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

C. H. 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

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 122×10^6 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 "<u>Products of Incomplete Combustion</u>", 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": <u>NOx Control</u>, 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": <u>CO Control</u>, 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.

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
J. [illegible], CFD
[illegible], EPA
[illegible], NPS
[illegible]/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).

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

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 Ind 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

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.

PERMITTEE:
Orlando CoGen Limited, L.P.

Permit Number: AC 48-206720
PSD-FL-184
Expiration Date: August 31, 1994

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)).

PERMITTEE:
Orlando CoGen Limited, L.P.

Permit Number: AC 48-206720
PSD-FL-184
Expiration Date: August 31, 1994

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

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:

- Combustion Products (e.g., particulates). Controlled generally by efficient 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 0.01 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:

Pollutant	Emission Standards/Limitations 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:	Approved by:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Carol M. Browner, Secretary Dept. of Environmental Regulation
August 14 1992 Date	August 17 1992 Date

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

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

CH Fancy

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.

Kim Irby — Clerk

6-8-92 — 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.

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

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

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

Department of Environmental Regulation
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

2-02-002-03 : Turbine : Cogen
Natural Gas

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	$\leq$ 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. 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:

- o An analysis of existing air quality;
- o A PSD increment analysis (for PM, PM10, and NOx);
- o An ambient Air Quality Standards analysis (AAQS);
- o An analysis of impacts on soils, vegetation, visibility and growth-related air quality impacts; and
- o 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.

#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.

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:

$$NOx = (NOx_{obs}) \left[\frac{(P_{ref})}{P_{obs}}\right]^{0.5} e^{19 (H_{obs} - 0.00633)} \left[\frac{(288°K)}{T_{AMB}}\right]^{1.53}$$

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.

PERMITTEE:
Orlando Cogen Limited, L.P.

Permit Number: AC 48-206720
PSD-FL-184
Expiration Date: June 30, 1994

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: Approved by:

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

Carol M. Browner, Secretary
Dept. of Environmental Regulation

_______________ 1992
Date

_______________ 1992
Date

Orlando CoGen Limited, L.P.

7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

19 October 1992

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

Bruce RAV 10-27-92
FYI & file
Patty

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., construction has begun for the subject project. Foundation work began on 9/25/92 and the following schedule of major milestones is anticipated:

11/30/92	erect boiler
12/15/92	install gas turbine
9/1/93	first gas firing

As the schedule unfolds we will keep the Department informed of the project's progress in a timely manner. 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

RECEIVED
OCT 26 1992
Division of Air
Resources Management

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
A. Collins, C Dist.
D. Nestel, OCEPD
K. Kosky, KBN
CHF/PL

90115B1
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	Allowable Emission Limits tons/year/facility
NO_x	CT	NG	BACT: ~~25~~ 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.

Post-It™ brand fax transmittal memo 7671 | # of pages ▸ 1

To Peter Cunningham	From Ken Kosky
Co. HBG&S	Co. KBN
Dept. 90115	Phone #
Fax # [illegible]	Fax #

May 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

RECEIVED
MAY 27 1992
Bureau of
Air Regulation

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.

68.9
57.4
11.5
×4.38 = 50.4707

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.

2-27-92 submittal

154
50.4
204.4707 ÷ 1,903,000 = $9310/ton   1,903,000 ÷ 249 = 7642.6 Table 4-7   @65% removal = 260.6 = 7302.4
Footnotes for Table 4-6 b.
Annualize Cost for SCR
100.8
305.2
6235.3

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

KBN

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

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)

Table 2-1. Stack, Operating, and Emission Data for the Proposed Cogeneration Facility

Parameter	Maximum Emissions CT Only[a]	CT/Duct Burner CT[b]	CT/Duct Burner 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

Pollutants	Project With SCR Primary	Secondary[a]	Total	Project Without SCR 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).

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

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

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

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,

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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)

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)	$1.04x10^{-3}$	$9.56x10^{-4}$	$9.25x10^{-4}$	$8.59x10^{-4}$	$1.36x10^{-4}$
(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)	$3.61x10^{-1}$	$3.31x10^{-1}$	$3.21x10^{-1}$	$2.98x10^{-1}$	$1.99x10^{-2}$

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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
```

