Orlando Cogen Limited, L.P. File Copy

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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: ~~2~~15 ppmvd at 15% O_2	~~95.7~~ 57.4[c]	~~400.9~~ 273.9
	DB	NG	BACT: 0.1 lb/MMBtu	12.2[c]	
CO	CT	NG	BACT: 10 ppmvd	22.3	114.6
	DB	NG	BACT: 0.1 lb/MMBtu	12.2	
PM/PM_{10}	CT	NG	BACT: 0.011 lb/MMBtu	11.0	41.67
	DB	NG	BACT: 0.01 lb/MMBtu	1.22	
VOC	CT	NG	Proposed by Applicant	3.18	19.75
	DB	NG	Proposed by Applicant	3.7	

[a] CT = combustion turbine
DB = duct burner

[b] NG = natural gas

[c] COMPLIANCE WITH ALLOWABLE EMISSION LIMIT IS BASED ON A 24-HOUR AVERAGE OF BOTH LIMITS; i.e. 69.6 lb/hr.

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

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KBN

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

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RE: Orange County--A.P.
Orlando CoGen Limited, L.P.
Combustion Turbine and Heat Recovery Steam Generator
AC 48-206720 and PSD-FL-184

Attention: Mr. Preston Lewis and Mr. Bruce Mitchell

Dear Preston and Bruce:

As discussed yesterday, the applicant for the above-referenced project, after discussions with the combustion turbine (CT) vendor (i.e., ABB), will agree to a nitrogen oxide (NO_x) emission limit for the CT based on 18 parts per million volume dry (ppmvd) corrected to 15 percent oxygen. On this basis, the maximum NO_x emission rate proposed as Best Available Control Technology (BACT) for the project will be 68.9 lb/hr for the CT at an ambient temperature of 20°F. The maximum NO_x emission rate at 59°F is proposed as 62.2 lb/hr. The maximum annual emission rate is proposed as 301.8 tons per year (TPY) at 20°F. Table 2-1 from the application has been revised to reflect the proposed BACT emission limit.

This proposed change in the emission limit for NO_x has considerable ramifications for the economic and environmental considerations in the BACT analysis. The cost effectiveness for installing and operating selective catalytic reduction (SCR) on the project at 18 ppmvd (corrected to 15 percent oxygen) is estimated at $12,300 per ton of NO_x removed (annualized cost of $1,903,000 divided by a net NO_x reduction of 154 TPY). This cost effectiveness exceeds the cost effectiveness found unreasonable for other similar projects by about $5,000 per ton of NO_x removed (or about 75 percent). At 18 ppmvd (corrected), the costs for SCR are clearly unreasonable and should be rejected as BACT.

The proposed BACT emission limit for NO_x emissions reduces the maximum potential emissions for the project by 106 TPY or by 26 percent from that originally proposed for the project. At the proposed emission level, the net reduction with SCR when all pollutants except carbon dioxide (CO_2) are considered will be only 29 TPY (see revised Table 4-7). Indeed, the amount of increased CO_2 emissions with SCR is estimated to be two orders of magnitude larger than the net emission reduction with SCR. Taking together the low overall environmental benefit and the potential hazards of handling ammonia in an urban area, application of SCR as BACT for this project appears environmentally unreasonable. As

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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)
B. Mitchell
C. Holladay
C. Collins, C Dist.
J. Harper, EPA
C. Shaver, NPS

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

	Maximum Emissions			
		CT/Duct Burner		
Parameter	CT Only[a]	CT[b]	Duct Burner[c]	Total
Stack Data (ft)				
Height	115			115
Diameter	15.7			15.7
Operating Data				
Temperature (°F)	250			220
Velocity (ft/sec)	69.9			58.14
Building Data (ft)				
Height	76			76
Length	60			60
Width	43			43
Maximum Hourly Emissions (lb/hr)				
SO_2	2.82	2.59	0.37	2.96
PM/PM10	11.0	9.0	1.22	10.22
NO_x	68.9	62.2	12.2	74.4
CO	23.3	21.0	12.2	33.2
VOC	3.18	2.98	3.7	6.7
Sulfuric Acid Mist	0.02	0.02	0.003	0.02
Annual Potential Emissions (TPY)				
SO_2	12.35	11.34	0.68	12.02
PM/PM10	48.18	39.42	2.25	41.67
NO_x	301.8	272.5	22.5	295.0
CO	102.1	92.1	22.5	114.6
VOC	13.9	13.0	6.75	19.75
Sulfuric Acid Mist	0.95	0.87	0.05	0.92

Note: 10^6 Btu/hr = million British thermal units per hour.
CO = carbon monoxide.
CT = combustion turbine.
°F = degrees Fahrenheit.
ft = feet.
ft/sec = feet per second.
HRSG = heat recovery steam generator.
lb/hr = pounds per hour.
Neg = negative.
NO_x = nitrogen oxides.
O_2 = oxygen molecule.
PM = particulate matter.
PM10 = particulate matter less than or equal to 10 micrometers.
ppmvd = parts per million by volume dry.
SO_2 = sulfur dioxide.
TPY = tons per year.
VOC = volatile organic compound.

[a] Performance based on 20°F with NO_x emissions at 18 ppmvd (corrected to 15 percent O_2); 8,760 hr/yr operation.

[b] Performance based on 59°F with NO_x emissions of 18 ppmvd (corrected to 15 percent O_2), 8,760 hr/yr operation; stack parameters based on 90°F ambient temperature.

[c] Performance based on 122 x 10^6 Btu/hr heat input for HRSG; annual emissions based on 4,500 hours per year operation at an average heat input of 100 x 10^6 Btu/hr.

