/LAER clearinghouse indicates that several of the combustion turbines using dry low-NO_x combustion technology to control NO_x to 25 ppmvd (corrected to 15 percent O_2) have been permitted with CO limitations that are higher than those proposed by the applicant. The applicant has stated that the CT is a new design, and CO margins must be higher. The majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, additional 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. The existing gas turbine applications have been limited to smaller cogeneration facilities burning natural gas.

Given the applicant's proposed BACT level for carbon monoxide of 10 ppm, a lower emission rate as BACT would not produce a significant reduction in emissions or impacts. Also, this CO concentration level is near the lowest established as BACT even with catalytic oxidation. For these reasons, it appears that the limit proposed by the applicant is reasonable as BACT.

Emission of volatile organic compounds are each below the significant level and therefore do not require a BACT analysis.

Acid Gases

The emissions of nitrogen oxides represent a significant proportion of the total emissions and need to be controlled if deemed appropriate.

The applicant has stated that BACT for nitrogen oxides will be met by using dry low-NO_x combustion to limit emissions to 25 ppmvd at 15% oxygen when burning natural gas.

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 at 15% oxygen. 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.

A review of the combined cycle facilities in which SCR has been established as a BACT requirement indicates that the majority of these facilities are also intended to operate at high capacity factors. As this is the case, the proposed project is similar to other facilities in which SCR has been established as BACT.

Given the applicant's proposed BACT level for nitrogen oxides control stated above, an evaluation can be made of the cost and associated benefit of using SCR as follows:

The applicant has indicated that the total levelized annual cost (operating plus amortized capital cost) to install SCR for natural gas firing at 100 percent capacity factor is $1,903,000. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

Based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions with dry low-NO_x combustion from the Orlando CoGen facility will be 401 tons/year. Assuming that SCR would reduce the NO_x emissions to a level of 9 ppmvd when firing natural gas, about 141 tons of NO_x would be emitted annually. When this reduction is taken into consideration with the total levelized annual cost of $1,903,000, the cost per ton of controlling NO_x is $7,319. This calculated cost is higher than has previously been approved as BACT.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics.

In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement was made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

For fuel oil firing, the cost associated with controlling NO_x emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now 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 operation 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.

Based on this strategy SCR has been both proposed and 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 established.

The Orlando CoGen facility has proposed not to utilize fuel oil; therefore, those consequences of SCR attributable to oil firing will not likely occur. However, the small amount of sulfur in natural gas would likely form ammonium salts.

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NO_x control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NO_x control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Also, air emissions result from the lost generations that must be replaced. The lost generation is due to the back pressure on the turbine covered by the catalyst. Although the use of SCR does have some environmental impacts, the disadvantages may outweigh the benefit which would be provided by reducing nitrogen oxide emissions by 80 percent or greater. The benefit of NO_x control by using SCR is substantiated by the fact that nearly one half of all BACT determinations have established SCR as the control measure for nitrogen oxides over the last 5 years.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of natural gas have been evaluated. Toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than 0.1 TPY.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of natural gas.

Potentially Sensitive Concerns

With regard to controlling NO_x emissions with SCR, the applicant has identified the following technical limitations:

1. SCR would reduce output of combustion turbines by one-half percent.

2. SCR could result in the release of unreacted quantities of ammonia to the atmosphere.
3. SCR would require handling of ammonia by plant operators. Since it is a hazardous material, there is a concern about safety and productivity of operators.
4. SCR results in contaminated catalyst from flue gas trace elements which could be considered hazardous. Safety of operators and disposal of spent catalyst is a concern.

The combustion turbine proposed for the project (ABB 11N-EV) is a heavy-frame machine that is highly efficient and uses advanced dry low-NO_x combustion technology. Information supplied by the applicant indicates that actual emissions will be 25 ppmvd or lower on a continuous basis. The manufacturer's guarantee is 25 ppm; the Department, the applicant, and the manufacturer expect lower emissions.

BACT Determination by DER

NO_x Control

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, capacity factors ranging from low to high). However, the cost and other concerns expressed by the applicant are valid, and advanced NO_x combustion controls have been accepted as BACT on similar projects.

The information that the applicant presented and Department calculations indicates that the incremental cost of controlling NO_x ($7,319/ton) is high compared to other BACT determinations which require SCR. Furthermore, actual NO_x levels are expected to be less than the 25 ppm guarantee which would increase the cost effectiveness of SCR. Based on the information presented by the applicant and the studies conducted, the Department believes that the use of SCR for NO_x control is not justifiable as BACT. Therefore, the Department is willing to accept for NO_x control when firing natural gas.

The emissions of NO_x from the duct burners will be limited to 0.1 lb/MMBtu which has been the BACT limit established for similar facilities. Duct firing will be used for supplying steam and limited to an equivalent to 4,500 hours/year at 100 MMBtu/hr.

The emission limits for the Orlando CoGen Limited, L.P. project are thereby established as follows:

Pollutant	Emission Limit CT (Natural Gas Firing)	Duct Burner[a]
NOx	25 ppmvd @ 15% O_2	0.1 lb/MMBtu
CO	10 ppmvd	0.1 lb/MMBtu
PM & PM10	0.011 lb/MMBtu	0.01 lb/MMBtu

[a] Natural gas will be used only for supplemental firing for no greater than 4,500 full-load equivalent hours at 100 MMBtu/hr on a total annual Btu basis.

<u>Details of the Analysis May Be Obtained by Contacting</u>:

Bruce Mitchell, P.E., BACT Coordinator
Department of Environmental Regulation
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	Carol M. Browner, Secretary Dept. of Environmental Regulation
______________ 1992 Date	______________ 1992 Date

Table 1. Allowable Emission Limits Combined Cycle Combustion Turbine Cogeneration Facility

Pollutant	Source[a]	Fuel[b]	Basis of Limit	Allowable Emission Limits lb/hr/source	 tons/year/facility
NO_x	CT	NG	BACT: 25 ppmvd at 15% O_2	95.7	400.9
	DB	NG	BACT: 0.1 lb/MMBtu	12.2	
CO	CT	NG	BACT: 10 ppmvd	22.3	114.6
	DB	NG	BACT: 0.1 lb/MMBtu	12.2	
PM/PM_{10}	CT	NG	BACT: 0.011 lb/MMBtu	11.0	41.67
	DB	NG	BACT: 0.01 lb/MMBtu	1.22	
VOC	CT	NG	Proposed by Applicant	3.18	19.75
	DB	NG	Proposed by Applicant	3.7	

[a] CT = combustion turbine
DB = duct burner

[b] NG = natural gas

PERMITTEE:
Orlando CoGen Limited, L.P.
7201 Hamilton Blvd.
Allentown, PA 18195-1501

Permit Number: AC 48-206720
Expiration Date: June 1, 1994
County: Orange
Latitude/Longitude: 28°26'23"N
81°24'28"W
Project: 128-MW Combined Cycle
Gas Turbine

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 128-MW combined cycle gas turbine cogeneration facility to be located in Orlando Central Park and supply steam to the adjacent Air Products and Chemicals plant in Orange County, Florida. The UTM coordinates are 459.5 km East and 3,146.1 km North.

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. Orlando CoGen Limited's application dated December 19, 1991.
2. Department's sufficiency request dated January 28, 1992.
3. Letter from KBN Engineering and Applied Science, Inc., dated February 27, 1992, to supply additional information.

PERMITTEE:
Orlando CoGen Limited, L.P.

Permit Number: AC 48-206720
Expiration Date: June 1, 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.

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

GENERAL CONDITIONS:

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.

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:

Emission Limits

1. The maximum allowable emissions from this facility shall not exceed the emission rates listed in Table 1.

2. Unless the Department has determined other concentrations are required to protect public health and safety, predicted acceptable ambient air concentrations (AAC) of the following pollutants shall not be exceeded:

PERMITTEE:
Orlando CoGen Limited, L.P.

Permit Number: AC 48-206720
Expiration Date: June 1, 1994

SPECIFIC CONDITIONS:

Pollutant	Acceptable Ambient Concentrations $\mu g/m^3$ 8 Hours	24 Hours	Annual
Beryllium	0.02	0.005	0.0004
Lead	1.5	0.36	0.09
Mercury: allyl compounds	0.1	0.024	-
• all forms of vapor except allyl	0.5	0.12	-
• allyl & organic compounds	1	0.24	

3. Visible emissions shall not exceed 10% opacity.

Operating Rates

4. This source is allowed to operate continuously (8,760 hours per year).

5. This source is allowed to use natural gas as the primary fuel.

6. The permitted materials and utilization rates for the combined cycle gas turbine shall not exceed the values as follows:

- Maximum heat input shall not exceed 829.6 MMBtu/hr/CT (gas) at ISO conditions.
- Duct firing shall be limited to natural gas firing only with a maximum heat input of 122 MMBtu/hr.
- Duct firing shall be limited to 450,000 MMBtu/year/HRSG-duct burner, which is an equivalent to 4,500 hours at 100 MMBtu/hour.

7. Any change in the method of operation, equipment or operating hours shall be submitted to the DER's Bureau of Air Regulation and Central District offices.

8. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility shall be included in the operating permit.

Compliance Determination

9. Compliance with the NO_x, CO, and visible emission standards shall be determined by the following reference methods as described in 40 CFR 60, Appendix A (July 1, 1990) and adopted by reference in F.A.C. Rule 17-2.700.

PERMITTEE:
Orlando CoGen Limited, L.P.

Permit Number: AC 48-206720
Expiration Date: June 1, 1994

SPECIFIC CONDITIONS:

- Method 1. Sample and Velocity Traverses
- Method 2. Volumetric Flow Rate
- Method 3. Gas Analysis
- Method 9. Determination of the Opacity of the Emissions from Stationary Sources
- Method 10. Determination of the Carbon Monoxide Emission from Stationary Sources
- Method 20. Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines

10. An initial compliance test shall be performed using natural gas.

11. Compliance with the SO_2 emission limit can also be determined by calculations based on fuel analysis from the natural gas supplier.

12. Compliance with the total volatile organic compound emission limits will be assumed, provided the CO allowable emission rate is achieved; specific VOC compliance testing is not required.

13. During performance tests,, to determine compliance with the proposed NO_x standard, measured NO_x emission at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_{x\ obs}) \left[\frac{(P_{ref})}{P_{obs}}\right] 0.5 \quad e^{19\ (H_{obs}\ -\ 0.00633)} \left[\frac{(288^{\circ}K)}{T_{AMB}}\right] 1.53$$

where:

NO_x = Emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x\ obs}$ = Measured NO_x emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{AMB} = Temperature of ambient air at test.

SPECIFIC CONDITIONS:

14. Test results will be the average of 3 valid runs. The Central District office will be notified at least 30 days in advance of the compliance test. The source shall operate between 90% and 100% of permitted capacity as adjusted for ambient temperature during the compliance test. Compliance test results shall be submitted to the Central District office no later than 45 days after completion.

15. Dry low-NO_x combustion shall be utilized for NO_x control. The NO_x emissions shall be continuously monitored using procedures specified in 40 CFR Part 60.

Rule Requirements

16. This source shall comply with all applicable provisions of Chapter 403, Florida Statutes and Chapters 17-2 and 17-4, Florida Administrative Code.

17. This source shall comply with all requirements of 40 CFR 60, Subparts GG and Db and F.A.C. Rule 17-2.660(2)(a), Standards of Performance for Stationary Gas Turbines and Standards of Performance for Industrial, Commercial, and Institutional Steam Generating Units.

18. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-2.210(1)).

19. This source shall comply with F.A.C. Rule 17-2.700, Stationary Point Source Emission Test Procedures.

20. Pursuant to F.A.C. Rule 17-2.210(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur, nitrogen content and lower heating value of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual reports shall be sent to the Department's Southwest District office.

21. 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).

SPECIFIC CONDITIONS:

22. An application for an operation permit must be submitted to the Central District office at least 90 days prior to the expiration date of this construction permit or within 45 days after completion of compliance testing, whichever occurs first. 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. Rule 17-4.220).

Issued this _______ day
of _________________, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
Carol M. Browner, Secretary

CONTACT REPORT

DATE: 3-23-92 **ORIGINATOR:** Heather V. Rooney

CONTACT BY: _X_ TELEPHONE ____ MEETING OTHER: __________

NAME, TITLE, AND ORGANIZATION

Mr. Preston Lewis
Florida Department of Environmental Regulation

ADDRESS AND TELEPHONE NUMBER

Mr. Preston Lewis
Florida Department of Environmental Regulation
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400
(904)488-1344

CONTACT SUMMARY

Mr. Lewis was contacted to request cooperation in identifying and supplying the following information: state and local regulations for stationary gas turbines and the basis of those regulations; general emission test data for stationary gas turbines; and copies of permits for stationary gas turbines.

Mr. Lewis stated that the state emission regulations for Florida are more stringent than the Federal regulations. The majority of the turbines are utilized for utility power generation and are regulated through a BACT review. BACT determinations are decided on a case by case basis for those turbines over 250,000 Btu/hr. The BACT determinations for Florida have primarily been combustion controls either with or without wet injection. In addition, many of the determinations require the facilities to ensure that the necessary space is available for future SCR installation if it is deemed necessary. The BACT NOx emission limits are 25 ppm for gas and 42 ppm for oil. In addition a CO catalyst may be required if CO emission levels exceed 42 ppm. Mr. Lewis stated that CO levels have been more favorable with dry Low NOx combustor controls than with wet Low NOx combustor controls.

Mr. Lewis also stated that compliance testing is required shortly after the turbine is operational and then either once a year or every three years depending on the permitting requirements. The compliance tests require monitoring of criteria pollutants and air toxics. Continuous Emission Monitors (CEMs) are required for monitoring NOx and SO2 for the major sources.

Confirmation Signature and Date

Recd, Ck 272703 1824

KBN

February 27, 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

Subject: Orange County - A.P.
Orlando CoGen Limited, L.P.
Combustion Turbine and Heat Recovery Steam Generator
AC 48-206720 and PSD-FL-184

RECEIVED
MAR 0 2 1992
Division of Air
Resources Management

Attention: Bruce Mitchell

Dear Bruce:

This correspondence provides the information requested in the Department's letter dated January 28, 1992. A discussion of the items is presented in the same order as listed in the January 28th letter.

1. As described in the introduction to Appendix A, all emission calculations are performed on a Lotus 1-2-3 spreadsheet. A printout showing all equations was also presented. This printout was annotated to show the source of all data not calculated. Presented in an updated Appendix A are example calculations for 20°F condition. Calculations for other temperatures are the same as shown on the printout. Included in the updated Appendix A are the emission factors used for POM and formaldehyde. All other emissions were calculated based on the manufacturer's specifications. During the review of the spreadsheets, it was noted that the sulfuric acid mist emission was incorrect. The relevant tables in the report have been updated to reflect the correct emissions. This change does not affect PSD applicability.

2. Tables 4-5, 4-6, and 4-7 were also generated in Lotus 1-2-3. These tables have been annotated to include equations as well as the origin of data. The revised tables are enclosed. It was also noticed that the cost for interest during construction in Table 4-5 included an additional cost that was not correct. This cost has been corrected and included on the annotated tables.

   The cost to modify the heat recovery steam generator (HRSG) to incorporate space for SCR has been estimated by the HRSG manufacturer to range from $500,000 to $750,000 which is higher than the estimate in Table 4-5 of $303,000. The manufacturer's estimate is higher due to the need to split the boiler into two sections, move boiler tubes, and add additional structural steel for support of the steam drums. Also, an additional $500,000 (not accounted for in Table 4-5) is required to expand the turbine/boiler building. These costs were not added to the capital costs since the cost analysis contains contingency funds to account for project-specific cost differences. Nonetheless, the Department should consider this total cost, i.e. about $1,000,000 to $1,250,000, in establishing any permit condition that may require the installation of a duct module for SCR.

3. The low-NO_x combustor in the ABB 11N-EV is currently available and in use in the United States. There is no separate model number for the combustor. Information on the proposed machine is attached. The ABB 11N-EV with the low-NO_x combustor can achieve lower NO_x emissions than 25 ppmvd corrected to 15 percent oxygen; however, the guaranteed NO_x emission rate is based on 25 ppmvd (corrected).

4. Information on the ABB dry low-NO_x combustor is attached. The information includes:
   a. ABB literature on low-NO_x combustor.
   b. Letter (2/14/92) from ABB describing performance of dry low-NO_x combustor.
   c. Test results from the Midland Michigan unit.
   d. ASME technical paper on the ABB dry low-NO_x combustor.

   This information clearly indicates that the combustion turbine selected for the project can achieve NO_x emission levels well below 25 ppmvd (corrected to 15 percent oxygen). However, the guaranteed emission rate is 25 ppmvd (corrected to 15 percent oxygen).

5. SCR is not currently incorporated into the design of the proposed facility. The cost to provide this space has been estimated to be from $1,000,000 to $1,250,000. Although SCR could be installed at a future date if sufficient duct space were left in the HRSG, it does not appear practical to require such space in light of the actual performance data from ABB. Based on actual performance data from the Midland, Michigan unit, NO_x levels are expected to be in the 15 ppmvd range (corrected to 15 percent oxygen) for the proposed project. At an actual emission level of 15 ppmvd, the cost effectiveness of SCR would be approximately $12,000/ton of NO_x removed.

Please call if you have any questions.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President and Principal Engineer

KFK/dmpm

Enclosures

cc: John P. Jones, Orlando CoGen Limited, L.P.
Gary Kinsey, Air Products
File (2)
C. Holladay
C. Collins
D. Nester
C. Shaver
J. Harper

91134C2/2

KBN

February 27, 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

Subject: Orange County - A.P.
Orlando CoGen Limited, L.P.
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Kennard F. Kosky

Kennard F. Kosky, P.E.
President and Principal Engineer

KFK/dmpm

Enclosures

cc: John P. Jones, Orlando CoGen Limited, L.P.
Gary Kinsey, Air Products
File (2)

REVISED APPENDIX A

(INCLUDES EXAMPLE CALCULATIONS)

EMISSION CALCULATIONS AND FACTORS

Emission rates for all regulated and nonregulated pollutants were calculated using both manufacturer's data and EPA emission factors. The design information and emissions data are presented in Tables A-1 through A-5. These tables were generated using a computerized spreadsheet (i.e., Lotus 1-2-3). Tables A-1 through A-5 have been annotated to show the columns (i.e., A ,B, C, and D) and rows (i.e., 1, 2, 3, ...) in the spreadsheet. Following these tables is a printout of all the calculations made in the spreadsheet, along with the basis for the calculation. The calculations, as well as text comments, are listed alphanumerically in ascending order. For example, in Table A-1, column B, row 12 is listed as A:B12 on the calculation page, and the data input is 10,690: As noted, these data were provided by ABB. A copy of the relevant EPA emission factors also is included in this appendix.

Table A-1. Design Information and Stack Parameters for Orlando CoGen Limited, L.P. Cogeneration Project

Data A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
General:					
Power (kW)	87,360.0	78,830.0	75,690.0	68,350.0	NA
Heat Rate (Btu/kwh)	10,690.0	10,870.0	10,960.0	11,270.0	NA
Heat Input (mmBtu/hr)	933.9	856.9	829.6	770.3	122.0
Natural Gas (lb/hr)	44,732.4	41,044.3	39,735.7	36,897.3	5,843.8
(cf/hr)	987,186.5	905,795.0	876,915.9	814,275.4	128,964.1
Fuel:					
Heat Content - (LHV)	20,877 Btu/lb	20,877 Btu/lb	20,877 Btu/lb	20,877 Btu/lb	20,877 Btu/lb
Sulfur	1 gr/100cf	1 gr/100cf	1 gr/100cf	1 gr/100cf	1 gr/100cf
CT Exhaust:	CT Only:	CT Only:	CT Only:	CT Only:	CT & DB Exhaust:
Volume Flow (acfm)	1,601,395	1,529,035	1,500,057	1,429,720	675,048
Volume Flow (scfm)	603,523	569,344	555,810	522,778	524,155
Mass Flow (lb/hr)	2,631,000	2,482,000	2,423,000	2,279,000	2,285,000
Temperature (°F)	941	958	965	984	220
Moisture (% Vol.)	6.10	6.70	7.10	9.30	9.20
Oxygen (% Vol.)	14.40	14.50	14.40	14.20	14.00
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	811,556	754,813	726,343		675,048
Temperature (°F)	250	240	230		220
Diameter (ft)	15.7	15.7	15.7		15.7
Velocity (ft/sec)	69.90	65.01	62.56		58.14

Note: CT and duct burner will fire natural gas only.
Duct burner maximum firing will be 450,000 MM Btu/year; i.e., 4,500 hours at 100 MM Btu/hr.
Duct burner operation is planned when ambient temperature is greater than 59°F.

Table A-2. Maximum Criteria Pollutant Emissions for Orlando CoGen Limited, L.P. Cogeneration Project

Pollutant A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
Particulate:					
Basis	Manufacturer	Manufacturer	Manufacturer	Manufacturer	0.01 lb/MMBtu
lb/hr	11.00	9.00	9.00	9.00	1.22
TPY	48.18	39.42	39.42	39.42	2.25
Sulfur Dioxide:					
Basis	1 gr/100 cf	1 gr/100 cf	1 gr/100 cf	1 gr/100 cf	1 gr/100 cf
lb/hr	2.82	2.59	2.51	2.33	0.37
TPY	12.35	11.34	10.97	10.19	0.68
Nitrogen Oxides:					
Basis	25 ppm[a]	25 ppm[a]	25 ppm[a]	25 ppm[a]	0.1 lb/MMBtu
lb/hr	95.7	86.4	84.6	75.5	12.20
TPY	419.2	378.4	370.6	330.5	22.50
ppm	25.0	25.0	25.0	25.0	
Carbon Monoxide:					
Basis	10 ppm[a]	10 ppm[a]	10 ppm[a]	10 ppm[a]	0.1 lb/MMBtu
lb/hr	23.3	21.0	20.6	18.4	12.20
TPY	102.06	92.12	90.23	80.47	22.50
ppm	10.0	10.0	10.0	10.0	
VOCs:					
Basis	3 ppm[b]	3 ppm[b]	3 ppm[b]	3 ppm[b]	0.03 lb/MMBtu
lb/hr	3.18	2.98	2.89	2.66	3.66
TPY	13.9	13.0	12.7	11.6	6.75
ppm	3.0	3.0	3.0	3.0	
Lead:					
Basis					
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

[a] Corrected to 15% O_2 dry conditions.

[b] Corrected to dry conditions.

Note: Annual emission for CT when firing natural gas based on 8,760 hrs/yr. Annual emissions for duct burner based on 450,000 MM Btu/year operation; i.e., 4,500 hours at 100 MM Btu/hr. Duct burner operation planned when ambient temperature is greater than 59°F.

Table A-3. Maximum Other Regulated Pollutant Emissions for Orlando CoGen Limited, L.P. Cogeneration Project

Pollutant A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
As (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Be (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Hg (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
F (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
H_2SO_4 (lb/hr)	2.16x10^{-1}	1.98x10^{-1}	1.92x10^{-1}	1.78x10^{-1}	2.82x10^{-2}
(TPY)	9.45x10^{-1}	8.67x10^{-1}	8.40x10^{-1}	7.80x10^{-1}	0.01
					0.05

Sources: EPA, 1988; EPA, 1980.

Table A-4. Maximum Non-Regulated Pollutant Emissions for Orlando CoGen Limited, L.P. Cogeneration Project