```
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:888: [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.
```

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) . . . . SO_2 Emission * 0.05 (% H_2SO_4 Formed) * MW_{H2SO4}/MW_{SO2}
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:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

NOTE C

Same as D except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$m_{CO} = PV_{CO\ Act}M_{CO}\ /\ RT$$
$$= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO}\ /\ RT$$

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)

$87{,}360.0 \times 10{,}690.9/10^6 = 933.9 \times 10^6$ Btu/hr

ROW 14--Natural Gas (lb/hr):

Heat Input (10^6 Btu/hr) $\div$ Fuel Heat Content (Btu/lb)

$933.9 \times 10^6 \div 20{,}877 = 44{,}732.4$ 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) $\div$ Heat content (Btu/cf)

$933.9 \times 10^6 \div 946 = 987{,}186.5$ 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) $\div$ (28 x 2,116.8 lb/ft^2) $\div$ 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

Table A-2:

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 $\div$ 2,000 lb/ton

= 2.25 ton/year

ROW 63--SO_2 Emissions (lb/hr):

987,186.5 cf/hr x 1 gr $\div$ 7,000 gr/lb x 2 lb SO_2/lb S $\div$ 100 cf

= 2.82 lb/hr

ROW 68--NO_x Emissions (lb/hr) - See Note B:

25 ppm x [20.9 $\div$ 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 $\div$ [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 $\div$ (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

Pollutants	Project With SCR Primary	Project With SCR Secondary[a]	Project With SCR Total	Project Without SCR 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:

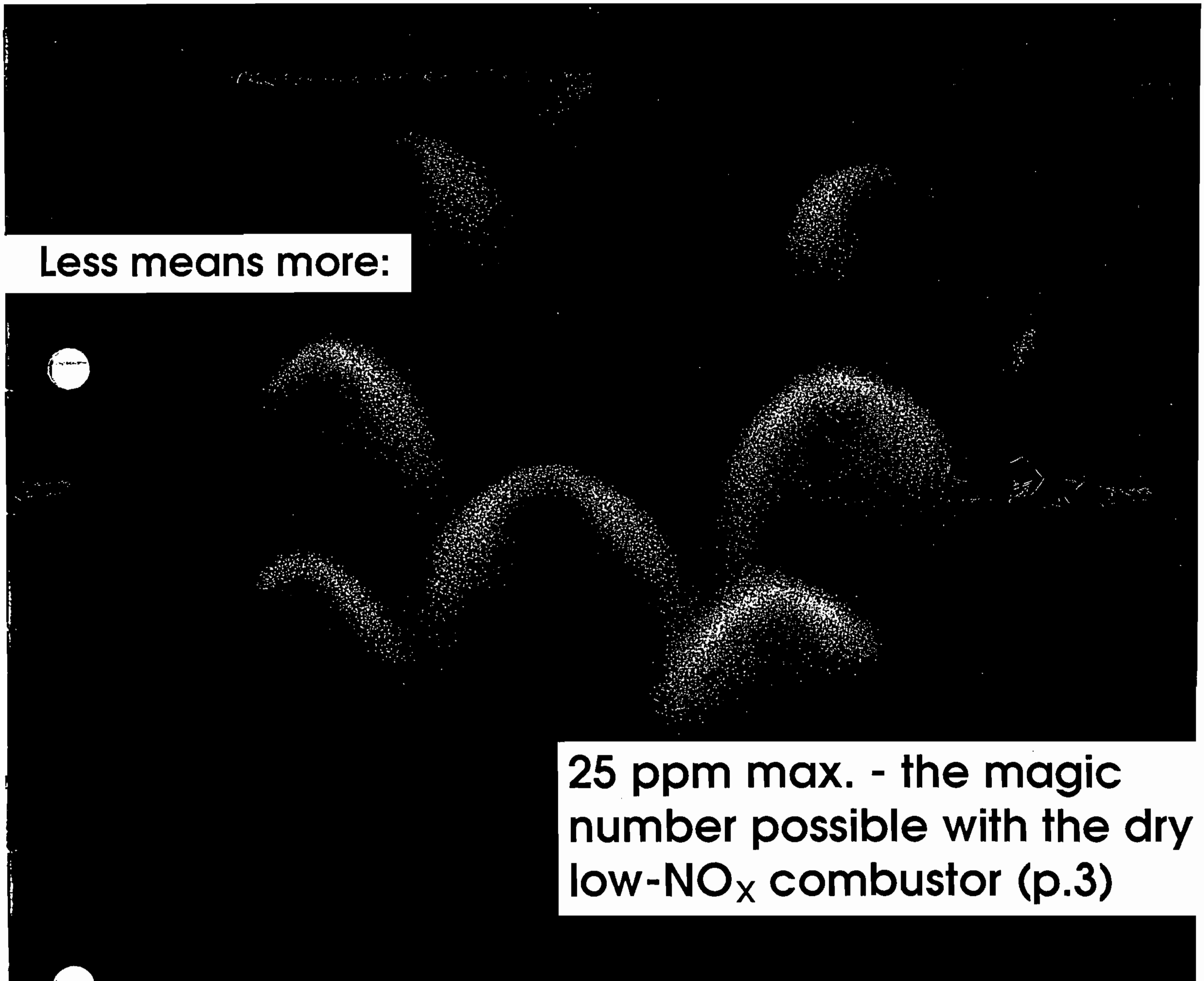
- Successful ignition and light-off
- Successful achievement of Dry Low NO_x of less than 25 ppmvd at full load
- Demonstrated achievement of part load low NO_x levels
- Demonstrated reliability
- Completion of work to schedule