Table 4-7. Maximum Potential Emission Differentials TPY With and Without Selective Catalytic Reduction

	Project With SCR			Project Without SCR	
Pollutants	Primary	Secondary[a]	Total	CT/DB	Difference[b]
Particulate	24 [c]	2.06	26	0	26
Sulfur Dioxide	0	22.64	23	0	23
Nitrogen Oxides	141 [d]	11.32	152	295	(143)
Carbon Monoxide	0	0.68	1	0	1
Volatile Organic Compounds	0	0.10	0	0	0
Ammonia	64 [e]	0.00	64	0	64
Total	229	36.81	266	295	(29)
Carbon Dioxide[f]	--	3,535	3,535	--	3,535

Note: Btu/kWh = British thermal units per kilowatt-hour.
CT = combustion turbine.
DB = duct burner.
MW = megawatt.
% = percent.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Lost energy of 0.47 MW from heat rate penalty and electrical for 8,760 hours per year operation (0.5% of 78.83 MW plus 0.080 MW). Assumes Florida Power Corp. baseloaded oil-fired unit would replace lost energy. EPA emission factors used for 1% sulfur fuel oil and an assumed heat rate of 10,000 Btu/kWh. Emission factors use were (lb/10^6 BTU): PM = 0.1; SO_2 = 1.1; NO_x = 0.55, CO = 0.033 and VOC = 0.005. Example calculation for PM - 0.47 MW x 10,000 BTU/kwh x 1,000 kw/MW x 8,760 hr/yr x 0.1 lb pm/10^6 BTU ÷ 2,000 lb/ton = 2.06 TPY.

[b] Difference = Total with SCR minus project without SCR.

[c] Assume sulfur reacts with ammonia; 11.65 TPY SO_2 x 132 (MW of ammonia salt) ÷ 64 (MW of SO_2).

[d] 9 ppm NO_x emissions.

[e] 10 ppm ammonia slip (ideal gas law at actual flow rate from stack): 726,343 acfm x 60 m/hr x 10 ppm/10^6 x 2,116.8 lb/ft^2 ÷ 1,545 x 17 (molecular weight of NH_3) ÷ (460 +230) x 8,760 ÷ 2,000.

[f] Reflects differential emissions due to lost energy efficiency with SCR (i.e., 0.47 MW CO_2 calculated based on 85.7% carbon in fuel oil and 18,300 BTU/lb).

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FROM: ORLANDO COGEN LIMITED, L.P.

DATE: 26 MAY 1992

COMMENTS:

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Thank you
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Orlando
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26 May 1992

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

Subject: Orange County - A.P.
Orlando CoGen Limited, L.P. Cogeneration Project
Combustion Turbine and Heat Recovery Steam Generator
AC 48-206720 and PSD-FL-184

Attention: Preston Lewis

Dear Mr. Lewis:

This letter is to confirm your conversation earlier today with Mr. Kennard F. Kosky, President, KBN Engineering and Applied Sciences, Inc.

1. Orlando CoGen Limited has reviewed the technical capabilities of the proposed dry-low NO_x combustor with ABB, the gas turbine manufacturer. The equipment manufacturer is willing to guarantee the NO_x emissions levels from the gas turbine unit at a level of 18 PPM (corrected to 15% O_2). This equipment guarantee will become the basis for the emissions levels for the proposed facility's gas turbine.

2. Orlando CoGen Limited with the help of KBN Engineering and Applied Sciences, Inc. will provide the updated emissions data which corresponds to the 18 PPM NO_x emissions level. This information will be provided to the Department later this week.

Orlando CoGen Limited looks forward to finalizing this PSD permit application review with the Department. The facility is planning to start construction around mid-summer of this year to support a scheduled on-stream date of 1 January 1994.

Sincerely,

Wayne A Hinman

Wayne A. Hinman
President
Orlando CoGen (I), Inc.
General Partner of Orlando
CoGen Limited, L.P.

cc: Mr. Kennard F. Kosky, KBN

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26 May 1992

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

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Sincerely,

Wayne A Hinman

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President
Orlando CoGen (I), Inc.
General Partner of Orlando
CoGen Limited, L.P.

cc: Mr. Kennard F. Kosky, KBN
B. Mitchell
P. Lewis

KBN

April 13, 1992

Mr. Clair Fancy
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Subject: Orange County - A.P.
Orlando CoGen Limited, L.P. Cogeneration Project
AC 48-206720 and PSD-FL-184

Attention: Bruce Mitchell

Dear Bruce:

This correspondence and attachments presents information requested by the Department's March 31, 1991 letter. Please find attached the following:

1. The equations contained in Notes A, B and C have been further annotated to reference the equations from the Code of Federal Regulations (CFR) for which NOx, CO and VOC emissions are calculated from parts per million (ppm) with corrections to lb/hr. Also attached is a copy of the relevant CFR (i.e., 40 CFR Part 60 Appendix A, Method 20). Please recognize that the notes contained in the application were not titled as Notes-1 as indicated in the March 31, 1992 letter but as Notes A, B and C.

2. A computer disk containing the spreadsheet used to develop Tables A-1 through A-4 is enclosed with this correspondence. Please note that this spreadsheet is a work product of KBN Engineering and Applied Sciences, Inc. (KBN) and must be considered as confidential business information.

Submittal of this information clarifies all questions raised by the Department in the completeness determination for the above referenced project. Please call if there are any further questions on the material submitted herein.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

cc: Mr. John P. Jones
Mr. Gary Kinsey, P.E.
B. Mitchell
C. Holladay
C. Collins, C. Dist
D. Nester, Orange Co.
J. Harper, EPA
C. Shaver, NPS

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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)

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NOTE B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

1. $$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

[see Equation 20-4, EPA Method 20]

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

3. $$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

[see Equation 20-1, EPA Method 20]

4. $$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$$

[see Equation 20-1, EPA Method 20]

Substituting:

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

[Substitute Equation 2 in Equation 4]

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

[Substitute in Equation 3]

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

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

[Ideal Gas Law]

CO is calculated the same as NOx. JSG

NOTE C

~~CO and~~ VOC ~~are~~ is calculated by correcting to dry conditions: JSG

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

[see Equation 3 above]

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

[Ideal Gas Law]

device, the following equation may be used to adjust the emission rate for sulfur retention credits (no credits are allowed for oil-fired systems) (E_{ai}) for each sampling period using the following equation:

$$E_{ai} = 0.97\ K\ (\%S/GCV)$$

Eq. 19-25

where:

E_{ai}=average inlet SO_2 rate for each sampling period d, ng/J (lb/million Btu)

%S=sulfur content of as-fired fuel lot, dry basis, weight percent.