Pollutant A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - 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.
POM (lb/hr)	$1.04\text{x}10^{-3}$	$9.56\text{x}10^{-4}$	$9.25\text{x}10^{-4}$	$8.59\text{x}10^{-4}$	$1.36\text{x}10^{-4}$
(TPY)	$4.56\text{x}10^{-3}$	$4.19\text{x}10^{-3}$	$4.05\text{x}10^{-3}$	$3.76\text{x}10^{-3}$	$2.51\text{x}10^{-4}$
Formaldehyde (lb/hr)	$8.25\text{x}10^{-2}$	$7.57\text{x}10^{-2}$	$7.33\text{x}10^{-2}$	$6.80\text{x}10^{-2}$	$1.08\text{x}10^{-2}$
(TPY)	$3.61\text{x}10^{-1}$	$3.31\text{x}10^{-1}$	$3.21\text{x}10^{-1}$	$2.98\text{x}10^{-1}$	$1.99\text{x}10^{-2}$

```
A:A1: [W22] 'Table A-1.  Design Information and Stack Parameters for Orlando CoGen Limited, L.P.
A:G1: [W6] 1
A:A2: [W22] '            Cogeneration Project
A:G2: [W6] (G1+1)
A:A3: [W22] \_
A:B3: [W16] \_
A:C3: [W16] \_
A:D3: [W16] \_
A:E3: [W16] \_
A:F3: [W16] \_
A:G3: [W6] (G2+1)
A:G4: [W6] (G3+1)
A:A5: [W22] ^Data
A:B5: [W16] "Gas Turbine
A:C5: [W16] "Gas Turbine
A:D5: [W16] "Gas Turbine
A:E5: [W16] "Gas Turbine
A:F5: [W16] "Duct Burner
A:G5: [W6] (G4+1)
A:B6: [W16] "Natural Gas
A:C6: [W16] "Natural Gas
A:D6: [W16] "Natural Gas
A:E6: [W16] "Natural Gas
A:F6: [W16] "Natural Gas
A:G6: [W6] (G5+1)
A:B7: [W16] "20oF - B
A:C7: [W16] "59oF - C
A:D7: [W16] "72oF - D
A:E7: [W16] "102oF - E
A:F7: [W16] "90oF - F
A:G7: [W6] (G6+1)
A:A8: [W22] \_
A:B8: [W16] \_
A:C8: [W16] \_
A:D8: [W16] \_
A:E8: [W16] \_
A:F8: [W16] \_
A:G8: [W6] (G7+1)
A:G9: [W6] (G8+1)
A:A10: [W22] ^General:
A:G10: [W6] (G9+1)
A:A11: [W22] 'Power (kW)
A:B11: (,1) [W16] 87360 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C11: (,1) [W16] 78830
A:D11: (,1) [W16] 75690
A:E11: (,1) [W16] 68350
A:F11: (,1) [W16] "NA
A:G11: [W6] (G10+1)
A:A12: [W22] 'Heat Rate (Btu/kwh)
A:B12: (,1) [W16] 10690 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C12: (,1) [W16] 10870
A:D12: (,1) [W16] 10960
A:E12: (,1) [W16] 11270
A:F12: (,1) [W16] "NA
A:G12: [W6] (G11+1)
A:A13: [W22] 'Heat Input (mmBtu/hr)
A:B13: (,1) [W16] (B11*B12/1000000) . . . . . . . . . . . . . . . . . . . . . Power * Heat Rate
A:C13: (,1) [W16] (C11*C12/1000000)
A:D13: (,1) [W16] (D11*D12/1000000)
A:E13: (,1) [W16] (E11*E12/1000000)
A:F13: (,1) [W16] 122 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Maximum Proposed
A:G13: [W6] (G12+1)
A:A14: [W22] 'Natural Gas (lb/hr)
A:B14: (,1) [W16] (B13/0.020877)  . . . . . . . . . . . . . . . . . . . . . . Heat Input ÷ Heat Content
A:C14: (,1) [W16] (C13/0.020877)
A:D14: (,1) [W16] (D13/0.020877)
A:E14: (,1) [W16] (E13/0.020877)
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A:F14: (,1) [W16] (F13/0.020877)
A:G14: [W6] (G13+1)
A:A15: [W22] '        (cf/hr)
A:B15: (,1) [W16] (B13/946*10^6) . . . . . . . . . . . . . . . . . . . . . . . . Heat Input + Heat Content
A:C15: (,1) [W16] (C13/946*10^6)
A:D15: (,1) [W16] (D13/946*10^6)
A:E15: (,1) [W16] (E13/946*10^6)
A:F15: (,1) [W16] (F13/946*10^6)
A:G15: [W6] (G14+1)
A:G16: [W6] (G15+1)
A:A17: [W22] ^Fuel:
A:G17: [W6] (G16+1)
A:A18: [W22] 'Heat Content - (LHV)
A:B18: (,1) [W16] "20,877 Btu/lb . . . . . . . . . . . . . . . . . . . . . . . . . . . Fuel Specification
A:C18: (,1) [W16] "20,877 Btu/lb
A:D18: (,1) [W16] "20,877 Btu/lb
A:E18: (,1) [W16] "20,877 Btu/lb
A:F18: (,1) [W16] "20,877 Btu/lb
A:G18: [W6] (G17+1)
A:A19: [W22] 'Sulfur
A:B19: (,1) [W16] "1 gr/100cf . . . . . . . . . . . . . . . . . . . . . . Maximum Sulfur Content in Natural Gas
A:C19: (,1) [W16] "1 gr/100cf
A:D19: (,1) [W16] "1 gr/100cf
A:E19: (,1) [W16] "1 gr/100cf
A:F19: (,1) [W16] "1 gr/100cf
A:G19: [W6] (G18+1)
A:G20: [W6] (G19+1)
A:A21: [W22] ^CT Exhaust:
A:B21: (,1) [W16] "CT Only:
A:C21: (,1) [W16] "CT Only:
A:D21: (,1) [W16] "CT Only:
A:E21: (,1) [W16] "CT Only:
A:F21: (,1) [W16] "CT & DB Exhaust:
A:G21: [W6] (G20+1)
A:A22: [W22] 'Volume Flow (acfm)
A:B22: (,0) [W16] (B24*1545*(460+B25)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . See Note A
A:C22: (,0) [W16] (C24*1545*(460+C25)/(C28*2116.8*60))
A:D22: (,0) [W16] (D24*1545*(460+D25)/(D28*2116.8*60))
A:E22: (,0) [W16] (E24*1545*(460+E25)/(E28*2116.8*60))
A:F22: (,0) [W16] (F24*1545*(460+F25)/(F28*2116.8*60))
A:G22: [W6] (G21+1)
A:A23: [W22] 'Volume Flow (scfm)
A:B23: (,0) [W16] (B24*1545*(460+68)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . . See Note A
A:C23: (,0) [W16] (C24*1545*(460+68)/(C28*2116.8*60))
A:D23: (,0) [W16] (D24*1545*(460+68)/(D28*2116.8*60))
A:E23: (,0) [W16] (E24*1545*(460+68)/(E28*2116.8*60))
A:F23: (,0) [W16] (F24*1545*(460+68)/(F28*2116.8*60))
A:G23: [W6] (G22+1)
A:A24: [W22] 'Mass Flow (lb/hr)
A:B24: (,0) [W16] 2631000 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C24: (,0) [W16] 2482000
A:D24: (,0) [W16] 2423000
A:E24: (,0) [W16] 2279000
A:F24: (,0) [W16] 2285000
A:G24: [W6] (G23+1)
A:A25: [W22] 'Temperature (oF)
A:B25: (,0) [W16] 941 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C25: (,0) [W16] 958
A:D25: (,0) [W16] 965
A:E25: (,0) [W16] 984
A:F25: (,0) [W16] 220 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Air Products
A:G25: [W6] (G24+1)
A:A26: [W22] 'Moisture (% Vol.)
A:B26: (F2) [W16] 6.1 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C26: (F2) [W16] 6.7
A:D26: (F2) [W16] 7.1
A:E26: (F2) [W16] 9.3
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A:F26: (F2) [W16] 9.2
A:G26: [W6] (G25+1)
A:A27: [W22] 'Oxygen (% Vol.)
A:B27: (F2) [W16] 14.4 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C27: (F2) [W16] 14.5
A:D27: (F2) [W16] 14.4
A:E27: (F2) [W16] 14.2
A:F27: (F2) [W16] 14
A:G27: [W6] (G26+1)
A:A28: [W22] 'Molecular Weight
A:B28: (F2) [W16] 28 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB & KBN
A:C28: (F2) [W16] 28
A:D28: (F2) [W16] 28
A:E28: (F2) [W16] 28
A:F28: (F2) [W16] 28
A:G28: [W6] (G27+1)
A:G29: [W6] (G28+1)
A:G30: [W6] (G29+1)
A:A31: [W22] ^HRSG Stack:
A:G31: [W6] (G30+1)
A:A32: [W22] 'Volume Flow (acfm)
A:B32: (,0) [W16] (B22*(B33+460)/(B25+460)) . . . . . . . . . . . . . . . . . . . Adjustment for Temperature
A:C32: (,0) [W16] (C22*(C33+460)/(C25+460))
A:D32: (,0) [W16] (D22*(D33+460)/(D25+460))
A:F32: (,0) [W16] (F22*(F33+460)/(F25+460))
A:G32: [W6] (G31+1)
A:A33: [W22] 'Temperature (oF)
A:B33: (,0) [W16] 250 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Air Products
A:C33: (,0) [W16] 240
A:D33: (,0) [W16] 230
A:F33: (,0) [W16] 220
A:G33: [W6] (G32+1)
A:A34: [W22] 'Diameter (ft)
A:B34: (F0) [W16] 15.7 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Air Products
A:C34: (F0) [W16] 15.7
A:D34: (F0) [W16] 15.7
A:F34: (F0) [W16] 15.7
A:G34: [W6] (G33+1)
A:A35: [W22] 'Velocity (ft/sec)
A:B35: (F2) [W16] (B32/60/(B34^2*3.14159/4))  . . . . . . . . . . . . . . . . . . . . Volume Flow ÷ Area
A:C35: (F2) [W16] (C32/60/(C34^2*3.14159/4))
A:D35: (F2) [W16] (D32/60/(D34^2*3.14159/4))
A:F35: (F2) [W16] (F32/60/(F34^2*3.14159/4))
A:G35: [W6] (G34+1)
A:G36: [W6] (G35+1)
A:A37: [W22] \_
A:B37: [W16] \_
A:C37: [W16] \_
A:D37: [W16] \_
A:E37: [W16] \_
A:F37: [W16] \_
A:G37: [W6] (G36+1)
A:G38: [W6] (G37+1)
A:A39: [W22] 'Note: CT will fire natural gas only.
A:G39: [W6] (G38+1)
A:A40: [W22] '      Duct burner will use 450,000 MM Btu/year; i.e., 4,500 hours at 100 MM Btu/hr.
A:G40: [W6] (G39+1)
A:A41: [W22] '      Duct burner will only be operated when ambient temperature is greater than 72oF.
A:G41: [W6] (G40+1)
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A:A47: [W22] 'Table A-2.  Maximum Criteria Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G47: [W6] 47
A:A48: [W22] '          Cogeneration Project
A:G48: [W6] (G47+1)
A:A49: [W22] \_
A:B49: [W16] \_
A:C49: [W16] \_
A:D49: [W16] \_
A:E49: [W16] \_
A:F49: [W16] \_
A:G49: [W6] (G48+1)
A:G50: [W6] (G49+1)
A:A51: [W22] ^Pollutant
A:B51: [W16] "Gas Turbine
A:C51: [W16] "Gas Turbine
A:D51: [W16] "Gas Turbine
A:E51: [W16] "Gas Turbine
A:F51: [W16] "Duct Burner
A:G51: [W6] (G50+1)
A:B52: [W16] "Natural Gas
A:C52: [W16] "Natural Gas
A:D52: [W16] "Natural Gas
A:E52: [W16] "Natural Gas
A:F52: [W16] "Natural Gas
A:G52: [W6] (G51+1)
A:A53: [W22] ^A
A:B53: [W16] "20oF - B
A:C53: [W16] "59oF - C
A:D53: [W16] "72oF - D
A:E53: [W16] "102oF - E
A:F53: [W16] "90oF - F
A:G53: [W6] (G52+1)
A:A54: [W22] \_
A:B54: [W16] \_
A:C54: [W16] \_
A:D54: [W16] \_
A:E54: [W16] \_
A:F54: [W16] \_
A:G54: [W6] (G53+1)
A:G55: [W6] (G54+1)
A:A56: [W22] 'Particulate:
A:G56: [W6] (G55+1)
A:A57: [W22] '  Basis
A:B57: (,1) [W16] "Manufacturer
A:C57: (,1) [W16] "Manufacturer
A:D57: (,1) [W16] "Manufacturer
A:E57: (,1) [W16] "Manufacturer
A:F57: (,1) [W16] "0.01 lb/MMBtu
A:G57: [W6] (G56+1)
A:A58: [W22] '  lb/hr
A:B58: (F2) [W16] 11  . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  From ABB
A:C58: (F2) [W16] 9
A:D58: (F2) [W16] 9
A:E58: (F2) [W16] 9
A:F58: (F2) [W16] ($F$13*0.01)
A:G58: [W6] (G57+1)
A:A59: [W22] '  TPY
A:B59: (F2) [W16] (B58*8760/2000) . . . . . . . . . . . . . . . . .  Emissions * 8,760 hours/year ÷ 2,000 lb/ton
A:C59: (F2) [W16] (C58*8760/2000)
A:D59: (F2) [W16] (D58*8760/2000)
A:E59: (F2) [W16] (E58*8760/2000)
A:F59: (F2) [W16] (F58*3688.5/2000) .  Emissions * 3,688.5 hr/yr (4,500 hrs @ 100x10^6 + 122 x 10^6) ÷ 2,000 lb/ton
A:G59: [W6] (G58+1)
A:G60: [W6] (G59+1)
A:A61: [W22] 'Sulfur Dioxide:
A:G61: [W6] (G60+1)
A:A62: [W22] '  Basis
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A:B62: (,1) [W16] "1 gr/100 cf
A:C62: (,1) [W16] "1 gr/100 cf
A:D62: (,1) [W16] "1 gr/100 cf
A:E62: (,1) [W16] "1 gr/100 cf
A:F62: (,1) [W16] "1 gr/100 cf
A:G62: [W6] (G61+1)
A:A63: [W22] '  lb/hr
A:B63: (F2) [W16] (B15*1/7000*2/100)  . . . . . . . Fuel Used (CF/HR) * Sulfur Content * 2 lb SO2/lb S * 1/100 CF
A:C63: (F2) [W16] (C15*1/7000*2/100)
A:D63: (F2) [W16] (D15*1/7000*2/100)
A:E63: (F2) [W16] (E15*1/7000*2/100)
A:F63: (F2) [W16] (F15*1/7000*2/100)
A:G63: [W6] (G62+1)
A:A64: [W22] '  TPY
A:B64: (F2) [W16] (B63*8760/2000)
A:C64: (F2) [W16] (C63*8760/2000)
A:D64: (F2) [W16] (D63*8760/2000)
A:E64: (F2) [W16] (E63*8760/2000)
A:F64: (F2) [W16] (F63*3688.5/2000)
A:G64: [W6] (G63+1)
A:G65: [W6] (G64+1)
A:A66: [W22] 'Nitrogen Oxides:
A:G66: [W6] (G65+1)
A:A67: [W22] '  Basis
A:B67: (,1) [W16] "25 ppm*
A:C67: (,1) [W16] "25 ppm*
A:D67: (,1) [W16] "25 ppm*
A:E67: (,1) [W16] "25 ppm*
A:F67: (,1) [W16] "0.1 lb/MMBtu
A:G67: [W6] (G66+1)
A:A68: [W22] '  lb/hr
A:B68: (,1) [W16] (B70/5.9*(20.9*(1-B26/100)-B27)*B22*2116.8*46*60/(1545*(460+B25)*1000000))  . . . .  See Note B
A:C68: (,1) [W16] (C70/5.9*(20.9*(1-C26/100)-C27)*C22*2116.8*46*60/(1545*(460+C25)*1000000))
A:D68: (,1) [W16] (D70/5.9*(20.9*(1-D26/100)-D27)*D22*2116.8*46*60/(1545*(460+D25)*1000000))
A:E68: (,1) [W16] (E70/5.9*(20.9*(1-E26/100)-E27)*E22*2116.8*46*60/(1545*(460+E25)*1000000))
A:F68: (F2) [W16] ($F$13*0.1) . . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:G68: [W6] (G67+1)
A:A69: [W22] '  TPY
A:B69: (F1) [W16] (B68*8760/2000)
A:C69: (F1) [W16] (C68*8760/2000)
A:D69: (F1) [W16] (D68*8760/2000)
A:E69: (F1) [W16] (E68*8760/2000)
A:F69: (F2) [W16] (F68*3688.5/2000)
A:G69: [W6] (G68+1)
A:A70: [W22] '  ppm
A:B70: (,1) [W16] 25  . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C70: (,1) [W16] 25
A:D70: (,1) [W16] 25
A:E70: (,1) [W16] 25
A:G70: [W6] (G69+1)
A:G71: [W6] (G70+1)
A:A72: [W22] 'Carbon Monoxide:
A:G72: [W6] (G71+1)
A:A73: [W22] '  Basis
A:B73: (,1) [W16] "10 ppm+
A:C73: (,1) [W16] "10 ppm+
A:D73: (,1) [W16] "10 ppm+
A:E73: (,1) [W16] "10 ppm+
A:F73: (,1) [W16] "0.2 lb/MMBtu
A:G73: [W6] (G72+1)
A:A74: [W22] '  lb/hr
A:B74: (,1) [W16] (B76/5.9*(20.9*(1-B26/100)-B27)*B22*2116.8*28*60/(1545*(460+B25)*1000000))  . . . .  See Note C
A:C74: (,1) [W16] (C76/5.9*(20.9*(1-C26/100)-C27)*C22*2116.8*28*60/(1545*(460+C25)*1000000))
A:D74: (,1) [W16] (D76/5.9*(20.9*(1-D26/100)-D27)*D22*2116.8*28*60/(1545*(460+D25)*1000000))
A:E74: (,1) [W16] (E76/5.9*(20.9*(1-E26/100)-E27)*E22*2116.8*28*60/(1545*(460+E25)*1000000))
A:F74: (F2) [W16] ($F$13*0.2) . . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:G74: [W6] (G73+1)
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A:A75: [W22] '  TPY
A:B75: (F2) [W16] (B74*8760/2000)
A:C75: (F2) [W16] (C74*8760/2000)
A:D75: (F2) [W16] (D74*8760/2000)
A:E75: (F2) [W16] (E74*8760/2000)
A:F75: (F2) [W16] (F74*3688.5/2000)
A:G75: [W6] (G74+1)
A:A76: [W22] '  ppm
A:B76: (,1) [W16] 10
A:C76: (,1) [W16] 10
A:D76: (,1) [W16] 10
A:E76: (,1) [W16] 10
A:G76: [W6] (G75+1)
A:G77: [W6] (G76+1)
A:A78: [W22] 'VOC's:
A:G78: [W6] (G77+1)
A:A79: [W22] '  Basis
A:B79: (,1) [W16] "3 ppm+
A:C79: (,1) [W16] "3 ppm+
A:D79: (,1) [W16] "3 ppm+
A:E79: (,1) [W16] "3 ppm+
A:F79: (,1) [W16] "0.03 lb/MMBtu
A:G79: [W6] (G78+1)
A:A80: [W22] '  lb/hr
A:B80: (F2) [W16] (B82*(1-B26/100)*B22*2116.8*12*60/(1545*(460+B25)*1000000)) . . . . . . . . . . . . . See Note C
A:C80: (F2) [W16] (C82*(1-C26/100)*C22*2116.8*12*60/(1545*(460+C25)*1000000))
A:D80: (F2) [W16] (D82*(1-D26/100)*D22*2116.8*12*60/(1545*(460+D25)*1000000))
A:E80: (F2) [W16] (E82*(1-E26/100)*E22*2116.8*12*60/(1545*(460+E25)*1000000))
A:F80: (F2) [W16] ($F$13*0.03) . . . . . . . . . . . . . . . . . . . . . . . . . . . Emission Factor * Heat Input
A:G80: [W6] (G79+1)
A:A81: [W22] '  TPY
A:B81: (,1) [W16] (B80*8760/2000)
A:C81: (,1) [W16] (C80*8760/2000)
A:D81: (,1) [W16] (D80*8760/2000)
A:E81: (,1) [W16] (E80*8760/2000)
A:F81: (F2) [W16] (F80*3688.5/2000)
A:G81: [W6] (G80+1)
A:A82: [W22] '  ppm
A:B82: (,1) [W16] 3
A:C82: (,1) [W16] 3
A:D82: (,1) [W16] 3
A:E82: (,1) [W16] 3
A:G82: [W6] (G81+1)
A:G83: [W6] (G82+1)
A:A84: [W22] 'Lead:
A:G84: [W6] (G83+1)
A:A85: [W22] '  Basis
A:G85: [W6] (G84+1)
A:A86: [W22] '  lb/hr
A:B86: (S2) [W16] "NA
A:C86: (S2) [W16] "NA
A:D86: (S2) [W16] "NA
A:E86: (S2) [W16] "NA
A:F86: (S2) [W16] "NA
A:G86: [W6] (G85+1)
A:A87: [W22] '  TPY
A:B87: (S2) [W16] "NA
A:C87: (S2) [W16] "NA
A:D87: (S2) [W16] "NA
A:E87: (S2) [W16] "NA
A:F87: (S2) [W16] "NA
A:G87: [W6] (G86+1)
A:A88: [W22] \_
A:B88: [W16] \_
A:C88: [W16] \_
A:D88: [W16] \_
A:E88: [W16] \_
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A:F88: [W16] \_
A:G88: [W6] (G87+1)
A:G89: [W6] (G88+1)
A:A90: [W22] '* corrected to 15% O2 dry conditions
A:G90: [W6] (G89+1)
A:A91: [W22] '+ corrected to dry conditions
A:G91: [W6] (G90+1)
A:A92: [W22] 'Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr.  Annual emissions for
A:G92: [W6] (G91+1)
A:A93: [W22] '      duct burner based on 450,000 MM Btu/year operation; i.e., 4,500 hours at 100 MM Btu/hr.
A:G93: [W6] (G92+1)
A:A94: [W22] '      Duct burner will only be operated when ambient temperature is greater than 72oF.
A:G94: [W6] (G93+1)
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A:A96: [W22] 'Table A-3.  Maximum Other Regulated Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G96: [W6] 96
A:A97: [W22] '           Cogeneration Project
A:G97: [W6] (G96+1)
A:A98: [W22] \_
A:B98: [W16] \_
A:C98: [W16] \_
A:D98: [W16] \_
A:E98: [W16] \_
A:F98: [W16] \_
A:G98: [W6] (G97+1)
A:G99: [W6] (G98+1)
A:A100: [W22] ^Pollutant
A:B100: [W16] "Gas Turbine
A:C100: [W16] "Gas Turbine
A:D100: [W16] "Gas Turbine
A:E100: [W16] "Gas Turbine
A:F100: [W16] "Duct Burner
A:G100: [W6] (G99+1)
A:B101: [W16] "Natural Gas
A:C101: [W16] "Natural Gas
A:D101: [W16] "Natural Gas
A:E101: [W16] "Natural Gas
A:F101: [W16] "Natural Gas
A:G101: [W6] (G100+1)
A:A102: [W22] ^A
A:B102: [W16] "20oF - B
A:C102: [W16] "59oF - C
A:D102: [W16] "72oF - D
A:E102: [W16] "102oF - E
A:F102: [W16] "90oF - F
A:G102: [W6] (G101+1)
A:A103: [W22] \_
A:B103: [W16] \_
A:C103: [W16] \_
A:D103: [W16] \_
A:E103: [W16] \_
A:F103: [W16] \_
A:G103: [W6] (G102+1)
A:G104: [W6] (G103+1)
A:A105: [W22] '  As (lb/hr)
A:B105: [W16] "NEG.
A:C105: [W16] "NEG.
A:D105: [W16] "NEG.
A:E105: [W16] "NEG.
A:F105: [W16] "NEG.
A:G105: [W6] (G104+1)
A:A106: [W22] '     (TPY)
A:B106: [W16] "NEG.
A:C106: [W16] "NEG.
A:D106: [W16] "NEG.
A:E106: [W16] "NEG.
A:F106: [W16] "NEG.
A:G106: [W6] (G105+1)
A:G107: [W6] (G106+1)
A:A108: [W22] '  Be (lb/hr)
A:B108: [W16] "NEG.
A:C108: [W16] "NEG.
A:D108: [W16] "NEG.
A:E108: [W16] "NEG.
A:F108: [W16] "NEG.
A:G108: [W6] (G107+1)
A:A109: [W22] '     (TPY)
A:B109: [W16] "NEG.
A:C109: [W16] "NEG.
A:D109: [W16] "NEG.
A:E109: [W16] "NEG.
```

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A:F109: [W16] "NEG.
A:G109: [W6] (G108+1)
A:G110: [W6] (G109+1)
A:A111: [W22] '  Hg (lb/hr)
A:B111: [W16] "NEG.
A:C111: [W16] "NEG.
A:D111: [W16] "NEG.
A:E111: [W16] "NEG.
A:F111: [W16] "NEG.
A:G111: [W6] (G110+1)
A:A112: [W22] '      (TPY)
A:B112: [W16] "NEG.
A:C112: [W16] "NEG.
A:D112: [W16] "NEG.
A:E112: [W16] "NEG.
A:F112: [W16] "NEG.
A:G112: [W6] (G111+1)
A:G113: [W6] (G112+1)
A:A114: [W22] '  F (lb/hr)
A:B114: [W16] "NEG.
A:C114: [W16] "NEG.
A:D114: [W16] "NEG.
A:E114: [W16] "NEG.
A:F114: [W16] "NEG.
A:G114: [W6] (G113+1)
A:A115: [W22] '     (TPY)
A:B115: [W16] "NEG.
A:C115: [W16] "NEG.
A:D115: [W16] "NEG.
A:E115: [W16] "NEG.
A:F115: [W16] "NEG.
A:G115: [W6] (G114+1)
A:G116: [W6] (G115+1)
A:A117: [W22] '  H2SO4 (lb/hr)
A:B117: (S2) [W16] (B63*0.05*3.06/2)  . . . . . . . . . . . . .  SO2 Emission * 0.05 (%H2SO4 Formed) * MWH2SO4/MWSO2
A:C117: (S2) [W16] (C63*0.05*3.06/2)
A:D117: (S2) [W16] (D63*0.05*3.06/2)
A:E117: (S2) [W16] (E63*0.05*3.06/2)
A:F117: (S2) [W16] (F63*0.05*3.06/2)
A:G117: [W6] (G116+1)
A:A118: [W22] '     (TPY)
A:B118: (S2) [W16] (B117*8760/2000)
A:C118: (S2) [W16] (C117*8760/2000)
A:D118: (S2) [W16] (D117*8760/2000)
A:E118: (S2) [W16] (E117*8760/2000)
A:F118: (F2) [W16] (F117*3688.5/2000)
A:G118: [W6] (G117+1)
A:G119: [W6] (G118+1)
A:A120: [W22] \_
A:B120: [W16] \_
A:C120: [W16] \_
A:D120: [W16] \_
A:E120: [W16] \_
A:F120: [W16] \_
A:G120: [W6] (G119+1)
A:G121: [W6] (G120+1)
A:A122: [W22] 'Sources: EPA, 1988; EPA, 1980
A:G122: [W6] (G121+1)
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A:A125: [W22] 'Table A-4.  Maximum Non-Regulated Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G125: [W6] 125
A:A126: [W22] '          Cogeneration Project
A:G126: [W6] (G125+1)
A:A127: [W22] \_
A:B127: [W16] \_
A:C127: [W16] \_
A:D127: [W16] \_
A:E127: [W16] \_
A:F127: [W16] \_
A:G127: [W6] (G126+1)
A:G128: [W6] (G127+1)
A:A129: [W22] ^Pollutant
A:B129: [W16] "Gas Turbine
A:C129: [W16] "Gas Turbine
A:D129: [W16] "Gas Turbine
A:E129: [W16] "Gas Turbine
A:F129: [W16] "Duct Burner
A:G129: [W6] (G128+1)
A:B130: [W16] "Natural Gas
A:C130: [W16] "Natural Gas
A:D130: [W16] "Natural Gas
A:E130: [W16] "Natural Gas
A:F130: [W16] "Natural Gas
A:G130: [W6] (G129+1)
A:A131: [W22] ^A
A:B131: [W16] "20oF - B
A:C131: [W16] "59oF - C
A:D131: [W16] "72oF - D
A:E131: [W16] "102oF - E
A:F131: [W16] "90oF - F
A:G131: [W6] (G130+1)
A:A132: [W22] \_
A:B132: [W16] \_
A:C132: [W16] \_
A:D132: [W16] \_
A:E132: [W16] \_
A:F132: [W16] \_
A:G132: [W6] (G131+1)
A:G133: [W6] (G132+1)
A:A134: [W22] '  Manganese (lb/hr)
A:B134: [W16] "NEG.
A:C134: [W16] "NEG.
A:D134: [W16] "NEG.
A:E134: [W16] "NEG.
A:F134: [W16] "NEG.
A:G134: [W6] (G133+1)
A:A135: [W22] '     (TPY)
A:B135: [W16] "NEG.
A:C135: [W16] "NEG.
A:D135: [W16] "NEG.
A:E135: [W16] "NEG.
A:F135: [W16] "NEG.
A:G135: [W6] (G134+1)
A:G136: [W6] (G135+1)
A:A137: [W22] '  Nickel (lb/hr)
A:B137: [W16] "NEG.
A:C137: [W16] "NEG.
A:D137: [W16] "NEG.
A:E137: [W16] "NEG.
A:F137: [W16] "NEG.
A:G137: [W6] (G136+1)
A:A138: [W22] '     (TPY)
A:B138: [W16] "NEG.
A:C138: [W16] "NEG.
A:D138: [W16] "NEG.
A:E138: [W16] "NEG.
```

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A:F138: [W16] "NEG.
A:G138: [W6] (G137+1)
A:G139: [W6] (G138+1)
A:A140: [W22] '  Cadmium (lb/hr)
A:B140: [W16] "NEG.
A:C140: [W16] "NEG.
A:D140: [W16] "NEG.
A:E140: [W16] "NEG.
A:F140: [W16] "NEG.
A:G140: [W6] (G139+1)
A:A141: [W22] '     (TPY)
A:B141: [W16] "NEG.
A:C141: [W16] "NEG.
A:D141: [W16] "NEG.
A:E141: [W16] "NEG.
A:F141: [W16] "NEG.
A:G141: [W6] (G140+1)
A:G142: [W6] (G141+1)
A:A143: [W22] '  Chromium (lb/hr)
A:B143: [W16] "NEG.
A:C143: [W16] "NEG.
A:D143: [W16] "NEG.
A:E143: [W16] "NEG.
A:F143: [W16] "NEG.
A:G143: [W6] (G142+1)
A:A144: [W22] '    (TPY)
A:B144: [W16] "NEG.
A:C144: [W16] "NEG.
A:D144: [W16] "NEG.
A:E144: [W16] "NEG.
A:F144: [W16] "NEG.
A:G144: [W6] (G143+1)
A:G145: [W6] (G144+1)
A:A146: [W22] '  Copper (lb/hr)
A:B146: [W16] "NEG.
A:C146: [W16] "NEG.
A:D146: [W16] "NEG.
A:E146: [W16] "NEG.
A:F146: [W16] "NEG.
A:G146: [W6] (G145+1)
A:A147: [W22] '    (TPY)
A:B147: [W16] "NEG.
A:C147: [W16] "NEG.
A:D147: [W16] "NEG.
A:E147: [W16] "NEG.
A:F147: [W16] "NEG.
A:G147: [W6] (G146+1)
A:G148: [W6] (G147+1)
A:A149: [W22] '  Vanadium (lb/hr)
A:B149: [W16] "NEG.
A:C149: [W16] "NEG.
A:D149: [W16] "NEG.
A:E149: [W16] "NEG.
A:F149: [W16] "NEG.
A:G149: [W6] (G148+1)
A:A150: [W22] '     (TPY)
A:B150: [W16] "NEG.
A:C150: [W16] "NEG.
A:D150: [W16] "NEG.
A:E150: [W16] "NEG.
A:F150: [W16] "NEG.
A:G150: [W6] (G149+1)
A:G151: [W6] (G150+1)
A:A152: [W22] '  Selenium (lb/hr)
A:B152: [W16] "NEG.
A:C152: [W16] "NEG.
A:D152: [W16] "NEG.
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A:E152: [W16] "NEG.
A:F152: [W16] "NEG.
A:G152: [W6] (G151+1)
A:A153: [W22] '    (TPY)
A:B153: [W16] "NEG.
A:C153: [W16] "NEG.
A:D153: [W16] "NEG.
A:E153: [W16] "NEG.
A:F153: [W16] "NEG.
A:G153: [W6] (G152+1)
A:G154: [W6] (G153+1)
A:A155: [W22] ' POM (lb/hr)
A:B155: (S2) [W16] (B13*0.48*2.324/1000000) . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-161
A:C155: (S2) [W16] (C13*0.48*2.324/1000000)
A:D155: (S2) [W16] (D13*0.48*2.324/1000000)
A:E155: (S2) [W16] (E13*0.48*2.324/1000000)
A:F155: (S2) [W16] (F13*0.48*2.324/1000000)
A:G155: [W6] (G154+1)
A:A156: [W22] '    (TPY)
A:B156: (S2) [W16] (B155*8760/2000)
A:C156: (S2) [W16] (C155*8760/2000)
A:D156: (S2) [W16] (D155*8760/2000)
A:E156: (S2) [W16] (E155*8760/2000)
A:F156: (S2) [W16] (F155*3688.5/2000)
A:G156: [W6] (G155+1)
A:G157: [W6] (G156+1)
A:A158: [W22] ' Formaldehyde (lb/hr)
A:B158: (S2) [W16] (B13*38*2.324/1000000) . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-156
A:C158: (S2) [W16] (C13*38*2.324/1000000)
A:D158: (S2) [W16] (D13*38*2.324/1000000)
A:E158: (S2) [W16] (E13*38*2.324/1000000)
A:F158: (S2) [W16] (F13*38*2.324/1000000)
A:G158: [W6] (G157+1)
A:A159: [W22] '    (TPY)
A:B159: (S2) [W16] (B158*8760/2000)
A:C159: (S2) [W16] (C158*8760/2000)
A:D159: (S2) [W16] (D158*8760/2000)
A:E159: (S2) [W16] (E158*8760/2000)
A:F159: (S2) [W16] (F158*3688.5/2000)
A:G159: [W6] (G158+1)
A:A160: [W22] \_
A:B160: [W16] \_
A:C160: [W16] \_
A:D160: [W16] \_
A:E160: [W16] \_
A:F160: [W16] \_
A:G160: [W6] (G159+1)
A:G161: [W6] (G160+1)
A:G162: [W6] (G161+1)
A:G165: [W6] 165
A:G166: [W6] (G165+1)
A:G167: [W6] (G166+1)
A:G168: [W6] (G167+1)
A:G169: [W6] (G168+1)
A:G170: [W6] (G169+1)
A:G171: [W6] (G170+1)
A:G172: [W6] (G171+1)
A:G173: [W6] (G172+1)
A:G174: [W6] (G173+1)
A:G175: [W6] (G174+1)
A:G176: [W6] (G175+1)
A:G177: [W6] (G176+1)
A:G178: [W6] (G177+1)
A:G179: [W6] (G178+1)
A:G180: [W6] (G179+1)
A:G181: [W6] (G180+1)
A:G182: [W6] (G181+1)
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A:G183: [W6] (G182+1)
A:G184: [W6] (G183+1)
A:G185: [W6] (G184+1)
A:G186: [W6] (G185+1)
A:G187: [W6] (G186+1)
A:G188: [W6] (G187+1)
A:G189: [W6] (G188+1)
A:G190: [W6] (G189+1)
A:G191: [W6] (G190+1)
```

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 (K)

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:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$$

Substituting:

$$\begin{aligned} V_{NOx\ Act} &= V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9 \\ &= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9 \\ &= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9 \end{aligned}$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

NOTE C

Same as D except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$\begin{aligned} m_{CO} &= PV_{CO\ Act}M_{CO}\ /\ RT \\ &= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO}\ /\ RT \end{aligned}$$

ORLANDO COGEN LIMITED
EXAMPLE CALCULATIONS - 20°F CONDITIONS

ROWS listed below correspond to the ROW listed in Table.

Table A-1: (Note: all other data not calculated)

ROW 13--Heat Input (10^6 Btu/hr):

Power (kW) x Heat Rate (10^6 Btu/kWh)

87,360.0 x 10,690.9/10^6 = 933.9 x 10^6 Btu/hr

ROW 14--Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) ÷ Fuel Heat Content (Btu/lb)

933.9 x 10^6 ÷ 20,877 = 44,732.4 lb/hr

Note: 20,877 is input as 0.020877 since heat input is in 10^6 Btu, i.e. 933.9

ROW 15--Natural Gas (cf/hr):

Heat input (10^6 Btu/hr) ÷ Heat content (Btu/cf)

933.9 x 10^6 ÷ 946 = 987,186.5 cf/hr

ROW 21--Volume Flow (acfm) - See Note A:

V = mRT/PM

2,631,000 lb/hr x 1,545 x (941 + 460°K) ÷ (28 x 2,116.8 lb/ft^2) ÷ 60(min/hr)

= 1,601,395 acfm

ROW 22--Volume Flow (scfm) - See Note A:

Same as ROW 21 except adjusted for standard temperature of 68°F

2,631,000 lb/hr x 1,545 x (941 + 68°K) ÷ (28 x 2,116.8) ÷ 60

= 603,523 scfm

ROW 32--Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,601,395 (acfm) x (250 +460°K) ÷ (941 ÷ 460°K)

= 811,556 acfm

ROW 35--Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

811,556 ft^3/min ÷ 60 ÷ (15.7^2 ÷ 4 x 3.14159)

= 69.90 ft/sec

<u>Table A-2</u>:

ROWS 59, 64, 69, 75, 81, 118, 156, and 159--(Except Duct Burner) :

Emissions in tons per year; example for particulate:

11 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton

= 48.18 ton/yr

For Duct Burner the hours per year at full load was used to calculate annual emissions:

450,000 x 10^6 Btu/year ÷ 122 x 10^6 Btu/hr

= 3,688.5 hr/yr

Annual Emissions are therefore:

1.22 lb PM/hr x 3,688.5 hr/yr ÷ 2,000 lb/ton

= 2.25 ton/year

ROW 63--SO_2 Emissions (lb/hr):

987,186.5 cf/hr x 1 gr ÷ 7,000 gr/lb x 2 lb SO_2/lb S ÷ 100 cf

= 2.82 lb/hr

ROW 68--NO_x Emissions (lb/hr) - See Note B:

25 ppm x [20.9 ÷ 5.9 (1 - 6.1/100) - 14.4] x 2,116.8 lb/ft^2 x 1,601,395 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (941 + 460°K) x 10^6 (adjust for ppm)]

= 95.7 lb/hr

ROW 74--CO Emissions (lb/hr):

Same as NO_x except ppm and molecular weight changed; confirmation calculation:

95.7 lb/hr NO_x x 10/25 x 28/46

= 23.3 lb/hr

ROW 80--VOC Emissions (lb/hr) - See Note C:

3 ppm x (1-6.1/100) x 1,601,395 acfm x 2,116.8 lb/ft^2 x 12 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (941 + 460) x 10^6)

= 3.18 lb/hr

Table A-3:

ROW 117--H_2SO_4 Mist Emissions (lb/hr):

Based on 5 percent SO_2 converted to acid mist

2.82 lb SO_2/hr x 0.05 x 98 ÷ 64 (or a ratio 3.06/2)

$= 2.16 \times 10^{-1}$

Table A-4:

ROW 155--POM Emissions (lb/hr):

EPA emission factor as noted in printout:

933.9 (MMBtu) x 0.48 pg/J x 2.324 lb/10^{12} Btu/pg/J ÷ 10^6 (to adjust to 10^{12} Btu)

$= 1.04 \times 10^{-4}$ lb/hr

ROW 158--Formaldehyde Emissions (lb/hr):

EPA emission factor as noted in printout.

Same calculation as ROW 155.

REVISIONS TO TABLE 2-1 AND 3-3

REFLECTING MINOR CHANGES
(i.e., H_2SO_4 AND ANNUAL EMISSIONS)

Table 2-1. Stack, Operating, and Emission Data for the Proposed Cogeneration Facility

	Maximum Emissions			
		CT/Duct Burner		
Parameter	CT Only[a]	CT[b]	Duct Burner[c]	Total
Stack Data (ft)				
Height	115			115
Diameter	15.7			15.7
Operating Data				
Temperature (°F)	250			220
Velocity (ft/sec)	69.9			58.14
Building Data (ft)				
Height	76			76
Length	60			60
Width	43			43
Maximum Hourly Emissions (lb/hr)				
SO_2	2.82	2.59	0.37	2.96
PM/PM10	11.0	9.0	1.22	10.22
NO_x	95.7	86.4	12.2	98.6
CO	23.3	21.0	12.2	33.2
VOC	3.18	2.98	3.7	6.7
Sulfuric Acid Mist	0.02	0.02	0.003	0.02
Annual Potential Emissions (TPY)				
SO_2	12.35	11.34	0.68	12.02
PM/PM10	48.18	39.42	2.25	41.67
NO_x	419.2	378.4	22.5	400.9
CO	102.1	92.1	22.5	114.6
VOC	13.9	13.0	6.75	19.75
Sulfuric Acid Mist	0.95	0.87	0.05	0.92

Note: 10^6 Btu/hr = million British thermal units per hour.
CO = carbon monoxide.
CT = combustion turbine.
°F = degrees Fahrenheit.
ft = feet.
ft/sec = feet per second.
HRSG = heat recovery steam generators.
lb/hr = pounds per hour.
Neg = negative.
NO_x = nitrogen oxides.
O_2 = oxygen molecule.
PM = particulate matter.
PM10 = particulate matter less than or equal to 10 micrometers.
ppmvd = parts per million by volume dry.
SO_2 = sulfur dioxide.
TPY = tons per year.
VOC = volatile organic compound.

[a] Performance based on 20°F with NO_x emissions at 25 ppmvd (corrected to 15 percent O_2); 8,760 hr/yr operation.

[b] Performance based on 59°F with NO_x emissions of 25 ppmvd (corrected to 15 percent O_2), 8,760 hr/yr operation; stack parameters based on 90°F ambient temperature.

[c] Performance based on 122 x 10^6 Btu/hr heat input for HRSG; annual emissions based on 4,500 hours per year operation at an average heat input of 100 x 10^6 Btu/hr.

Table 3-3. Maximum Emissions Due To the Orlando CoGen Limited, L.P. Project Compared to the PSD Significant Emission Rates

	Emissions (TPY)		
Pollutant	Potential Emissions From Proposed Facility	Significant Emission Rate	PSD Review
Sulfur Dioxide	12.02	40	No
Particulate Matter (TSP)	41.67	25	Yes
Particulate Matter (PM10)	41.67	15	Yes
Nitrogen Dioxide	400.9	40	Yes
Carbon Monoxide	114.6	100	Yes
Volatile Organic Compounds	19.75	40	No
Lead	NEG	0.6	No
Sulfuric Acid Mist	0.92	7	No
Total Fluorides	NEG	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	NEG	0.0004	No
Mercury	NEG	0.1	No
Vinyl Chloride	NEG	1	No
Benzene	NEG	0	No
Radionuclides	NEG	0	No
Inorganic Arsenic	NEG	0	No

Note: NEG = Negligible.
TPY = Tons per year.

BACKUP CALCULATIONS FOR TABLES 4-5, 4-6, AND 4-7

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 1 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	607,500	Developed from manufacturer budget quotations[a]
Ammonia Storage Tank	172,400	Developed from manufacturer budget quotations[b]
HRSG Modification	303,000	Developed from manufacturer budget quotations[c]
Indirect Capital Costs		
Installation	419,300	20% of SCR associated equipment and catalyst[d]
Engineering, Erection Supervision, Startup, and O&M Training	329,000	10% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG costs, installation labor.[e]
Project Support	180,900	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	18,100	0.5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs and installation labor.
Interest During Construction	575,000	15% of all direct and indirect capital costs, including catalyst cost[g]
Contingency	458,000	20% of all capital costs[h]
Total Capital Costs	3,096,700	Sum of all capital costs

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 2 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Annualized Capital Costs	373,700	Capital recovery of 10% over 20 years, 11.74% per year[i]
Recurring Capital Costs		
SCR Catalyst (Materials and Labor)	1,489,200	Developed from manufacturer budget quotations[j]
Contingency	297,800	20% of recurring capital costs[k]
Total Recurring Capital Costs	1,787,000	Sum of recurring capital costs
Annualized Recurring Capital Costs	718,600	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 that all calculations were 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 2,482 10^3 lb/hr = \$245,000

   2. Control system costs = \$362,500

      Total is \$607,500

b. Ammonia tank size is based on SCR size as follows:

   \$69.4/1,000 lb mass flow x 2,482 x 10^3 lb/hr = \$172,400

c. HRSG modifications based on mass flow at \$122.2 per 1,000 lb mass flow.

   \$122.2/10^3 lb x 2,482 x 10^3 lb/hr = \$303,000

d. From EPA OAQPS cost control manual

   (\$607,500 + \$1,489,200) x 0.2 = \$419,300

e. From EPA OAQPS cost control manual

   (\$607,500 + \$172,400 + \$1,787,000 + \$303,000 + \$419,300) x 0.10

   = \$329,000

f. Engineering estimate; same as engineering costs except use 0.005.

g. From OAQPS cost control manual and engineering estimate.

   0.15 (\$607,500 + \$172,400 + \$303,000 + \$419,300 + \$329,000 + \$180,900

   + \$19,200 + \$18,100 + \$1,787,000) = \$575,000

h. From EPA OAQPS cost control manual and engineering estimate

   0.20 (\$607,500 + \$172,400 + \$303,000 + \$419,300 + \$329,000 + \$180,900

   + \$19,200 + \$18,100 + \$575,000) - (0.25 x 0.15 x \$1,787,000)

   = \$458,000; note that the (0.2 x 0.15 x \$1,787,000)

   removes contingency for catalyst.

i. OAQPS cost control manual; standard statistical tables for 10% interest over 20 years

$3,096,700 x 0.1174 = $363,700

j. Developed from manufacturer data at $0.6/lb mass flow:

$0.6 x 2,482,000 = $1,489,200

k. Same rationale as h:

0.2 x $1,489,200 = $1,787,000

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 $1,787,000 = $718,600

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 1 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Annual Costs		
Operating Personnel	20,800	16 hours/week @ $25/hour[a]
Ammonia	27,900	$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	58,300	Capital recovery (11.74%/year) for 1/3 of catalyst cost[d]
Catalyst Disposal Cost	68,900	Engineering estimate[e]
Contingency	43,700	20% of indirect costs[f]
Energy Costs		
Electrical	35,000	80 kWh/hr; $0.05/kWh[g]
Heat Rate Penalty	172,600	4" back pressure, heat rate reduction of 0.5%, energy loss at $0.05/kWh[h]
MW Loss Penalty	98,700	84 MW lost for 3 days; lost capacity @ $0.05/kW; cost of natural gas @ $3/MMBtu subtracted[i]
Fuel Escalation Costs	94,400	Real cost increase of fuel [j]
Contingency	60,400	20% of energy costs; excludes fuel escalation[k]
Total Direct Annual Costs	688,800	Sum of all direct annual costs

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 2 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Indirect Annual Costs		
Overhead	34,200	60% of ammonia and 115% of O&M labor, and 15% of O&M labor (OAQPS Cost Control Manual)[l]
Property Taxes and Insurance	97,700	2% of total capital costs[m]
Annualized Capital Costs	373,700	Capital recovery of 10% over 20 years, 11.74% per year (from Table 4-5)
Recurring Capital Costs	718,600	Capital recovery of 10% over 3 years, 40.21% per year (from Table 4-5)
Total Indirect Annual Costs	1,214,200	Sum of all indirect annual costs
Total Annual Costs	1,903,000	Total annualized cost[n]

Note: All calculations rounded off 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 that all calculations were rounded off 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

400.9 TPY NO_x x 0.65 (~16 ppm removed/25 ppm) x $300 x 17/46

(molecular weight of ammonia to NO_x)

= 27,900

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.