ABB will be releasing additional information regarding this unit as it becomes available in the coming weeks.

POWER NEWS

Publisher: ABB Asea Brown Boveri AG, Power Plants Business Segment **Editor:** Dr. Jutta Thellmann **Addresses:** Asea Brown Boveri AG, Dept. KWM, CH-5401 Baden/Switzerland; Asea Brown Boveri AG, Dept. KW/DC, D-6800 Mannheim/West Germany; ABB Atom, S-72104 Västerås/Sweden; ABB Stal, S-61220 Finspong/Sweden; ABB Generation, S-72176 Västerås/Sweden; EB Power Generation, N-3002 Drammen/Norway

Publication No. CH-KW 2040 90 E



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)

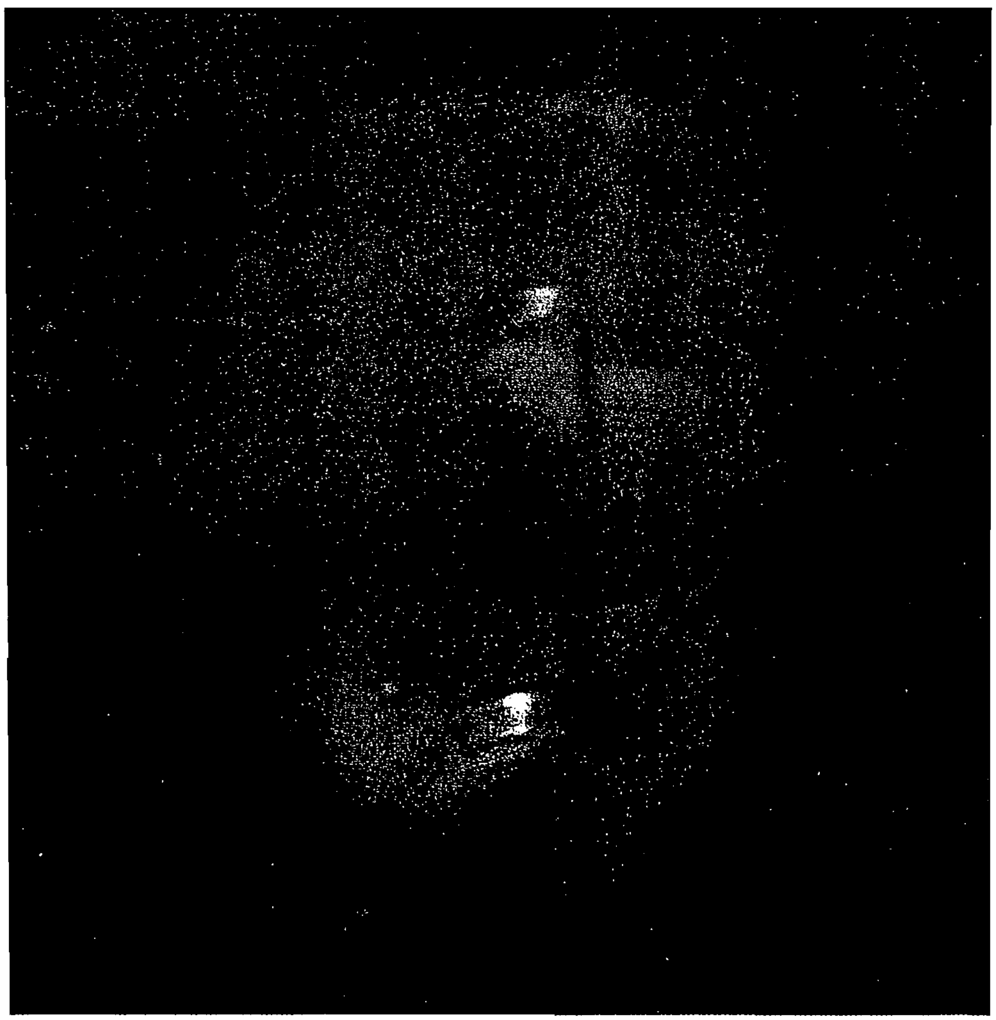
ABB

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.



The blue flame shows that less NOx is being produced at the lower flame temperature.

Stoichiometry as an interference factor

With conventional gas turbine burners, the fuel is injected directly into the flame. The fuel air 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 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

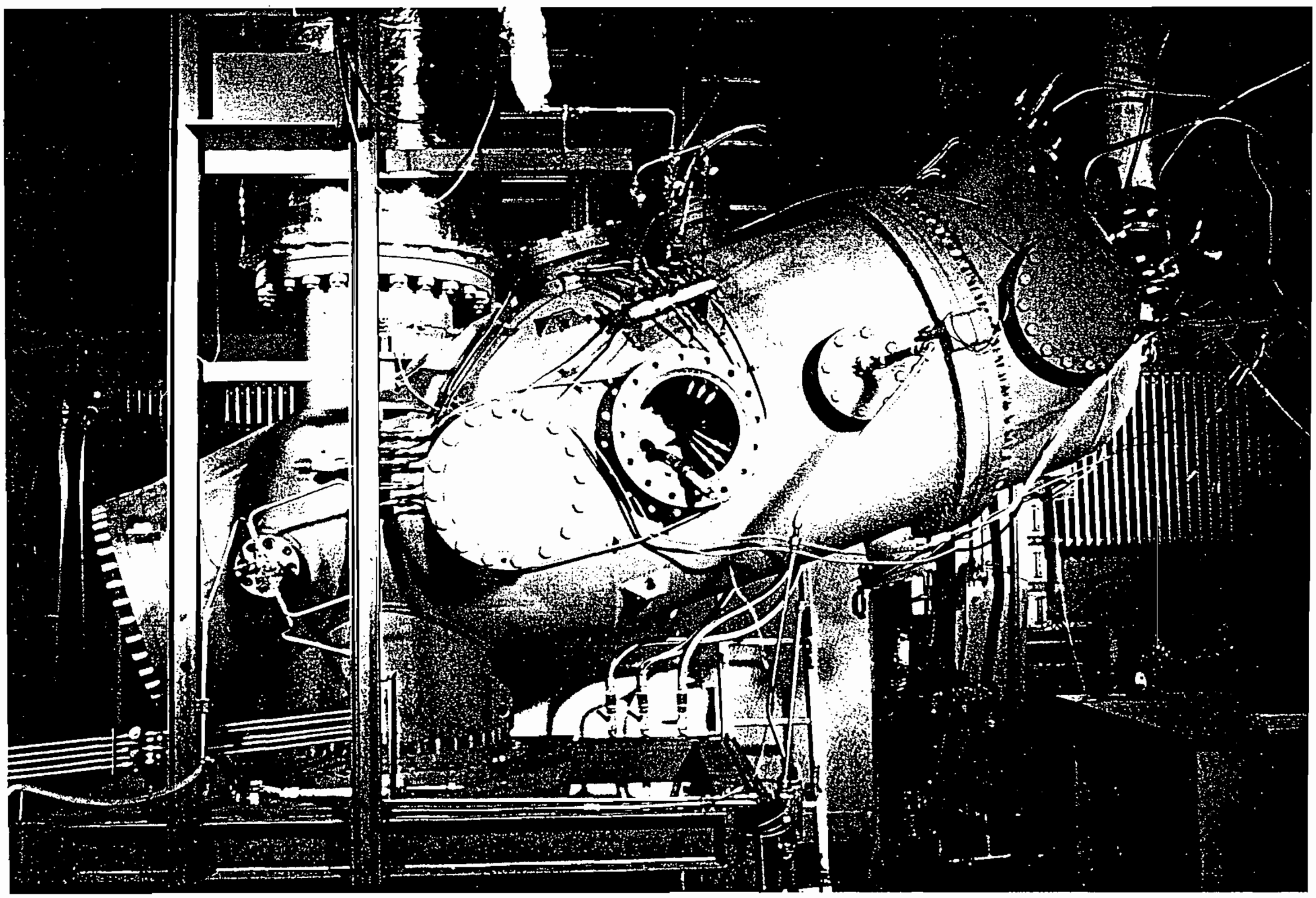
In the second concept a number of small burners are arranged in a circle. This arrangement resulted in a drastic reduction in the size of the combustor. The first such combustor was installed in a GT 8 in 1987 and is still operating today.

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.

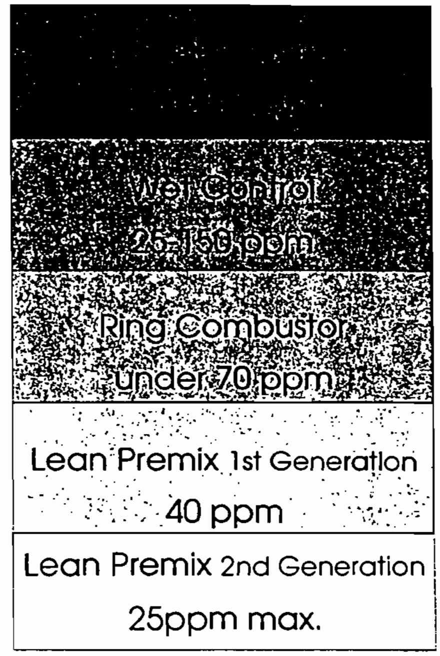
2. The premix flames are no longer stabilized by central diffusion flames, but by adjacent burners of the same type, however operated in another premix mode.

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.

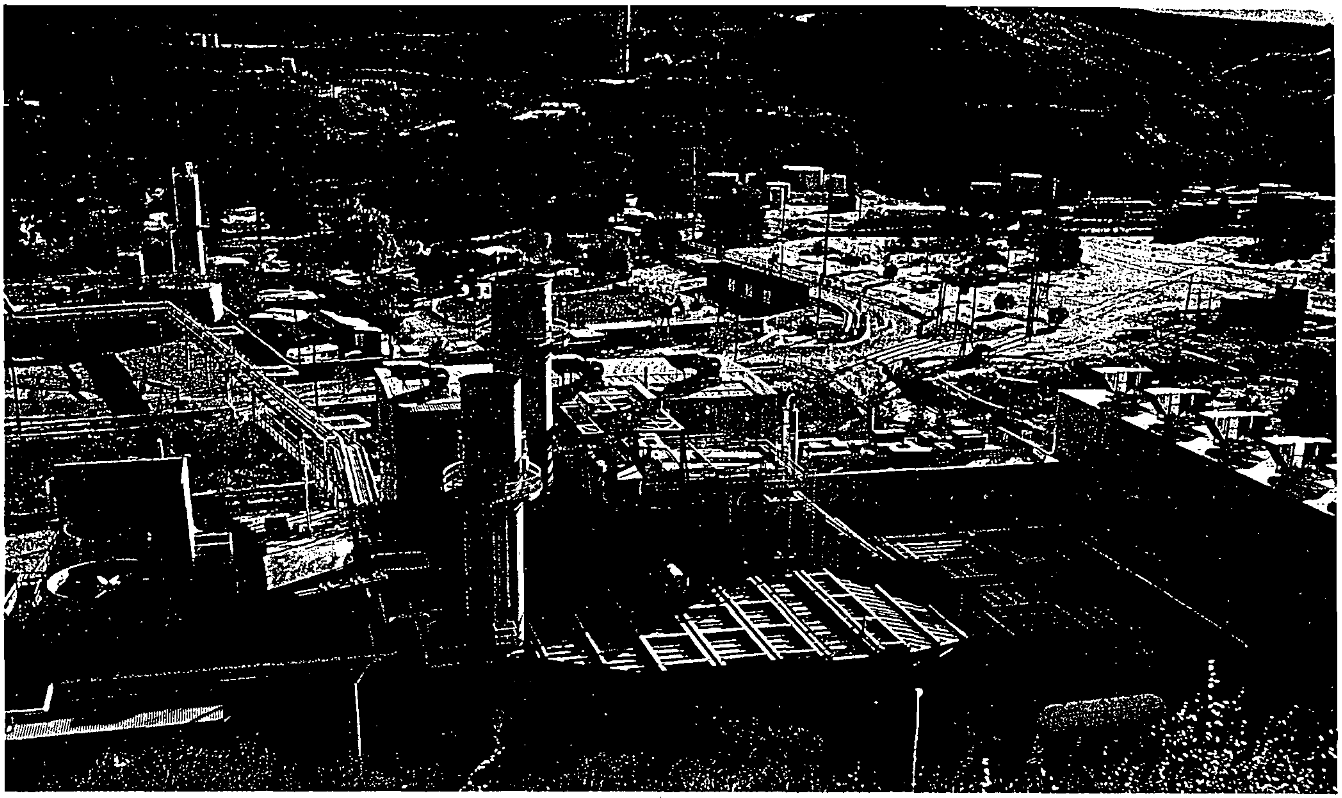
The swirling flames, which are at different temperatures, mix thoroughly and uniformly. The result is a low-NOx, dynamically stabilized flame.

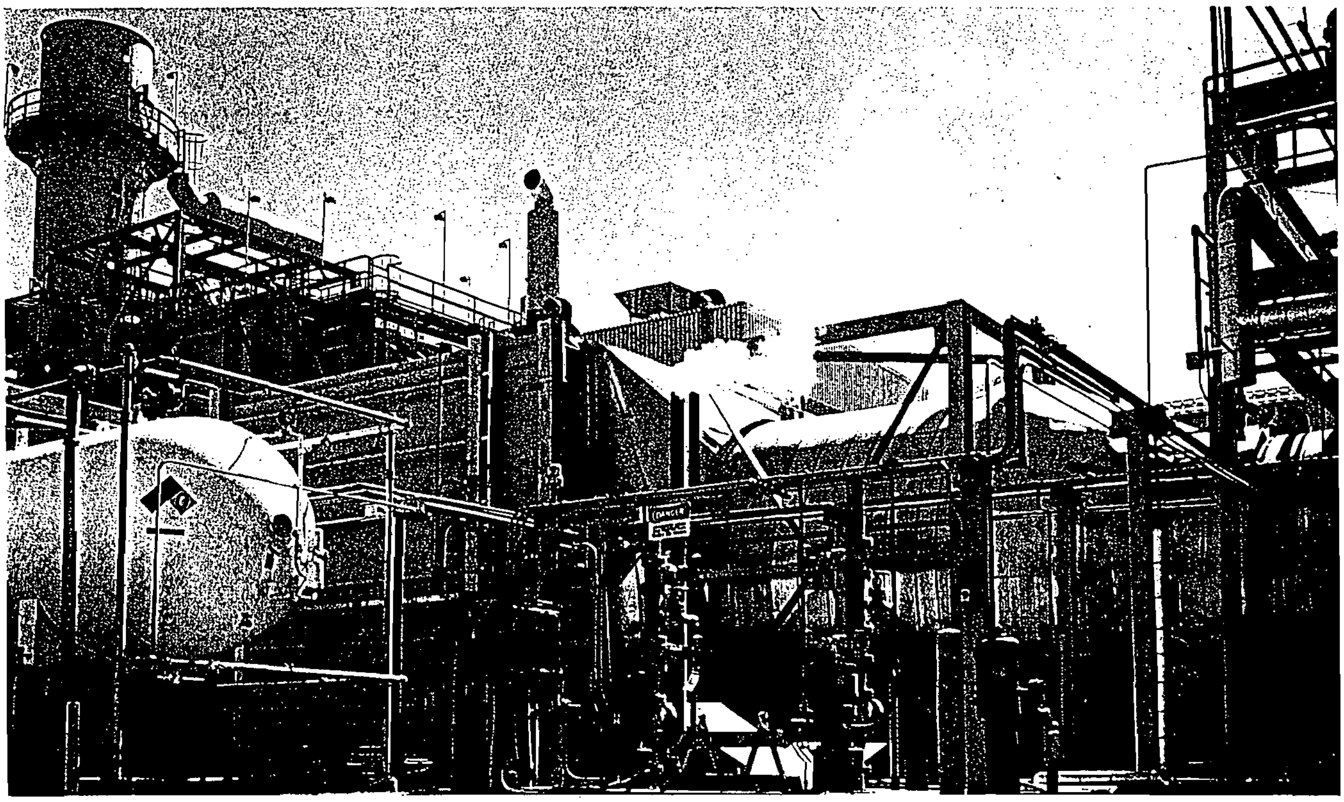
This idea, which was derived from basic studies carried out by Dr. J.J. Keller at the ABB Research Centre in Dättwil, enables the goal of 25 ppm max. to be achieved.