GCV=gross calorific value of the fuel lot consistent with the sulfur analysis, kJ/kg (Btu/lb).

$K = 2\times10^7$[(kg)(ng)/(%)(J)] {2×10^4(lb)(Btu/(%))(million Btu)}

After calculating E_{ai} use the procedures in Section 4-2 to determine the average SO_2 emission rate to the atmosphere for the performance test period (E_{ao}).

7. *Determination of Compliance When Minimum Data Requirement Is Not Met*

7.1 Adjusted Emission Rates and Control Device Removal Efficiency. When the minimum data requirement is not met, the Administrator may use the following adjusted emission rates or control device removal efficiencies to determine compliance with the applicable standards.

Eq. 19-27

7.1.1 Emission Rate. Compliance with the emission rate standard may be determined by using the lower confidence limit of the emission rate (E_{ao}^*) as follows:

$$E_{ao}^* = E_{ao} - t_{0.95}\ S_o$$

Eq. 19-26

where:

S_o=standard deviation of the hourly average emission rates for each performance test period, ng/J (lb/million Btu).

$t_{0.95}$-values shown in Table 19-2 for the indicated number of data points n.

7.1.2 Control Device Removal Efficiency. Compliance with the overall emission reduction ($\%R_o$) may be determined by using the lower confidence limit of the emission rate (E_{ao}^*) and the upper confidence limit of the inlet pollutant rate (E_{ai}^*) in calculating the control device removal efficiency ($\%R_g$) as follows:

$$\%R_g = 100\ [1.0 - E_{ao}^*/E_{ai}^*]$$

$$E_{ai}^* = E_{ai} + t_{0.95}\ S_i$$

Eq. 19-28

where:

S_i=standard deviation of the hourly average inlet pollutant rates for each performance test period, ng/J (lb/million Btu).

TABLE 19-2—VALUES FOR $T_{0.95}$

n[1]	$t_{0.95}$	n[1]	$t_{0.95}$	n[1]	$t_{0.95}$
2	6.31	8	1.89	22-26	1.71
3	2.42	9	1.86	27-31	1.70
4	2.35	10	1.83	32-51	1.68
5	2.13	11	1.81	59-91	1.67
6	2.02	12-16	1.77	92-151	1.66
7	1.94	17-21	1.73	152 or more	1.65

[1] The values of this table are corrected for n-1 degrees of freedom. Use n equal to the number (H) of hourly average data points.

7.2 Standard Deviation of Hourly Average Pollutant Rates. Compute the standard deviation (S_e) of the hourly average pollutant rates using the following equation:

$$S_e = \sqrt{(1/H) - (1/H_r)}\ \ (\sqrt{[\sum_{j=1}^{H}(E_{hj} - E_a)^2]/(H - 1)}\ )$$

Eq. 19-29

where:

S=standard deviation of the hourly average pollutant rates for each performance test period, ng/J (lb/million Btu).

H_r=total numbers of hours in the performance test period (e.g., 720 hours for 30-day performance test period).

Equation 19-29 may be used to compute the standard deviation for both the outlet (S_o) and, if applicable, inlet (S_i) pollutant rates.

METHOD 20—DETERMINATION OF NITROGEN OXIDES, SULFUR DIOXIDE, AND DILUENT EMISSIONS FROM STATIONARY GAS TURBINES

1. *Principle and Applicability*

1.1 Applicability. This method is applicable for the determination of nitrogen oxides (NO_x), sulfur dioxide (SO_2), and a diluent gas, either oxygen (O_2) or carbon dioxide (CO_2), emissions from stationary gas turbines. For the NO_x and diluent concentration determinations, this method includes:

(1) Measurement system design criteria; (2) Analyzer performance specifications and performance test procedures; and (3) Procedures for emission testing.

1.2 Principle. A gas sample is continuously extracted from the exhaust stream of a stationary gas turbine; a portion of the sample stream is conveyed to instrumental analyzers for determination of NO_x and diluent content. During each NO_x and diluent determination, a separate measurement of SO_2 emissions is made, using Method 6, or its equivalent. The diluent determination is used to adjust the NO_x and SO_2 concentrations to a reference condition.

2. *Definitions*

2.1 Measurement System. The total equipment required for the determination of a gas concentration or a gas emission rate. The system consists of the following major subsystems:

2.1.1 Sample Interface. That portion of a system that is used for one or more of the following: sample acquisition, sample transportation, sample conditioning, or protection of the analyzers from the effects of the stack effluent.

2.1.2 NO_x Analyzer. That portion of the system that senses NO_x and generates an output proportional to the gas concentration.

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2.1.3 O_2 Analyzer. That portion of the system that senses O_2 and generates an output proportional to the gas concentration.

2.1.4 CO_2 Analyzer. That portion of the system that senses CO_2 and generates an output proportional to the gas concentration.

2.1.5 Data Recorder. That portion of the measurement system that provides a permanent record of the analyzer(s) output. The data recorder may include automatic data reduction capabilities.

2.2 Span Value. The upper limit of a gas concentration measurement range that is specified for affected source categories in the applicable part of the regulations.

2.3 Calibration Gas. A known concentration of a gas in an appropriate diluent gas.

2.4 Calibration Error. The difference between the gas concentration indicated by the measurement system and the known concentration of the calibration gas.