$1,489,200 x 0.1174 (20 years @ 10 percent) ÷ 3 = $58,300

e. Estimated as $27.77/1,000 lb mass flow; based on catalyst volume.

$27.77 x 2,482 (1,000 lb mass flow) = $68,900

f. OAQPS cost control manual background documents

0.2 x ($20,800 + $27,900 + $8,100 + $58,300 + $68,900) = $43,700

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.

78.83 MW x 0.005 x 8,760 hrs/yr x 1,000 kW/mw x $0.05/kWh = $172,600

i. 3 days required to change catalyst or maintenance; saving in gas usage subtracted

84 MW x 3 days x 24 hours x $0.05/kWh x 1,000 mwh - (856.9 x 10^6 Btu/hr

x 3 days x 24 hours x $3/$10^6$ Btu) = $98,700

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 + $172,600) = $94,400

k. OAQPS cost control manual background documents

0.2 x ($35,000 + $172,600 x $98,700) = $60,400

l. 0.6 ($27,900 + 1.15 x $20,800) + 0.15 x $20,800 = $34,200

m. From OAQPS cost control manual

0.02 x ($3,096,700 + $2,787,000)

n. Total direct annual costs plus total indirect annual costs:

$688,800 + $1,214,200 = $1,903,000

Table 4-7. Maximum Potential Emission Differentials TPY With and Without Selective Catalytic Reduction

	Project With SCR			Project Without SCR	
Pollutants	Primary	Secondary[a]	Total	CT/DB	Difference[b]
Particulate	24 [c]	2.06	26	0	26
Sulfur Dioxide	0	22.64	23	0	23
Nitrogen Oxides	141 [d]	11.32	152	401	(249)
Carbon Monoxide	0	0.68	1	0	1
Volatile Organic Compounds	0	0.10	0	0	0
Ammonia	64 [e]	0.00	64	0	64
Total	229	36.81	266	401	(135)
Carbon Dioxide[f]	--	3,535	3,535	--	3,535

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 0.47 MW from heat rate penalty and electrical for 8,760 hours per year operation (0.5% of 78.83 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 - 0.47 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 = 2.06 TPY.

[b] Difference = Total with SCR minus project without SCR.

[c] Assume sulfur reacts with ammonia; 11.65 TPY SO_2 x 132 (MW of ammonia salt) + 64 (MW of SO_2).

[d] 9 ppm NO_x emissions.

[e] 10 ppm ammonia slip (ideal gas law at actual flow rate from stack): 726,343 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., 0.47 MW CO_2 calculated based on 85.7% carbon in fuel oil and 18,300 BTU/lb).

INFORMATION ON DRY LOW-NO$_x$ COMBUSTOR FOR ABB GT 11N-EV

DRY LOW NOx EMISSIONS

ABB's second generation "EV" Burners, proposed to Air Products for the Orlando Cogeneration Project, when operated on natural gas, require no introduction of steam or water to maintain low NOx emissions.

ABB guarantees to achieve a Dry Low NOx emission level for the unit proposed, equipped with the "EV" burner, of 25ppmvd, (15% O_2 corrected) when operating at base load on the natural gas fuel specified.

EXPERIENCE

ABB pioneered development of Dry Low NOx combustor technology in 1984. Our first generation "lean pre-mix" burner achieved 36ppmvd (15% corrected) on a model 13B gas turbine located in Germany.

Since that time ABB has placed in operation or has on order, nine (9) first generation "lean pre-mix burners" and twelve (12) second generation "EV burners" (as proposed for the GT 11N's for Air Products). The total accumulated operating hours ABB has now exceeds over 80,000 hours.

The following is a list of installations, type of burner, (first or second generation) accumulated operating hours, and measured or anticipated NOx levels.

DRY LOW NO_x REFERENCE LIST

INSTALLATION	YR	LOCATION	MODEL	TYPE BURNER	NOx level	Hrs
Lauswaard	84	Germany	13B	1st	36	20,000
Lauswaard	87	Germany	13B	1st	36	16,000
Korneburg	87	Austria	13D	1st	47	8,000
Lage Weide 5	87	Netherlands	11D5	1st	38	22,000
Hemweg 7	88	Netherlands	13E	1st	38	3,000
Pegus 12	89	Netherlands	13E	1st	38	14,000
Almere	89	Netherlands	8	1st(1)	65	4,000
Purmerend	88	Netherlands	8	1st(1)	69	7,000
Galileistraat 1	89	Netherlands	8	1st(1)	63	8,000
Lunds Energiverk	90	Sweden	10	2nd	25	--
Pegus	90	Netherlands	9	2nd	25	--
MCV1	91	Midland	11N	2nd	25	--
Anyang	91	Korea	11N	2nd	25	--
Anyang	91	Korea	11N	2nd	25	--
Anyang	91	Korea	11N	2nd	25	--
Anyang	91	Korea	11N	2nd	25	--
Anyang	91	Korea	11N	2nd	25	--
Bandang	91	Korea	11N	2nd	25	--
Bandang	91	Korea	11N	2nd	25	--
Bandang	91	Korea	11N	2nd	25	--
Bandang	91	Korea	11N	2nd	25	--

(1) annular combustor

CONCLUSION

ABB is the most experienced gas turbine generator set manufacturer in the world for providing Dry Low NOx combustor technology. We have accumulated over 80,000 hours of operating experience and have obtained the know-how for the requirements needed to apply this technology. We have installed or on order, 21 units representing approximately 1600 MW of installed worldwide capacity using Dry Low NOx combustor technology, and we remain the market leader in this field. The second generation Dry type "EV" burners proposed to Air Products will provide a low NOx level over operating ranges, the simplest design, the most probable least amount of future maintenance, and is backed by a company that has the most experience in this technology.

For more information and technical details, please refer to Part III, Section 1.1.2.

GT11N WITH DRY LOW NO_x EV BURNER

The following photograph shows a GT11N in operation with a second generation dry low NO_x EV burner. This unit is located at the MCV1 (Midland Cogeneration Venture) in Midland, Michigan. The unit is presently completing tests, which will be completed in the coming weeks.

Major achievements were made at Midland which include:

- Successful ignition and light-off
- Successful achievement of Dry Low NO_x of less than 25 ppmvd at full load
- Demonstrated achievement of part load low NO_x levels
- Demonstrated reliability
- Completion of work to schedule

ABB will be releasing additional information regarding this unit as it becomes available in the coming weeks.

POWER NEWS

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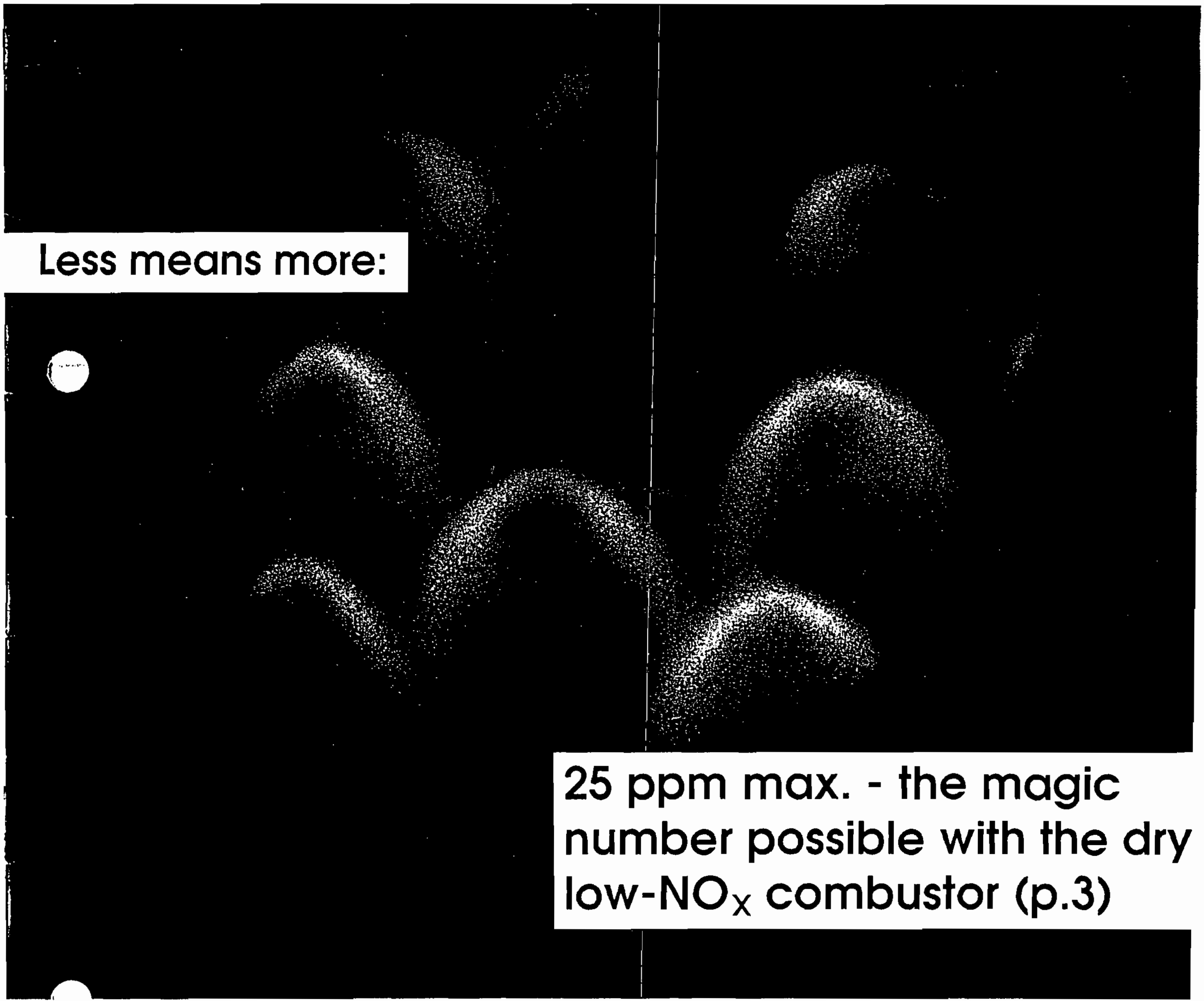


Less means more:

25 ppm max. - the magic number possible with the dry low-NO_X combustor (p.3)

ABB Power Plants gathering honours (p. 8)

ABB

Less means more: 25 ppm max. - the magic number possible with the dry low-NOx combustor

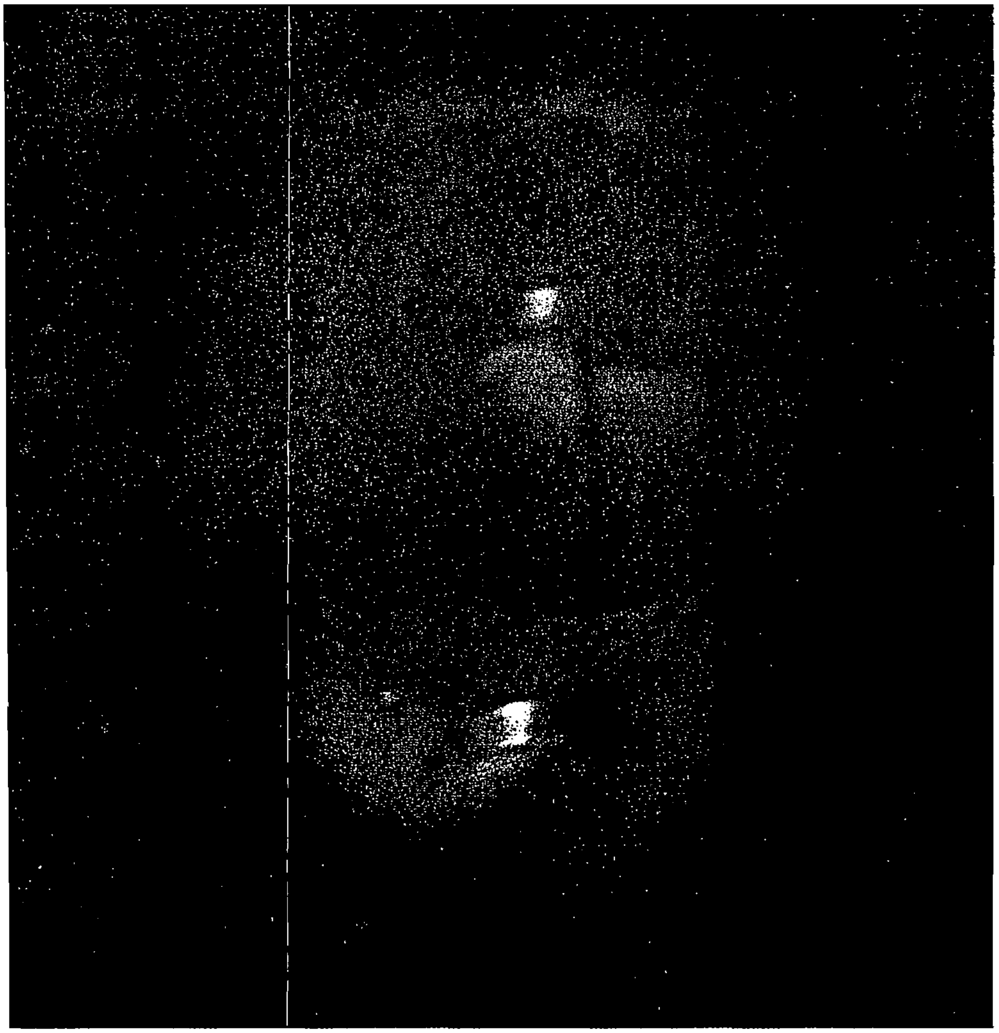
The production of nitrogen oxides that accompanies fossil fuel combustion is one of the key problems the power generation industry will have to resolve if pollutant emissions are to be reduced. Research into new combustor technologies is currently the most important activity in the gas turbine sector that is addressing this problem.

The approach adopted by the business area PGT (Power Generation Gas Turbines) at the time new combustor concepts were being considered was both logical and simple: as the nitrogen oxides are produced during the combustion process, it was in the combustor that technical improvements would have to be introduced to reduce them.

Although a simple deduction, its realization involves a highly complex technology with limits imposed by physical and chemical conditions.

Stoichiometry as an interference factor

With conventional gas turbine burners, the fuel is injected directly into the flame. The fuel air



The blue flame shows that less NOx is being produced at the lower flame temperature.

mixture exhibits a concentration gradient within which the very hot stoichiometric mixture is produced. As the formation of nitrogen oxides depends on a high temperature and a certain residence time, conventional burners (i.e. the diffusion type) produce large amounts of nitrogen oxide as a matter of course.

In contrast to the oil firing used to heat private households, gas turbines bring far larger quantities of air into contact with the fuel than would be required for the theoretically necessary stoichiometric mixture. Combustion begins at the high stoichiometric flame temperature of 2000 °C or above, and ends at a far lower turbine inlet temperature. However, due to the high flame temperature in the combustor's primary zone NOx formation is generally too high. It is therefore necessary to drastically reduce the flame temperature from the beginning.

A paradox shows the way: cold flames

There have been many approaches to solving this dilemma. However, all of them were directed at reducing the formation of nitrogen oxides by lowering the flame temperature.

Fire and water: diffusion flames with wet control

By injecting water or steam directly into the flame, it is possible to lower the temperature and consequently reduce nitrogen oxide emissions to values of 25 to 150 ppm. This method is used widely throughout the world, and has the desirable byproduct of generating more power. This is possible as a larger volume of gas is forced through the turbine than in conventional combustion without water injection.

A less desirable "byproduct" is the drop in efficiency in plants with a heat recovery facility with steam turbine (combined cycle power plants) that results from the poorer utilization of injected steam in the gas turbine.

The "dry" approach

Improved efficiency and a further reduction in nitrogen oxide emissions, particularly for the combined cycle power plant - the current No. 1 on the list of clean plants - was and still is the driving force behind the development of dry low-NOx burner concepts.

This type of burner has special benefits for plants operated non-stop. Since their first-time costs make up only approximately 6 % of the total running costs over their lifetime, it pays to invest more in improving their efficiency. In a combined cycle plant, efficiencies 1 to 2 % higher than with wet control are possible with this method.

PGT developed three concepts along these lines:

- The first-generation lean premix burner
- The ring combustor
- The second-generation lean premix burner

The third-named concept was based on preliminary work carried out at the ABB Research Centre in Dättwil and subsequent joint development for its application in ABB gas turbines.

Lean Premix Burner

This concept is based on the simple principle of premixing air and fuel, with the maximum amount of excess air, before combustion. The amount of air used is about twice the theoretical amount required for combustion, thus giving the method its name "lean premix". From the outset, the flame temperature is at least 500 °C lower than in the earlier method. The hot yellow flame is replaced by a blue flame which is much colder and produces less NOx.

ABB première

Such burners were first deployed in 1984 on a Type 13 gas turbine. The father of this low-NOx development, the engineer Hans Koch, replaced the turbine's diffusion burner by a bundle of lean premix burners.

One difficulty he had to overcome was caused by the premixed flames exhibiting a much smaller range of stability than the conventional diffusion flames, where the stabilizing element was simply the boundary between the air and fuel. Small, central diffusion flames were added to try and achieve better stabilization, but these caused the pollutant emissions to increase again.

A second difficulty to be overcome involved the machine's control with these low-pollutant air fuel mixtures. The amount of fuel needed to control the machine varies widely with the load (in the ratio of 1:4). A lean premix burner

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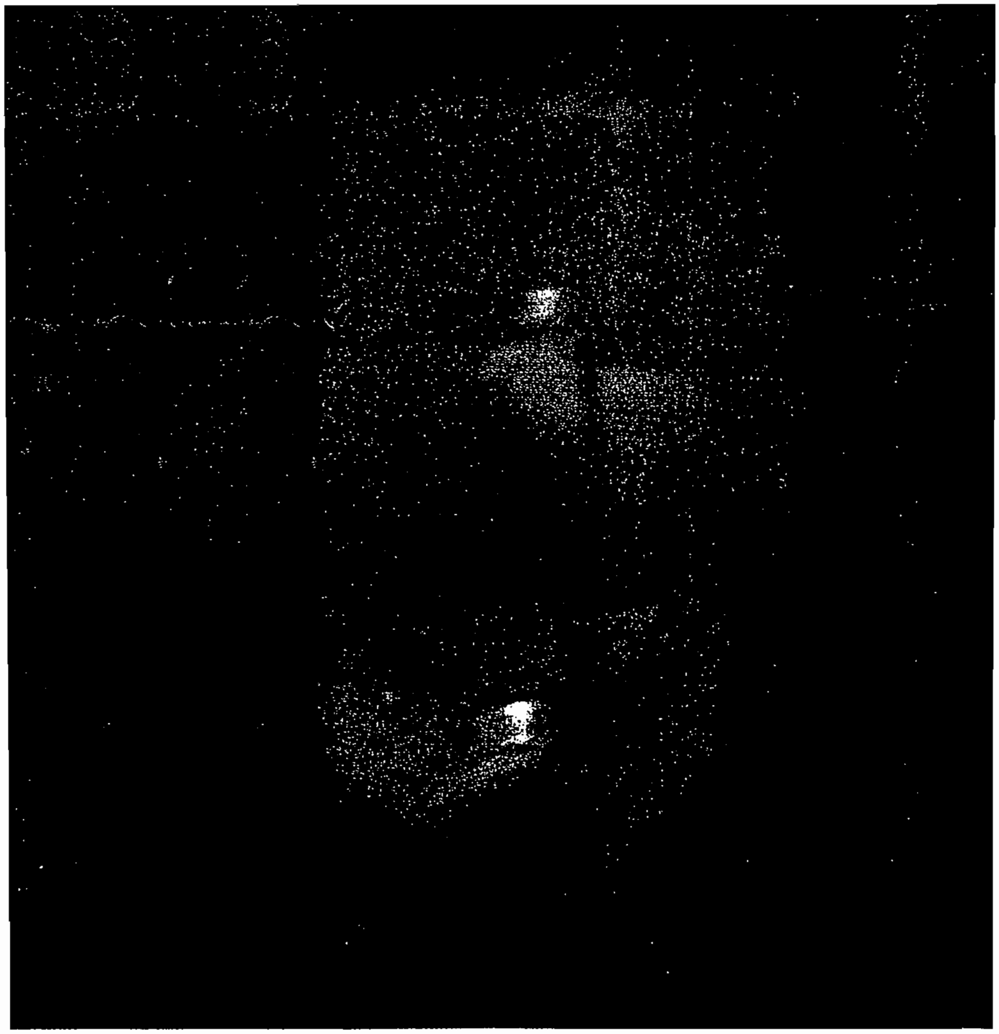

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would be extinguished by such fuel throttling.

The problem was resolved by supplying fuel to groups of burners at a time instead of all together, and in a particular, rather ingenious order.

The result of this initial development work was a reduction in NOx values to 38 ppm. A number of ABB gas turbines are currently operating with such combustors, two of the largest being rated 150 MW.

The ring combustor

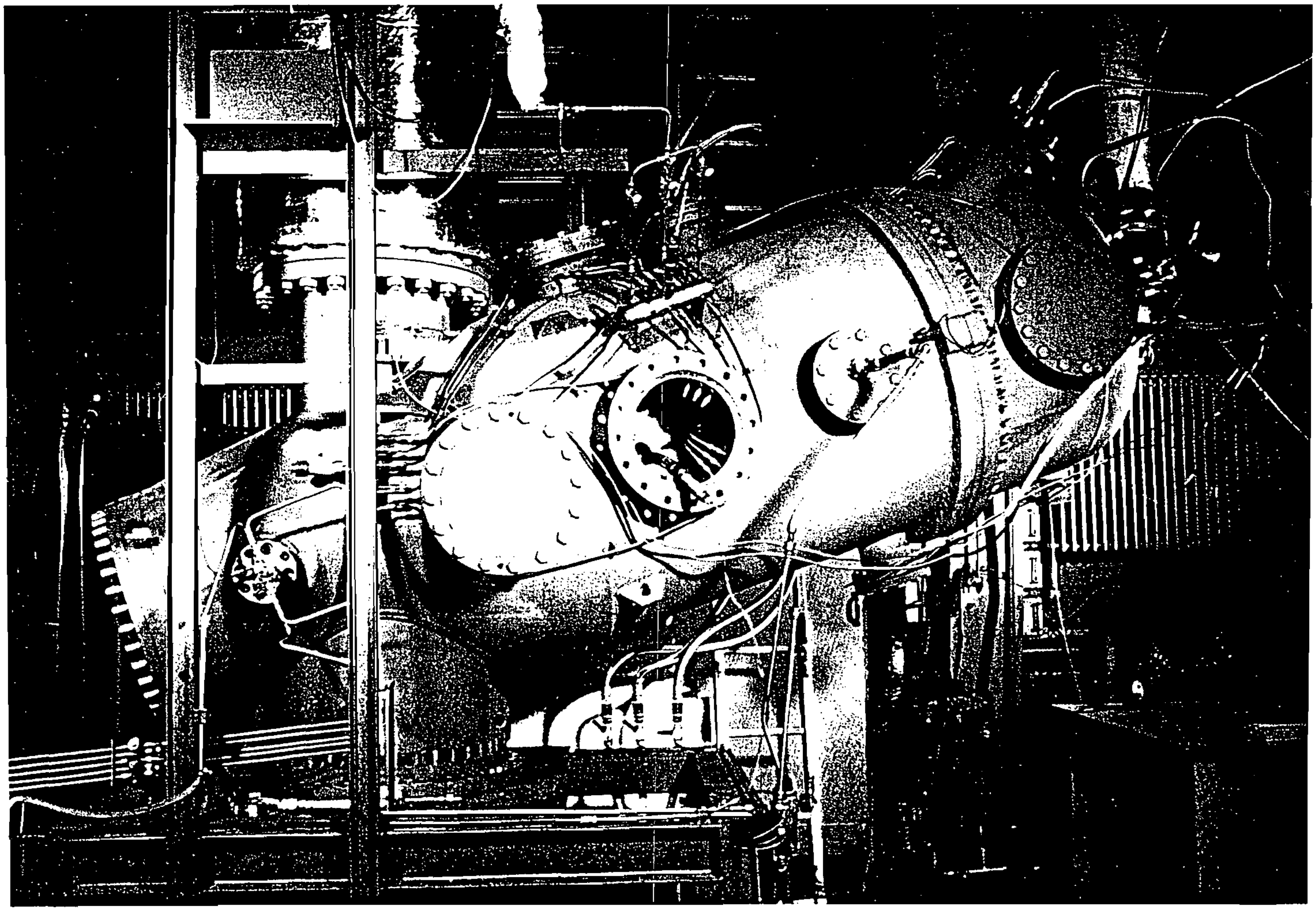
In the second concept a number of small burners are arranged in a circle. This arrangement resulted in a drastic reduction in the size of the combustor. The first such combustor was installed in a GT 8 in 1987 and is still operating today.

In the ring combustor natural gas is injected through very small nozzles. Although the flames are of the diffusion type, their small size enables the NOx emission to be reduced to 70 ppm. However, as it became clear that this method would not lead to a reduction in NOx values to 25 ppm max., efforts were redirected to the development of a second-generation lean premix burner.

Second-generation lean premix burner

The development goals were set clearly in 1987: pollutants were to be reduced to 25 ppm during gas combustion, with the added possibility of oil combustion with injected water.

The second generation has some genuinely new features:



Complex flames
As the laws of similarity are far more complicated in combustion engineering than in mechanical or fluids engineering, model experiments do not say enough about how the final product will behave in operation. Burners and even complete burner groups used for experiments must therefore be full size.

1. The torsion body which is characteristic of blades with aerodynamic profiles is replaced by a cone with tangential air inlets.

2. The premix flames are no longer stabilized by central diffusion flames, but by adjacent burners of the same type, however operated in another premix mode.

The principle, highly simplified, is that some of the burners are kept constantly hot as a kind of pilot system, while the fuel to the other burners - the main system - is controlled over a wide range. The swirling flames, which are at different temperatures, mix thoroughly and uniformly. The result is a low-NOx, dynamically stabilized flame.

This idea, which was derived from basic studies carried out by Dr. J.J. Keller at the ABB Research Centre in Dättwil, enables the goal of 25 ppm max. to be achieved.

When used in a combined cycle power plant, it also allows efficiency to be improved by 1 to 2 % compared with the wet control method.

Wet Control
25-150 ppm

Ring Combustor
under 70 ppm

Lean Premix 1st Generation
40 ppm

Lean Premix 2nd Generation
25ppm max.

Annular combustor
Detail of a ring combustor. The burner matrix can be seen on the left.

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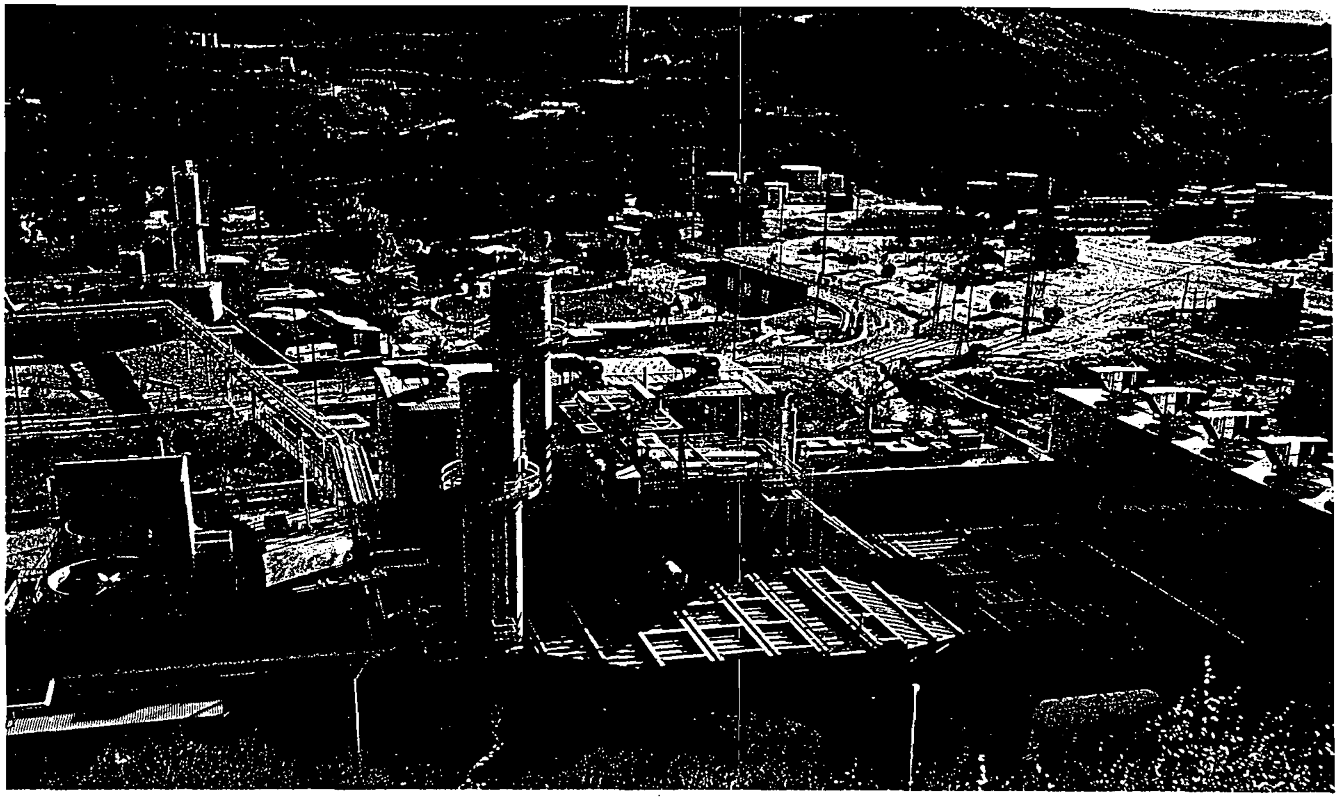
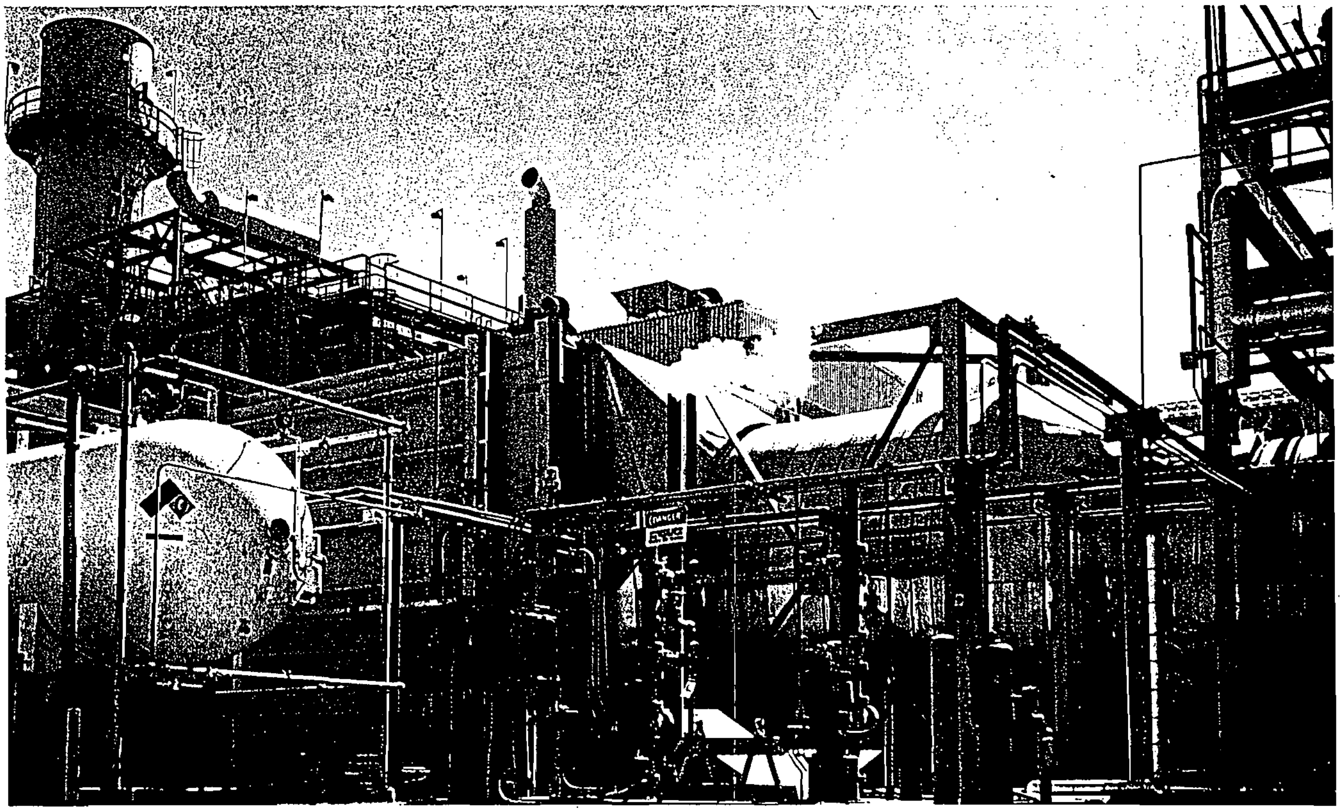




The cleanest power plant in the world - AES Placerita, California.
The strictest regulations concerning the emission of pollutants are applied in the USA and Japan. In the USA, it is California which leads the field. AES Placerita is currently the world's cleanest power plant, with pollutant values below 10 ppm. Special soundproofing equipment has been installed which also reduces noise during normal operation to less than 39 dBA at a distance of 244 m (the proximity of the plant's nearest neighbour).

ABB Power Plants gathering honours

Since the end of October two power plants built by ABB have been singled out to receive a prestigious award from the American trade journal "Power".

Hot on the heels of the 1989 International Energy Conservation Award, which went to Hemweg 7 combined cycle plant in the Netherlands as one of three power facilities to make a name for itself in energy conservation, comes an Environmental Protection Award.

The new award is for the Römerbrücke district heating plant in West Germany, and goes to the utility Stadtwerke Saarbrücken AG, VKW Düsseldorf, who delivered the circofluid FBC, and ABB Mannheim, who acted as general contractor for the turnkey plant.

The jury cited extremely low emissions, high cost-efficiency, in part due to the fact that coal high in inerts can also be burnt, and harmony with the urban surroundings as reasons for the award.