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.



Annular combustor
Detail of a ring combustor. The burner matrix can be seen on the left.





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

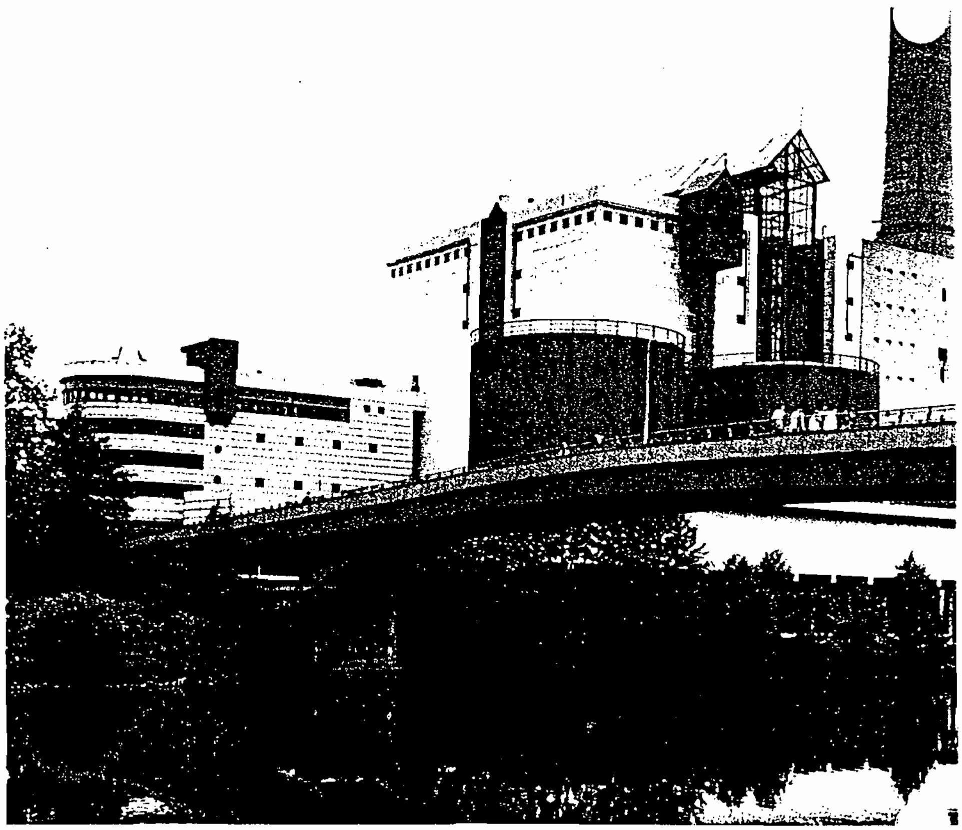
Since the end of October two power plants built by ABB have been singled out to receive a prestigious award from the American trade journal "Power".

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.



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

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

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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 to form two inlet slots. The resulting vortex flow developed inside the cone mixes the gaseous fuel with the air entering from the slots in the side of the burner. This lean mixture then leaves the cone creating a vortex breakdown which forms a stable flame zone. No diffusion or pilot stage is needed, therefore, the flame is stable and there is no risk of flashback. The simplicity of this design accounts for the EV-burner's exceptional reliability.

The burner system can be switched on or off in a matter of seconds to accommodate load changes. Unlike other designs, the temperature distribution is uniform throughout, guaranteeing the combustor thermal efficiency.

A patent for ABB's Dry Low NO_X system was granted in the United States in 1985.

ABB believes the EV-burner has the near term potential to achieve even lower emission levels without recourse to selective catalytic reduction (SCR).

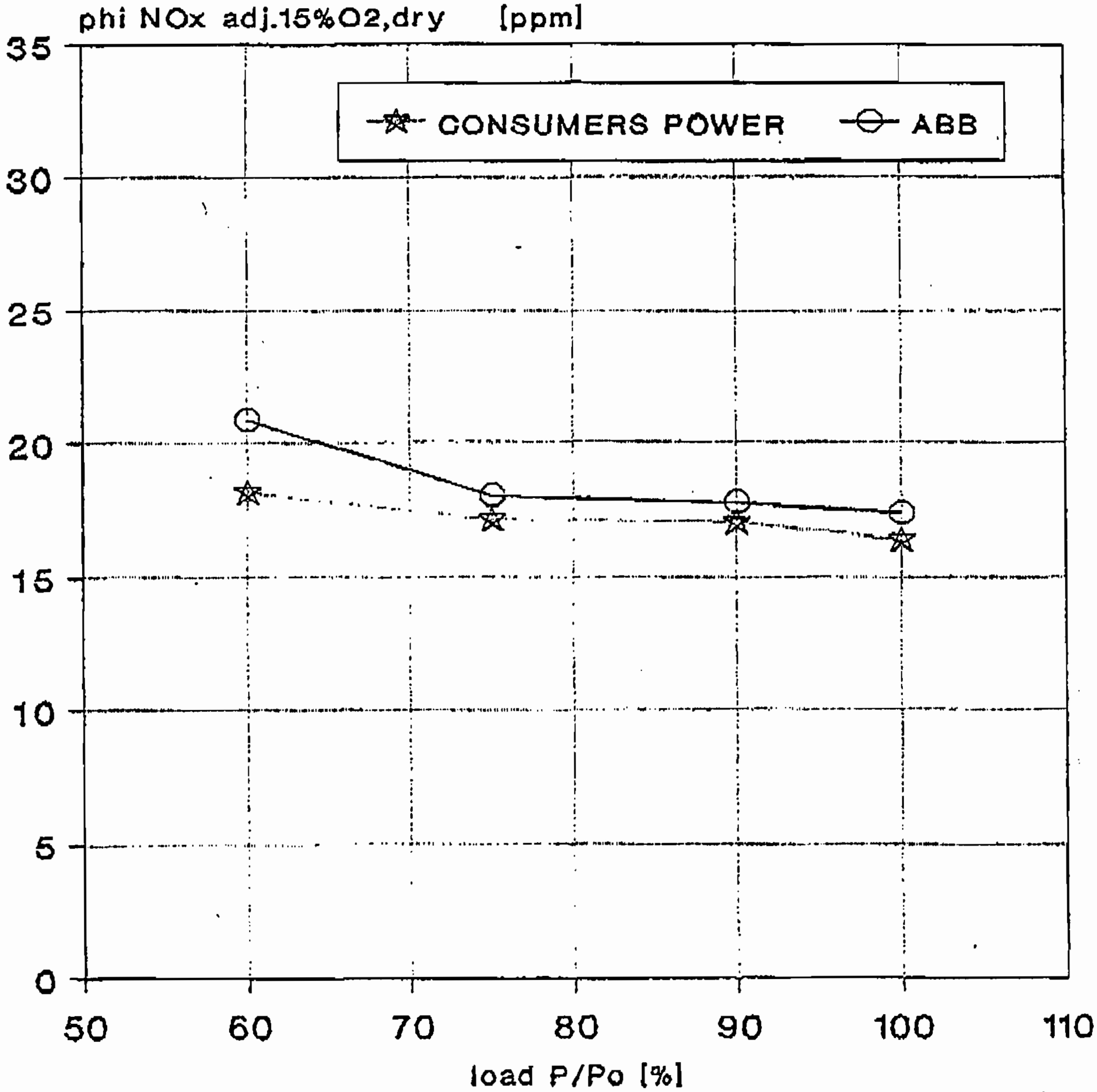
The MCV began commercial operation in March 1990. With 12 ABB gas turbines, the plant has a capacity of 1370 MW, and up to 1.35 million pounds per hour of process steam for industrial use. Principal customers are the Dow Chemical Company for steam and electricity and Consumers Power for electricity.