2.5 Zero Drift. The difference in the measurement system output readings from zero after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input concentration at the time of the measurements was zero.

2.6 Calibration Drift. The difference in the measurement system output readings from the known concentration of the calibration gas after a stated period of operation during which no unscheduled maintenance, repair, or adjustment took place and the input at the time of the measurements was a high-level value.

2.7 Response Time. The amount of time required for the measurement system to display on the data output 95 percent of a step change in pollutant concentration.

2.8 Interference Response. The output response of the measurement system to a component in the sample gas, other than the gas component being measured.

3. *Measurement System Performance Specifications*

3.1 NO_2 to NO Converter. Greater than 90 percent conversion efficiency of NO_2 to NO.

3.2 Interference Response. Less than ± 2 percent of the span value.

3.3 Response Time. No greater than 30 seconds.

3.4 Zero Drift. Less than ± 2 percent of the span value over the period of each test run.

3.5 Calibration Drift. Less than ± 2 percent of the span value over the period of each test run.

4. *Apparatus and Reagents*

4.1 Measurement System. Use any measurement system for NO_x and diluent that is expected to meet the specifications in this method. A schematic of an acceptable measurement system is shown in Figure 20-1. The essential components of the measurement system are described below:

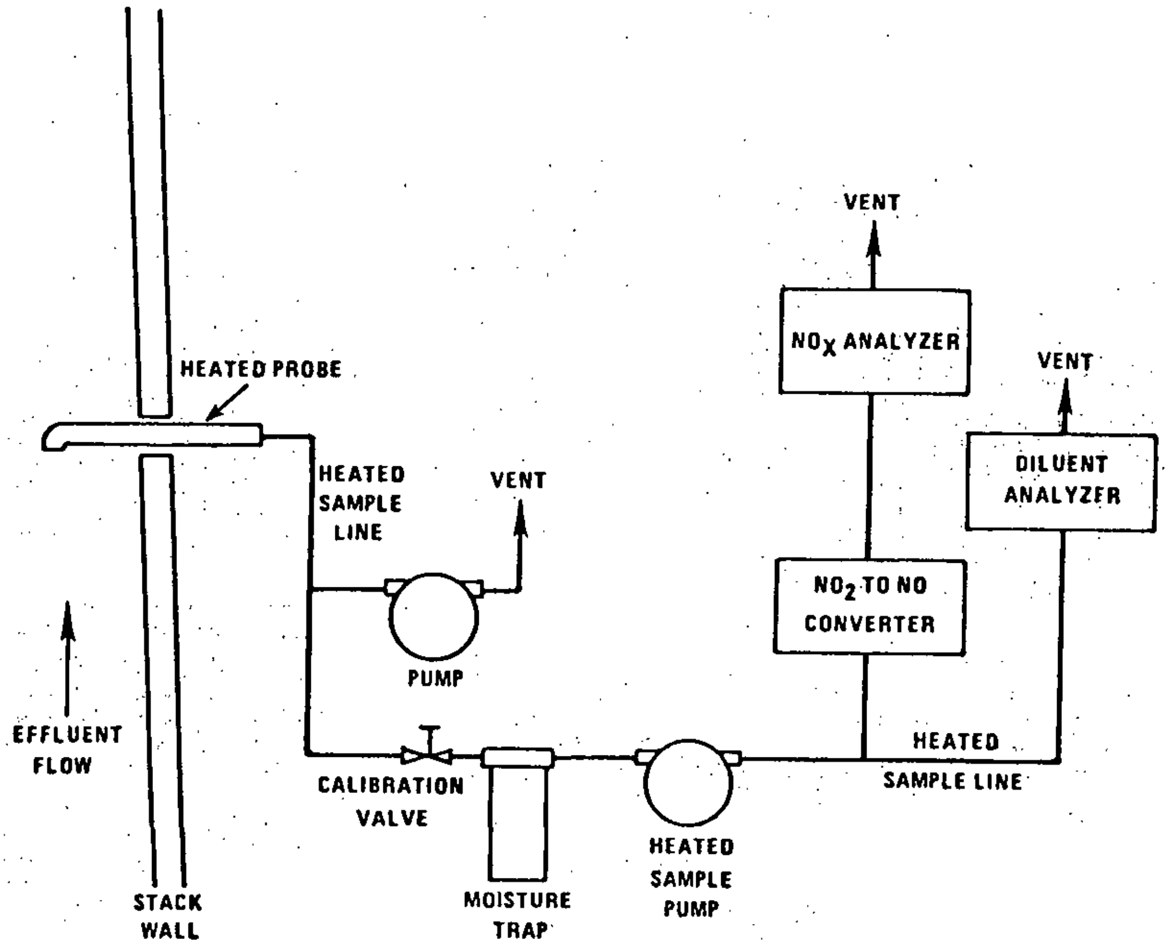

Figure 20-1. Measurement system design.
[Figure 20-1 revised by 51 FR 32455, September 12, 1986]

4.1.2 Sample Line. Heated (>95°C) stainless steel or Teflon tubing to transport the sample gas to the sample conditioners and analyzers.

4.1.3 Calibration Valve Assembly. A three-way valve assembly to direct the zero and calibration gases to the sample conditioners and to the analyzers. The calibration valve assembly shall be capable of blocking the sample gas flow and of introducing calibration gases to the measurement system when in the calibration mode.

4.1.4 NO_2 to NO Converter. That portion of the system that converts the nitrogen dioxide (NO_2) in the sample gas to nitrogen oxide (NO). Some analyzers are designed to measure NO_x as NO_2 on a wet basis and can be used without an NO_2 to NO converter or a moisture removal trap provided the sample line to the analyzer is heated (>95°C) to the inlet of the analyzer. In addition, an NO_2 to NO converter is not necessary if the NO_2 portion of the exhaust gas is less than 5 percent of the total NO_x concentration. As a guideline, an NO_2 to NO converter is not necessary if the gas turbine is operated at 90 percent or more of peak load capacity. A converter is necessary under lower load conditions.