Gerhard Hebel and Dr. Hans Hubert Lienhard, who accepted the awards on behalf of ABB, emphasized in their congratulations to the utilities that such reductions in pollutant emissions are always joint efforts, requiring close cooperation between the utilities and the power plant builder. Utilities must show a willingness to embrace new ideas, to make major financial commitments, and, not least, to undertake joint development projects. Finally they pointed out that joint effort would enable modern power plant technologies to be developed for the world market, and that these technologies would also be available to third-world countries.

The 1989
Energy Conservation
Award
For outstanding achievement by industry in
optimizing use of our energy resources
Awarded by Power International to:
UNA Amsterdam
Hemweg Station

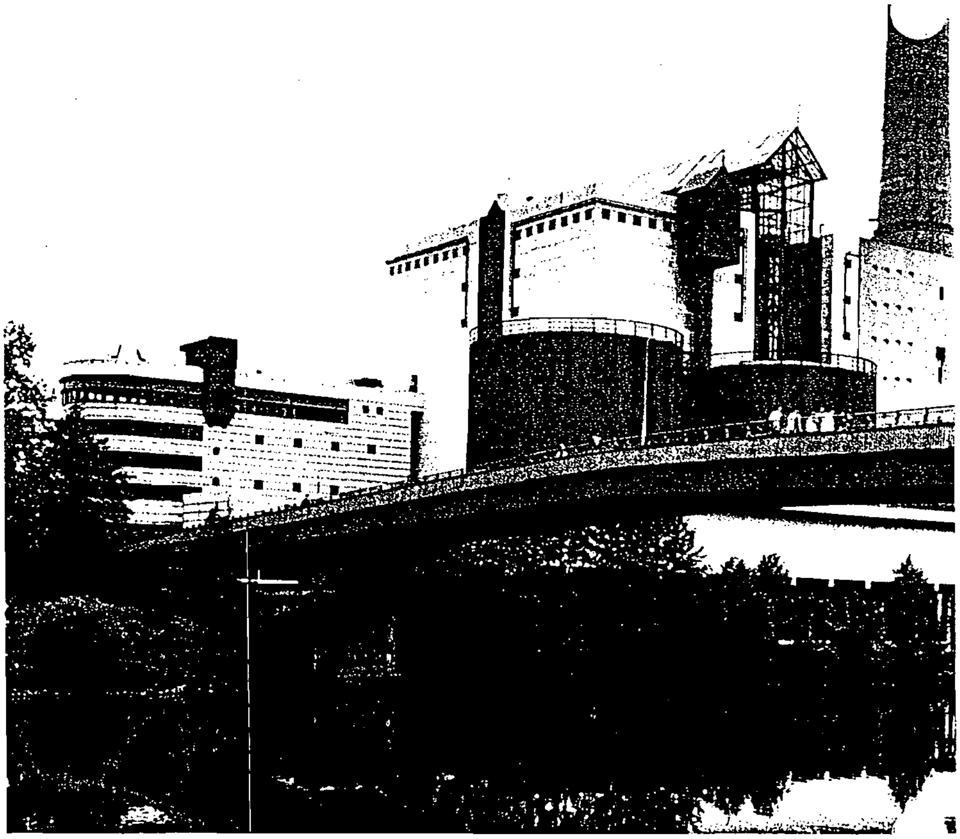
This flag represents the international concern for
protection of our energy resources.
Presented to Asea Brown Boveri AG for its engineering leadership in the project

Editor

The 1989
Environmental Protection
Award
For outstanding achievement by industry in
optimizing use of our natural environment
Awarded by Power International to:
Stadtwerke Saarbrücken AG
Römerbrücke Station

The "E" stands for Environment and is a symbol
of concern for the purity of our world's air and water.
Presented to Asea Brown Boveri AG for its engineering leadership in the project

Editor



Römerbrücke
Stadtwerke Saarbrücken's Römerbrücke district heating power plant was supplied turnkey by ABB

ABB
ASEA BROWN BOVERI

February 14, 1992

Mr. Jack Kindt
Environmental/Energy Division
Air Products and Chemicals, Inc.
7201 Hamilton Blvd.
Allentown, PA 18195-1501

Subject: ABB GT11N, EV Combustor

cc. Chris Allevik

Dear Mr. Kindt,

ABB has proven in Midland, Mi that their GT11N-EV can reach NOx emission values of less than 25 ppmvd (15%O2) when firing natural gas. As you can see from the attached press release, the GT11N has actually run as low as 9 ppm, even though the continuous operating level as of now is 13 ppmvd (15%O2) with CO levels below 8 ppm. Please be aware that these values are below the actual air permit requirement for Midland and that they are based on long-term testing on-site. More than 1500 operating hours have been accumulated at Midland.

Included is also a graph which shows NOx measurements by ABB as well as a third-party company (CONSUMERS POWER) at a certain point within the test period. The burner air to fuel ratio can be adjusted to show different NOx levels. Here they show values of less than 25 ppmvd (15%O2) over a load range from 60% to 100%

I have also attached a copy of the ASME paper 90-GT-308 which shows burner tests under full-engine conditions. The paper summarizes the effect of pressure, temperature and air to fuel ratio on NOx formation for the ABB EV burner. NOx values of less than 25 ppmvd (15%O2) were measured at full load.

If you have any questions, please don't hesitate to call me at 908-932-6368.

Very truly yours,

Gregor Gnaedig
Performance Engineer
Gas Turbine Engineering

ABB Power Generation Inc.

Gas Turbine Power Division
1460 Livingston Avenue
North Brunswick, New Jersey 08902
Telephone: 908-932-6000
Telefax: 908-932-6194

ABB
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NEWS RELEASE

CONTACT: Andrew J. Lazarus
A. J. Lazarus Associates, Inc.
1500 Broadway, Suite 1705
New York, NY 10036
(212) 768-2490

FOR IMMEDIATE RELEASE

ABB ANNOUNCES COMMERCIALIZATION OF DRY LOW NO$_X$ COMBUSTOR; MICHIGAN UNIT ACHIEVES 9 PPM LEVEL UNDER FULL LOAD

North Brunswick, New Jersey, December 3, 1991 -- ABB (Asea Brown Boveri) announces commercial operation of its advanced Dry Low NO$_X$ Combustor at the Midland Cogeneration Venture (MCV) facility in Michigan. According to ABB's Gas Turbine Power Division, after more than 1000 hours of operation, the EV-burner has achieved emission levels well below the permit requirements. These results, announced by ABB after systematic on-site tests, have demonstrated the ability to provide 9 ppm Dry NO$_X$ performance and CO levels below 8 ppm under full load.

"Our experience with advanced lean pre-mix burner technology, which began in 1984, is substantiated by more than 120,000 accumulated hours of operational experience. We have installed or have on order 23 units representing approximately 2000 MW of world-wide capacity. This gives us a leading position in Dry Low NO$_X$ combustion technology and reinforces our commitment to a clean environment in the future", said Harvey Padewer, President of ABB's Gas Turbine Power Division.

(more)

A significant departure from more conventional premix burners the Dry Low NO_X EV-burners consist of two half-cones shifted t form two inlet slots. The resulting vortex flow developed insid the cone mixes the gaseous fuel with the air entering from th slots in the side of the burner. This lean mixture then leaves th cone creating a vortex breakdown which forms a stable flame zone. No diffusion or pilot stage is needed, therefore, the flame i stable and there is no risk of flashback. The simplicity of thi design accounts for the EV-burner's exceptional reliability.

The burner system can be switched on or off in a matter o seconds to accommodate load changes. Unlike other designs, th temperature distribution is uniform throughout, guaranteeing th combustor thermal efficiency.

A patent for ABB's Dry Low NO_X system was granted in th United States in 1985.

ABB believes the EV-burner has the near term potential t achieve even lower emission levels without recourse to selectiv catalytic reduction (SCR).

The MCV began commercial operation in March 1990. With 12 AB gas turbines, the plant has a capacity of 1370 MW, and up to 1.3 million pounds per hour of process steam for industrial use. Principal customers are the Dow Chemical Company for steam an electricity and Consumers Power for electricity.

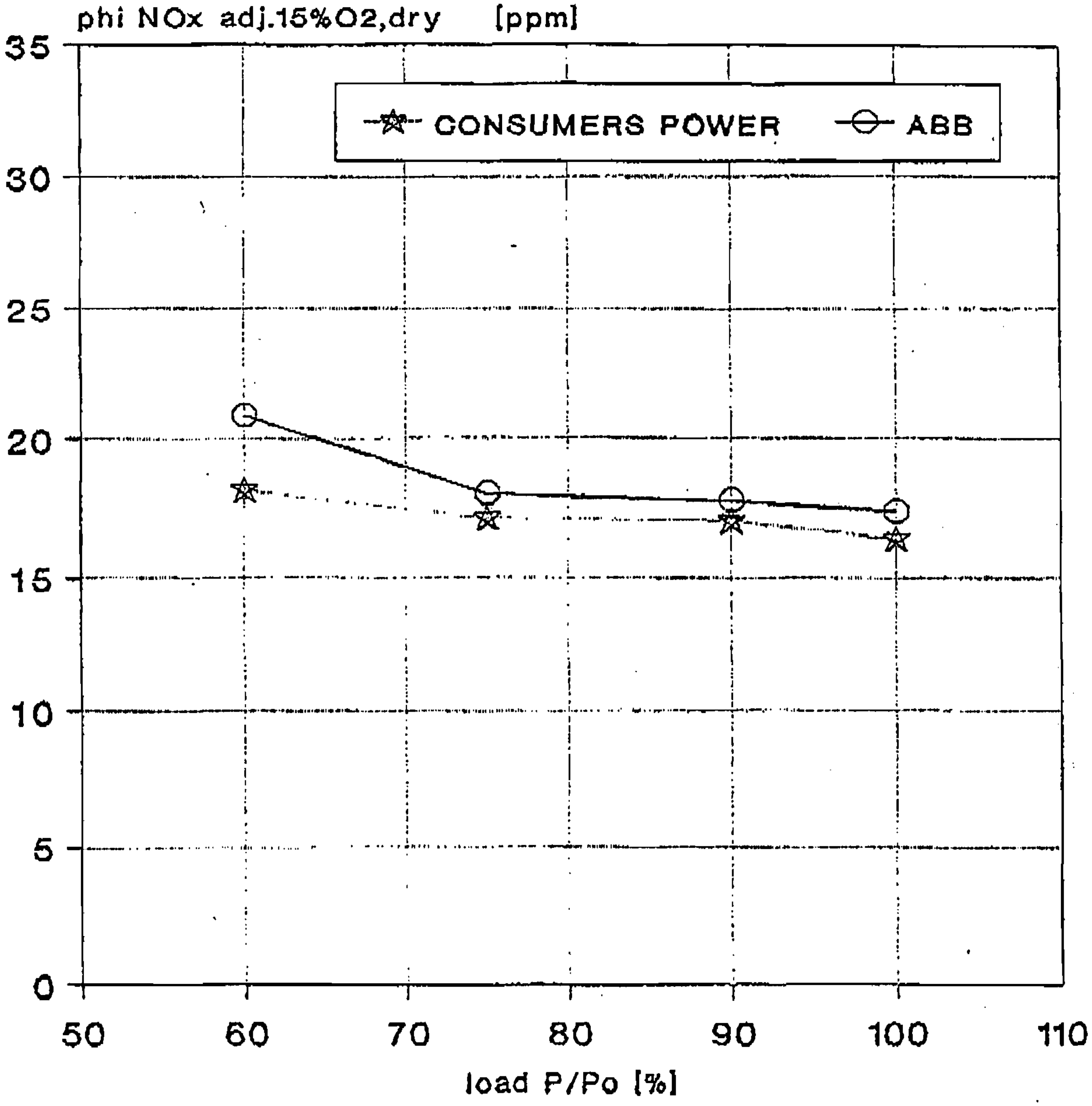
(more)

ABB's Gas Turbine Power Division is part of ABB Power Generation Inc. and supplies a complete range of gas turbines for peaking, baseload and combined cycle operations from its North Brunswick, New Jersey headquarters. ABB Power Generation Inc. offers equipment and services for steam and gas turbine generators, combined cycle and hydro-electric power plants. ABB, with approximately $6 billion sales and some 30,000 employees in the United States, provides products and services for power, automation, environmental control, transit and other markets.

# # #

GT11N-EV

phi NOx adj.15%O2,dry = f (P/Po)



stable load conditions
fuel : natural gas

ASEA BROWN BOVERI

9

New York, N.Y. 10017

Giegel

Second Generation Low-Emission Combustors for ABB Gas Turbines: Burner Development and Tests at Atmospheric Pressure

TH. SATTELMAYER, M. P. FELCHLIN, J. HAUMANN, J. HELLAT, D. STYNER
ABB Corporate Research Center, Aerodynamics Department
CH-5405 Baden, Switzerland

ABSTRACT:

Based on fundamental research concerning swirling flows, including the vortex breakdown phenomenon, as well as on stability considerations of premixed flames, a second generation of low emission burners has been developed.
The lean premixing technique provides NOx-emissions below 25ppmv for natural gas. For liquid fuels the oxides of nitrogen are limited to 42ppmv (oil no. 2).
The novel burner technology will be applied to the well-known ABB silo combustor. As a first step the Conical Premix Burner will be used to retrofit the ABB type 11N. For the ABB gas turbine type 8 the design of a novel fully annular combustor is in progress.
Most of the conceptual work concerning burner aerodynamics and burner-burner interaction has been carried out on scaled-down burner- and combustor-models. For a second step a sector of the combustor in 1:1 scale has been tested at atmospheric pressure. Additional high pressure tests provide information about the combustor performance at engine conditions.
The present paper summarizes the results of the first two steps beginning with the early ideas in the conceptual phase up to the 1:1 tests which prove the low-NOx capability for both gaseous and liquid fuels under atmospheric pressure conditions.

NOMENCLATURE:

b	width of air inlet slot (conical premix burner)
c	air velocity
cf	fuel concentration
D	burner diameter
$\dot{m}$	mass flow rate
r	radius
T_{air}	air temperature upstream of burner
T_p	calculated primary zone temperature
T_{Burner}	burner temperature
T_c	gas temperature on burner centerline
u	axial air velocity
v	radial air velocity
w	tangential air velocity
x	axial coordinate
y	coordinate (combustor height)
z	coordinate (combustor width)
α_c	cone angle (Fig. 9)
α_w	angle of flow near burner wall (Fig.9)
Φ_{burner}	equivalence ratio fuel/air of burner
Φ_{main}	equivalence ratio fuel/air of main burner
Φ_{pilot}	equivalence ratio fuel/air of pilot burner
λ_{burner}	excess air coefficient of burner
λ_{comb}	excess air coefficient of combustor

GOAL OF THE CONTINUING CO DEVELOPMENT PROGRAM AT ABB

In 1984 the first Dry-Low-NOx combustor of ABB
service in Lausward (FRG). The cluster of burners is sh
1. Combustion air and gaseous fuel are mixed in an a
before the mixture enters a large tubular combustor via
NOx-emissions below 40ppmv have been measured
pressures up to 14.5 bars and inlet temperatures up to 3
the large residence times in the combustor, very high
efficiencies are obtained above approximately 40% load
Using the experience gained from six units (total G
MW) with more than 63000 hours of operation, the fir
investigation of low emission combustion is to i
performance of ABB silo combustors by replacing the p
including the mixing tubes (FIG. 2). For this purpose
fuel burner of considerably simpler design has been
Additionally, several kinds of burner staging have been
to simplify the fuel supply and control system. In order
reliability of the present silo combustor technology,
changes are made to parts of the hot gas path downs
burners.
Due to the NOx-limitation of 25ppmv, the percentage o
for combustion increases with increasing pressure ratio
temperature of the compressor. Simultaneously, more
for wall cooling, as long as the basic combustor design
cooling technique remain unchanged. The air consump
cooling can be minimized by reducing the overall surfa
gas path from burner to turbine inlet. As a conseque
turbines with very high pressure ratios (e.g. ABB typ
combustor is of a fully annular design (FIG. 3) and will
with 18 main burners and 18 alternately distributed
burners. All burners are of the same type.

*Presented at the Gas Turbine and Aeroengine Congress and Exposition—June 11-14, 1990—Brussels, Belgium
This paper has been accepted for publication in the Transactions of the ASME
Discussion of it will be accepted at ASME Headquarters until September 30, 1990

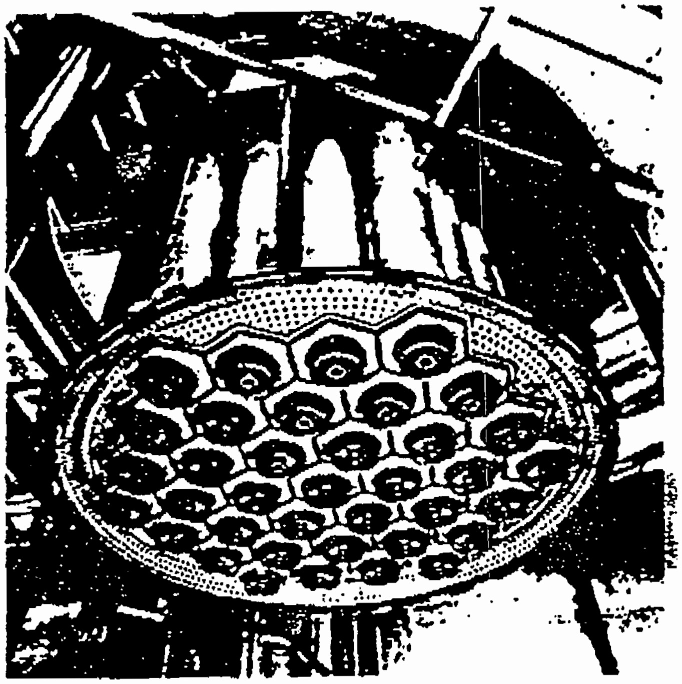


FIG. 1: 1st GENERATION OF LOW NOx-COMBUSTORS (CLUSTER OF PREMIX BURNERS)

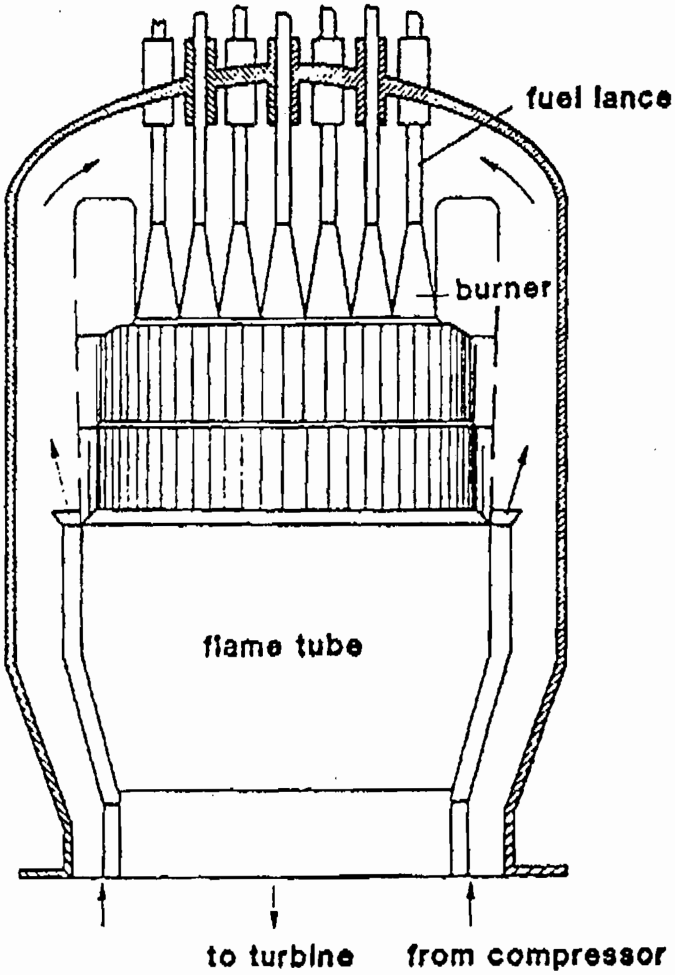


FIG. 2: SILO-COMBUSTOR EQUIPPED WITH CONICAL PREMIX BURNERS (e.g. GT11N)

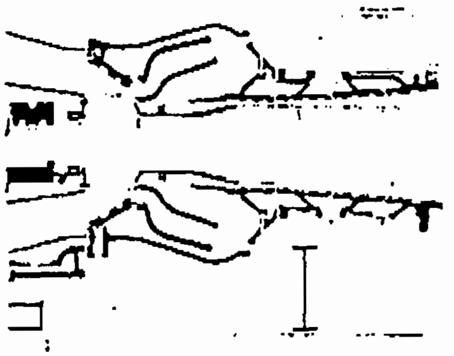


FIG. 3: ANNULAR COMBUSTOR EQUIPPE
PREMIX BURNERS (e.g. GT8)

PREMIX BURNER DEVELOPMENT
DOWN MODELS

A unique property of the Conical Premix Burne
stabilization in free space near the burner outle
breakdown of a swirling flow [2]. The swir
simple design (FIG. 5) consists of two halves
shifted to form two air inlet slots of constant w
tube known from conventional burner desig
Gaseous or liquid fuels can be burnt. The operat
cases is shown in FIG. 4. Gaseous fuels a
combustion air by means of fuel distribution n
rows of small holes perpendicular to the inlet
Complete mixing of fuel and air is obtained shor
distributing the holes along the inlet slots
concentration profile in the burner exit plane ca
fuels are injected at the burner tip using a p
assisted atomizer. Due to the flame stabiliz
premixing and combustion chambers can be
mixing and complete evaporation is achieved d
swirler before the recirculation zone is approach
the mixture takes place near the flow stagnation
perfectly nonluminescent oil flame is obtained
more conventional premix burner designs, no di
is needed to improve the stability of the premixe
equipped with Conical Premix Burners always
premixed mode. Due to the fact that neither gase
present upstream of the swirler exceptional reli
obtained. Since the zone of ignition is significant
burner walls, the heat transfer to the burner secti

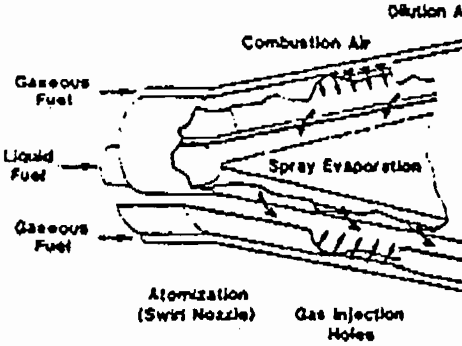


FIG 4: OPERATING PRINCIPLE OF THE C
BURNER

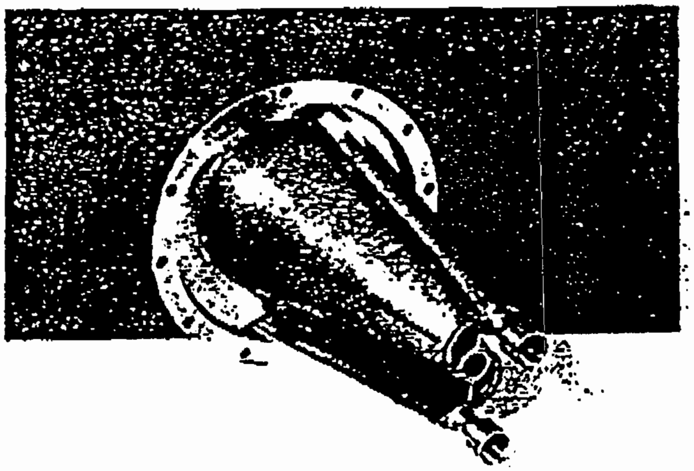


FIG 5: PROTOTYPE BURNER FOR HIGH PRESSURE TESTS

Frequently, severe stability problems occur with premixed flames in gas turbine combustors. An important property of the burner flow field is how strong the disturbances originating from combustion will influence the local position of the ignition zone near the stagnation point. A weak characteristic causes fluctuating local heat release and destabilizes the combustion process.

Vortex breakdown theory [2] clearly indicates that the most stable transition from a supercritical closed vortex flow into an annular form with recirculation on the axis is obtained only for swirling flows without a deficit in axial velocity on the burner axis, as known from flows generated from e.g. radial swirler configurations.

For the Conical Premix Burner it can easily be shown that an analytical solution can be given for potential flow between the burner tip and the zone of vortex breakdown.

The solution does not depend on the axial burner coordinate:

$$u = f(u_{re}, \beta r); v(r) = 0; w(r) = f(u_{in}, \beta r)$$

The parameter β is a function of the cone angle and the width of the inlet slots:

$$\beta = \text{Const.} \cdot (\tan \alpha / b)$$

FIG. 6 shows the theoretical velocity field for a prototype burner with an orifice diameter of 100mm near the exit plane.

The existence of an analytical solution leads to a high degree of understanding without using any elaborate numerical computer codes. Fuel concentration or spray penetration and evaporation calculations, for example, can be easily performed.

Theoretical considerations lead to the result that vortex breakdown near the burner exit plane will occur when parameter β exceeds a certain minimum value βmin. Burners with lower values of β violate the vortex breakdown criterion and lead to flow fields completely unsuitable for combustion purposes. .

FIG. 7 shows Laser-Doppler-Anemometer measurements for a burner geometry fulfilling the theoretical criterion for vortex breakdown. The appropriate profiles within the burner are generated as predicted. The transition from a closed vortex flow with high velocities on the axis to its annular flow state with stagnation on the axis takes place within a short distance close to the burner outlet.

Satisfactory agreement between calculated (see FIG. 6) and measured velocity profiles is obtained in the region upstream of vortex breakdown (FIG. 8). The breakdown of the vortex flow occurs slightly upstream of the burner exit plane. As a consequence, only low swirl velocities are measured near the burner axis at the burner outlet due to the recirculation zone.

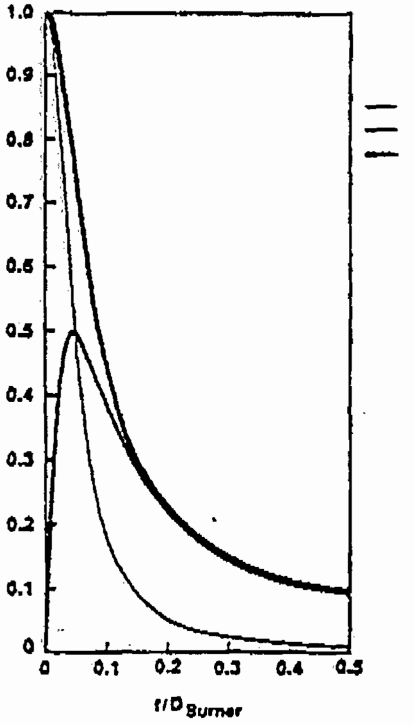


FIG.6: VELOCITY DISTRIBUTION WIT
(POTENTIAL FLOW WITHOUT BREAKDOWN)

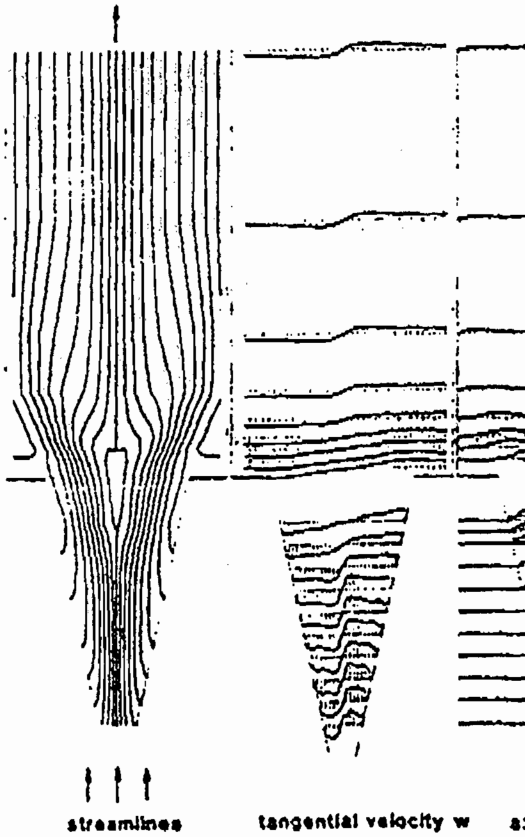


FIG 7: VELOCITY DISTRIBUTION (LDA-ME
NON-REACTING FLOW)

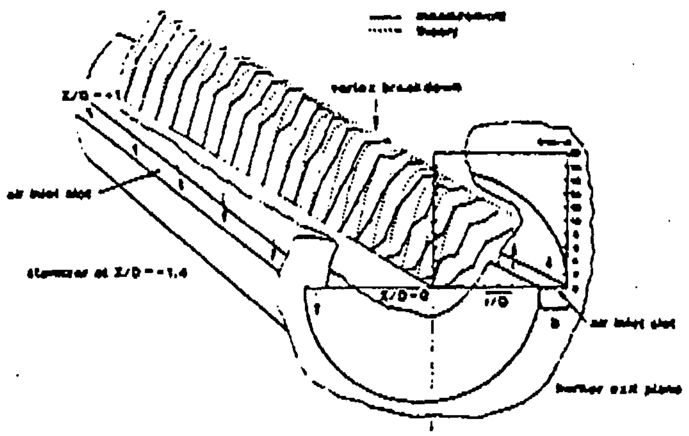


FIG. 8: COMPARISON OF PREDICTED AND MEASURED SWIRL PROFILES

The flow direction near the burner wall depends on the distance between burner wall and burner centerline. Therefore, different curves are obtained for the three circumferential positions of measurement depicted in FIG. 9. Only in the region of vortex breakdown can major differences between prediction and measurement be seen.

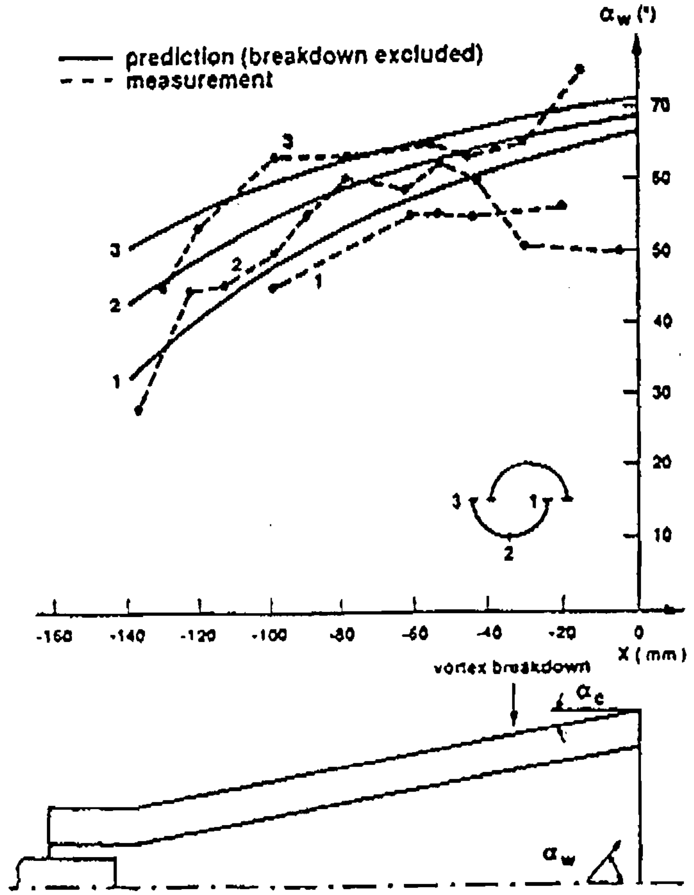


FIG. 9: COMPARISON OF PREDICTED AND MEASURED FLOW DIRECTION NEAR THE BURNER WALLS

Temperature profile measurements on the burner axis provide information about the flame position in the case of reacting flow. FIG.10 reveals that the air in the upstream part of the burner remains cold and that the temperature rise due to combustion takes place near the stagnation point found for cold flow. The beginning of the temperature rise depends weakly on the air preheat temperature.

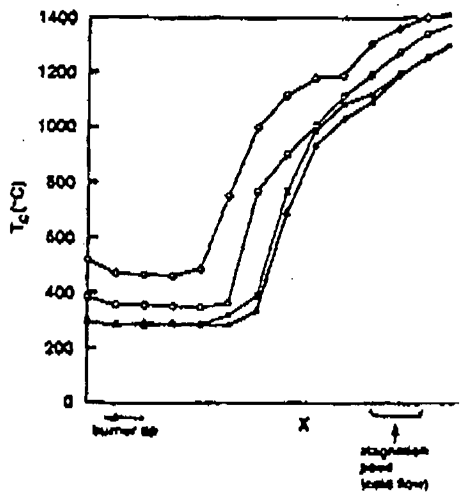


FIG 10: POSITION OF TEMPERATURE AXIS

In a first approach, completely homogeneous m desirable to abate the formation of nitrogen o profile with a slightly lower mixture strength i recirculation (FIG. 11) yields ultra low em Conical Premix Burner.

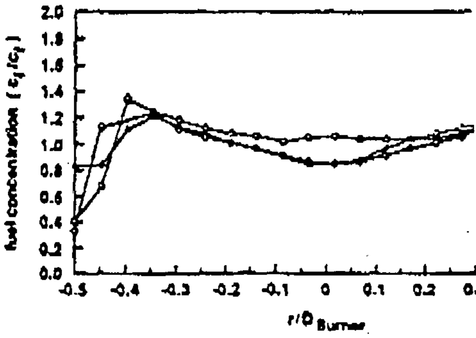


FIG. 11: FUEL DISTRIBUTION IN BUR (NONREACTING GAS FLOW, TRACER TRACER: CO)

Typical results of emission measurements for atmospheric pressure are shown in FIG.12. used in the tests is rated to approximately 150k ceramic, almost adiabatic flame tube was used. injected along the inlet slots, very low NO emissions are obtained when the blowoff ($\lambda \le 2.3$). Since the average flame temperature re where quenching of the reaction from CO to CO in carbon monoxide formation can hardly premixed flame extinguishes without any sig stage of incomplete combustion. Similar res clusters of burners, all operated with the sam when quenching effects near cooled liner walls strong.

Additionally, it can be concluded from FIG. 1 further simplify the Conical Premix Burner us the injection of gaseous fuel (no fuel distributio slots required) leads to unsatisfactory NOx-e are not well mixed until combustion begins.