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

ABB
ASEA BROWN BOVERI

Gieger

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
c_f	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 CON 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 ar before the mixture enters a large tubular combustor via NOx-emissions below 40ppmv have been measured a pressures up to 14.5 bars and inlet temperatures up to 38 the large residence times in the combustor, very high efficiencies are obtained above approximately 40% load Using the experience gained from six units (total GT MW) with more than 63000 hours of operation, the firs investigation of low emission combustion is to i performance of ABB silo combustors by replacing the pr including the mixing tubes (FIG. 2). For this purpose a 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 downst burners.
Due to the NOx-limitation of 25ppmv, the percentage of for combustion increases with increasing pressure ratio a 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 type combustor is of a fully annular design (FIG. 3) and will with 18 main burners and 18 alternately distributed s 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

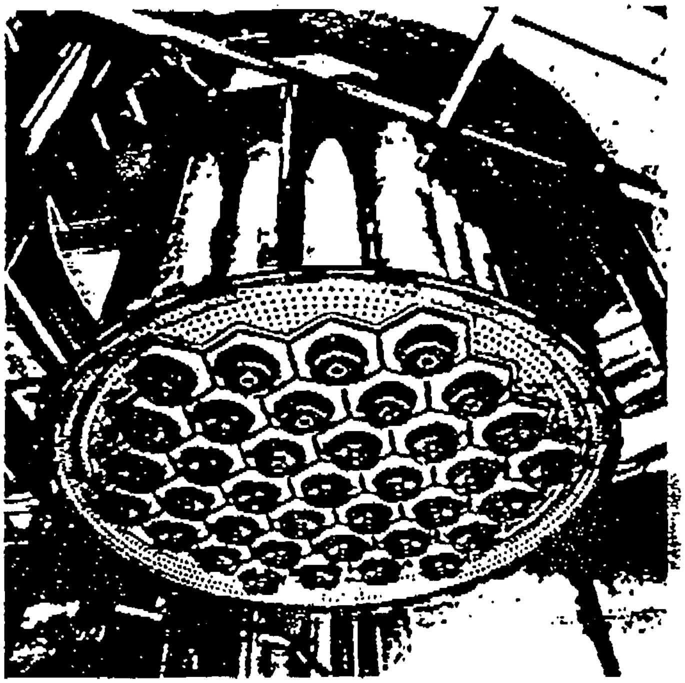


FIG. 1: 1[st] GENERATION OF LOW NOx-COMBUSTORS (CLUSTER OF PREMIX BURNERS)

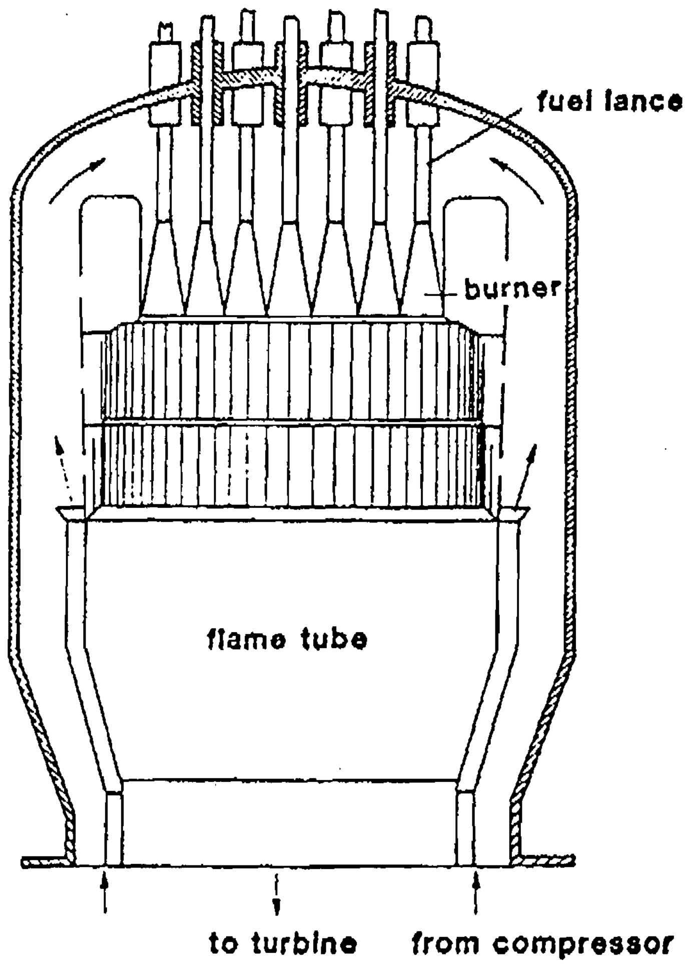


FIG. 2: SILO-COMBUSTOR EQUIPPED WITH CONICAL PREMIX BURNERS (e.g. GT11N)

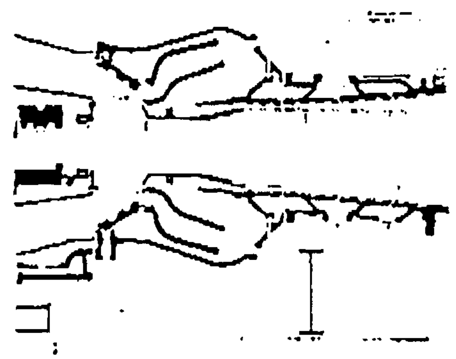


FIG. 3: ANNULAR COMBUSTOR EQUIPPE
PREMIX BURNERS (e.g. GT8)

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
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 stagnatio
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

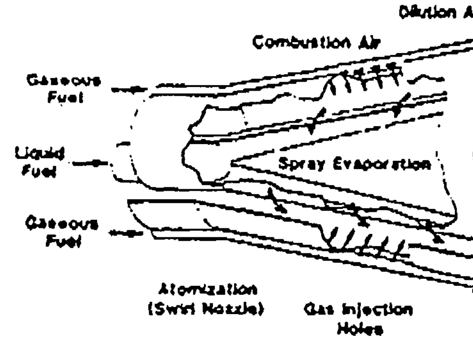


FIG 4: OPERATING PRINCIPLE OF THE C
BURNER

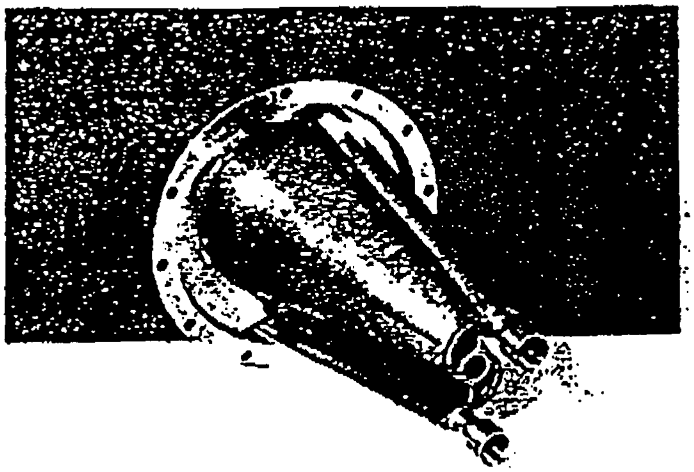


FIG 5: PROTOTYPE BURNER FOR HIGH PRESSURE TESTS

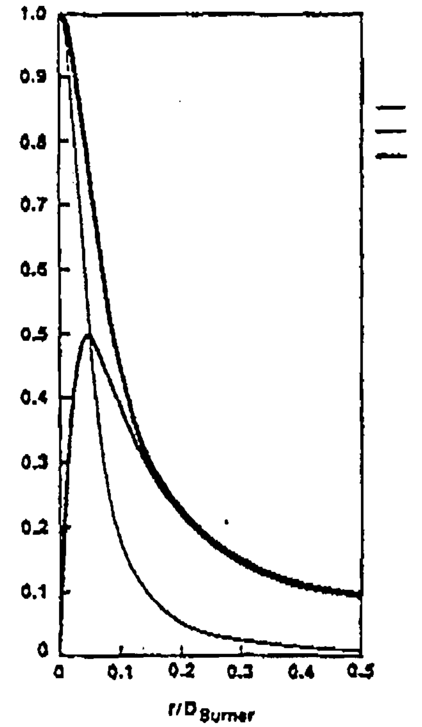