4.1.5 Moisture Removal Trap. A refrigerator-type condenser or other type device designed to continuously remove condensate from the sample gas while maintaining minimal contact between any condensate and the sample gas. The moisture removal trap is not necessary for analyzers that can measure NO_x concentrations on a wet basis; for these analyzers, (a) heat the sample line up to the inlet of the analyzers, (b) determine the moisture content using methods subject to the approval of the Administrator, and (c) correct the NO_x and diluent concentrations to a dry basis.

[4.1.5 amended by 51 FR 32455, September 12, 1986]

4.1.6 Particulate Filter. An in-stack or an out-of-stack glass fiber filter, of the type specified in EPA Method 5; however, an out-of-stack filter is recommended when the stack gas temperature exceeds 250 to 300°C.

[4.1.6. amended by 55 FR 47472, November 14, 1990]

4.1.7 Sample Pump. A nonreactive leak-free sample pump to pull the sample gas through the system at a flow rate sufficient to minimize transport delay. The pump shall be made from stainless steel or coated with Teflon or equivalent.

4.1.8 Sample Gas Manifold. A sample gas manifold to divert portions of the sample gas stream to the analyzers. The manifold may be constructed of glass, Teflon, stainless steel, or equivalent.

4.1.9 Diluent Gas Analyzer. An analyzer to determine the percent O_2 or CO_2 concentration of the sample gas.

[4.1.9 amended by 51 FR 32455, September 12, 1986]

4.1.10 Nitrogen Oxides Analyzer. An analyzer to determine the ppm NO_x concentration in the sample gas stream.

4.1.11 Data Recorder. A strip-chart recorder, analog computer, or digital recorder for recording measurement data.

[4.1.11 amended by 51 FR 32455 September 12, 1986]

4.2 Sulfur Dioxide Analysis. EPA Method 6 apparatus and reagents.

[4.2 amended by 55 FR 47472, November 14, 1990]

4.3 NO_x Calibration Gases. The calibration gases for the NO_x analyzer shall be NO in N_2. Use four calibration gas mixtures as specified below:

4.3.1 High-level Gas. A gas concentration that is equivalent to 80 to 90 percent of the span value.

4.3.2 Mid-level Gas. A gas concentration that is equivalent to 45 to 55 percent of the span value.

4.3.3 Low-level Gas. A gas concentration that is equivalent to 20 to 30 percent of the span value.

4.3.4 Zero Gas. A gas concentration of less than 0.25 percent of the span value. Ambient air may be used for the NO_x zero gas.

4.4 Diluent Calibration Gases.

[4.4 revised, 4.4.1 and .2 added by 51 FR 32455, September 12, 1986]

4.4.1 For O_2 calibration gases, use purified air at 20.9 percent O_2 as the high-level O_2 gas. Use a gas concentration between 11 and 15 percent O_2 in nitrogen for the mid-level gas, and use purified nitrogen for the zero gas.

4.4.2 For CO_2 calibration gases, use a gas concentration between 8 and 12 percent CO_2 in air for the high-level calibration gas. Use a gas concentration between 2 and 5 percent CO_2 in air for the mid-level calibration gas, and use purified air (<100 ppm CO_2) as the zero level calibration gas.

5. *Measurement System Performance Test Procedures*

Perform the following procedures prior to measurement of emissions (Section 6) and only once for each test program, i.e., the series of all test runs for a given gas turbine engine.

5.1 Calibration Gas Checks. There are two alternatives for checking the concentrations of the calibration gases. (a) The first is to use calibration gases that are documented traceable to National Bureau of Standards Reference Materials. Use *Traceability Protocol for Establishing True Concentrations of Gases Used for Calibrations and Audits of Continuous Source Emission Monitors* (Protocol Number 1) that is available from the Environmental Monitoring Systems Laboratory, Quality Assurance Branch, Mail Drop 77, Environmental Protection Agency, Research Triangle Park, North Carolina 27711. Obtain a certification from the gas manufacturer that the protocol was followed. These calibration gases are not to be analyzed with the Reference Methods. (b) The second alternative is to use calibration gases not prepared according to the protocol. If this alternative is chosen, within 1 month prior to the emission test, analyze each of the calibration gas mixtures in triplicate using Method 7 or the procedure outlined in Citation 1. for NO_x and use Method 3. for O_2 or CO_2. Record the results on a data sheet (example is shown in Figure 20-2). For the low-level, mid-level, or high-level has mixtures, each of the individual NO_x analytical results must be within 10 percent (or 10 ppm, whichever is greater) of the triplicate set average (O_2 or CO_2 test results must be within 0.5 percent O_2 pr CO_2); otherwise, discard the entire set and repeat the triplicate analyses. If the average of the triplicate reference method test results is within 5 percent for NO_x gas or 0.5 percent O_2 or CO_2 for the O_2 or CO_2 gas of the calibration gas manufacturer's tag value, use the tag value; otherwise, conduct at least three additional reference method test analyses until the results of six individual NO_x runs (the three original plus three additional) agree within 10 percent (or 10 ppm, whichever is greater) of the average (O_2 or CO_2 test results must be within 0.5 percent O_2 or CO_2). Then use this average for the cylinder value.

[5.1 amended by 51 FR 32455, September 12, 1986; 52 FR 34639, September 14, 1987; 55 FR 47472, November 14, 1990]

5.2 Measurement System Preparation. Prior to the emission test, assemble the measurement system following the manufacturer's written instructions in preparing and operating the NO_2 to NO converter, the NO_x analyzer, the diluent analyzer, and other components.

[5.2 amended by 51 FR 32455, September 12, 1986]

FIGURE 20-2—ANALYSIS OF CALIBRATION GASES

Date ——— (Must be within 1 month prior to the test period)

Reference method used ———————

Sample run	Gas concentration, ppm		
	Low level[a]	Mid level[b]	High level[c]
1			
2			
3			
Average			
Maximum % deviation[d].			