For liquid fuels better mixing is obtained due to droplet evaporation within the burner. FIG. 13 of nozzle position on burner performance for tw which differ slightly from each other in terms spray angle. Generally, the nozzle position w emissions are measured also yields minimu

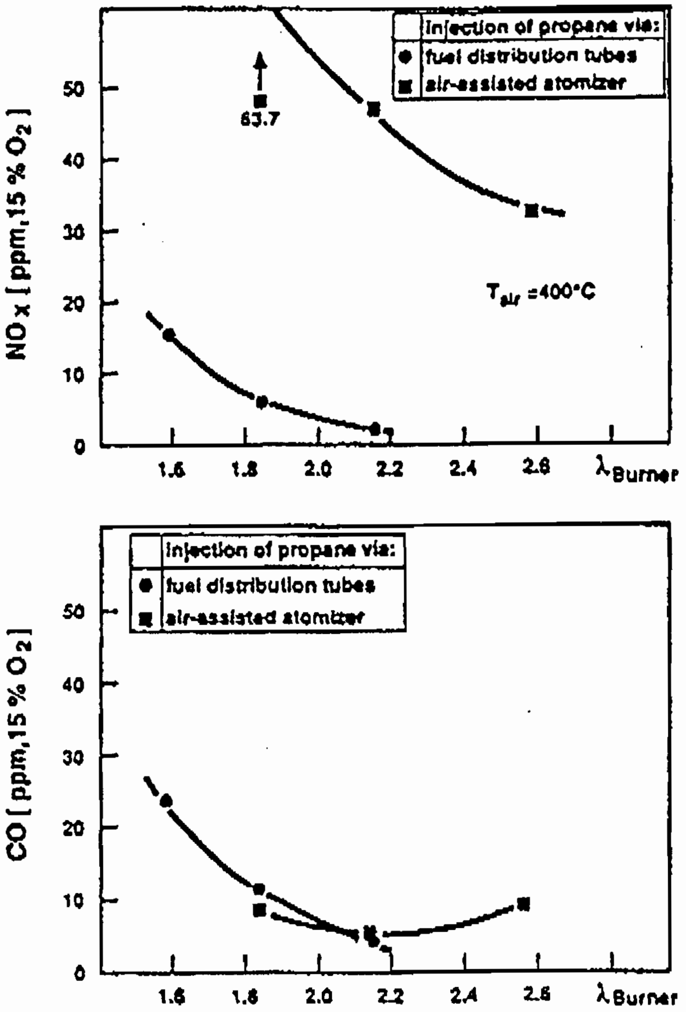


FIG. 12: NOx- AND CO- EMISSIONS OF PROTOTYPE BURNER (GASEOUS FUEL)

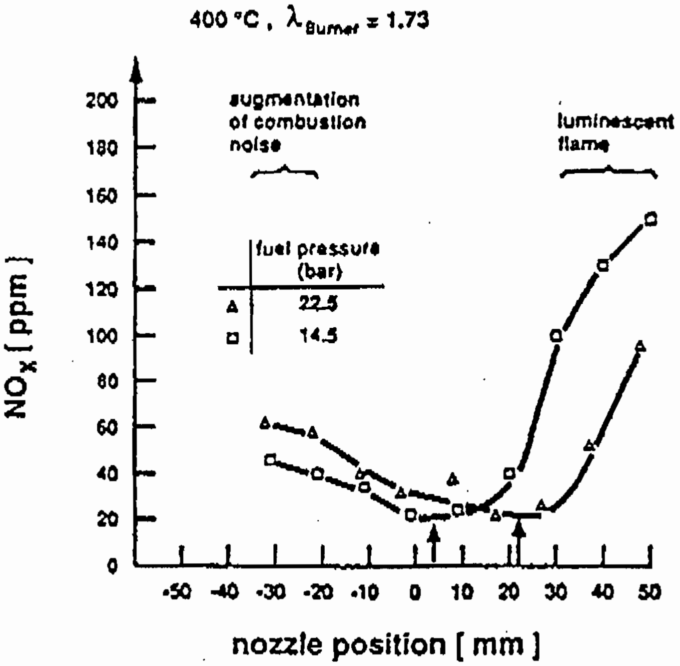


FIG 13: INFLUENCE OF NOZZLE POSITION ON NOx-EMISSIONS (PRESSURIZED NOZZLES)

Shifting the nozzle downstream leads to a deterioration of evapor: and results in luminescent flames from droplet combustion. nozzle positions far upstream nonuniform fuel concentration ii burner exit plane is obtained, which augments NOx generation ii outer region of the flow. At the same time, combustion n increases due to the lack of fuel in the recirculation zone on the bu axis. For air-assisted nozzles similar results were obtained.FIC proves the low-NOx capability of the Conical Premix Burne atmospheric pressure. The lowest NOx-emissions measured fo (λ_{Burner}=2) are approximately twice as high as those measured propane if the data is compared on the basis of the burner equival ratio.

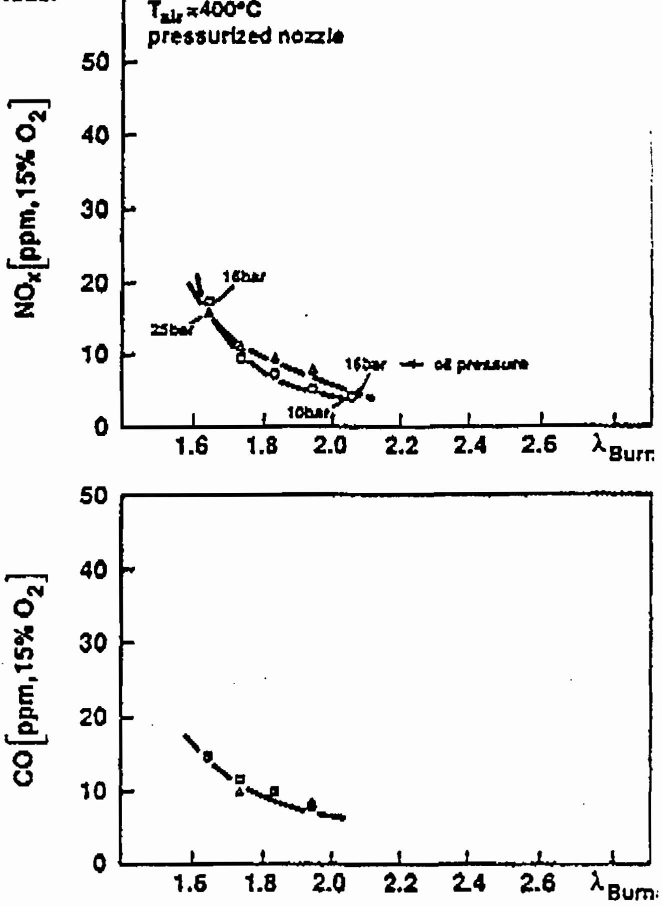
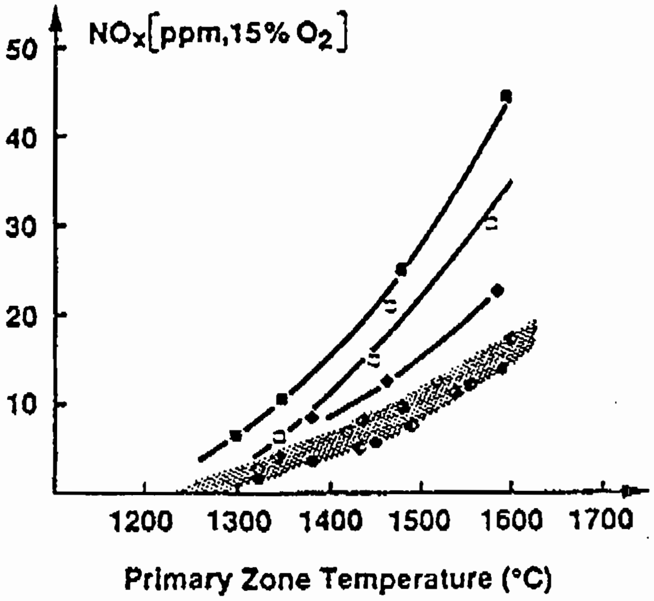


FIG. 14: NOx- AND CO- EMISSIONS OF PROTOTYPE BURN (LIQUID FUEL, FUEL BOUND NITROGEN NEGLIGIBLE)

In order to take the chemical composition of the fuel i consideration, the data is correlated to the primary zone temperat (FIG. 15) calculated on the basis of the total air mass flow includ dilution air (see FIG. 4). Parameters are:

- kind of fuel (fuel bound nitrogen negligible)
- combustor inlet temperature
- burner (gaseous fuel, dual fuel)
- kind of atomizer (pressurized, air-assisted)
- size of atomizer
- spray angle

Despite the wide scattering of the data, FIG. 15 clearly indicates t the optimum nozzle configuration for oil (pressurized nozzle, sp angle 30 deg.) yields similar emissions to those measured propane at different air inlet temperatures. Since the NOx-generat of premixed flames is mainly governed by the flame temperature can be concluded that a high degree of premixing is obtained even the case of liquid fuels as long as the combustion air is stron preheated. Tests using air-assisted atomizers reveal that deterioration of droplet evaporation at lower air inlet temperatu leads to a remarkable increase in NOx-formation at constant fla temperature.



	burner type	fuel	spray angle	fuel or atomization air pressure (bar)	T_{air} (°C)	nozzle
○	prototype for gaseous fuel only	propane			20	
●	prototype for gaseous or liquid fuel	-			400	
◇		oil	30	10 - 15	-	pressurized
◇		-	30	15 ÷ 25	-	
◆		-	60	10 - 15	-	
■		-	22	0.2	-	air-assisted
□		-	32	0.2	-	

FIG. 15: INFLUENCE OF PRIMARY ZONE TEMPERATURE ON NOx-EMISSIONS

BURNER STAGING PRINCIPLE

For single shaft gas turbines running with constant speed, the fuel consumption changes by approximately a factor of 3 from idling to full load. Modern premix burners, however, must be operated at almost constant equivalence ratio if a certain NOx-limitation is not to be exceeded. An advantage of ABB silo combustors is that this is achieved by burner (fuel) staging: In principle, purely premixed combustion can be maintained down to very low load by concentrating the fuel flow on an appropriate number of burners in the centre of the combustor.
Since the same procedure for can combustors will lead to unsatisfactory temperature profiles at the turbine inlet, additional diffusion stages are required, which exhibit an augmentation of NOx-emissions below full load.

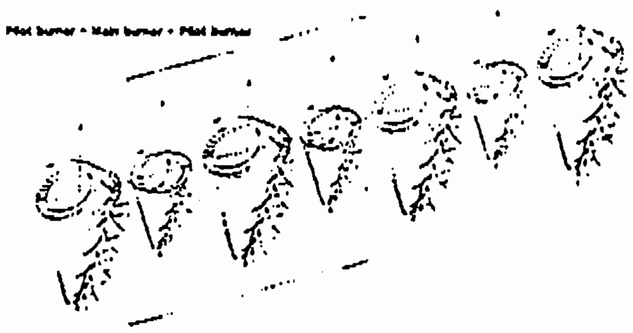


FIG. 16: MAIN- AND PILOT-BURNER CONFIGURATION OF THE ANNULAR COMBUSTOR

A novel piloting technique has been realized in the ABB combustor (FIG. 16). Pilot- and main-burners are alte distributed and have the same direction of swirl.Stable com from idling to full load is obtained as long as the pilot burners in self-stabilized mode. The fuel flow is split to obtain the equivalence ratios of the pilot burner independent of the output of the combustor. Supplementary fuel is fed to th burners. At low load the mixture obtained from the main bu too lean to ignite at the burner outlet. Nevertheless, high com efficiencies and uniform temperature profiles at the turbine i obtained due to the unstable arrangement of hot (pilot burne cold (main burners) vorticities which generate intense mixin primary zone. Without any sudden transition in com performance, the self-stabilized mode of the main burners is near full load.

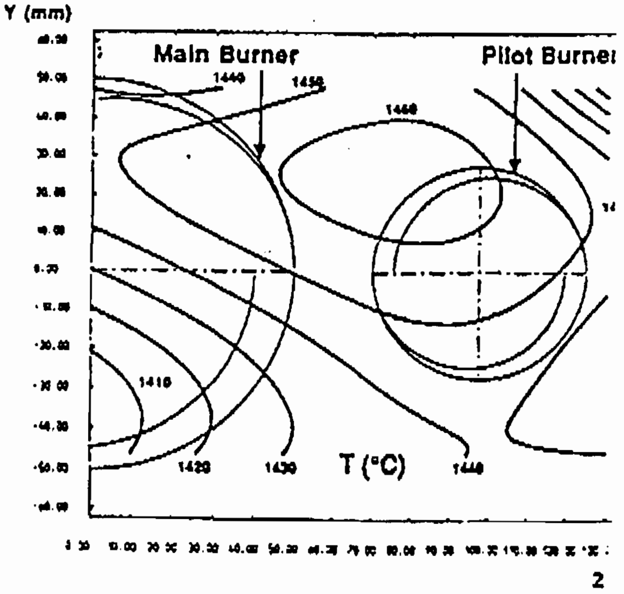


FIG. 17: TEMPERATURE DISTRIBUTION AT HIGH (X=400MM,Φpilot=Φmain=0.56)

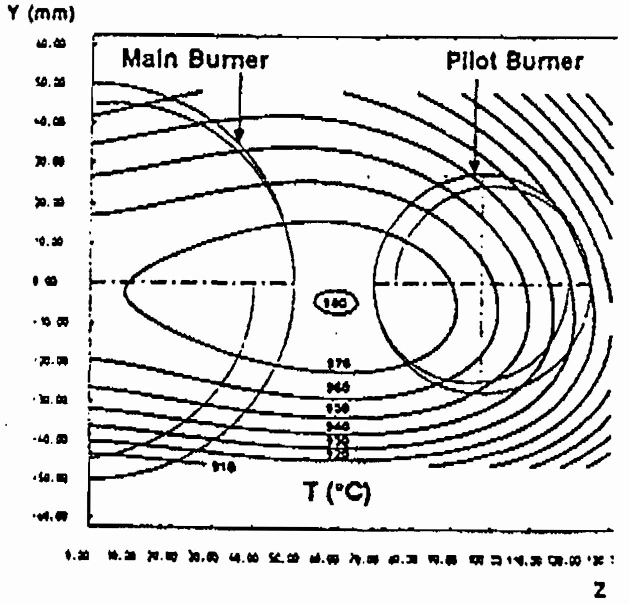


FIG. 18: TEMPERATURE DISTRIBUTION AT LOW (X=400MM,Φpilot=0.56,Φmain=0)

FIG. 17 and FIG. 18 show two examples of the temperature field measured in a combustor model with a burner configuration consisting of two pilot burners and one main burner located between them. It can be understood easily that a very uniform temperature profile is obtained at high load (FIG. 17) due to equal equivalence ratios of all burners. More interesting is the result for pilot burner operation only (FIG. 18): Although 77% of the combustion air passes through the main burners in the annular configuration, the temperature field quality remains very satisfactory even when all fuel is fed to the pilot burners.
In characterizing the temperature field by means of pattern factors for the whole cross section (OTDF) and for the profiles measured in y-direction (PTDF), an impression of the temperature uniformity can be gained (TABLE 19, coordinate Z: see FIG. 18)).

Fuel	Mode	OTDF(%)	PTDF(%) (y-profile)
without wall cooling (=adiabatic wall):			
Propane	$\phi_p=\phi_m$	4	2-4
	$\phi_m=0$	10	6–8
Oil	$\phi_p=\phi_m$	7	2-7
	$\phi_m=0$	12	4–7
wall cooling included:			
Propane	$\phi_p=\phi_m$	<12	<3 Z=0 <9 Z=100mm
	$\phi_m=0$	<20	<6 Z=0 <10 Z=100mm

TABLE 19: TEMPERATURE PATTERN FACTORS

As long as adiabatic conditions are considered, very low values are calculated from the measurements. A combination of film cooling with convective cooling using a finned liner was found to be appropriate for the annular combustor with its low flame temperature and its well-defined flow direction near the wall. Including the effect of wall cooling causes pattern factors to increase slightly. Side wall effects of the test rig cause a deterioration in ODTF. For this reason the values given for ODTF in TABLE 19 are higher than those to be expected for the annular burner configuration. The measurements indicate, nevertheless, an adequate temperature uniformity at the turbine inlet section. An additional mixing section will not be required and the entire air flow can be used as burner or wall cooling air, respectively.
Emission measurements provide information about the burnout and the NOx-generation in the partial load regime, when the main burners do not operate in self stabilized mode. In FIG. 20 the NOx-emissions are plotted versus the pilot burner and main burner equivalence ratios. Independently from how the fuel flow is split, the thermal output of the combustor remains constant along the straight λ_{comb} lines. NOx-emissions below 5ppmv are obtained in a wide range of operation when the fuel flow to the pilot burner is properly chosen. When a uniform full load equivalence ratio for all burners of approximately ϕ=0.44 (λ_{comb}=2.3) is fixed (see FIG. 14), idling is reached at λ_{comb}=6. With regard to nitrogen oxides, the pilot burner equivalence ratio should be decreased from ϕ_p=0.65 to 0.44 while the main burner load is increased from ϕ=0.03 to 0.44. Almost complete burnout was measured for $\lambda_{comb}\leq 3.3$ (FIG. 21) or - in terms of gas turbine output - above 50% load. At lower loads the pilot burner equivalence ratio must be increased slightly to improve burnout. As long as NOx-generation at very low loads is not considered, almost complete burnout can be achieved even at idling.

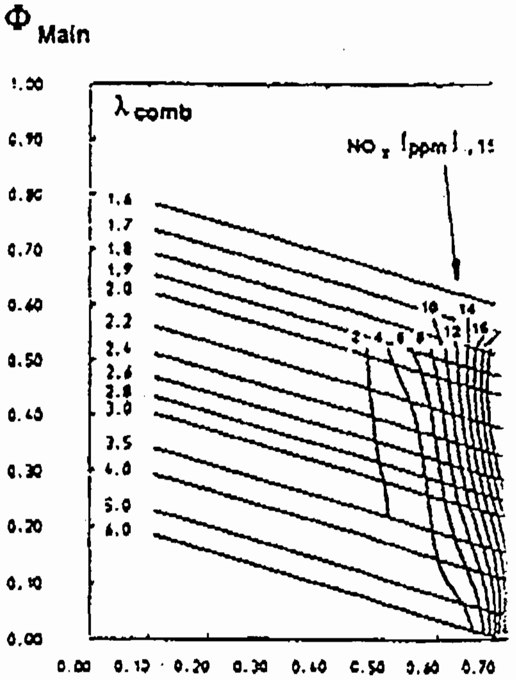


FIG. 20: NOx-EMISSION CHART (400°C, PROP

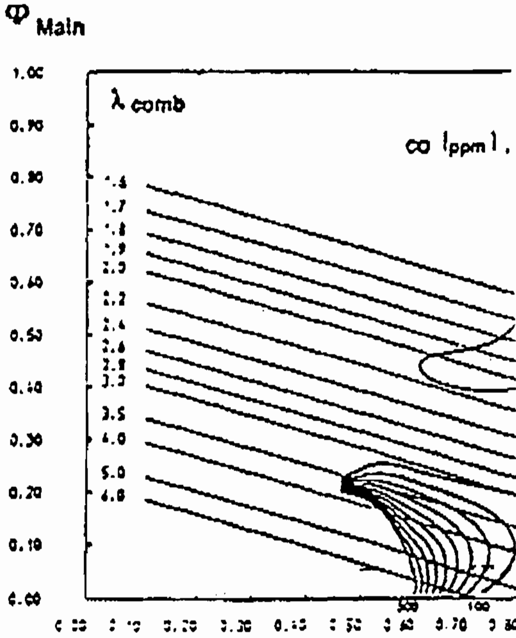


FIG. 21: CO-EMISSION CHART (400°C, PROPAN

Based on the tests at atmospheric pressure, it can be the technique of piloting proposed for the ABB ann leads to very promising results in the partial load regi to those /obtained for burner staging in silo combusto

VALIDATION OF RESULTS IN 1:1 AMBIENT PRESSURE

Subsequent to the conceptual phase of the combustor experiments were performed on 1:1 scale at atmosph pressure using natural gas and oil no. 2 as fuels. included single burner tests as well as tests of a com (test rig comprising 2 pairs of burners). The NOx-e high load regime (main burners) are shown in FIG. 2 problems of flame stability, ultra low emissions a

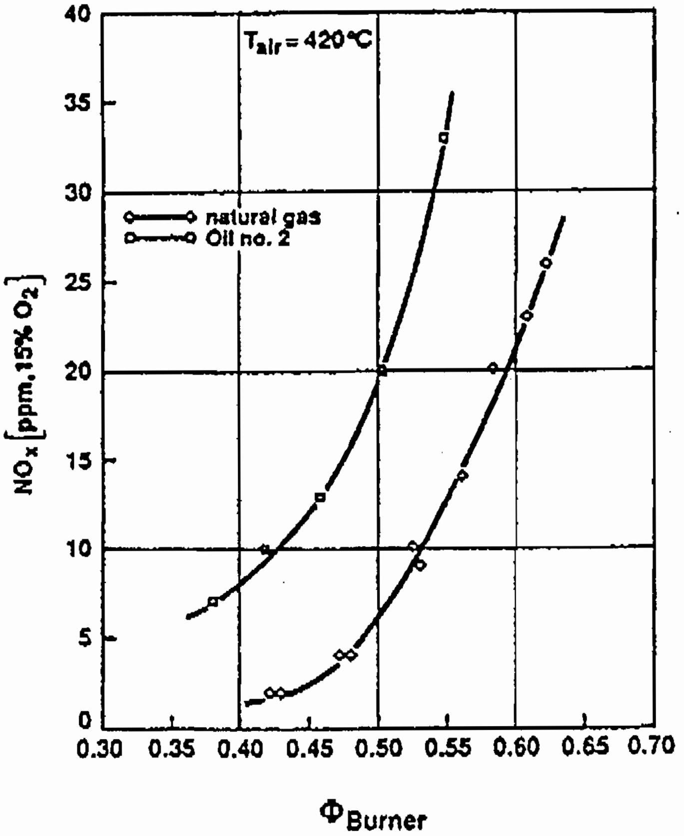


FIG. 22: OPTIMUM PERFORMANCE OF THE MAIN BURNER AT ENGINE SIZE AND ATMOSPHERIC PRESSURE (420°C)

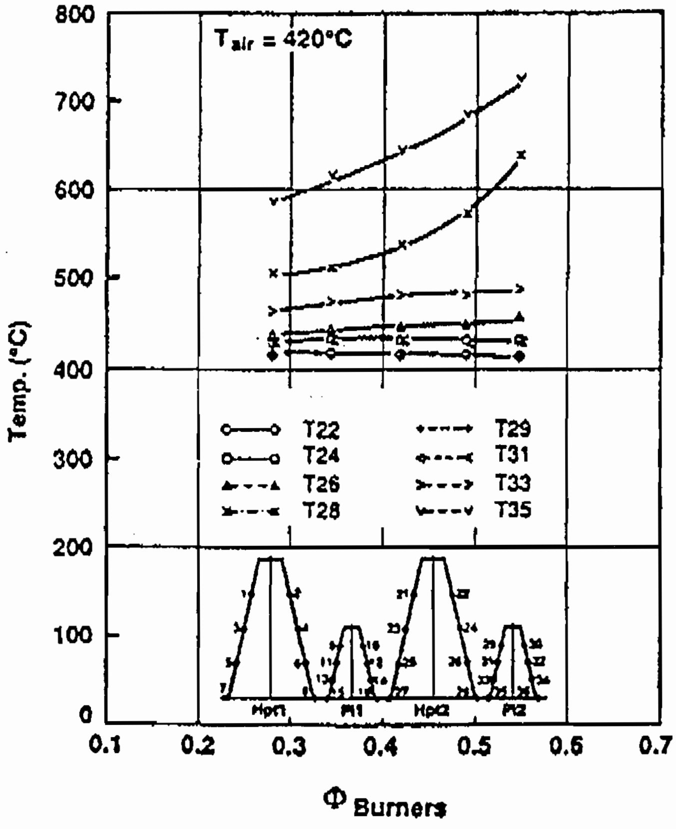


FIG. 23: BURNER TEMPERATURES (ϕ_p~2.2·ϕburner, ϕ_m~0.65·ϕburner)

natural gas. For oil no. 2 the emissions obtained from t down models cannot be fully validated. Beside the effects o from fuel bound nitrogen, which can clearly be detected, t performance at 1:1 scale is due to the influence of burne droplet spray penetration. The calculation of the spir evaporation of droplets for the three cases:

1. scaled down burner operated at atmospheric pressure
2. burner of engine size operated at atmospheric pressure
3. burner of engine size under engine conditions

predicts the desired homogeneous fuel concentration only in 1 and 3. Tests at engine size but at atmospheric pressure (cas to a high concentration of the fuel vapour in the outer pa burner exit plane, generated from the droplets with an initia size greater than the mass median diameter of the spray. T liquid fuel from igniting within the burner, the residence time minimized. For all test cases the calculated residence time exceed approximately 6ms.
To answer the question whether the desired NOx-limitatio reached under engine conditions, the influence of air pre NOx-formation must be known. Based on experimental data scaling laws can be found in the literature. Oversimplifie approaches indicate an influence proportional to the squar combustor pressure. If the equivalence ratio at full load is ad

ΦBurner=0.44, full load emissions for natural gas will not e NOx-target even in the case of a scaling law NOx~pcombust By stabilizing the flame in free space, the heat transfer to the Premix Burner is minimized. FIG. 23 proves that the temperature (thermocouples 22,24,26,29,31 and 33) significantly exceed the temperature of the air. O thermocouples at the burner exit plane (28 and 35) record temperatures, since the impingement cooling of the combus panel was not present in the tests at atmosperic pressure.

CONCLUSIONS

Compared to the first generation of ABB low-NOx bur Conical Premix Burner exhibits several advantages:

- simple design
- no fuel upstream from burner (flashback impossible)
- no premixing tube
- simple oil injection technique

The following results have been obtained during the test pr ambient pressure:

a.) burner models:

- zone of recirculation in free space (vortex breakdow acts as a flameholder
- excellent stability of premixed flame
- ignition near burner exit plane
- zone of reaction displaced from burner walls
- low-NOx-capability for gaseous as well as liquid fuel

b.) partial load performance:

- simple piloting concept for the annular combustor
- only two burner groups (pilot burners and main burne
- excellent temperature profile without mixing zone
- low NOx-emissions as well as complete burnout ab load

c.) combustor segment (1:1 scale):

- natural gas: validation of results from model experimen
- natural gas: NOx-emissions extremely low: less than 25 engine conditions
- oil no. 2: NOx-emissions somewhat higher than i experiments
- low burner temperatures

References

[1] Koch et. al.:
Dry-NOx Brennkammer, Entwicklung und erreichte Resultate
CIMAG, Oslo, 1985

[2] Keller et. al.:
Vortex breakdown as a fundamental element of vortex dynamics
ZAMP, Vol.39, Nr.3, May 1988

[3] Aigner et. al.:
Second generation low emission combustors for ABB gas turbines: Tests at full engine conditions
to be published: ASME Gas Turbine Conference, 1990, Brussels

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

January 28, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John P. Jones, President
Orlando CoGen Inc.
7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

Dear Mr. Jones:

Re: Completeness Review for Application to Construct A Combustion Turbine and Associated Heat Recovery Steam Generator
AC 48-206720 and PSD-FL-184

The Department has reviewed the application package received on December 30, 1991. Based on a technical evaluation of the material, the application package is deemed incomplete. Therefore, please submit to the Department's Bureau of Air Regulation the following information, including all calculations, assumptions and reference material, and the status will, again, be ascertained:

1. The emission calculations are not adequately shown in Appendix A. All calculations affecting emissions should be shown in their entirety, since Tables 3-3, A-1, A-2, A-3 and A-4, are a product of Appendix A. For example, the Appendix A calculation for NOx emissions, corrected to 15% oxygen, is only a set-up with no final calculations. The application should clearly show how all emission-related quantities were obtained. Also, please provide copies of any emission factors (i.e., page, table, actual vendor testing data, AP-42, vendor guarantee, etc.) used in the calculations.

2. For Tables 4-5, 4-6 and 4-7, please provide the calculations to support your data and provide a copy of the reference material (i.e., page, table, errata sheet, vendor guarantee, etc.) used to derive this data.

3. For the proposed combustion turbine, the ABB 11N-EV, please provide documentation from the vendor that there is a dry low-NOx combustor currently available for operation. Also, provide any pertinent information (i.e., model #, design, etc.) on the combustor. If the combustor is not currently available, what design considerations are being made in order

to be able to install/retrofit one at a later date and, in the interim, meet the proposed 25 ppmvd (corrected to 15% oxygen) or possible lower BACT (best available control technology) limit?

4. On page 4-12, under the heading "Dry Low-NOx Combustor", it is stated that the proposed unit can achieve less than the proposed 25 ppmvd, when firing natural gas. Please provide the levels of NOx emissions that have been achieved by this unit to date; also, and if available, provide a copy of the synopsis page of any test data.

5. Can a selective catalytic reduction (SCR) system be retrofitted to the proposed source under its current design configuration? If not, please explain in detail.

If there are any questions, please call Bruce Mitchell at 904-488-1344 or write to me at the above address.

Sincerely,

A Preston Lewis
For
C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/BM/plm

c: C. Collins, CD
D. Nester, OCEPD
G. Smallridge, Esq., DER
C. Shaver, NPS
J. Harper, EPA
D. Buff, P.E., KBN

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. John P. Jones, President
Orlando CoGen Inc.
7201 Hamilton Boulevard
Allentow, Pennsylvania 18195-1501

4a. Article Number
P 832 538 770

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

7. Date of Delivery
2-4-92

5. Signature (Addressee)
Tony Hetrick

6. Signature (Agent)

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

PS Form **3811**, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

P 832 538 770

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

UNITED STATES POSTAL SERVICE

Sent to Mr. John P. Jones, Orlando CoGen Inc.	
Street & No. 7201 Hamilton Blvd.	
P.O., State & ZIP Code Allentow, PA 18195-1501	
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: 1-28-92 Permit: AC 48-206720 PSD-FL-184	

PS Form **3800**, June 1990

To Bruce Mitchell

Date 1/28/92 Time 10:44

WHILE YOU WERE OUT

M Bud Rolofson

of Nat'l Park Service

Phone

Area Code Number Extension

☒	TELEPHONED	☐	PLEASE CALL
☐	CALLED TO SEE YOU	☐	WILL CALL AGAIN
☐	WANTS TO SEE YOU	☐	URGENT
	☐	RETURNED YOUR CALL	

Message Have no comments on Owl, Co-Dev Complet

MS

Operator

Florida Department of Environmental Regulation
Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

January 10, 1992

Mr. Dennis Nester
Air Program Supervisor
Orange County Environmental
Protection Department
2002 E. Michigan Avenue
Orlando, Florida 32806

Dear Mr. Nester:

RE: Orlando CoGen Limited
Orange County, PSD-FL-184

The Department has received the above referenced PSD application package. Please review this package for completeness by January 27, 1992, and forward your comments to the Department's Bureau of Air Regulation. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact Bruce Mitchell or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

/pa

Enclosures

KBN

Letter of Transmittal

RECEIVED
JAN 9 1992
Division of Air
Resources Management

Date: January 8, 1992

Project No.: 91134/0200

To: C.H.Fancy, P.E.
Chief, Bureau of Air Regulation
FDER
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Orlando CoGen

The following items are being sent to you: ☐ *with this letter* ☐ *under separate cover*

Copies	*Description*
3	PSD Permit Application for Orlando CoGen Limited, L.P. Cogeneration Project

These are transmitted:

☒ *As requested*

☐ *For review*

☐ *For review and comment*

☐ *For approval*

☐ *For your information*

☐ __________

Remarks:

Sender: Jan Wyckoff

Copy to: Project File (2)
Dave Buff

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

AF1/LOT1 (07/91)

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 7, 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: Orlando CoGen Limited
Orange County, PSD-FL-184

The Department has received the above referenced PSD application package. Please review this package for completeness by January 27, 1992, and forward your comments to the Department's Bureau of Air Regulation. The Bureau's FAX number is (904)922-6979.

If you have any questions, please call Bruce Mitchell or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

/pa

Enclosure

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 7, 1992

Ms. Jewell A. Harper, Chief
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30308

Dear Mrs. Harper:

RE: Orlando CoGen Limited
Orange County, PSD-FL-184

The Department has received the above referenced PSD application package. Please review this package for completeness by January 27, 1992, and forward your comments to the Department's Bureau of Air Regulation. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact Bruce Mitchell or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

/pa

Enclosures

KBN

RECEIVED
DER - MAIL ROOM
1991 DEC 30 PM 12: 55

December 27, 1991

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

Re: Orlando CoGen Limited, L.P. Project
Orange County, FL

Dear Mr. Fancy:

Please find enclosed on behalf of Orlando CoGen Limited, L.P., four signed and sealed air construction permit application forms for a gas turbine cogeneration facility. Also enclosed is the application fee of $7,500. The proposed facility will be located in Orlando, Florida (Orange County). KBN Engineering and Applied Sciences, Inc. has assisted Orlando CoGen in preparing the permit application. If you have any questions concerning our submittal, please call me at (904) 331-9000, of Gary Kinsey at (215) 481-4029.

We look forward to working with you on this project.

Sincerely,

David A. Buff

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

DAB/dmpm

Enclosure

cc: Gary Kinsey

RECEIVED
DEC 30 1991
Division of Air
Resources Management

91134C2/1

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

196679 **Air Products and Chemicals, Inc.**
Allentown, PA 18195

AIR PRODUCTS

12 13 91
DATE OF ISSUE

309454
VENDOR CODE

PAY ****$7,500.00**

PAY TO THE ORDER OF:

FLORIDA DEPARTMENT OF ENVIR
REGULATION
N
N N

L. Baker
White

CITIBANK DELAWARE
ONE PENN'S WAY
NEW CASTLE DE 19720

[redacted] 311

[redacted]

Re: Orlando CoGen Limited, L.P. Project
Orange County, FL

Dear Mr. Fancy:

Please find enclosed on behalf of Orlando CoGen Limited, L.P., four signed and sealed air construction permit application forms for a gas turbine cogeneration facility. Also enclosed is the application fee of $7,500. The proposed facility will be located in Orlando, Florida (Orange County). KBN Engineering and Applied Sciences, Inc. has assisted Orlando CoGen in preparing the permit application. If you have any questions concerning our submittal, please call me at (904) 331-9000, of Gary Kinsey at (215) 481-4029.

We look forward to working with you on this project.

Sincerely,

David A. Buff

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

DAB/dmpm

Enclosure

00/031

cc: Gary Kinsey

91134C2/1

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

PSD PERMIT APPLICATION FOR ORLANDO COGEN LIMITED, L.P. COGENERATION PROJECT

Prepared For:

Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Prepared By:

KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, FL 32605

December 1991
91134C1

PART A

AIR CONSTRUCTION PERMIT APPLICATION FORM

#7500 pd.
12-30-91
Rcpt.#180729

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

AC48-206720
PSD-FL-184

RECEIVED
DEC 30 1991
Bureau of
Air Regulation

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *Cogeneration Facility* [x] New[1] [ ] Existing[1]

APPLICATION TYPE: [x] Construction [ ] Operation [ ] Modification

COMPANY NAME: *Orlando CoGen Limited, L.P.* COUNTY: *Orange*

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) *HRSG Stack*

SOURCE LOCATION: Street *Orlando Central Park* City *Orlando*

UTM: East *459.50* North *3,146.10*

Latitude *28* ° *26* ' *23* "N Longitude *81* ° *24* ' *28* "W

APPLICANT NAME AND TITLE: *Orlando CoGen Limited, L.P.*

APPLICANT ADDRESS: *7201 Hamilton Boulevard, Allentown, PA 18195-1501*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Orlando CoGen Limited, 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:

John P. Jones, President, Orlando CoGen (I), Inc., General Partner of Orlando CoGen Limited, L.P.
Name and Title (Please Type)

Date: 12/19/91 Telephone No. *(215) 481-4911*

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.