FIG.6: VELOCITY DISTRIBUTION WIT
(POTENTIAL FLOW WITHOUT BREAKDOWN)

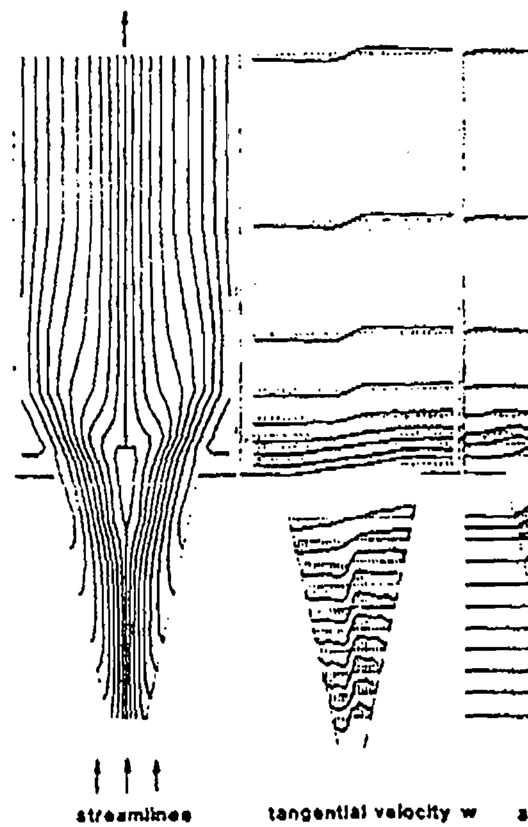


FIG 7: VELOCITY DISTRIBUTION (LDA-ME
NON-REACTING FLOW)

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:

$$u = f(u_{ref}, \beta r); v(r) = 0; w(r) = f(u_{ref}, \beta r)$$

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.

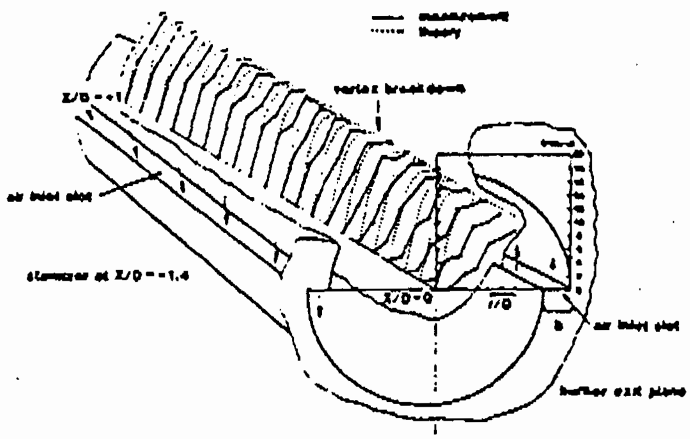


FIG. 8: COMPARISON OF PREDICTED AND MEASURED SWIRL PROFILES

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.

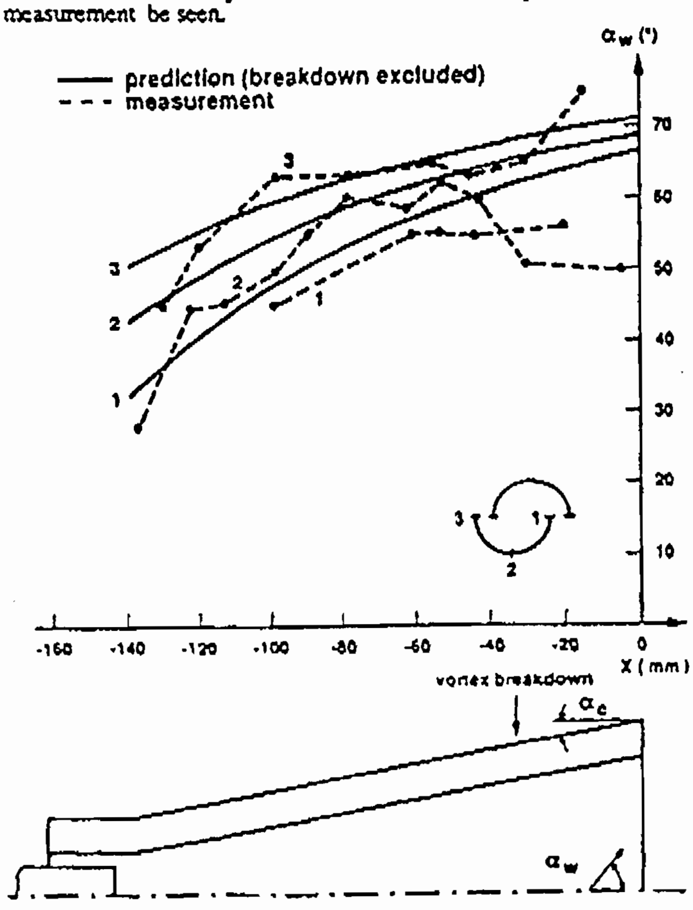


FIG. 9: COMPARISON OF PREDICTED AND MEASURED FLOW DIRECTION NEAR THE BURNER WALLS

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.

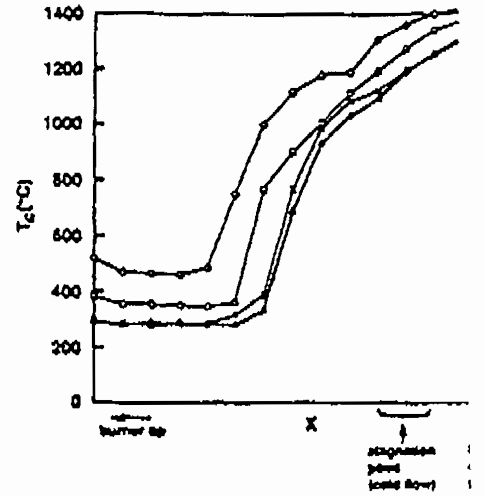


FIG 10: POSITION OF TEMPERATURE AXIS

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.

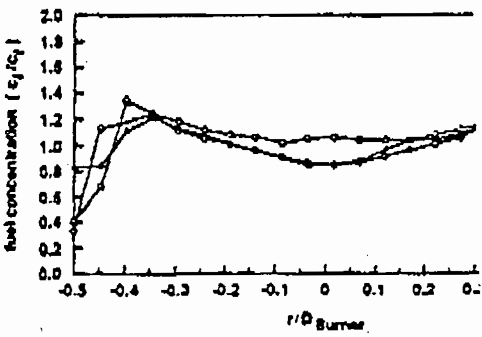


FIG. 11: FUEL DISTRIBUTION IN BURN
(NONREACTING GAS FLOW, TRACER
TRACER: CO)

Typical results of emission measurements for p
atmospheric pressure are shown in FIG.12. T
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 l
($\lambda \leq 2.3$). Since the average flame temperature re
where quenching of the reaction from CO to CO
in carbon monoxide formation can hardly b
premixed flame extinguishes without any sign
stage of incomplete combustion. Similar resu
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 usi
the injection of gaseous fuel (no fuel distribution
slots required) leads to unsatisfactory NOx-em
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 wh
emissions are measured also yields minimum

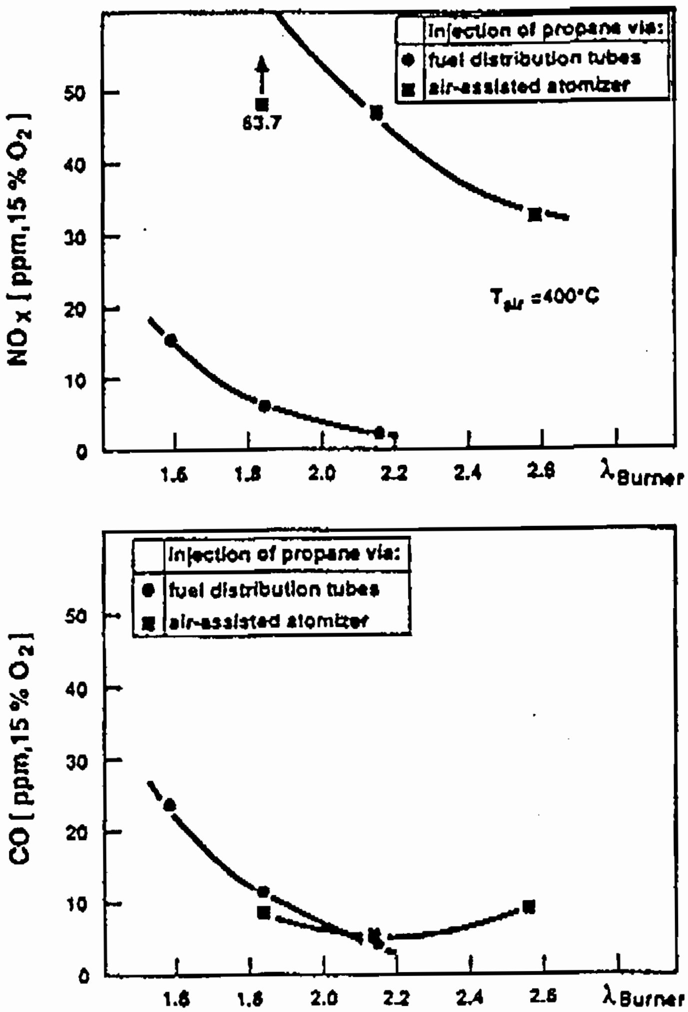


FIG. 12: NOx- AND CO- EMISSIONS OF PROTOTYPE BURNER (GASEOUS FUEL)

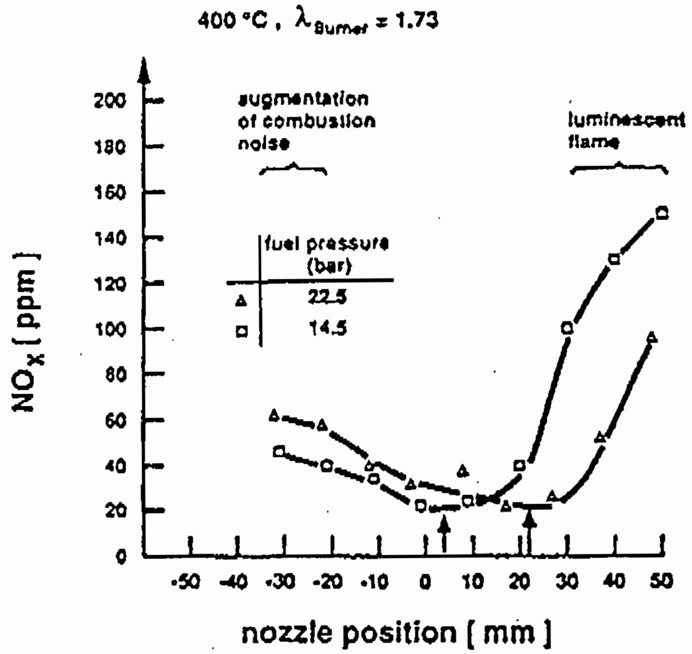


FIG 13: INFLUENCE OF NOZZLE POSITION ON NOx-EMISSIONS (PRESSURIZED NOZZLES)