[a] Average must be 20 to 30% of span value.

[b] Average must be 45 to 55% of span value.

[c] Average must be 80 to 90% of span value

[d] Must be <±10% of applicable average or 10 ppm whichever is greater.

5.3 Calibration Check. Conduct the calibration checks for both the NO_x and the diluent analyzers as follows:

[5.3 amended by 51 FR 32455, September 12, 1986]

5.3.1 After the measurement system has been prepared for use (Section 5.2), introduce zero gases and the mid-level calibration gases; set the analyzer output responses to the appropriate levels. Then introduce each of the remainder of the calibration gases described in Sections 4.3 or 4.4, one at a time, to the measurement system. Record the responses on a form similar to Figure 20-3.

5.3.2 If the linear curve determined from the zero and mid-level calibration gas responses does not predict the actual response of the low-level (not applicable for the diluent analyzer) and high-level gases within 2 percent of the span value, the calibration shall be considered invalid. Take corrective measures on the measurement system before proceeding with the test.

[5.3.2 amended by 51 FR 32455 September 12, 1986]

5.4 Interference Response. Introduce the gaseous components listed in Table 20-1 into the measurement system separately, or as gas mixtures. Determine the total interference output response of the system to these components in concentration units; record the values on a form similar to Figure 20-4. If the sum of the interference responses of the test gases for either the NO_x or diluent analyzers is greater than 2 percent of the applicable span value, take corrective measure on the measurement system.

[5.4 amended by 51 FR 32455, September 12, 1986]

FIGURE 20-3—ZERO AND CALIBRATION DATA

Turbine type .... Identification number ....

Date .... Test number ....

Analyzer type .... Identification number ....

	Cylinder value, ppm or %	Initial analyzer response, ppm or %	Final analyzer responses, ppm or %	Difference: initial-final, ppm or %
Zero gas				
Low-level gas				
Mid-level gas				
High-level gas				

$$\text{Percent drift} = \frac{\text{Absolute difference}}{\text{Span value}} \times 100$$

TABLE 20-1—INTERFERENCE TEST GAS CONCENTRATION

CO	500±50 ppm	CO_2	10±1 percent.
SO_2	200±20 ppm	O_2	20.9±1 percent.

FIGURE 20-4—INTERFERENCE RESPONSE

Date of test ———

Analyzer type ———————————

Serial No. ———————————

Test gas type	Concentration, ppm	Analyzer output response	% of span

$$\% \text{ of span} = \frac{\text{Analyzer output response}}{\text{Instrument span}} \times 100.$$

Conduct an interference response test of each analyzer prior to its initial use in the field. Thereafter, recheck the measurement system if changes are made in the instrumentation that could alter the interference response, e.g., changes in the type of gas detector.

In lieu of conducting the interference response test, instrument vendor data, which demonstrate that for the test gases of Table 20-1 the interference performance specification is not exceeded, are acceptable.

5.5 Response time. To determine response time, first introduce zero gas into the system at the calibration valve until all readings are stable; then, switch to monitor the stack effluent until a stable reading can be obtained. Record the upscale response time. Next, introduce high-level calibration gas into the system. Once the system has stabilized at the high-level concentration, switch to monitor the stack effluent and wait until a stable value is reached. Record the downscale response time. Repeat the procedure three times. A stable value is equivalent to a change of less than 1 percent of span value for 30 seconds or less than 5 percent of the measured average concentration for 2 minutes. Record the response time data on a form similar to Figure 20-5, the readings of the upscale or downscale reponse time, and report the greater time as the "response time" for the analyzer. Conduct a response time test prior to the initial field use of the measurement system, and repeat if changes are made in the measurement system.

FIGURE 20-5—RESPONSE TIME

Date of test ———

Analyzer type ———————

S/N ———————————

Span gas concentration: ——— ppm.

Analyzer span setting: ——— ppm.

Upscale:

1 ——— seconds.

2 ——— seconds.

3 ——— seconds.

Average upscale response —— seconds.

Downscale:

1 ——— seconds.

2 ——— seconds.

3 ——— seconds.

Average downscale response —— seconds.

System response time = slower average time = ——— seconds.

5.6 NO_2 to NO Conversion Efficiency.

5.6.1 Add gas from the mid-level NO in N_2 calibration gas cylinder to a clean, evacuated, leak-tight Tedlar bag. Dilute this gas approximately 1:1 with 20.9 percent O_2, purified air. Immediately attach the bag outlet to the calibration valve assembly and begin operation of the sampling system. Operate the sampling system, recording the NO_x response, for at least 30 minutes. If the NO_2 to

[Appendix A, Method 20]

NO conversion is 100 percent, the instrument response will be stable at the hightest peak valve observed. If the response at the end of 30 minutes decreases more than 2.0 percent of the highest peak valve, the system is not acceptable and corrections must be made before repeating the check.

5.6.2 Alternatively, the NO_2 to NO converter check described in Title 40, Part 86: Certification and Test Procedures for Heavy-duty Engines for 1979 and Later Model Years may be used. Other alternative procedures may be used with approval of the Administrator.

6. Emission Measurement Test Procedure

6.1 Preliminaries.

6.1.1 Selection of a Sampling Site. Select a sampling site as close as practical to the exhaust of the turbine. Turbine geometry, stack configuration, internal baffling, and point of introduction of dilution air will vary for different turbine designs. Thus, each of these factors must be given special consideration in order to obtain a representative sample. Whenever possible, the sampling site shall be located upstream of the point of introduction of dilution air into the duct. Sample ports may be located before or after the upturn elbow, in order to accommodate the configuration of the turning vanes and baffles and to permit a complete, unobstructed traverse of the stack. The sample ports shall not be located within 5 feet or 2 diameters (whichever is less) of the gas discharge to atmosphere. For supplementary-fired, combined-cycle plants, the sampling site shall be located between the gas turbine and the boiler. The diameter of the sample ports shall be sufficient to allow entry of the sample probe.