DAVID A. BUFF

Signed David A. Buff

David A. Buff
Name (Please Type)

KBN Engineering and Applied Sciences, Inc.
Company Name (Please Type)

1034 NW 57th Street, Gainesville, FL 32605
Mailing Address (Please Type)

Florida Registration No. *19011* Date: 12/27/91 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 of a cogeneration facility that consists of one combustion turbine and associated heat recovery steam generator; See Section 2.0 in PSD application.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction *June 1992* Completion of Construction *June 1, 1994*

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 design of the project. Dry low NO_x combustion technology and natural gas 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: *See Section 2.0 in PSD Application*

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*

3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. *Yes*

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? *Yes*

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 is Attached.***

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): *Not Applicable*

2. Product Weight (lbs/hr): *Not Applicable*

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) *See Table 2-1 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	*2.96*	*12.35*	*NA*	*NA*	*2.96*	*12.35*	*See*
PM	*11.00*	*48.18*	*NA*	*NA*	*11.0*	*48.18*	*Figure*
NO_x	*98.6*	*419.2*	*94 ppmvd*		*98.6*	*419.2*	*2-1 in*
CO	*33.2*	*114.6*	*NA*	*NA*	*33.2*	*114.6*	*PSD*
VOC	*6.7*	*19.75*	*NA*	*NA*	*6.7*	*19.75*	*Appl.*

[1] See Section V, Item 2. ***Presents maximum based on either 20°F operation or combined CT and duct firing.***

[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 - 75 ppmvd NO_x corrected to 15% O_2 and heat rate at ISO conditions. FDER Rule 17-2.660.***

[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 *See Table A-1 in PSD Application*

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas (CT)	*0.906 (59°F)*	*0.987 (20°F)*	*933.9 at 20°F*
Natural Gas (Duct Burner)	*0.106*[a]	*0.129*	*122.0*

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.
[a] *Based on burning only natural gas for 4,500 hours/year @ 100 x* 10^6*Btu/hr*

Fuel Analysis:

Percent Sulfur: *1 grain/100 cubic feet (CF) of gas* Percent Ash: *Negligible*

Density: ______ lbs/gal Typical Percent Nitrogen: *Negligible*

Heat Capacity: *946 Btu/CF; 20,877* BTU/lb *NA* BTU/gal

Other Fuel Contaminants (which may cause air pollution): ______

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average *Not Applicable* Maximum ______

G. Indicate liquid or solid wastes generated and method of disposal.

All wastewaters generated from the plant will be discharged to the Orange County Wastewater treatment POTW facility at Sandlake Road.

H.Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: *115* ft. Stack Diameter: *15.7* ft.

Gas Flow Rate: *675,048* ACFM *475,933* DSCFM Gas Exit Temperature: *220* °F.

Water Vapor Content: *9.2* % Velocity: *58.14* FPS

See Table 2-1 in PSD application; CT/DB exhaust at 90°F shown. These parameters used in air modeling.

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)]
   See Table A-1 in PSD Application
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 Appendix A in PSD Application
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Appendix A 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 Appendix A 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 map pocket 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.

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? *See Section 4.2 in PSD Application*

[x] Yes [ ] No

Contaminant	Rate or Concentration
NO_x-CT	*75 ppmvd corrected to 15% O_2 and heat rate*
NO_x-DB	*0.2 lb/10^6Btu heat input*

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[x] Yes [ ] No *See Section 4.0 in PSD Application*

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
NO_x	*25 ppmvd corrected to 15% O_2*
CO	*10 ppmvd from CT; 16 ppmvd from CT/Duct Burner*
VOC	*3 ppmvd*
See Section 4.0 in PSD Application	*for other pollutants*

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

See Section 4.0 in PSD Application

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 Sections 3.4.2.2 and 5.2 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. *PSD Application Attached*

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*

PART B

PSD REPORT

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LIST OF FIGURES

ACRONYMS AND ABBREVIATIONS

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AAQS	Ambient Air Quality Standards
ABB	Asea Brown Boveri
BACT	best available control technology
10^6 Btu/hr	million British thermal units per hour
Btu/kWh	British thermal units per kilowatt hour
Btu/yr	British thermal units per year
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
CT	combustion turbine
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FBN	fuel-bound nitrogen
FDER	Florida Department of Environmental Regulation
FGD	flue gas desulfurization
ft	foot/feet
ft^3/yr	cubic feet per year
GEP	good engineering practice
gr/scf	grains per standard cubic feet
g/s	grams per second
H_2SO_4	sulfuric acid
HRSG	heat recovery steam generators
HSH	highest, second highest
ISC	Industrial Source Complex
ISCLT	Industrial Source Complex Long-Term
ISCST	Industrial Source Complex Short-Term
KBN	KBN Engineering and Applied Sciences, Inc.
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
kWh/hr	kilowatt-hour per year
LAER	lowest achievable emission rate
lb/hr	pounds per hour
m	meter
MW	megawatt
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH_3	ammonia

ACRONYMS AND ABBREVIATIONS
(Page 2 of 2)

NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSCR	nonselective catalytic reduction
NSPS	New Source Performance Standards
NTL	No Threat Levels
NWS	National Weather Service
PM(TSP)	total suspended particulate matter
PM10	particulate matter less than or equal to 10 micrometers
ppm	parts per million
ppmvd	parts per million volume, dry
PSD	prevention of significant deterioration
RCRA	Resource Conservation and Recovery Act
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective noncatalytic reduction
SO_2	sulfuric dioxide
TPH	tons per hour
TPY	tons per year
$\mu g/m^3$	micrograms per cubic meter
UNAMAP	Users Network for Applied Modeling of Air Pollution
VOC	volatile organic compound

1.0 INTRODUCTION

Orlando CoGen Limited, L.P. is proposing to locate a natural gas-fired, 128.9-megawatt (MW) nominal capacity, cogeneration facility in the Orlando Central Park. The proposed site, which is located in Orange County (Figure 1-1), will be under the control of Orlando CoGen Limited, L.P.. The proposed cogeneration facility will consist of one combustion turbine (CT) and a steam turbine, which will utilize the steam generated by a heat recovery steam generator (HRSG). Operational characteristics for the facility are provided in Table 1-1. The HRSG also will supply steam an adsorption chiller system, which will be used to supply chilled water service to the existing Air Products and Chemicals plant located adjacent to the site. A plot plan for the cogeneration facility is contained in the map pocket.

KBN Engineering and Applied Sciences, Inc. (KBN), has been contracted by Orlando CoGen Limited, L.P. to provide air permitting services for the facility. The prevention of significant deterioration (PSD) review included control technology review, source impact analysis, air quality analysis (monitoring), and additional impact analyses. Initially, preliminary analyses were performed to determine compliance with PSD increments and preconstruction de minimis monitoring levels for the proposed plant only. This analysis demonstrated that the proposed facility will have insignificant air quality impacts.

The proposed project will be a major facility because potential emissions of at least one regulated pollutant exceed 250 tons per year (TPY). PSD review is required for such pollutants and for any other regulated pollutant for which the potential emissions exceed the PSD significant emission rate. The potential emissions from the proposed project will exceed the PSD significant emission rates for nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), and particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM10). 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 PSD and nonattainment regulations to the project are presented in Section 3.0. The control technology

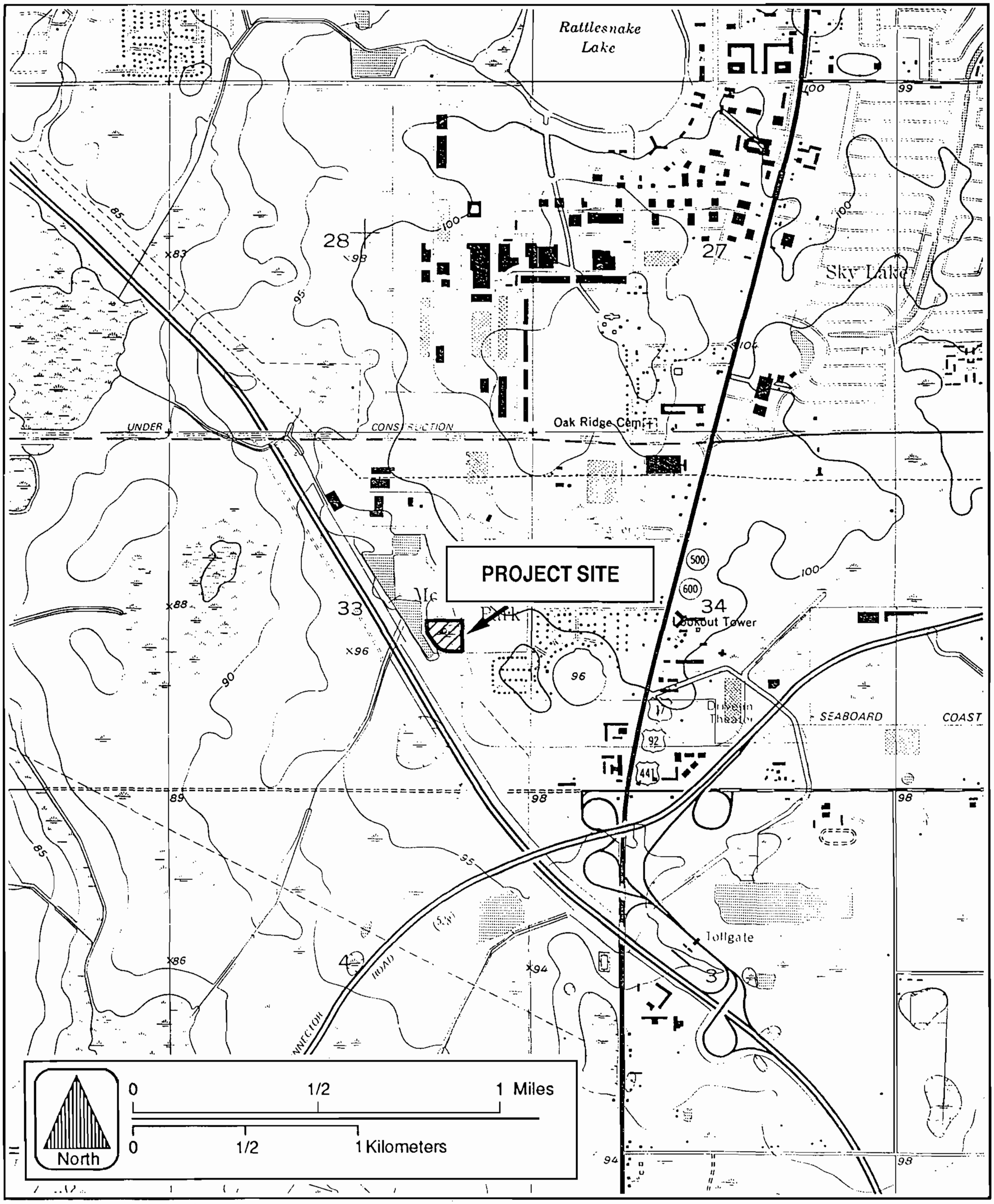


Figure 1-1. SITE LOCATION MAP,
ORLANDO COGEN LIMITED, L.P.

Table 1-1. Characteristics of the Orlando CoGen Limited, L.P. Project

Characteristic	CT Only @ ISO Condition	Design Condition[a]
Net Capacity (kW)		
Combustion Turbine	78,830	78,830
Steam Cycle	35,740	50,100
Total	114,570	128,930
Equipment Characteristics		
Type of CT	ABB 11N-EV	ABB 11N-EV
CT Heat Input (10^6 Btu/hr)	856.9	856.9
Duct Burner Heat Input (10^6 Btu/hr)	--	122.0[b]
CT NO_x Control	Dry Low-NO_x Combustor	
Natural Gas Fuel		
CT (ft^3/hr)	905,795	905,795
Duct Burner (ft^3/hr)	--	128,964[b]

Note: CT = combustion turbine.
ft^3/hr = cubic feet per hour.
HRSG = heat recovery steam generator.
10^6 Btu/hr = million British thermal units per hour.

[a] At ISO condition (59°F ambient temperature) for CT and maximum duct firing in HRSG.

[b] Duct firing will be implemented at an ambient temperature of 59°F or higher. Maximum heat input will be 122 x 10^6 Btu/hr.

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The proposed project will consist of one CT that will exhaust through one HRSG. The CT will be an Asea Brown Boveri (ABB) 11N-EV machine. The ABB 11N-EV is a heavy frame industrial gas turbine that uses a single dry low-NO_x combustion chamber. The CT will be served by a single HRSG, exhausting to an individual stack. There will be no bypass stacks on the CT for simple cycle operation. There will be a single electric generator, which will be driven directly by the CT and a steam turbine. A flow diagram of the project is presented in Figure 2-1.

Natural gas will be used to fuel the CT; distillate fuel oil will not be used. Supplementary firing of only natural gas in the HRSG will occur only when the ambient temperature is 59°F or greater. The supplementary firing is expected to occur during "on-peak" power demand time periods. The maximum duct burner firing will be 4,500 hours at an average heat input of 100 million British thermal units per hour (10^6 Btu/hr), or 450,000 million British thermal units per year (x 10^6 Btu/yr). Maximum duct burner firing will be 122 x 10^6 Btu/hr.

Air emission sources associated with the proposed project consist of the CT and supplemental firing in the HRSG. Dry low-NO_x combustion will be used to control emissions of NO_x from the CT; low-NO_x burners will minimize NO_x emissions when duct firinyg. The use of natural gas will minimize the emissions of sulfur dioxide (SO_2) and other pollutants from the unit.

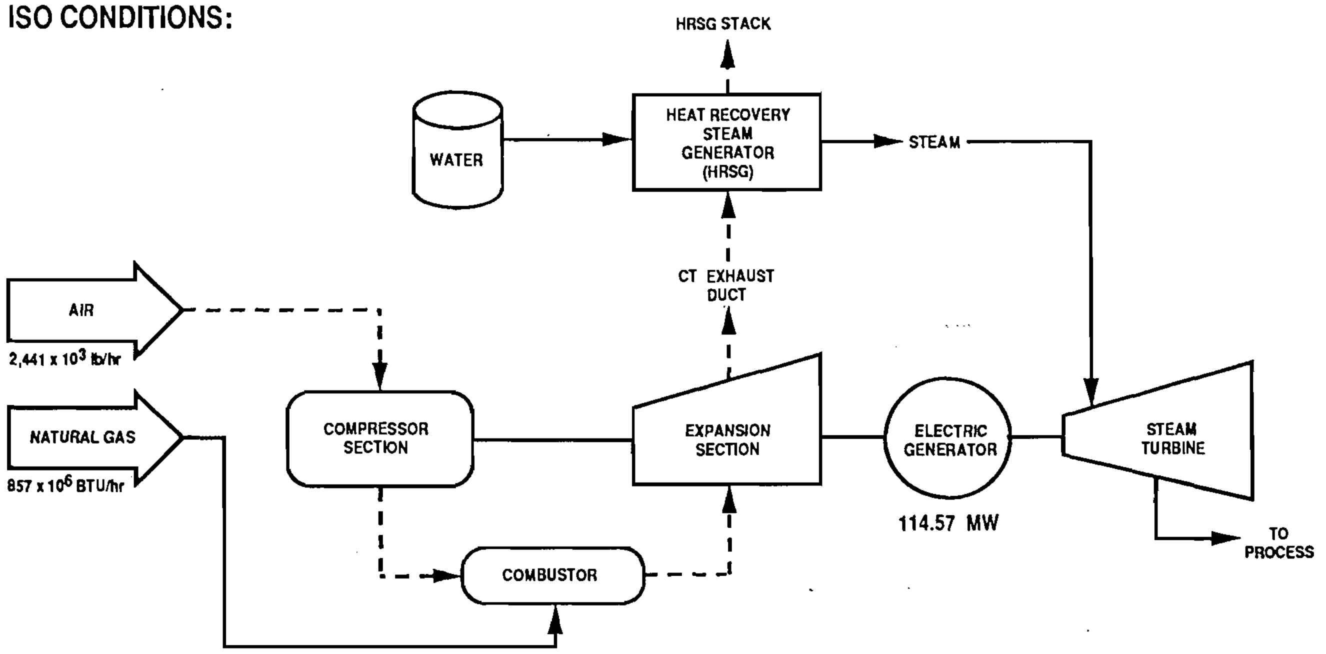
2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

Emissions and stack parameters for the CT/HRSG are presented in Table 2-1. Maximum emissions for the CT occur at the lowest ambient operating temperature [i.e., 20 degrees Fahrenheit (°F)]. Emissions and stack parameters for this case are presented in Table 2-1 for the CT only.

In the case of duct firing, duct firing will occur only at ambient temperatures of 59°F or greater. The maximum heat input to the duct burner will be 122 x 10^6 Btu/hr at a higher ambient temperature. Since the CTs emissions are higher at lower ambient temperatures, the CT

KBN27/CITRUS FLOW.1

ISO CONDITIONS:



DESIGN CONDITIONS:

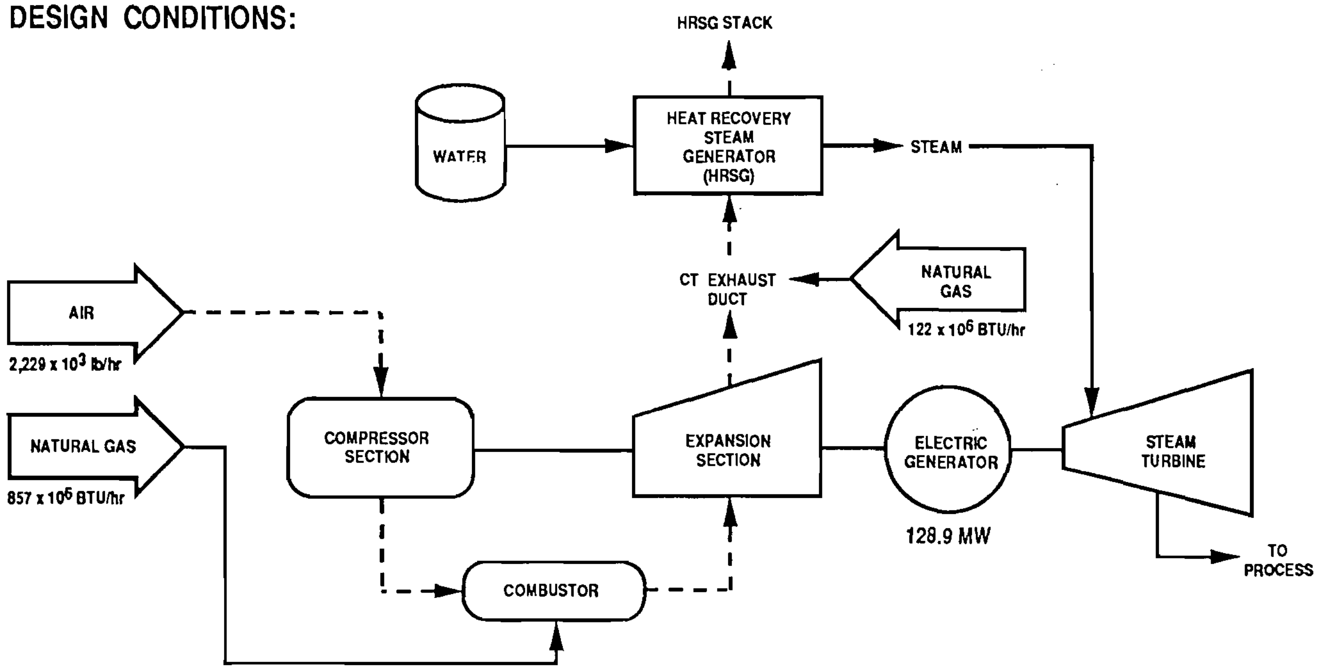


Figure 2-1. SIMPLIFIED FLOW DIAGRAM OF PROPOSED UNIT, ORLANDO COGEN LIMITED, L.P.

Table 2-1. Stack, Operating, and Emission Data for the Proposed Cogeneration Facility

	Maximum Emissions			
		CT/Duct Burner		
Parameter	CT Only[a]	CT[b]	Duct Burner[c]	Total
Stack Data (ft)				
Height	115			115
Diameter	15.7			15.7
Operating Data				
Temperature (°F)	250			220
Velocity (ft/sec)	69.9			58.14
Building Data (ft)				
Height	76			76
Length	60			60
Width	43			43
Maximum Hourly Emissions (lb/hr)				
SO_2	2.82	2.59	0.37	2.96
PM/PM10	11.0	9.0	1.22	10.22
NO_x	95.7	86.4	12.2	98.6
CO	23.3	21.0	12.2	33.2
VOC	3.18	2.98	3.7	6.7
Sulfuric Acid Mist	0.02	0.02	0.003	0.02
Annual Potential Emissions (TPY)				
SO_2	12.35	11.34	0.68	12.02
PM/PM10	48.18	39.42	2.25	41.67
NO_x	419.2	378.4	22.5	400.9
CO	102.1	92.1	22.5	114.6
VOC	13.9	13.0	6.75	19.75
Sulfuric Acid Mist	0.095	0.087	0.01	0.097

Note: 10^6 Btu/hr = million British thermal units per hour.
CO = carbon monoxide.
CT = combustion turbine.
°F = degrees Fahrenheit.
ft = feet.
ft/sec = feet per second.
HRSG = heat recovery steam generators.
lb/hr = pounds per hour.
Neg = negative.
NO_x = nitrogen oxides.
O_2 = oxygen molecule.
PM = particulate matter.
PM10 = particulate matter less than or equal to 10 micrometers.
ppmvd = parts per million by volume dry.
SO_2 = sulfur dioxide.
TPY = tons per year.
VOC = volatile organic compound.

[a] Performance based on 20°F with NO_x emissions at 25 ppmvd (corrected to 15 percent O_2); 8,760 hr/yr operation.

[b] Performance based on 59°F with NO_x emissions of 25 ppmvd (corrected to 15 percent O_2), 8,760 hr/yr operation; stack parameters based on 90°F ambient temperature.

[c] Performance based on 122 x 10^6 Btu/hr heat input for HRSG; annual emissions based on 4,500 hours per year operation at an average heat input of 100 x 10^6 Btu/hr.

emissions for the case of duct firing were based on 59°F ambient temperature, with duct firing emissions based on 122 x 10^6 Btu/hr.

These emissions, as well as the total emissions for the CT and duct firing, are shown in Table 2-1. Stack parameters for the duct firing case are based on 90°F ambient temperature, which produces the lowest volume flow and, hence, lowest plume rise of the exhaust gases.

Gas turbine performance data and maximum emissions for regulated criteria pollutants, regulated noncriteria pollutants, and nonregulated pollutants from the CT are presented in Tables A-1 through A-5 of Appendix A.

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 project can begin operation.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida Ambient Air Quality Standards (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; 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. 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

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.

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	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 to 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.
TPY = tons per year.
$\mu g/m^3$ = micrograms per cubic meter.

Sources: 40 CFR 52.21.
Chapter 17-2, F.A.C.

of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations that are essentially identical to federal regulations [Chapter 17-2.500, 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, 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 nitrogen dioxide (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; and
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.

Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990). The "draft" guidance requires starting 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.

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) (EPA, 1987b). The source impact analysis for criteria pollutants 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.

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 volatile organic compound (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 Orange County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants. Orange County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_x. The site is located more than 100 km from the closest part of the Chassahowitzka National Wilderness Class I Area.

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The proposed project is considered to be a major facility because potential emissions of at least one regulated pollutant will exceed 250 TPY (refer to Table 2-1); therefore, PSD review is required for any pollutant for which the potential emissions exceed the PSD significant emission rates presented in Table 3-2 (i.e., major source). As shown in Table 3-3, potential emissions from the proposed project will exceed the PSD significant emission rates for NO_x, CO, and PM/PM10. Therefore, the project is subject to PSD review for these pollutants.

3.4.2.2 Ambient Monitoring

Based on the increase in emissions from the proposed project, presented in Table 3-3, a PSD preconstruction ambient monitoring analysis is required for PM/PM10, NO_x, and CO. However, if the increase in impacts 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 maximum emission 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 impacts are below the respective de minimis monitoring concentration for each pollutant. Therefore, preconstruction monitoring is not required for these pollutants.

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 proposed stack for the proposed CT/HRSG will be 115 ft (35.1 m) high and, therefore, does not exceed the GEP stack height. The potential for downwash of the units' emissions caused by nearby structures is discussed in Section 6.0.

3.4.3 NONATTAINMENT REVIEW

The project site is located in Orange County, which is classified as an attainment area for all criteria pollutants. The site is also located more than 50 km from any nonattainment area. Therefore, nonattainment requirements are not applicable.

Table 3-3. Maximum Emissions Due To the Orlando CoGen Limited, L.P. Project Compared to the PSD Significant Emission Rates

	Emissions (TPY)		
Pollutant	Potential Emissions From Proposed Facility	Significant Emission Rate	PSD Review
Sulfur Dioxide	12.35	40	No
Particulate Matter (TSP)	48.18	25	Yes
Particulate Matter (PM10)	48.18	15	Yes
Nitrogen Dioxide	419.2	40	Yes
Carbon Monoxide	114.6	100	Yes
Volatile Organic Compounds	19.75	40	No
Lead	NEG	0.6	No
Sulfuric Acid Mist	0.097	7	No
Total Fluorides	NEG	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	NEG	0.0004	No
Mercury	NEG	0.1	No
Vinyl Chloride	NEG	1	No
Benzene	NEG	0	No
Radionuclides	NEG	0	No
Inorganic Arsenic	NEG	0	No

Note: NEG = Negligible.
TPY = Tons per year.

3.4.4 HAZARDOUS POLLUTANT REVIEW

The FDER has a draft policy (FDER, 1991) that may be used 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 (NTLs) 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. Impacts of emissions of hazardous/toxic pollutants from the proposed facility are presented in Section 7.0. Based on this analysis, the NTL will not be exceeded for any pollutant.

Table 3-4. Predicted Maximum Impacts Due To the Orlando CoGen Limited, L.P. Project Compared to PSD De Minimis Monitoring Concentrations

Pollutant	Averaging Time	Concentration ($\mu g/m^3$) Predicted Maximum Impact	Concentration ($\mu g/m^3$) De Minimis Monitoring Concentration
Particulate Matter (PM10)	24-hour	2.4	10
Nitrogen Dioxide	Annual	0.6	14
Carbon Monoxide	8-hour	12	575

Note: $\mu g/m^3$ = micrograms per cubic meter.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of NO_x, CO, and PM/PM(10) for the Orlando CoGen project (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, and is consistent with EPA's draft policy requiring a 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. There are no NSPS emission limits for PM/PM10 or CO.

As noted from Table 4-1, the NSPS NO_x emission limit is adjusted based on unit heat rate and to allow for fuel-bound nitrogen (FBN). For a FBN content of 0.015 percent or less, no increase in the NSPS is provided; for a FBN content of between 0.015 and 0.10 percent, the NSPS is increased by the factor of 0.4 times the FBN content (in percent by weight).

For the proposed CT, the NSPS emission limit is 94 parts per million (ppm), corrected to 15 percent oxygen dry conditions. The applicable NSPS for the duct burners is 40 CFR 60, Subpart Db. The applicable requirements are presented in Table 4-2.

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

Note: 10^6 Btu/hr = million British thermal units per hour.
O_2 = oxygen molecule.
ppm = parts per million.

[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.

Table 4-2. Federal NSPS for Natural Gas Fired Industrial Steam-Generating Units, 40 CFR 60, Subpart Db[a]

Pollutant	Emission Limitation for Gaseous or Liquid Fuels
Particulate Matter	No emission limits
Visible Emissions	20% opacity (6-minute average), except up to 27% opacity is allowed for one 6-minute period per hour
Sulfur Dioxide	No emission limits
Nitrogen Oxides	1) Low heat release rate unit - 0.10 lb/10^6 Btu 2) High heat release rate unit - 0.20 lb/10^6 Btu 3) Duct burner in combined cycle system - 0.20 lb/10^6 Btu

Note: 10^6 Btu/hr = million British thermal units per hour.
lb/10^6 Btu = pound million British thermal units.
% = percent.

[a] Applies to any device that combusts fuel to produce steam and that has a maximum heat input of more than 100 x 10^6 Btu/hr. Sources subject to Subpart Da are not subject to Subpart Db.

Source: 40 CFR 60, Subpart Db.

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 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:

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					Control Method	Eff. (%)
					(lb/MMBtu)	(lb/hr)	(TPY)	pmvd	basis)		
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. I., I.	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	—

> 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.

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 the turbine, 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.
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.

Table 4-4. Cost, Technical, and Environmental Considerations of SCR Used on Combustion Turbines (Page 2 of 2)

Consideration	Description
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.

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 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).

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 ABB 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:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \dashrightarrow 2N_2 + CO_2 + 2H_2O$$

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$_x$OUT 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 will be the use of low-NO$_x$ natural gas burners that will limit the emissions to 0.1 lb/10^6 Btu heat input. The latest combined cycle projects with duct firing approved by FDER in November, 1991 (i.e., Lake Cogen Limited and Pasco Cogen Limited) established 0.1 lb NO$_x$/10^6 Btu as the BACT limits. This proposed limit is the lowest being permitted for similar facilities and is one-half the NSPS limit.

Summary of Technically Feasible NO$_x$ Control Methods--The available information suggests that SCR with dry low-NO$_x$ combustor technology 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).

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; maximum NO_x emissions are 141 TPY, and
2. Dry low-NO_x combustion at an emission rate of 25 ppmvd corrected to 15 percent O_2; maximum annual NO_x emissions are 401 TPY assuming an annual average temperature of 59°F (CT/duct firing case).

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 $1,917,900. The incremental reduction in NO_x emissions is 260 TPY. The incremental cost effectiveness of SCR over dry low-NO_x combustion alone is therefore estimated to be $7,377/ton of NO_x removed for the project.

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

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 1 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Capital Costs		
SCR Associated Equipment	607,500	Developed from manufacturer budget quotations
Ammonia Storage Tank	172,400	Developed from manufacturer budget quotations
HRSG Modification	303,000	Developed from manufacturer budget quotations
Indirect Capital Costs		
Installation	419,300	20% of SCR associated equipment and ammonia storage tank
Engineering, Erection Supervision, Startup, and O&M Training	329,000	10% SCR equipment and catalyst, ammonia storage tank, and HRSG costs
Project Support	180,900	5% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs
Ammonia Emergency Prepardness Program	19,200	Engineering estimate
Liability Insurance	18,100	0.5% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs
Interest During Construction	677,100	15% of all direct and indirect capital costs, including catalyst cost
Contingency	478,300	20% of all capital costs
Total Capital Costs	3,205,100	Sum of all capital costs
Annualized Capital Costs	376,500	Capital recovery of 10% over 20 years, 11.74% per year

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 2 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Recurring Capital Costs		
SCR Catalyst (Materials and Labor)	1,489,200	Developed from manufacturer budget quotations
Contingency	297,800	20% of recurring capital costs
Total Recurring Capital Costs	1,787,000	Sum of recurring capital costs
Annualized Recurring Capital Costs	718,600	Capital recovery of 10% over 3 years, 40.21% per year

Note: HRSG = heat recovery steam generators.
% = percent.
SCR = selective catalytic reduction.

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 1 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Direct Annual Costs		
Operating Personnel	20,800	16 hours/week @ $25/hour
Ammonia	27,900	$300/ton; NH_3:NO_x = 1:1 volume
Accident/Emergency Response Plan	8,100	Consultant estimate, 80 hours/year @ $75/hour plus expenses @ 35% labor
Inventory Cost	58,300	Capital recovery (11.74%/year) for 1/3 of catalyst cost
Catalyst Disposal Cost	68,900	Engineering estimate
Contingency	43,700	20% of indirect costs
Energy Costs		
Electrical	35,000	80 kWh/hr; $0.05/kWh
Heat Rate Penalty	172,600	4" back pressure, heat rate reduction of 0.5%, energy loss at $0.05/kWh
MW Loss Penalty	98,700	84 MW lost for 3 days; lost capacity @ $0.05/kW; cost of natural gas @ $3/MMBtu subtracted
Fuel Escalation Costs	94,400	Real cost increase of fuel
Contingency	60,400	20% of energy costs; excludes fuel escalation
Total Direct Annual Costs	688,800	Sum of all direct annual costs
Indirect Annual Costs		
Overhead	34,200	60% of ammonia; 115% of O&M labor, and 15% of O&M labor (OAQPS Cost Control Manual)

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR) (Page 2 of 2)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Property Taxes and Insurance	99,800	2% of total capital costs
Annualized Capital Costs	376,500	Capital recovery of 10% over 20 years, 11.74% per year
Recurring Capital Costs	718,600	Capital recovery of 10% over 3 years, 40.21% per year
<u>Total Indirect Annual Costs</u>	1,229,100	Sum of all indirect annual costs
<u>Total Annual Costs</u>	1,917,900	Total annualized cost

Note: All calculations rounded off 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.
% = percent.

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 63.5 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 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 3,900,000 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

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	24	2.06	26	0	26
Sulfur Dioxide	0	22.64	23	0	23
Nitrogen Oxides	141	11.32	152	401	(249)
Carbon Monoxide	0	0.68	1	0	1
Volatile Organic Compounds	0	0.10	0	0	0
Ammonia	64	0.00	64	0	64
Total	229	36.81	266	401	(135)
Carbon Dioxide[c]	--	3,535	3,535	--	3,535

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 0.47 MW for 8,760 hours per year operation. 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.

[b] Difference = Total with SCR minus project without SCR.

[c] Reflects differential emissions due to lost energy efficiency with SCR.

requirements of SCR could supply the electrical needs of 400 residential customers. To replace this lost energy, an additional 5.3 x 10^{10} British thermal units per year (Btu/yr) or about 53 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 for natural gas firing exceeds $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 $15,000 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 (approximately 1 percent of the allowable PSD increments and less than 1 percent of the AAQS for NO_x). 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., 0.1 lb/10^6 Btu) is at a level specified as BACT for similar recent projects.

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.

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					Control Method	Eff. (%)
					(lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd	basis)		
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					Control Method	Eff. (%)
					(lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd	basis)		
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	—		—	—

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 10 ppm, corrected to dry conditions when firing natural gas under full load conditions. This CO emission level is near the lowest established as the BACT level.

Catalytic oxidation is a post-combustion 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 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.

Combustion design is dependent upon the manufacturer's operating specifications. The CT proposed for the project has been designed to optimize combustion efficiency and minimize CO emissions. Installations with an oxidation catalyst and combustion controls generally have controlled CO levels to 10 ppm as LAER and BACT.

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.

4.3.2.2 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 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 10 ppmvd for the CT only, and 16 ppmvd for the CT/HRSG exhaust.

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 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 11 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 represents 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 MONITORING

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 stations or establishing a network to monitor existing air quality. Monitoring must be conducted for a period up to 1 year before 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 (EPA, 1987a) set forth preconstruction monitoring guidelines. 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 criterion 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. Using continuous instrumentation,
2. Producing quality control records that indicate the instruments' operations and performances,
3. Operating the instruments to satisfy quality assurance requirements, and
4. Recovering at least 80 percent of the data possible during the monitoring effort.

For the third criterion, currentness of data, the monitoring data must have been collected within a 3-year period preceding submittal of the 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 PM, NO_2, and CO emissions. The maximum predicted impacts from the proposed CT/HRSG are less than the de minimis levels for PM, NO_2, and CO (see Table 3-4). Therefore, preconstruction monitoring is not required.

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 particulate 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.

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 and discussions with FDER, the rural mode was selected because of the lack of residential, industrial, and commercial development within 3 km of the plant site.

It is noted that the ISCST model was used to assess impacts near the proposed facility, as well as at the Class I PSD area located about 120 km away. Although application of the ISCST model is generally limited to approximately a 50-km distance, this model has historically been used as a

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.

screening tool for assessing Class I impacts at greater distances. If the ISCST results indicate very low impacts (i.e., below the Class I significance levels), EPA and FDER generally have not required further refined modeling.