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 ir burner exit plane is obtained, which augments NOx generation ir outer region of the flow. At the same time, combustion r 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 measurec propane if the data is compared on the basis of the burner equival ratio.

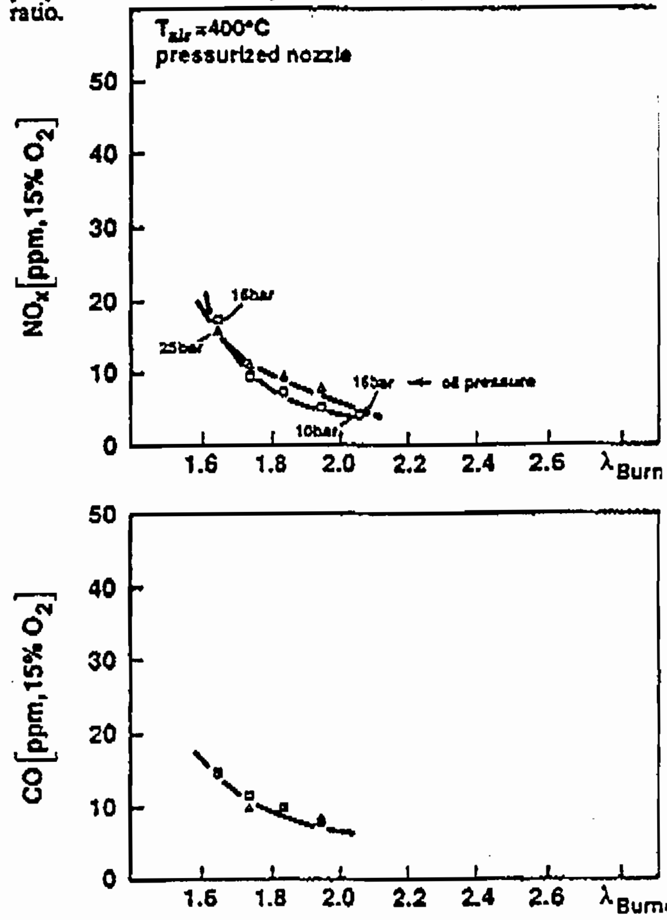
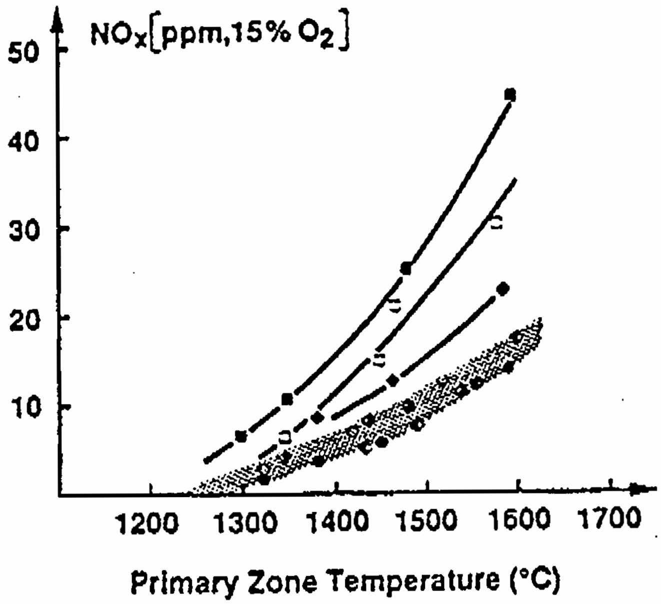


FIG. 14: NOx- AND CO- EMISSIONS OF PROTOTYPE BURN (LIQUID FUEL, FUEL BOUND NITROGEN NEGLIGIBLE)

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, spi 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 i deterioration of droplet evaporation at lower air inlet temperatu leads to a remarkable increase in NOx-formation at constant flai 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 - 16	-	pressurized
◊		-	30	16 - 25	-	pressurized
◆		-	60	10 - 16	-	pressurized
■		-	22	0.2	-	air-assisted
□		-	32	0.2	-	air-assisted

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.

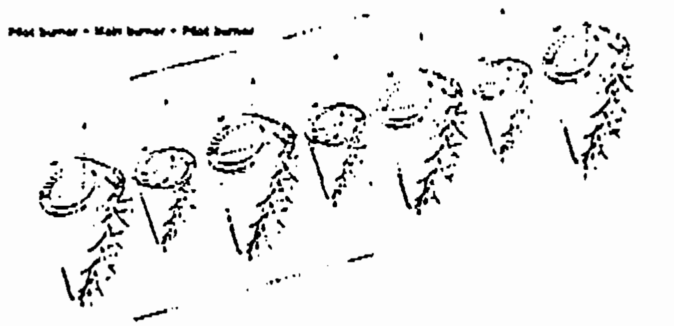


FIG. 16: MAIN- AND PILOT-BURNER CONFIGURATION OF THE ANNULAR COMBUSTOR

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.

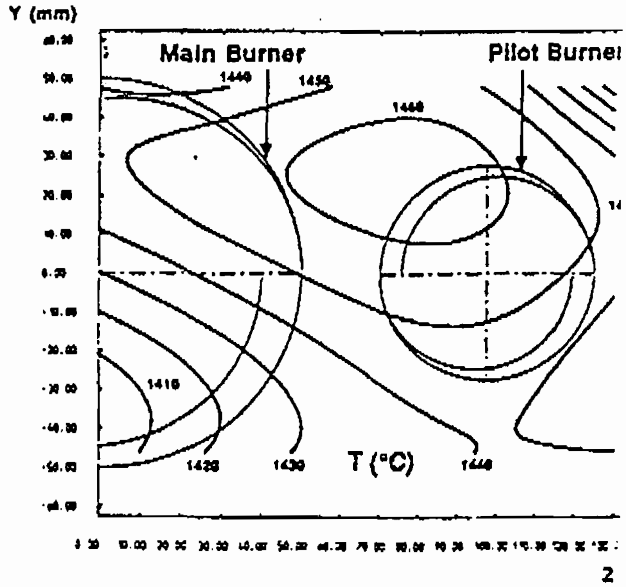


FIG. 17: TEMPERATURE DISTRIBUTION AT HIGH (X=400MM,Φpilot=Φmain=0.56)

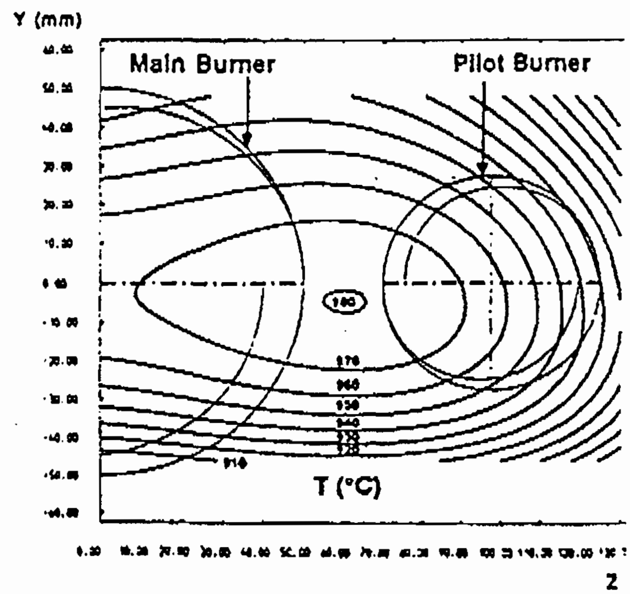


FIG. 18: TEMPERATURE DISTRIBUTION AT LOW (X=400MM,Φpilot=0.56,Φmain=0)

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 $\phi=0.44$ ($\lambda_{comb}=2.3$) is fixed (see FIG. 14), idling is reached at $\lambda_{comb}=6$. With regard to nitrogen oxides, the pilot burner equivalence ratio should be decreased from $\phi_p=0.65$ to 0.44 while the main burner load is increased from $\phi=0.03$ 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.

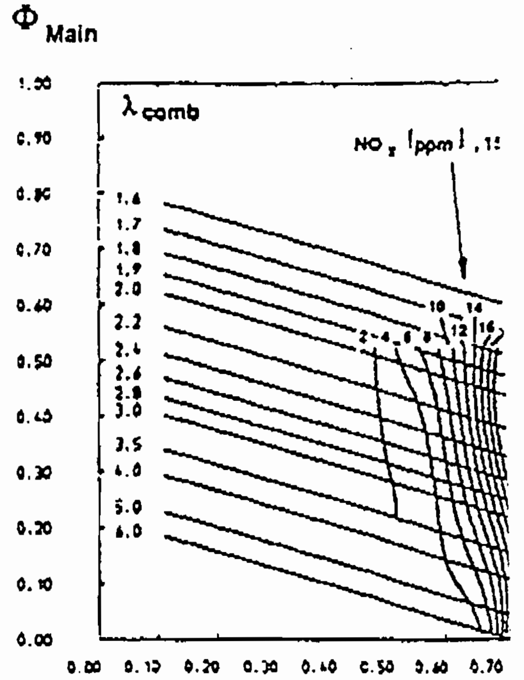


FIG. 20: NOx-EMISSION CHART (400°C, PROP

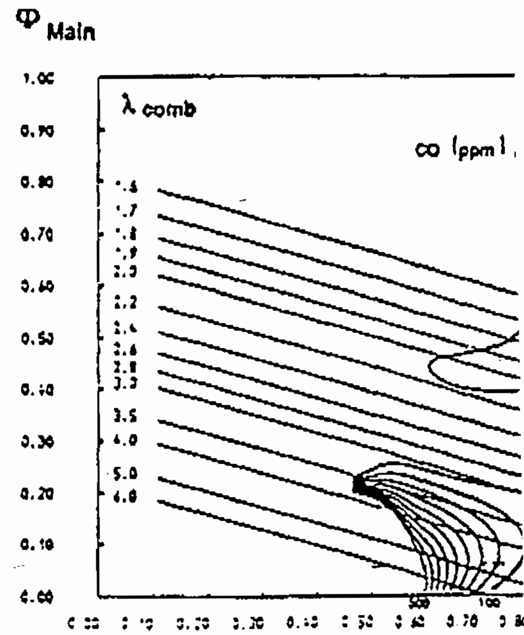


FIG. 21: CO-EMISSION CHART (400°C, PROPAN

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

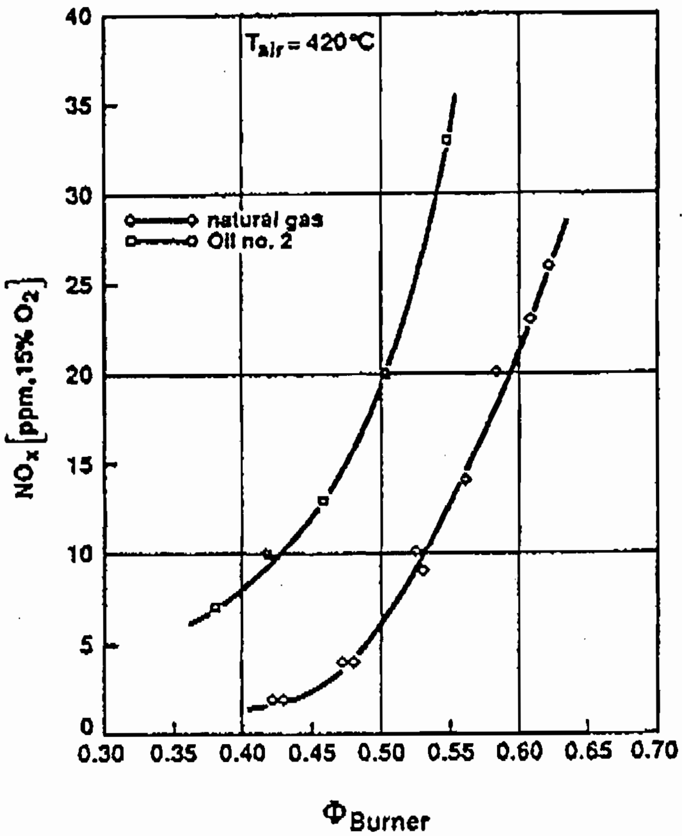


FIG. 22: OPTIMUM PERFORMANCE OF THE MAIN BURNER AT ENGINE SIZE AND ATMOSPHERIC PRESSURE (420°C)