6.1.2 A preliminary O_2 or CO_2 traverse is made for the purpose of selecting sampling points of low O_2 or high CO_2 concentrations, as appropriate for the measurement system. Conduct this test at the turbine operating condition that is the lowest percentage of peak load operation included in the test program. Follow the procedure below, or use an alternative procedure subject to the approval of the Administrator.

[6.1.2 revised by 51 FR 32455, September 12, 1986]

6.1.2.1 Minimum Number of Points. Select a minimum number of points as follows: (1) Eight, for stacks having cross-sectional areas less than 1.5 m^2 (16.1 ft^2); (2) eight plus one additional sample point for each 0.2 M^2 (2.2 ft^2 of areas, for stacks of 1.5 m^2 to 10.0 m^2 (16.1-107.6 ft^2) in cross-sectional area; and (3) 49 sample points (48 for circular stacks) for stacks greater than 10.0 m^2 (107.6 ft^2) in cross-sectional area. Note that for circular ducts, the number of sample points must be a multiple of 4, and for rectangular ducts, the number of points must be one of those listed in Table 20-2; therefore, round off the number of points (upward), when appropriate.

[6.1.2.2 and 6.1.2.3 amended by 51 FR 32455, September 12, 1986]

6.1.2.2 Cross-sectional Layout and Location of Traverse Points. After the number of traverse points for the preliminary diluent sampling has been determined, use Method 1 to locate the traverse points.

6.1.2.3 Preliminary Diluent Measurement. While the gas turbine is operating at the lowest percent of peak load, conduct a preliminary diluent measurement as follows: Position the probe at the first traverse point and begin sampling. The minimum sampling time at each point shall be 1 minute plus the average system response time. Determine the average steady-state concentration of diluent at each point and record the data on Figure 20-6.

6.1.2.4 Selection of Emission Test Sampling Points. Select the eight sampling points at which the lowest O_2 concentrations or highest CO_2 concentrations were obtained. Sample at each of these selected points during each run at the different turbine load conditions. More than eight points may be used, if desired, providing that the points selected as described above are included.

[6.1.2.4 revised by 51 FR 32455, September 12, 1986]

TABLE 20-2—CROSS-SECTIONAL LAYOUT FOR RECTANGULAR STACKS

	Matrix layout
No. of traverse points:	
9	3 x 3
12	4 x 3
16	4 x 4
20	5 x 4
25	5 x 5
30	6 x 5
36	6 x 6
42	7 x 6
49	7 x 7

FIGURE 20-6—PRELIMINARY DILUENT TRAVERSE

Date ________

Location:
  Plant ________
  City, State ________
Turbine identification:
  Manufacturer ________
  Model, serial number ________

Sample point	Oxygen concentration, ppm

[Figure 20-6 amended by 51 FR 32455, September 12, 1986]

6.2 NO_x and Diluent Measurement. This test is to be conducted at each of the specified load conditions. Three test runs at each load condition constitute a complete test.

[6.2 amended by 51 FR 32455, September 12, 1986]

6.2.1 At the beginning of each NO_x test run and, as applicable, during the run, record turbine data as indicated in Figure 20-7. Also, record the location and number of the traverse points on a diagram.

6.2.2 Position the probe at the first point determined in the preceding section and begin sampling. The minimum sampling time at each point shall be at least 1 minute plus the average system response time. Determine the average steady-state concentration of **diluent and NO_x at each point and record the data on Figure 20-8.**

[6.2.2 amended by 51 FR 32455, September 12, 1986]

FIGURE 20-7—STATIONARY GAS TURBINE DATA

TURBINE OPERATION RECORD

Test operator ________ Date ____
Turbine identification:
  Type ________
  Serial No. ________
Location:
  Plant ________
  City ________
Ambient temperature ________
Ambient humidity ________
Test time start ________
Test time finish ________
Fuel flow rate[a] ________
Water or steam Flow rate[a] ________
Ambient Pressure ________
Ultimate fuel Analysis:
  C ________
  H ________
  O ________
  N ________
  S ________
  Ash ________
  H_2O ________
Trace Metals:
  Na ________
  Va ________
  K ________
  etc[b] ________
Operating load ________

---

[a] Describe measurement method, i.e., continuous flow meter, start finish volumes, etc.

[b] i.e., additional elements added for smoke suppression.

FIGURE 20-8—STATIONARY GAS TURBINE SAMPLE POINT RECORD

Turbine identification:
  Manufacturer ________
  Model, serial No. ________
Location:
  Plant ________
  City, State ________
Ambient temperature ________
Ambient pressure ________
Date ________
Test time: start ________
Test time: finish ________
Test operator name ________
Diluent instrument type ________
  Serial No ________

NO_x instrument type-——————————
Serial No. ———————————

Sample point	Time, min	O_2*, %	NO_x*, ppm

*Average steady-state value from recorder or instrument readout.

[Figure 20-8 amended by 51 FR 32455, September 12, 1986]

6.2.3 After sampling the last point, conclude the test run by recording the final turbine operating parameters and by determining the zero and calibration drift, as follows:

Immediately following the test run at each load condition, or if adjustments are necessary for the measurement system during the tests, reintroduce the zero and mid-level calibration gases as described in Sections 4.3, and 4.4, one at a time, to the measurement system at the calibration valve assembly. (Make no adjustments to the measurement system until after the drift checks are made). Record the analyzers' responses on a form similar to Figure 20-3. If the drift values exceed the specified limits, the test run preceding the check is considered invalid and will be repeated following corrections to the measurement system. Alternatively, recalibrate the measurement system and recalculate the measurement data. Report the test results based on both the initial calibration and the recalibration data.