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) stations at the Orlando International Airport and Ruskin, respectively. The 5-year period of meteorological data was from 1982 through 1986. The NWS station in Orlando, located less than 10 km east 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 Ruskin using the Holzworth approach (Holzworth, 1972). The Ruskin station is located about 127 km southwest of the site. 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 air emission rates for the proposed CT/HRSG were presented in Section 2.0.

Modeling of the proposed CT/HRSG demonstrated that the facility's PM, NO_x, and CO impacts are below their respective significant impact levels (see Section 7.0). Therefore, further modeling for this facility is not required, and an emission inventory for other sources is not necessary.

6.4 RECEPTOR LOCATIONS

In the ISCST modeling, concentrations were predicted for the screening phase using a polar receptor grid and polar discrete receptors. A description of the receptor locations for determining maximum predicted impacts is presented below.

The screening grid receptors consisted of 360 polar grid receptors located at distances of 500; 1,000; 1,500; 2,000; 2,500; 3,000; 3,500; 4,000; and 5,000 m along 36 radials, with each radial spaced at 10-degree increments. An additional 71 discrete receptors were included to depict the property boundary and the 100-m distance, if it was beyond the property boundary. Property boundary receptors are presented in Table 6-2. Site maps depicting the site boundaries are included in the map pocket.

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 1.6 km, the refined receptor grid would consist of receptors at the following locations:

The refined modeling analysis also included receptors located a distance of 70 m when beyond plant property. The 70-m distance is representative of the minimum distance at which the ISCST model will predict a concentration for the modeled building height.

Directions (degrees)	Distance (km)
82, 84, 86, 88, 90, 92, 94, 96, 98	1.3, 1.4, 1.5, 1.6, 1.7, 1.8, and 1.9 per direction

Table 6-2. Property Boundary Receptors Used in the Modeling Analysis

Receptor Location[a]		Receptor Location[a]	
Direction (deg)	Distance (m)	Direction (deg)	Distance (m)
10	75	190	59
20	78	200	56
30	85	210	52
40	96	220	49
50	101	230	46
60	89	240	46
70	82	250	47
80	78	260	49
90	77	270	53
100	78	280	56
110	82	290	59
120	89	300	64
130	97	310	72
140	82	320	86
150	72	330	85
160	66	340	78
170	63	350	75
180	62	360	74

Note:
deg = degrees.
m = meter.
CT/HRSG = combustion turbine/heat recovery steam generators.

[a] With respect to CT/HRSG stack location.

Source: KBN, 1991.

Concentrations in the refined analysis were predicted 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, those concentrations were refined as well.

Because the maximum impacts of the proposed facility are below PSD significant impact levels and the closest PSD Class I area is 121 km from the site, the maximum PSD Class I increment consumption at the Chassahowitzka Wilderness Area, a PSD Class I area, was determined for the proposed facility alone. Receptors were located at 13 discrete Cartesian receptors surrounding the border of the PSD Class I area. The highest predicted concentration over 5 years of meteorological data was compared with PSD Class I significant impact levels, which were adopted as policy by EPA on September 10, 1991 (Memorandum from John Calcagnito to Thomas Maslany). The analysis was performed for both PM and NO_x.

6.5 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings and structures planned at the plant, the stack of the proposed facility 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:

$$M_w = \frac{\Pi W^2}{4}$$

$$M_w = 0.8886W$$

where: M_w = input to the model to produce a building width of W used in the dispersion calculation.
W = the actual building width.

The single, most dominant building structure at the site will be the HRSG building. This building is 76 ft tall, 60 ft long, and 43 ft wide. For aesthetic purposes, the building has been made large enough to cover all the tanks and has been extended to be flush with the bottom section of the rectangular stack. The building dimensions are summarized in Table 6-3. The site layout map of the proposed facility is included in the map pocket.

Table 6-3. Building Dimensions Used in ISCST Modeling Analysis To Address Potential Building Wake Effects

Source	Associated Building	Actual Building Dimensions (m)			Projected Width[a] (m)	Modeled Building Dimensions (m)	
		Length	Width	Height		Length, Width	Height
HRSG Stack	HRSG Building	18.29	13.11	23.16	22.50	19.93	23.16

Note: m = meter.

[a] Diagonal of actual building dimensions.

Source: KBN, 1991.

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED UNIT ONLY

7.1.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the maximum concentrations as a result of the proposed facility only operating at worst-case operating conditions is presented in Table 7-1. The results are presented for a generic emission rate concentration of 10 grams per second (g/s). Table 7-1 indicates the maximum screening concentrations for each year and averaging time with an emission rate of 10 g/s. Based on the results in Table 7-1, refined modeling was performed. The results of the refined modeling are presented in Table 7-2. The maximum pollutant-specific concentrations for PM, NO_2, and CO were determined from the maximum generic impacts and are presented in Table 7-3.

The maximum predicted NO_2 concentration as a result of the proposed facility only is 0.61 $\mu g/m^3$. Since this concentration is below the significance level for NO_2 (1.0 $\mu g/m^3$), no further modeling analysis is necessary for this pollutant. The maximum predicted 1-hour and 8-hour CO concentrations are 47 and 12 $\mu g/m^3$, respectively. Because these concentrations are below the PSD significant impact levels of 2,000 and 500 $\mu g/m^3$, additional modeling is not necessary for CO.

The maximum predicted annual and 24-hour average PM concentrations are 0.07 and 2.44 $\mu g/m^3$, respectively. These maximum impacts are less than the PM significant impact levels. Therefore, additional modeling is not required for this pollutant.

7.1.2 CLASS I ANALYSIS

The maximum predicted facility impacts at the Chassahowitzka Wilderness Area using a generic emission rate of 10 g/s are presented in Table 7-4. The maximum annual and 24-hour generic impacts are 0.01 and 0.17 $\mu g/m^3$, respectively. The pollutant-specific results are presented in Table 7-5. The maximum PSD PM annual and 24-hour increment consumption is 0.001 and 0.02 $\mu g/m^3$, respectively. These concentrations, developed from the ISCST model, are considerably below the PSD Class I area significant impact levels of 0.27 and 1.35 $\mu g/m^3$, respectively. As a result, no further modeling of the Class I areas was performed.

Table 7-1. Maximum Predicted Impacts for the Orlando CoGen Limited, L.P. Facility Using a Generic Emission Rate of 10 g/s - Screening Analysis

			Receptor Location[a]		
Averaging Time	Year	Concentration ($\mu g/m^3$)	Direction (degrees)	Distance (m)	Day/ Period
Annual					
	1982	0.45	240	100	-/-
	1983	0.36	110	82	-/-
	1984	0.40	240	100	-/-
	1985	0.34	250	100	-/-
	1986	0.24	280	100	-/-
1-Hour[b]					
	1982	112.73	360	74	169/8
	1983	80.42	80	78	83/16
	1984	80.41	340	78	272/4
	1985	67.69	90	77	137/17
	1986	54.13	100	78	27/14
3-Hour[b]					
	1982	40.23	100	78	14/6
	1983	51.42	80	78	83/6
	1984	61.43	340	78	272/2
	1985	47.19	90	77	137/6
	1986	34.04	100	78	27/5
8-Hour[b]					
	1982	19.67	100	78	14/3
	1983	17.99	90	77	45/2
	1984	23.42	340	78	272/1
	1985	28.28	90	77	43/1
	1986	16.34	60	89	58/2
24-Hour[b]					
	1982	9.82	100	78	14/1
	1983	9.36	90	77	45/1
	1984	9.34	50	101	272/1
	1985	17.30	90	77	43/1
	1986	8.24	100	78	27/1

Note: g/s = grams per second.
m = meter.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed stack.
[b] All short-term concentrations indicate highest predicted concentrations.

Source: KBN, 1991.

Table 7-2. Maximum Predicted Impacts for the Orlando CoGen Limited, L.P. Facility Using a Generic Emission Rate of 10 g/s--Refined Analysis

			Receptor Location[a]		
Averaging Time	Year	Concentration ($\mu g/m^3$)	Direction (degrees)	Distance (m)	Day/ Period
Annual					
	1982	0.49	236	70	—/—
1-Hour[b]					
	1982	112.73	360	74	169/8
8-Hour[b]					
	1985	29.67	84	78	43/1
24-Hour[b]					
	1984	17.64	92	77	43/1

Note: g/s = grams per second.
m = meter.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed stack.
[b] All short-term concentrations indicate highest predicted concentrations.

Source: KBN, 1991.

Table 7-3. Maximum Predicted Pollutant Impacts of the Orlando CoGen Limited, L.P. Facility Compared to PSD Significant Impact Levels

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ($\mu g/m^3$)	Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
Particulate Matter	Annual	11.0	0.49	0.07	1
	24-Hour		17.64	2.44	5
Nitrogen Oxides	Annual	98.6	0.49	0.61	1
Carbon Monoxide	1-Hour	33.2	112.73	47	2,000
	8-Hour		29.67	12	500

Note: Short-term maximum impacts are highest predicted concentrations for 1982-86.

lb/hr = pounds per hour.
$\mu g/m^3$ = micrograms per cubic meter.

Source: KBN, 1991.

Table 7-4. Maximum Predicted PSD Class I Impacts for the Orlando CoGen Limited, L.P. Facility Using a Generic Emission Rate of 10 g/s

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] X (m)	Receptor Location[a] Y (m)	Day/ Period
Annual					
	1982	0.006	342000	3174000	-/-
	1983	0.005	343700	3178300	-/-
	1984	0.007	340300	3165700	-/-
	1985	0.005	340300	3165700	-/-
	1986	0.008	340300	3167700	-/-
24-Hour[b]					
	1982	0.165	342000	3174000	106/1
	1983	0.106	340700	3171900	103/1
	1984	0.118	340300	3167700	354/1
	1985	0.102	341100	3183400	242/1
	1986	0.126	343000	3176200	35/1

Note: g/s = grams per second.
m = meter.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed stack.
[b] All short-term concentrations indicate highest predicted concentrations.

Source: KBN, 1991.

Table 7-5. Maximum Predicted Pollutant Impacts of the Orlando CoGen Limited, L.P. Facility Compared to PSD Class I Significant Impact Levels

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ($\mu g/m^3$)	Predicted Impact ($\mu g/m^3$)	PSD Class I Significant Impact Levels ($\mu g/m^3$)
Particulate Matter (PM10)	Annual	11.0	0.01	0.001	0.27
	24-Hour		0.17	0.02	1.35
Nitrogen Oxides	Annual	98.6	0.01	0.01	0.1

Note: Short-term maximum impacts are highest predicted concentrations for 1982-86.

lb/hr = pounds per hour.
$\mu g/m^3$ = micrograms per cubic meter.

Source: KBN, 1991.

The maximum NO_x PSD increment consumption is 0.01 $\mu g/m^3$. This is well below the PSD Class I area significant impact level of 0.1 $\mu g/m^3$.

7.2 TOXIC POLLUTANT ANALYSIS

The maximum impacts of regulated and nonregulated hazardous pollutants that will be emitted in significant amounts by the proposed facility (see Table 3-3) are presented in Table 7-6. Inorganic As is the only pollutant to be addressed and is compared in the table to FDER NTL. The maximum 8-hour, 24-hour, and annual impacts for As are well below the NTL for each respective averaging time.

7.3 ADDITIONAL IMPACT ANALYSIS

7.3.1 IMPACTS UPON SOILS AND VEGETATION

Predicted impacts of all regulated pollutants are less than the significant impact levels (see Table 7-3). As a result, no impacts are expected to occur to soils or vegetation as a result of the proposed emissions of regulated pollutants.

7.3.2 IMPACTS DUE TO ADDITIONAL GROWTH

A small work force will be employed by the facility (fewer than 12 personnel). These additional personnel are expected to have an insignificant effect on the residential, commercial, and industrial growth in Orange County.

7.3.3 IMPACTS TO VISIBILITY

The plant is located approximately 121 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). The results of the screening analysis are presented in Table 7-7. The model results show that the screening criteria are not exceeded. As a result, the proposed facility is not expected to significantly impair visibility in the Chassahowitzka Wilderness Area, and no further visibility modeling is required.

Table 7-6. Predicted Maximum Impacts of Toxic Pollutants for the Orlando CoGen Limited. L.P. Facility

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic[a] Impact (μg/m³)	Predicted Impact (μg/m³)	No Threat Levels (μg/m³)
Sulfuric acid mist	8-Hour	0.022[b]	29.67	0.008	0.10
	24-Hour		17.64	0.005	2.38
	Annual		NA	NA	NA
Formaldehyde	8-hour	0.084[b]	29.67	0.031	4.5
	24-hour		17.64	0.019	1.08
	Annual		0.49	0.0005	0.077

Note: Short-term generic impacts are highest predicted concentrations for 1982-1986.

g/s = grams per second.
lb/hr = pounds per hour.
NA = not applicable.
TPY = tons per year.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Generic impacts are based on an emission rate of 10 g/s.
[b] Based on maximum CT emissions with duct burner.

Source: KBN, 1991.

Table 7-7. Visibility Screening Analysis for the Orlando CoGen Limited, L.P. Facility (Page 1 of 2)

```
                 Visual Effects Screening Analysis for
                   Source: ORLANDO COGEN LIMITED, L.P.
                   Class I Area: CHASSAHOWITZKA WILDERNES

                   ***   Level-1 Screening   ***
 Input Emissions for

    Particulates    11.00  LB /HR
    NOx (as NO2)    96.80  LB /HR
    Primary NO2       .00  LB /HR
    Soot              .00  LB /HR
    Primary SO4       .00  LB /HR

     **** Default Particle Characteristics Assumed

                 Transport Scenario Specifications:

     Background Ozone:                    .04 ppm
     Background Visual Range:           25.00 km
     Source-Observer Distance:         121.00 km
     Min. Source-Class I Distance:     121.00 km
     Max. Source-Class I Distance:     131.00 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.  121.0    84.  2.00  .000    .05   .000
  SKY      140.  84.  121.0    84.  2.00  .000    .05   .000
  TERRAIN   10.  90.  123.4    79.  2.00  .000    .05   .000
  TERRAIN  140.  90.  123.4    79.  2.00  .000    .05   .000
```

Table 7-7. Visibility Screening Analysis for the Orlando CoGen Limited, L.P. Facility (Page 2 of 2)

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.	117.1	94.	2.00	.000	.05	.000
SKY	140.	75.	117.1	94.	2.00	.000	.05	.000
TERRAIN	10.	70.	115.0	99.	2.00	.000	.05	.000
TERRAIN	140.	70.	115.0	99.	2.00	.000	.05	.000

Note:
km = kilometer.
lb/hr = pounds per hour.
m/s = meters per second.
NO_x = nitrogen oxides.
NO_2 = nitrogen dioxide.
ppm = parts per million.
SO_4 = sulfate.

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APPENDIX A

EMISSION CALCULATIONS AND FACTORS

Emission rates for all regulated and nonregulated pollutants were calculated using both manufacturer's data and EPA emission factors. The design information and emissions data are presented in Tables A-1 through A-5. These tables were generated using a computerized spreadsheet (i.e., Lotus 1-2-3). Tables A-1 through A-5 have been annotated to show the columns (i.e., A ,B, C, and D) and rows (i.e., 1, 2, 3, ...) in the spreadsheet. Following these tables is a printout of all the calculations made in the spreadsheet, along with the basis for the calculation. The calculations, as well as text comments, are listed alphanumerically in ascending order. For example, in Table A-1, column B, row 12 is listed as A:B12 on the calculation page, and the data input is 10,690: As noted, these data were provided by ABB. A copy of the relevant EPA emission factors also is included in this appendix.

Table A-1. Design Information and Stack Parameters for Orlando CoGen Limited, L.P. Cogeneration Project

Data A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
General:					
Power (kW)	87,360.0	78,830.0	75,690.0	68,350.0	NA
Heat Rate (Btu/kwh)	10,690.0	10,870.0	10,960.0	11,270.0	NA
Heat Input (mmBtu/hr)	933.9	856.9	829.6	770.3	122.0
Natural Gas (lb/hr)	44,732.4	41,044.3	39,735.7	36,897.3	5,843.8
(cf/hr)	987,186.5	905,795.0	876,915.9	814,275.4	128,964.1
Fuel:					
Heat Content - (LHV)	20,877 Btu/lb	20,877 Btu/lb	20,877 Btu/lb	20,877 Btu/lb	20,877 Btu/lb
Sulfur	1 gr/100cf	1 gr/100cf	1 gr/100cf	1 gr/100cf	1 gr/100cf
CT Exhaust:	CT Only:	CT Only:	CT Only:	CT Only:	CT & DB Exhaust:
Volume Flow (acfm)	1,601,395	1,529,035	1,500,057	1,429,720	675,048
Volume Flow (scfm)	603,523	569,344	555,810	522,778	524,155
Mass Flow (lb/hr)	2,631,000	2,482,000	2,423,000	2,279,000	2,285,000
Temperature (°F)	941	958	965	984	220
Moisture (% Vol.)	6.10	6.70	7.10	9.30	9.20
Oxygen (% Vol.)	14.40	14.50	14.40	14.20	14.00
Molecular Weight	28.00	28.00	28.00	28.00	28.00
HRSG Stack:					
Volume Flow (acfm)	811,556	754,813	726,343		675,048
Temperature (°F)	250	240	230		220
Diameter (ft)	15.7	15.7	15.7		15.7
Velocity (ft/sec)	69.90	65.01	62.56		58.14

Note: CT and duct burner will fire natural gas only.
Duct burner maximum firing will be 450,000 MM Btu/year; i.e., 4,500 hours at 100 MM Btu/hr.
Duct burner operation is planned when ambient temperature is greater than 59°F.

Table A-2. Maximum Criteria Pollutant Emissions for Orlando CoGen Limited, L.P. Cogeneration Project

Pollutant A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
Particulate:					
Basis	Manufacturer	Manufacturer	Manufacturer	Manufacturer	0.01 lb/MMBtu
lb/hr	11.00	9.00	9.00	9.00	1.22
TPY	48.18	39.42	39.42	39.42	2.25
Sulfur Dioxide:					
Basis	1 gr/100 cf	1 gr/100 cf	1 gr/100 cf	1 gr/100 cf	1 gr/100 cf
lb/hr	2.82	2.59	2.51	2.33	0.37
TPY	12.35	11.34	10.97	10.19	0.68
Nitrogen Oxides:					
Basis	25 ppm[a]	25 ppm[a]	25 ppm[a]	25 ppm[a]	0.1 lb/MMBtu
lb/hr	95.7	86.4	84.6	75.5	12.20
TPY	419.2	378.4	370.6	330.5	22.50
ppm	25.0	25.0	25.0	25.0	
Carbon Monoxide:					
Basis	10 ppm[b]	10 ppm[b]	10 ppm[b]	10 ppm[b]	0.1 lb/MMBtu
lb/hr	23.3	21.0	20.6	18.4	12.20
TPY	102.06	92.12	90.23	80.47	22.50
ppm	10.0	10.0	10.0	10.0	
VOCs:					
Basis	3 ppm[b]	3 ppm[b]	3 ppm[b]	3 ppm[b]	0.03 lb/MMBtu
lb/hr	3.18	2.98	2.89	2.66	3.66
TPY	13.9	13.0	12.7	11.6	6.75
ppm	3.0	3.0	3.0	3.0	
Lead:					
Basis					
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

[a] Corrected to 15% O_2 dry conditions.

[b] Corrected to dry conditions.

Note: Annual emission for CT when firing natural gas based on 8,760 hrs/yr. Annual emissions for duct burner based on 450,000 MM Btu/year operation; i.e., 4,500 hours at 100 MM Btu/hr. Duct burner operation planned when ambient temperature is greater than 59°F.

Table A-3. Maximum Other Regulated Pollutant Emissions for Orlando CoGen Limited, L.P. Cogeneration Project

Pollutant A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - F
As (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Be (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
Hg (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
F (lb/hr)	NEG.	NEG.	NEG.	NEG.	NEG.
(TPY)	NEG.	NEG.	NEG.	NEG.	NEG.
H_2SO_4 (lb/hr)	2.16×10^{-2}	1.98×10^{-2}	1.92×10^{-2}	1.78×10^{-2}	2.82×10^{-3}
(TPY)	9.45×10^{-2}	8.67×10^{-2}	8.40×10^{-2}	7.80×10^{-2}	0.01

Sources: EPA, 1988; EPA, 1980.

Table A-4. Maximum Non-Regulated Pollutant Emissions for Orlando CoGen Limited, L.P. Cogeneration Project

Pollutant A	Gas Turbine Natural Gas 20°F - B	Gas Turbine Natural Gas 59°F - C	Gas Turbine Natural Gas 72°F - D	Gas Turbine Natural Gas 102°F - E	Duct Burner Natural Gas - 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.
POM (lb/hr)	$1.04x10^{-3}$	$9.56x10^{-4}$	$9.25x10^{-4}$	$8.59x10^{-4}$	$1.36x10^{-4}$
(TPY)	$4.56x10^{-3}$	$4.19x10^{-3}$	$4.05x10^{-3}$	$3.76x10^{-3}$	$2.51x10^{-4}$
Formaldehyde (lb/hr)	$8.25x10^{-2}$	$7.57x10^{-2}$	$7.33x10^{-2}$	$6.80x10^{-2}$	$1.08x10^{-2}$
(TPY)	$3.61x10^{-1}$	$3.31x10^{-1}$	$3.21x10^{-1}$	$2.98x10^{-1}$	$1.99x10^{-2}$

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 (K)

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:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$$

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:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$m_{CO} = PV_{CO\ Act}M_{CO}\ /\ RT$$
$$= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO}\ /\ RT$$

```
A:A1: [W22] 'Table A-1.  Design Information and Stack Parameters for Orlando CoGen Limited, L.P.
A:G1: [W6] 1
A:A2: [W22] '         Cogeneration Project
A:G2: [W6] (G1+1)
A:A3: [W22] \_
A:B3: [W16] \_
A:C3: [W16] \_
A:D3: [W16] \_
A:E3: [W16] \_
A:F3: [W16] \_
A:G3: [W6] (G2+1)
A:G4: [W6] (G3+1)
A:A5: [W22] ^Data
A:B5: [W16] "Gas Turbine
A:C5: [W16] "Gas Turbine
A:D5: [W16] "Gas Turbine
A:E5: [W16] "Gas Turbine
A:F5: [W16] "Duct Burner
A:G5: [W6] (G4+1)
A:B6: [W16] "Natural Gas
A:C6: [W16] "Natural Gas
A:D6: [W16] "Natural Gas
A:E6: [W16] "Natural Gas
A:F6: [W16] "Natural Gas
A:G6: [W6] (G5+1)
A:B7: [W16] "20oF - B
A:C7: [W16] "59oF - C
A:D7: [W16] "72oF - D
A:E7: [W16] "102oF - E
A:F7: [W16] "90oF - F
A:G7: [W6] (G6+1)
A:A8: [W22] \_
A:B8: [W16] \_
A:C8: [W16] \_
A:D8: [W16] \_
A:E8: [W16] \_
A:F8: [W16] \_
A:G8: [W6] (G7+1)
A:G9: [W6] (G8+1)
A:A10: [W22] ^General:
A:G10: [W6] (G9+1)
A:A11: [W22] 'Power (kW)
A:B11: (,1) [W16] 87360 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C11: (,1) [W16] 78830
A:D11: (,1) [W16] 75690
A:E11: (,1) [W16] 68350
A:F11: (,1) [W16] "NA
A:G11: [W6] (G10+1)
A:A12: [W22] 'Heat Rate (Btu/kwh)
A:B12: (,1) [W16] 10690 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C12: (,1) [W16] 10870
A:D12: (,1) [W16] 10960
A:E12: (,1) [W16] 11270
A:F12: (,1) [W16] "NA
A:G12: [W6] (G11+1)
A:A13: [W22] 'Heat Input (mmBtu/hr)
A:B13: (,1) [W16] (B11*B12/1000000) . . . . . . . . . . . . . . . . . . . . . . . . Power * Heat Rate
A:C13: (,1) [W16] (C11*C12/1000000)
A:D13: (,1) [W16] (D11*D12/1000000)
A:E13: (,1) [W16] (E11*E12/1000000)
A:F13: (,1) [W16] 122 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Maximum Proposed
A:G13: [W6] (G12+1)
A:A14: [W22] 'Fuel Oil (lb/hr)
A:B14: (,1) [W16] (B13/0.020877)  . . . . . . . . . . . . . . . . . . . . . . Heat Input ÷ Heat Content
A:C14: (,1) [W16] (C13/0.020877)
A:D14: (,1) [W16] (D13/0.020877)
A:E14: (,1) [W16] (E13/0.020877)
```

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A:F14: (,1) [W16] (F13/0.020877)
A:G14: [W6] (G13+1)
A:A15: [W22] '        (cf/hr)
A:B15: (,1) [W16] (B13/946*10^6) . . . . . . . . . . . . . . . . . . . . . . Heat Input ÷ Heat Content
A:C15: (,1) [W16] (C13/946*10^6)
A:D15: (,1) [W16] (D13/946*10^6)
A:E15: (,1) [W16] (E13/946*10^6)
A:F15: (,1) [W16] (F13/946*10^6)
A:G15: [W6] (G14+1)
A:G16: [W6] (G15+1)
A:A17: [W22] ^Fuel:
A:G17: [W6] (G16+1)
A:A18: [W22] 'Heat Content - (LHV)
A:B18: (,1) [W16] "20,877 Btu/lb . . . . . . . . . . . . . . . . . . . . . . . . . Fuel Specification
A:C18: (,1) [W16] "20,877 Btu/lb
A:D18: (,1) [W16] "20,877 Btu/lb
A:E18: (,1) [W16] "20,877 Btu/lb
A:F18: (,1) [W16] "20,877 Btu/lb
A:G18: [W6] (G17+1)
A:A19: [W22] 'Sulfur
A:B19: (,1) [W16] "1 gr/100cf . . . . . . . . . . . . . . . . . . . . . Maximum Sulfur Content in Natural Gas
A:C19: (,1) [W16] "1 gr/100cf
A:D19: (,1) [W16] "1 gr/100cf
A:E19: (,1) [W16] "1 gr/100cf
A:F19: (,1) [W16] "1 gr/100cf
A:G19: [W6] (G18+1)
A:G20: [W6] (G19+1)
A:A21: [W22] ^CT Exhaust:
A:B21: (,1) [W16] "CT Only:
A:C21: (,1) [W16] "CT Only:
A:D21: (,1) [W16] "CT Only:
A:E21: (,1) [W16] "CT Only:
A:F21: (,1) [W16] "CT & DB Exhaust:
A:G21: [W6] (G20+1)
A:A22: [W22] 'Volume Flow (acfm)
A:B22: (,0) [W16] (B24*1545*(460+B25)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . See Note A
A:C22: (,0) [W16] (C24*1545*(460+C25)/(C28*2116.8*60))
A:D22: (,0) [W16] (D24*1545*(460+D25)/(D28*2116.8*60))
A:E22: (,0) [W16] (E24*1545*(460+E25)/(E28*2116.8*60))
A:F22: (,0) [W16] (F24*1545*(460+F25)/(F28*2116.8*60))
A:G22: [W6] (G21+1)
A:A23: [W22] 'Volume Flow (scfm)
A:B23: (,0) [W16] (B24*1545*(460+68)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . See Note A
A:C23: (,0) [W16] (C24*1545*(460+68)/(C28*2116.8*60))
A:D23: (,0) [W16] (D24*1545*(460+68)/(D28*2116.8*60))
A:E23: (,0) [W16] (E24*1545*(460+68)/(E28*2116.8*60))
A:F23: (,0) [W16] (F24*1545*(460+68)/(F28*2116.8*60))
A:G23: [W6] (G22+1)
A:A24: [W22] 'Mass Flow (lb/hr)
A:B24: (,0) [W16] 2631000 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C24: (,0) [W16] 2482000
A:D24: (,0) [W16] 2423000
A:E24: (,0) [W16] 2279000
A:F24: (,0) [W16] 2285000
A:G24: [W6] (G23+1)
A:A25: [W22] 'Temperature (oF)
A:B25: (,0) [W16] 941 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C25: (,0) [W16] 958
A:D25: (,0) [W16] 965
A:E25: (,0) [W16] 984
A:F25: (,0) [W16] 220 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Air Products
A:G25: [W6] (G24+1)
A:A26: [W22] 'Moisture (% Vol.)
A:B26: (F2) [W16] 6.1 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C26: (F2) [W16] 6.7
A:D26: (F2) [W16] 7.1
A:E26: (F2) [W16] 9.3
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A:F26: (F2) [W16] 9.2
A:G26: [W6] (G25+1)
A:A27: [W22] 'Oxygen (% Vol.)
A:B27: (F2) [W16] 14.4 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C27: (F2) [W16] 14.5
A:D27: (F2) [W16] 14.4
A:E27: (F2) [W16] 14.2
A:F27: (F2) [W16] 14
A:G27: [W6] (G26+1)
A:A28: [W22] 'Molecular Weight
A:B28: (F2) [W16] 28 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Calculated
A:C28: (F2) [W16] 28
A:D28: (F2) [W16] 28
A:E28: (F2) [W16] 28
A:F28: (F2) [W16] 28
A:G28: [W6] (G27+1)
A:G29: [W6] (G28+1)
A:G30: [W6] (G29+1)
A:A31: [W22] ^HRSG Stack:
A:G31: [W6] (G30+1)
A:A32: [W22] 'Volume Flow (acfm)
A:B32: (,0) [W16] (B22*(B33+460)/(B25+460)) . . . . . . . . . . . . . . . . . . . Adjustment for Temperature
A:C32: (,0) [W16] (C22*(C33+460)/(C25+460))
A:D32: (,0) [W16] (D22*(D33+460)/(D25+460))
A:F32: (,0) [W16] (F22*(F33+460)/(F25+460))
A:G32: [W6] (G31+1)
A:A33: [W22] 'Temperature (oF)
A:B33: (,0) [W16] 250 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Air Products
A:C33: (,0) [W16] 240
A:D33: (,0) [W16] 230
A:F33: (,0) [W16] 220
A:G33: [W6] (G32+1)
A:A34: [W22] 'Diameter (ft)
A:B34: (F0) [W16] 15.7 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Air Products
A:C34: (F0) [W16] 15.7
A:D34: (F0) [W16] 15.7
A:F34: (F0) [W16] 15.7
A:G34: [W6] (G33+1)
A:A35: [W22] 'Velocity (ft/sec)
A:B35: (F2) [W16] (B32/60/(B34^2*3.14159/4)) . . . . . . . . . . . . . . . . . . . . Volume ÷ Flow
A:C35: (F2) [W16] (C32/60/(C34^2*3.14159/4))
A:D35: (F2) [W16] (D32/60/(D34^2*3.14159/4))
A:F35: (F2) [W16] (F32/60/(F34^2*3.14159/4))
A:G35: [W6] (G34+1)
A:G36: [W6] (G35+1)
A:A37: [W22] \_
A:B37: [W16] \_
A:C37: [W16] \_
A:D37: [W16] \_
A:E37: [W16] \_
A:F37: [W16] \_
A:G37: [W6] (G36+1)
A:G38: [W6] (G37+1)
A:A39: [W22] 'Note: CT will fire natural gas only.
A:G39: [W6] (G38+1)
A:A40: [W22] '      Duct burner will use 450,000 MM Btu/year; i.e., 4,500 hours at 100 MM Btu/hr.
A:G40: [W6] (G39+1)
A:A41: [W22] '      Duct burner will only be oprated when ambient temperature is greater than 72oF.
A:G41: [W6] (G40+1)
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A:A47: [W22] 'Table A-2.  Maximum Criteria Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G47: [W6] 47
A:A48: [W22] '          Cogeneration Project
A:G48: [W6] (G47+1)
A:A49: [W22] \_
A:B49: [W16] \_
A:C49: [W16] \_
A:D49: [W16] \_
A:E49: [W16] \_
A:F49: [W16] \_
A:G49: [W6] (G48+1)
A:G50: [W6] (G49+1)
A:A51: [W22] ^Pollutant
A:B51: [W16] "Gas Turbine
A:C51: [W16] "Gas Turbine
A:D51: [W16] "Gas Turbine
A:E51: [W16] "Gas Turbine
A:F51: [W16] "Duct Burner
A:G51: [W6] (G50+1)
A:B52: [W16] "Natural Gas
A:C52: [W16] "Natural Gas
A:D52: [W16] "Natural Gas
A:E52: [W16] "Natural Gas
A:F52: [W16] "Natural Gas
A:G52: [W6] (G51+1)
A:A53: [W22] ^A
A:B53: [W16] "20oF - B
A:C53: [W16] "59oF - C
A:D53: [W16] "72oF - D
A:E53: [W16] "102oF - E
A:F53: [W16] "90oF - F
A:G53: [W6] (G52+1)
A:A54: [W22] \_
A:B54: [W16] \_
A:C54: [W16] \_
A:D54: [W16] \_
A:E54: [W16] \_
A:F54: [W16] \_
A:G54: [W6] (G53+1)
A:G55: [W6] (G54+1)
A:A56: [W22] 'Particulate:
A:G56: [W6] (G55+1)
A:A57: [W22] '  Basis
A:B57: (,1) [W16] "Manufacturer
A:C57: (,1) [W16] "Manufacturer
A:D57: (,1) [W16] "Manufacturer
A:E57: (,1) [W16] "Manufacturer
A:F57: (,1) [W16] "0.01 lb/MMBtu
A:G57: [W6] (G56+1)
A:A58: [W22] '  lb/hr
A:B58: (F2) [W16] 11 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C58: (F2) [W16] 9
A:D58: (F2) [W16] 9
A:E58: (F2) [W16] 9
A:F58: (F2) [W16] ($F$13*0.01)
A:G58: [W6] (G57+1)
A:A59: [W22] '  TPY
A:B59: (F2) [W16] (B58*8760/2000) . . . . . . . . . . . . . . . . . . . .  Emissions * 8,760 hours/year ÷ 2,000 lb/ton
A:C59: (F2) [W16] (C58*8760/2000)
A:D59: (F2) [W16] (D58*8760/2000)
A:E59: (F2) [W16] (E58*8760/2000)
A:F59: (F2) [W16] (F58*3688.5/2000) .  Emissions * 3,688.5 hr/yr (4,500 hrs @ 100x10^6 + 122 x 10^6) ÷ 2,000 lb/ton
A:G59: [W6] (G58+1)
A:G60: [W6] (G59+1)
A:A61: [W22] 'Sulfur Dioxide:
A:G61: [W6] (G60+1)
A:A62: [W22] '  Basis
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A:B62: (,1) [W16] "1 gr/100 cf
A:C62: (,1) [W16] "1 gr/100 cf
A:D62: (,1) [W16] "1 gr/100 cf
A:E62: (,1) [W16] "1 gr/100 cf
A:F62: (,1) [W16] "1 gr/100 cf
A:G62: [W6] (G61+1)
A:A63: [W22] '  lb/hr
A:B63: (F2) [W16] (B15*1/7000*2/100)  . . . . . . . Fuel Used (CF/HR) * Sulfur Content * 2 lb SO2/lb S * 1/100 CF
A:C63: (F2) [W16] (C15*1/7000*2/100)
A:D63: (F2) [W16] (D15*1/7000*2/100)
A:E63: (F2) [W16] (E15*1/7000*2/100)
A:F63: (F2) [W16] (F15*1/7000*2/100)
A:G63: [W6] (G62+1)
A:A64: [W22] '  TPY
A:B64: (F2) [W16] (B63*8760/2000)
A:C64: (F2) [W16] (C63*8760/2000)
A:D64: (F2) [W16] (D63*8760/2000)
A:E64: (F2) [W16] (E63*8760/2000)
A:F64: (F2) [W16] (F63*3688.5/2000)
A:G64: [W6] (G63+1)
A:G65: [W6] (G64+1)
A:A66: [W22] 'Nitrogen Oxides:
A:G66: [W6] (G65+1)
A:A67: [W22] '  Basis
A:B67: (,1) [W16] "25 ppm*
A:C67: (,1) [W16] "25 ppm*
A:D67: (,1) [W16] "25 ppm*
A:E67: (,1) [W16] "25 ppm*
A:F67: (,1) [W16] "0.1 lb/MMBtu
A:G67: [W6] (G66+1)
A:A68: [W22] '  lb/hr
A:B68: (,1) [W16] (B70/5.9*(20.9*(1-B26/100)-B27)*B22*2116.8*46*60/(1545*(460+B25)*1000000))  . . . . See Note B
A:C68: (,1) [W16] (C70/5.9*(20.9*(1-C26/100)-C27)*C22*2116.8*46*60/(1545*(460+C25)*1000000))
A:D68: (,1) [W16] (D70/5.9*(20.9*(1-D26/100)-D27)*D22*2116.8*46*60/(1545*(460+D25)*1000000))
A:E68: (,1) [W16] (E70/5.9*(20.9*(1-E26/100)-E27)*E22*2116.8*46*60/(1545*(460+E25)*1000000))
A:F68: (F2) [W16] ($F$13*0.1) . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:G68: [W6] (G67+1)
A:A69: [W22] '  TPY
A:B69: (F1) [W16] (B68*8760/2000)
A:C69: (F1) [W16] (C68*8760/2000)
A:D69: (F1) [W16] (D68*8760/2000)
A:E69: (F1) [W16] (E68*8760/2000)
A:F69: (F2) [W16] (F68*3688.5/2000)
A:G69: [W6] (G68+1)
A:A70: [W22] '  ppm
A:B70: (,1) [W16] 25  . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From ABB
A:C70: (,1) [W16] 25
A:D70: (,1) [W16] 25
A:E70: (,1) [W16] 25
A:G70: [W6] (G69+1)
A:G71: [W6] (G70+1)
A:A72: [W22] 'Carbon Monoxide:
A:G72: [W6] (G71+1)
A:A73: [W22] '  Basis
A:B73: (,1) [W16] "10 ppm+
A:C73: (,1) [W16] "10 ppm+
A:D73: (,1) [W16] "10 ppm+
A:E73: (,1) [W16] "10 ppm+
A:F73: (,1) [W16] "0.2 lb/MMBtu
A:G73: [W6] (G72+1)
A:A74: [W22] '  lb/hr
A:B74: (,1) [W16] (B76/5.9*(20.9*(1-B26/100)-B27)*B22*2116.8*28*60/(1545*(460+B25)*1000000))  . . . . See Note C
A:C74: (,1) [W16] (C76/5.9*(20.9*(1-C26/100)-C27)*C22*2116.8*28*60/(1545*(460+C25)*1000000))
A:D74: (,1) [W16] (D76/5.9*(20.9*(1-D26/100)-D27)*D22*2116.8*28*60/(1545*(460+D25)*1000000))
A:E74: (,1) [W16] (E76/5.9*(20.9*(1-E26/100)-E27)*E22*2116.8*28*60/(1545*(460+E25)*1000000))
A:F74: (F2) [W16] ($F$13*0.2) . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:G74: [W6] (G73+1)
```