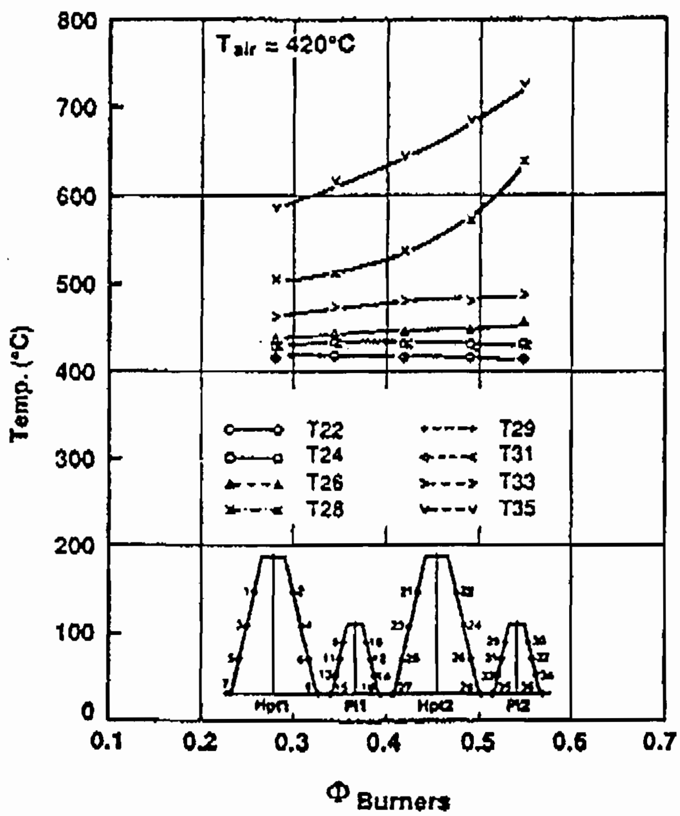


FIG. 23: BURNER TEMPERATURES (ϕ_p~2.2·ϕburner, ϕ_m~0.65·ϕburner)

natural gas. For oil no. 2 the emissions obtained from tl down models cannot be fully validated. Beside the effects o from fuel bound nitrogen, which can clearly be detected, tl 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. To 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 ac

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 combu: 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 burner
- 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 2: engine conditions
- oil no. 2: NOx-emissions somewhat higher than i experiments
- low burner temperatures

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LOW NOx COMBUSTOR WITH EV BURNERS

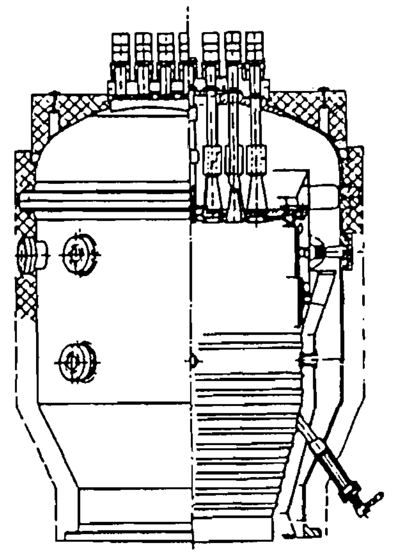

ABB pioneered development of Dry Low NOx combustor technology in 1984. The first unit to become operational achieved 36 ppmvd on our first generation burner. Second generation burners, now operational can achieve 25 ppmvd when operating on natural gas.

FEATURE	BENEFIT
• Experience	ABB is the most experienced manufacturer of Dry Low NO_x combustor technology having nine (9) units operational with over 80,000 hours of running experience
• Top mounted, Up–right design	This design allows full arc admission and even temperature distribution prior to reaching first stage turbine blades. It enables maintenance personnel to physically enter the combustion chamber for inspection with removal of the EV burner section.
• Infra–red frye–eye monitoring	Enables a more complete "examination" of the flame resulting in secure light–off and fewer trips.
• Less number of burners and simplier design	The ABB approach uses less burners than other manfacturers and the piping and control system is much less complicated offering less maintenance and less replacement parts.

ABB
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