```
A:A75: [W22] '  TPY
A:B75: (F2) [W16] (B74*8760/2000)
A:C75: (F2) [W16] (C74*8760/2000)
A:D75: (F2) [W16] (D74*8760/2000)
A:E75: (F2) [W16] (E74*8760/2000)
A:F75: (F2) [W16] (F74*3688.5/2000)
A:G75: [W6] (G74+1)
A:A76: [W22] '  ppm
A:B76: (,1) [W16] 10
A:C76: (,1) [W16] 10
A:D76: (,1) [W16] 10
A:E76: (,1) [W16] 10
A:G76: [W6] (G75+1)
A:G77: [W6] (G76+1)
A:A78: [W22] 'VOC's:
A:G78: [W6] (G77+1)
A:A79: [W22] '  Basis
A:B79: (,1) [W16] "3 ppm+
A:C79: (,1) [W16] "3 ppm+
A:D79: (,1) [W16] "3 ppm+
A:E79: (,1) [W16] "3 ppm+
A:F79: (,1) [W16] "0.03 lb/MMBtu
A:G79: [W6] (G78+1)
A:A80: [W22] '  lb/hr
A:B80: (F2) [W16] (B82*(1-B26/100)*B22*2116.8*12*60/(1545*(460+B25)*1000000)) . . . . . . . . . . . . See Note C
A:C80: (F2) [W16] (C82*(1-C26/100)*C22*2116.8*12*60/(1545*(460+C25)*1000000))
A:D80: (F2) [W16] (D82*(1-D26/100)*D22*2116.8*12*60/(1545*(460+D25)*1000000))
A:E80: (F2) [W16] (E82*(1-E26/100)*E22*2116.8*12*60/(1545*(460+E25)*1000000))
A:F80: (F2) [W16] ($F$13*0.03)  . . . . . . . . . . . . . . . . . . . . . . . . . . Emission Factor * Heat Input
A:G80: [W6] (G79+1)
A:A81: [W22] '  TPY
A:B81: (,1) [W16] (B80*8760/2000)
A:C81: (,1) [W16] (C80*8760/2000)
A:D81: (,1) [W16] (D80*8760/2000)
A:E81: (,1) [W16] (E80*8760/2000)
A:F81: (F2) [W16] (F80*3688.5/2000)
A:G81: [W6] (G80+1)
A:A82: [W22] '  ppm
A:B82: (,1) [W16] 3
A:C82: (,1) [W16] 3
A:D82: (,1) [W16] 3
A:E82: (,1) [W16] 3
A:G82: [W6] (G81+1)
A:G83: [W6] (G82+1)
A:A84: [W22] 'Lead:
A:G84: [W6] (G83+1)
A:A85: [W22] '  Basis
A:G85: [W6] (G84+1)
A:A86: [W22] '  lb/hr
A:B86: (S2) [W16] "NA
A:C86: (S2) [W16] "NA
A:D86: (S2) [W16] "NA
A:E86: (S2) [W16] "NA
A:F86: (S2) [W16] "NA
A:G86: [W6] (G85+1)
A:A87: [W22] '  TPY
A:B87: (S2) [W16] "NA
A:C87: (S2) [W16] "NA
A:D87: (S2) [W16] "NA
A:E87: (S2) [W16] "NA
A:F87: (S2) [W16] "NA
A:G87: [W6] (G86+1)
A:A88: [W22] \_
A:B88: [W16] \_
A:C88: [W16] \_
A:D88: [W16] \_
A:E88: [W16] \_
```

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A:F88: [W16] \_
A:G88: [W6] (G87+1)
A:G89: [W6] (G88+1)
A:A90: [W22] '* corrected to 15% O2 dry conditions
A:G90: [W6] (G89+1)
A:A91: [W22] '+ corrected to dry conditions
A:G91: [W6] (G90+1)
A:A92: [W22] 'Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr.  Annual emissions for
A:G92: [W6] (G91+1)
A:A93: [W22] '      duct burner based on 450,000 MM Btu/year operation; i.e., 4,500 hours at 100 MM Btu/hr.
A:G93: [W6] (G92+1)
A:A94: [W22] '      Duct burner will only be oprated when ambient temperature is greater than 72oF.
A:G94: [W6] (G93+1)
```

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A:A96: [W22] 'Table A-3.  Maximum Other Regulated Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G96: [W6] 96
A:A97: [W22] '          Cogeneration Project
A:G97: [W6] (G96+1)
A:A98: [W22] \_
A:B98: [W16] \_
A:C98: [W16] \_
A:D98: [W16] \_
A:E98: [W16] \_
A:F98: [W16] \_
A:G98: [W6] (G97+1)
A:G99: [W6] (G98+1)
A:A100: [W22] ^Pollutant
A:B100: [W16] "Gas Turbine
A:C100: [W16] "Gas Turbine
A:D100: [W16] "Gas Turbine
A:E100: [W16] "Gas Turbine
A:F100: [W16] "Duct Burner
A:G100: [W6] (G99+1)
A:B101: [W16] "Natural Gas
A:C101: [W16] "Natural Gas
A:D101: [W16] "Natural Gas
A:E101: [W16] "Natural Gas
A:F101: [W16] "Natural Gas
A:G101: [W6] (G100+1)
A:A102: [W22] ^A
A:B102: [W16] "20oF - B
A:C102: [W16] "59oF - C
A:D102: [W16] "72oF - D
A:E102: [W16] "102oF - E
A:F102: [W16] "90oF - F
A:G102: [W6] (G101+1)
A:A103: [W22] \_
A:B103: [W16] \_
A:C103: [W16] \_
A:D103: [W16] \_
A:E103: [W16] \_
A:F103: [W16] \_
A:G103: [W6] (G102+1)
A:G104: [W6] (G103+1)
A:A105: [W22] '  As (lb/hr)
A:B105: [W16] "NEG.
A:C105: [W16] "NEG.
A:D105: [W16] "NEG.
A:E105: [W16] "NEG.
A:F105: [W16] "NEG.
A:G105: [W6] (G104+1)
A:A106: [W22] '     (TPY)
A:B106: [W16] "NEG.
A:C106: [W16] "NEG.
A:D106: [W16] "NEG.
A:E106: [W16] "NEG.
A:F106: [W16] "NEG.
A:G106: [W6] (G105+1)
A:G107: [W6] (G106+1)
A:A108: [W22] '  Be (lb/hr)
A:B108: [W16] "NEG.
A:C108: [W16] "NEG.
A:D108: [W16] "NEG.
A:E108: [W16] "NEG.
A:F108: [W16] "NEG.
A:G108: [W6] (G107+1)
A:A109: [W22] '     (TPY)
A:B109: [W16] "NEG.
A:C109: [W16] "NEG.
A:D109: [W16] "NEG.
A:E109: [W16] "NEG.
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A:F109: [W16] "NEG.
A:G109: [W6] (G108+1)
A:G110: [W6] (G109+1)
A:A111: [W22] '  Hg (lb/hr)
A:B111: [W16] "NEG.
A:C111: [W16] "NEG.
A:D111: [W16] "NEG.
A:E111: [W16] "NEG.
A:F111: [W16] "NEG.
A:G111: [W6] (G110+1)
A:A112: [W22] '     (TPY)
A:B112: [W16] "NEG.
A:C112: [W16] "NEG.
A:D112: [W16] "NEG.
A:E112: [W16] "NEG.
A:F112: [W16] "NEG.
A:G112: [W6] (G111+1)
A:G113: [W6] (G112+1)
A:A114: [W22] '  F (lb/hr)
A:B114: [W16] "NEG.
A:C114: [W16] "NEG.
A:D114: [W16] "NEG.
A:E114: [W16] "NEG.
A:F114: [W16] "NEG.
A:G114: [W6] (G113+1)
A:A115: [W22] '    (TPY)
A:B115: [W16] "NEG.
A:C115: [W16] "NEG.
A:D115: [W16] "NEG.
A:E115: [W16] "NEG.
A:F115: [W16] "NEG.
A:G115: [W6] (G114+1)
A:G116: [W6] (G115+1)
A:A117: [W22] '  H2SO4 (lb/hr)
A:B117: (S2) [W16] (B63*0.005*3.06/2) . . . . . . . . . . . . . .  SO2 Emission * 0.005 (%H2SO4 Formed) * MWH2SO4/MWSO2
A:C117: (S2) [W16] (C63*0.005*3.06/2)
A:D117: (S2) [W16] (D63*0.005*3.06/2)
A:E117: (S2) [W16] (E63*0.005*3.06/2)
A:F117: (S2) [W16] (F63*0.005*3.06/2)
A:G117: [W6] (G116+1)
A:A118: [W22] '    (TPY)
A:B118: (S2) [W16] (B117*8760/2000)
A:C118: (S2) [W16] (C117*8760/2000)
A:D118: (S2) [W16] (D117*8760/2000)
A:E118: (S2) [W16] (E117*8760/2000)
A:F118: (F2) [W16] (F117*3688.5/2000)
A:G118: [W6] (G117+1)
A:G119: [W6] (G118+1)
A:A120: [W22] \_
A:B120: [W16] \_
A:C120: [W16] \_
A:D120: [W16] \_
A:E120: [W16] \_
A:F120: [W16] \_
A:G120: [W6] (G119+1)
A:G121: [W6] (G120+1)
A:A122: [W22] 'Sources: EPA, 1988; EPA, 1980
A:G122: [W6] (G121+1)
```

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A:A125: [W22] 'Table A-4.  Maximum Non-Regulated Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G125: [W6] 125
A:A126: [W22] '            Cogeneration Project
A:G126: [W6] (G125+1)
A:A127: [W22] \_
A:B127: [W16] \_
A:C127: [W16] \_
A:D127: [W16] \_
A:E127: [W16] \_
A:F127: [W16] \_
A:G127: [W6] (G126+1)
A:G128: [W6] (G127+1)
A:A129: [W22] ^Pollutant
A:B129: [W16] "Gas Turbine
A:C129: [W16] "Gas Turbine
A:D129: [W16] "Gas Turbine
A:E129: [W16] "Gas Turbine
A:F129: [W16] "Duct Burner
A:G129: [W6] (G128+1)
A:B130: [W16] "Natural Gas
A:C130: [W16] "Natural Gas
A:D130: [W16] "Natural Gas
A:E130: [W16] "Natural Gas
A:F130: [W16] "Natural Gas
A:G130: [W6] (G129+1)
A:A131: [W22] ^A
A:B131: [W16] "20oF - B
A:C131: [W16] "59oF - C
A:D131: [W16] "72oF - D
A:E131: [W16] "102oF - E
A:F131: [W16] "90oF - F
A:G131: [W6] (G130+1)
A:A132: [W22] \_
A:B132: [W16] \_
A:C132: [W16] \_
A:D132: [W16] \_
A:E132: [W16] \_
A:F132: [W16] \_
A:G132: [W6] (G131+1)
A:G133: [W6] (G132+1)
A:A134: [W22] '  Manganese (lb/hr)
A:B134: [W16] "NEG.
A:C134: [W16] "NEG.
A:D134: [W16] "NEG.
A:E134: [W16] "NEG.
A:F134: [W16] "NEG.
A:G134: [W6] (G133+1)
A:A135: [W22] '     (TPY)
A:B135: [W16] "NEG.
A:C135: [W16] "NEG.
A:D135: [W16] "NEG.
A:E135: [W16] "NEG.
A:F135: [W16] "NEG.
A:G135: [W6] (G134+1)
A:G136: [W6] (G135+1)
A:A137: [W22] '  Nickel (lb/hr)
A:B137: [W16] "NEG.
A:C137: [W16] "NEG.
A:D137: [W16] "NEG.
A:E137: [W16] "NEG.
A:F137: [W16] "NEG.
A:G137: [W6] (G136+1)
A:A138: [W22] '     (TPY)
A:B138: [W16] "NEG.
A:C138: [W16] "NEG.
A:D138: [W16] "NEG.
A:E138: [W16] "NEG.
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A:F138: [W16] "NEG.
A:G138: [W6] (G137+1)
A:G139: [W6] (G138+1)
A:A140: [W22] '  Cadmium (lb/hr)
A:B140: [W16] "NEG.
A:C140: [W16] "NEG.
A:D140: [W16] "NEG.
A:E140: [W16] "NEG.
A:F140: [W16] "NEG.
A:G140: [W6] (G139+1)
A:A141: [W22] '     (TPY)
A:B141: [W16] "NEG.
A:C141: [W16] "NEG.
A:D141: [W16] "NEG.
A:E141: [W16] "NEG.
A:F141: [W16] "NEG.
A:G141: [W6] (G140+1)
A:G142: [W6] (G141+1)
A:A143: [W22] '  Chromium (lb/hr)
A:B143: [W16] "NEG.
A:C143: [W16] "NEG.
A:D143: [W16] "NEG.
A:E143: [W16] "NEG.
A:F143: [W16] "NEG.
A:G143: [W6] (G142+1)
A:A144: [W22] '    (TPY)
A:B144: [W16] "NEG.
A:C144: [W16] "NEG.
A:D144: [W16] "NEG.
A:E144: [W16] "NEG.
A:F144: [W16] "NEG.
A:G144: [W6] (G143+1)
A:G145: [W6] (G144+1)
A:A146: [W22] '  Copper (lb/hr)
A:B146: [W16] "NEG.
A:C146: [W16] "NEG.
A:D146: [W16] "NEG.
A:E146: [W16] "NEG.
A:F146: [W16] "NEG.
A:G146: [W6] (G145+1)
A:A147: [W22] '    (TPY)
A:B147: [W16] "NEG.
A:C147: [W16] "NEG.
A:D147: [W16] "NEG.
A:E147: [W16] "NEG.
A:F147: [W16] "NEG.
A:G147: [W6] (G146+1)
A:G148: [W6] (G147+1)
A:A149: [W22] '  Vanadium (lb/hr)
A:B149: [W16] "NEG.
A:C149: [W16] "NEG.
A:D149: [W16] "NEG.
A:E149: [W16] "NEG.
A:F149: [W16] "NEG.
A:G149: [W6] (G148+1)
A:A150: [W22] '     (TPY)
A:B150: [W16] "NEG.
A:C150: [W16] "NEG.
A:D150: [W16] "NEG.
A:E150: [W16] "NEG.
A:F150: [W16] "NEG.
A:G150: [W6] (G149+1)
A:G151: [W6] (G150+1)
A:A152: [W22] '  Selenium (lb/hr)
A:B152: [W16] "NEG.
A:C152: [W16] "NEG.
A:D152: [W16] "NEG.
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A:E152: [W16] "NEG.
A:F152: [W16] "NEG.
A:G152: [W6] (G151+1)
A:A153: [W22] '    (TPY)
A:B153: [W16] "NEG.
A:C153: [W16] "NEG.
A:D153: [W16] "NEG.
A:E153: [W16] "NEG.
A:F153: [W16] "NEG.
A:G153: [W6] (G152+1)
A:G154: [W6] (G153+1)
A:A155: [W22] ' POM (lb/hr)
A:B155: (S2) [W16] (B13*0.48*2.324/1000000) . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-161
A:C155: (S2) [W16] (C13*0.48*2.324/1000000)
A:D155: (S2) [W16] (D13*0.48*2.324/1000000)
A:E155: (S2) [W16] (E13*0.48*2.324/1000000)
A:F155: (S2) [W16] (F13*0.48*2.324/1000000)
A:G155: [W6] (G154+1)
A:A156: [W22] '    (TPY)
A:B156: (S2) [W16] (B155*8760/2000)
A:C156: (S2) [W16] (C155*8760/2000)
A:D156: (S2) [W16] (D155*8760/2000)
A:E156: (S2) [W16] (E155*8760/2000)
A:F156: (S2) [W16] (F155*3688.5/2000)
A:G156: [W6] (G155+1)
A:G157: [W6] (G156+1)
A:A158: [W22] ' Formaldehyde (lb/hr)
A:B158: (S2) [W16] (B13*38*2.324/1000000) . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-156
A:C158: (S2) [W16] (C13*38*2.324/1000000)
A:D158: (S2) [W16] (D13*38*2.324/1000000)
A:E158: (S2) [W16] (E13*38*2.324/1000000)
A:F158: (S2) [W16] (F13*38*2.324/1000000)
A:G158: [W6] (G157+1)
A:A159: [W22] '    (TPY)
A:B159: (S2) [W16] (B158*8760/2000)
A:C159: (S2) [W16] (C158*8760/2000)
A:D159: (S2) [W16] (D158*8760/2000)
A:E159: (S2) [W16] (E158*8760/2000)
A:F159: (S2) [W16] (F158*3688.5/2000)
A:G159: [W6] (G158+1)
A:A160: [W22] \_
A:B160: [W16] \_
A:C160: [W16] \_
A:D160: [W16] \_
A:E160: [W16] \_
A:F160: [W16] \_
A:G160: [W6] (G159+1)
A:G161: [W6] (G160+1)
A:G162: [W6] (G161+1)
A:G165: [W6] 165
A:G166: [W6] (G165+1)
A:G167: [W6] (G166+1)
A:G168: [W6] (G167+1)
A:G169: [W6] (G168+1)
A:G170: [W6] (G169+1)
A:G171: [W6] (G170+1)
A:G172: [W6] (G171+1)
A:G173: [W6] (G172+1)
A:G174: [W6] (G173+1)
A:G175: [W6] (G174+1)
A:G176: [W6] (G175+1)
A:G177: [W6] (G176+1)
A:G178: [W6] (G177+1)
A:G179: [W6] (G178+1)
A:G180: [W6] (G179+1)
A:G181: [W6] (G180+1)
A:G182: [W6] (G181+1)
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A:G183: [W6] (G182+1)
A:G184: [W6] (G183+1)
A:G185: [W6] (G184+1)
A:G186: [W6] (G185+1)
A:G187: [W6] (G186+1)
A:G188: [W6] (G187+1)
A:G189: [W6] (G188+1)
A:G190: [W6] (G189+1)
A:G191: [W6] (G190+1)
```

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PSD	FL	-	184

Period during which document was received:		Detailed Description
APPLICATION 30 DEC 1991	1.	24"×28.5" BLUEPRINT: PLOT PLAN OF THE ORLANDO COGEN LIMITED PROJECT
POST PERMIT 22 DEC 1992	2.	24"×32.5" BLUEPRINT: PROCESS FLOW DIAGRAM AIR, FUEL, FLUE GAS, CONDENSATE, FEED WATER AND STEAM (DRAWING NUMBER 03-1-8011-55.10A, REV. 2)

BEST AVAILABLE COPY

Check Sheet

Company Name: Orlando Cogen Limited Partnership
Permit Number: AC 48-206720
PSD Number: PSD FL-184
Permit Engineer:

Cross References:
☐
☐
☐

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
- ☐ Other

Revision #5

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:

Tom Hess Energy Syst.
Air Products + Chemicals
7201 Hamilton Blvd
Allentown, PA 18195-1501

4a. Article Number
Z 392 979 008

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

7. Date of Delivery
7-7-95

5. Signature (Addressee)
Tony Hetrick

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: 1993—352-714 ``'N RECEIPT

Z 392 979 008

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

UNITED STATES POSTAL SERVICE

Sent to	Tom Hess
Street and No.	Air Products + Chem
P.O., State and ZIP Code	Allentown PA
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	Orlando Cogen AC48-206720 6-28-95

PS Form **3800**, March 1993

Z 392 940 715

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

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

PS Form **3800**, March 1993

Sent to Mr. John P. Jones	
Street and No. 7201 Hamilton Boulevard	
P.O., State and ZIP Code Allentown, PA 18195-1501	
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: 2/9/95 AC 48-206720(A)/PSD-FL-184(A)	

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. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

4a. Article Number
Z 392 940 715

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

5. Signature (Addressee)

6. Signature (Agent)

7. Date of Delivery
FEB 13 1995

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.

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.
KBN Engineering & Applied
Sciences, Inc.
1034 N.W. 57th Street
Gainesville, Florida 32605

4a. Article Number
Z 392 940 716

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

7. Date of Delivery
2-13-95

5. Signature (Addressee)
O.M. Reinert

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.

Z 392 940 716

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

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

PS Form 3800, March 1993

Sent to
Mr. Kennard F. Kosky, P.E

Street and No.
1034 N.W. 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: 2/9/95
AC 48-206720/PSD-FL-184

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, P.E.
KBN Engineering & Applied
Sciences, Inc.
6241 NW 23rd St.
Gainesville, Fl 32605

4a. Article Number
P872 562 682

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

7. Date of Delivery
11 16 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 872 562 682

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

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

Sent to Ken Kosky	
Street and No. KBN Engineering	
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 11-14-94 Amend. of Const. Pmt. AC48-206720 - PSD-Fl-184	

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. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

4a. Article Number
P 872 562 698

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

7. Date of Delivery
SEP 19 1994

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 872 562 698

UNITED STATES POSTAL SERVICE

Receipt for Certified Mail

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

Sent to
Mr. John P. Jones

Street and No.
7201 Hamilton Boulevard

P.O., State and ZIP Code
Allentown, PA 18195-1501

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: 9/14/94
AC48-206720, PSD-FL-184

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

[redacted]/630
Branch 311

005788

013479

26 August 19 94

PAY ************50*** **DOLLARS AND** 00 **CENTS** **$** *******50.00

TO THE ORDER OF

Florida Department of Environmental Protection
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

PLEASE DETACH AND RETAIN FOR YOUR RECORDS

INVOICE NUMBER	DATE		VOUCHER NO.	AMOUNT
	08/26/94	Air Permit extension		50.00

RECEIVED
SEP 01 1994
BAR ASBESTOS

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. John P. Hones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentow, PA 1819501501

4a. Article Number
P 872 563 651

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

7. Date of Delivery
8-23-94

5. Signature (Addressee)

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 872 563 651

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

UNITED STATES POSTAL SERVICE

Sent to Mr. John P. Homes, Orlando CoGen Ltd.	
Street and No. 7201 Hamilton Blvd.	
P.O., State and ZIP Code Allentow, PA 18195-1501	
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
Permit: AC48-206720
PSD-FL-184
Mailed: 8-16-94

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. Kennard F. Kosdy, P.E.
KBN Engineering & Applied Sciences,
1034 NW 57th Street
Gainesville, FL 32605

4a. Article Number
P 872 563 641

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

7. Date of Delivery
7 1 4

5. Signature (Addressee)
CM Reinert

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 872 563 641

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, KBN	
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: 7-12-94 Permit: AC48-206720 PSD-FL-184	

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.

RECEIVED
JUL 05 1994
Bureau of Air Regulation

3. Article Addressed to:

Mr. John P. Jones
President
Orlando CoGen (I), Inc.
Orlando CoGen Limited, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

4a. Article Number
P 872 562 714

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

7. Date of Delivery

5. Signature (Addressee)

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 872 562 714

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

UNITED STATES POSTAL SERVICE

Sent to Mr. John P. Jones	
Street and No. 7201 Hamilton Boulevard	
P.O., State and ZIP Code Allentown, PA 18195-1501	
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: 6/29/94 AC 48-206720	

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.

RECEIVED
JUN 23 1[illegible]
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.
KBN Engineering & Applied
Sciences, Inc.
1034 N.W. 57th Street
Gainesville, Florida 32605

4a. Article Number
P 872 562 720

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

7. Date of Delivery 6-22

Mary Reinert

5. Signature (Addressee)

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 872 562 720

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 N.W. 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: 6/20/94
AC 48-206720; PSD-FL-184

PS Form **3800**, JUNE 1991

Sincerely,

Charles M Collins

Charles M. Collins
PE Administrator,
Air Resources Management

5-9-94
Date

CMC/lbl

Copies furnished to:

Kennard F. Kosky ✓
Clair Fancy

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Fancy, Clair H. - Chief
2. ARM BAR TL
3. MAGNO 127
4.

RECEIVED
MAY 13 1994
Bureau of
Air Regulation

FROM: Theresa

DATE 5/12

PHONE

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

4a. Article Number
P 872 562 673

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

7. Date of Delivery
3-07-94

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 872 562 673

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

UNITED STATES POSTAL SERVICE

Sent to Ms. Jewell A. Harper	
Street and No. 345 Courtland Street, NE	
P.O., State and ZIP Code Atlanta, Georgia 30365	
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: 3/2/94 AC48-206720	

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

4a. Article Number
P 872 562 586

4b. Service Type

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

7. Date of Delivery
1-31-94

5. Signature (Addressee)
OM. Reinert

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 872 562 586

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 N.W. 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: 1/27/94
AC48-206720; PSD-FL-184

PS Form 3800, JUNE 1991

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

RECEIVED
SEP 21 1993
Division of Air
Resources Management

DEPARTMENT OF
ENVIRONMENTAL PROTECTION
SEP 20 1993
OFFICE OF THE SECRETARY

SEP 17 1993

4APT-AE

Mr. Clair H. Fancy, Chief
Air Resources Management Division
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Fl 32399-2400

RE: Orlando CoGen Limited, L.P. (OCL)
Stationary Gas Turbines, AC 48-206720, PSD-FL-184
Customized Fuel Monitoring Schedule

Dear Mr. Fancy:

This letter is in response to OCL's July 26, 1993, request for approval of a customized fuel monitoring schedule for the above referenced project. This request was sent to the Environmental Protection Agency (EPA), and a copy was forwarded to you. Since the authority for approving alternatives to the monitoring requirements in § 60.334(b) of 40 CFR Part 60, Subpart GG, was not delegated to the State of Florida, we have reviewed OCL's custom fuel monitoring schedule. Based on our review, we have determined that it is acceptable because it conforms to custom fuel monitoring guidance (a copy of this guidance memo is enclosed) issued by EPA Headquarters in 1987. Therefore, you may modify OCL's permit accordingly. Please note that the approved reference methods are cited in 40 CFR §60.335(d), and not in 40 CFR §60.335(b)(2) as referenced in OCL's July 26, 1993, letter.

If you have any questions regarding the determination provided in 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, and Toxics
Management Division

Enclosure

cc: Mr. Tom Hess, Orlando CoGen Limited, L.P.

10/13

John Brown —

~~For File~~'s let Harley know

Clar

I presume we have to submit to them on a case-by case basis.

Preston

(1) Region III can approve customized fuel mon.

(2) Make sure that Eng for ~~[illegible]~~ OCL knows about this.

(3) Make cy for Mike H. JB

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. John P. Jones, President
Orlando CoGen (I), Inc.
7201 Hamilton Blvd.
Allentown, PA 18195-1501

4a. Article Number
P 062 921 987

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

7. Date of Delivery
AUG 20 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, November 1990 ☆U.S. GPO: 1991—287-066 **DOMESTIC RETURN RECEIPT**

P 062 921 987

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

UNITED STATES POSTAL SERVICE

Sent to Mr. John P. Jones, Orlando CoGen Limited	
Street and No. 7201 Hamilton Blvd.	
P.O., State and ZIP Code Allentow, PA 18195-1501	
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: 8-17-92
Permit: AC 48-206720
PSD-FL-184

PS Form **3800**, June 1991

The Orlando Sentinel

Published Daily

$219.19

State of Florida } S.S.
COUNTY OF ORANGE

Before the undersigned authority personally appeared ______________________________, who on oath says that he/she is the Legal Advertising Representative of The Orlando Sentinel, a daily newspaper published at ORLANDO in ORANGE County, Florida; that the attached copy of advertisement, being a NOTICE OF INTENIST in the matter of AC 48-206720 in the ORANGE Court, was published in said newspaper in the issue; of 06/12/92

Affiant further says that the said Orlando Sentinel is a newspaper published at ORLANDO, in said ORANGE County, Florida, and that the said newspaper has heretofore been continuously published in said ORANGE County, Florida, each Week Day and has been entered as second-class mail matter at the post office in ORLANDO in said ORANGE County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he/she 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 the said newspaper.

Juanita Rosado

The foregoing instrument was acknowledged before me this 12th day of June, 1992, by JUANITA ROSADO, who is personally known to me and who did take an oath.

Noemi R. Lucero

NOEMI R. LUCERO

(SEAL)

Noemi R. Lucero
Notary Public, State of Florida
My commission expires August 28, 1994
Commission # CC042971

NOTICE OF INTENT STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION NOTICE OF INTENT TO ISSUE PERMIT
AC 48-206720
PSD-FL-184

The Department of Environmental Regulation gives notice of its intent to issue a permit to Orlando Cogen Limited, L.P., 7201 Hamilton Boulevard, Allentown, PA 18195-1501, to construct a 129 MW cogeneration facility consisting of one combined cycle gas turbine generators and associated steam cycle; also, steam will be supplied to the Air Products and Chemical Plant located adjacent to the proposed site. The proposed facility will be located in the Orlando Central Park, Orange County, Florida. A determination of Best Available Control Technology (BACT) was required. The Class I PM10 PSD increment consumed is 0.02 vs. 8 allowable 24-hour average and 0.001 vs. 4 allowable annual average, in micrograms per cubic meter. The Class I nitrogen dioxide increment consumed is 0.01 vs. 2.5 allowable annual average, in micrograms per cubic meter. The maximum predicted increases in ambient concentrations for the above three pollutants for all averaging times are less than significant in the Class II area surrounding the plant, thus no increment consumption was calculated. 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 (F.S.). 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, F.S.

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 petitoner 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, FL 32399-2400

Department of Environmental Regulation
Central District
3319 Maguire Blvd., Suite 232
Orlando, FL 32803-3767

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.

COR6B61004 Jun.12,1992

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. John P. Jones, President
Orlando Cogen (I), Inc.
7201 Hamilton Boulevard
Allentow, PA 18195-1501

4a. Article Number
P 710 058 541

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

7. Date of Delivery
JUN 11 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

P 710 058 541

Certified Mail Receipt

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

UNITED STATES POSTAL SERVICE

Sent to
Mr. John P. Jones, Orlando Cogen Limited

Street & No.
7201 Hamilton Blvd.

P.O., State & ZIP Code
Allentow, PA 18195-1501

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: 6-8-92
Permit: ACD48-206720
PSD-FL-184

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. John P. Jones, President
Orlando CoGen Inc.
7201 Hamilton Blvd.
Allentown, PA 18195-1501

4a. Article Number
P 617 884 161

4b. Service Type

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

7. Date of Delivery
4-6-92

5. Signature (Addressee)
Tony Hetrick

6. Signature (Agent)

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

PS Form **3811**, November 1990 ☆U.S. GPO: 1991—287-068 **DOMESTIC RETURN RECEIPT**

P 617 884 161

UNITED STATES POSTAL SERVICE

Certified Mail Receipt

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

Sent to
Mr. John P. Jones, Orlando CoGen Inc.

Street & No.
7201 Hamilton Blvd.

P.O., State & ZIP Code
Allentown, PA 18195-1501

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: 3-31-92
Permit: AC 48-206720
PSD-FL-184

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.
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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. John P. Jones, President
Orlando CoGen Inc.
7201 Hamilton Boulevard
Allentow, Pennsylvania 18195-1501

4a. Article Number
P 832 538 770

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

7. Date of Delivery
2-4-92

5. Signature (Addressee)
Tony Hetrick

6. Signature (Agent)

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

PS Form **3811**, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

P 832 538 770

Certified Mail Receipt

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

UNITED STATES POSTAL SERVICE

Sent to Mr. John P. Jones, Orlando CoGen Inc.	
Street & No. 7201 Hamilton Blvd.	
P.O., State & ZIP Code Allentow, PA 18195-1501	
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: 1-28-92 Permit: AC 48-206720 PSD-FL-184	

PS Form **3800**, June 1990

To Bruce Mitchell

Date 1/28/92 Time 10:44

WHILE YOU WERE OUT

M Bud Rolofson

of Nat'l Park Service

Phone
Area Code Number Extension

☒	TELEPHONED	☐	PLEASE CALL
☐	CALLED TO SEE YOU	☐	WILL CALL AGAIN
☐	WANTS TO SEE YOU	☐	URGENT
	☐	RETURNED YOUR CALL	

Message Have no comments
to Ord, Co-Dem
Complet

MS
Operator