6.3 SO_2 Measurement. This test is conducted only at the 100 percent peak load condition. Determine SO_2 using Method 6, or equivalent, during the test. Select a minimum of six total points from those required for the NO_x measurements; use two points for each sample run. The sample time at each point shall be at least 10 minutes. Average the O_2 readings taken during the NO_x test runs at sample points corresponding to the SO_2 traverse points (see Section 6.2.2) and use this average O_2 concentration to correct the integrated SO_2 concentration obtained by Method 6 to 15 percent O_2 (see Equation 20-1).

If the applicable regulation allows fuel sampling and analysis for fuel sulfur content to demonstrate compliance with sulfur emission unit. emission sampling with Method 6 is not required, provided the fuel sulfur content meets the limits of the regulation.

[6.3 amended by 55 FR 47472, November 14, 1990]

7. *Emission Calculations*

[7. revised by 51 FR 32455, September 12, 1986]

7.1 Moisture Correction. Measurement data used in most of these calculations must be on a dry basis. If measurements must be corrected to dry conditions, use the following equation:

$$C_d = \frac{C_w}{1 - B_{ws}}$$

Eq. 20-1

Where:

C_d = Pollutant or dilujent concentration adjusted to dry conditions, ppm or percent.

C_w = Pollutant or diluent concentrations measured under moist sample conditions, ppm or percent.

B_w= Moisture content of sample gas as measured with Method 4, reference method, or other approved method percsent/100.

7.2 CO_2 Correction Factor. If pollutant concentrations are to be corrected to 15 percent O_2 and O_2 concentration is measured in lieu of O_2 concentratin measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as follows:

7.2.1 Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2 and the following equation.

$$F_o = \frac{0.209 F_d}{F_c} \quad \text{Eq. 20-2}$$

Where:

F_o = Fuel factor based on the ratio of oxygen volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air, dimensionless.

0.209 = Fraction of air that is oxygen, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/10⁶ Btu).

F_c = Ratio of the volume of carbon dioxide produced to the gross calorific value of the fuel from Method 19, dsm³/J (dscf/10⁶ Btu).

7.2.2. Calculate the CO_2 correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \quad \text{Eq. 20-3}$$

where:

X_{CO} = CO_2 Correction factor, percent.

5.9 = 20.9 percent O_2 — 15 percent O_2, the defined O_2 correction value, percent.

7.3 Correction of Pollutant Concentrations to 15 percent O_2. Calculate the NO_x and SO_2 gas concentrations adjusted to 15 percent O_2 using Equation 20-4 or 20-5, as appropriate. The correction to 15 percent O_2 is very sensitive to the accuracy of the O_2 or CO_2 concentration measurement. At the level of the analyzer drift specified in Section 3, the O_2 or CO_2 correction can exceed 5 percent at the concentration levels expected in gas turbine exhaust gases. Therefore, O_2 or CO_2 analyzer stability and careful calibration are necessary.

7.3.1 Correction of Pollutant Concentration Using O_2 Concentration. Calculate the O_2 corrected pollutant concentration, as follows:

$$C_{adj} = C_d \frac{5.9}{20.9 - \%O_2} \quad \text{Eq. 20-4}$$

where:

C_{adj} = Pollutant concentration corrected to 15 percent O_2 ppm.

C_d = Pollutant concentration measured, dry basis, ppm.

$\%O_2$ = Measured O2 concentration dry basis, percent.

7.3.[illegible] Correction of Pollutant Concentration Using CO_2 corrected pollutant concentration, as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \quad \text{Eq. 20-5}$$

where:

CO_2 = Measured CO_2 concentration measured, dry basis, percent.

7.4 Average Adjusted NO_x Concentration. Calculate the average adjusted NO_x concentration by summing the adjusted values for each sample point and dividing by the number of points for each run.

7.5 NO_x and SO_2 Emission Rate Calculations. The emission rates for NO_x and SO_2 in units of pollutant mass per quantity of heat input can be calculated using the pollutants and diluent concentrations and fuel specific F-factors based on the fuel combustion characteristics. The measured concentrations of pollutant in units of parts per million by volume (ppm) must be converted to mass per unit volume concentration units for these calculations. Use the following table for such conversions:

CONVERSION FACTORS FOR CONCENTRATION

From	To	Multiply by
g/sm³	ng/sm³	10^9
mg/sm³	ng/sm³	10^6
lb/scf	ng/sm³	1.602×10^{13}
ppm (SO_2)	ng/sm³	2.660×10^6
ppm (NO_x)	ng/sm³	1.912×10^6
ppm (SO_2)	lb/scf	1.660×10^{-7}
ppm (NO_x)	lb/scf	1.194×10^{-7}

7.5.1 Calculation of Emission Rate Using Oxygen Correction. Both the O_2 concentration and the pollutant concentration must be on a dry basis. Calculate the pollutant emission rate, as follows:

$$E = C_d F_d \frac{20.9}{20.9 - \%O_2} \qquad \text{Eq. 20-6}$$

where:

E=Mass emission rate of pollutant, ng/J (lb/10⁶ Btu).

7.5.2 Calculation of Emission Rate Using Carbon Dioxide Correction. The CO_2 concentration and the pollutant concentration may be on either a dry basis or a wet basis, but both concentrations must be on the same basis for the calculations. Calculate the pollutant emission rate using Equation 20-7 or 20-8:

$$E = C_d F_c \frac{100}{\%CO_2} \qquad \text{Eq. 20-7}$$

$$E = C_w F_c \frac{100}{\%CO_{2w}} \qquad \text{Eq. 20-8}$$

where:

C_w=Pollutant concentration measured on a moist sample basis, ng/sm³ (lb/scf).

$\%CO_{2w}$=Measured CO_2 concentration measured on a moist sample basis, percent.

8. *Bibliography*

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METHOD 21—DETERMINATION OF VOLATILE ORGANIC COMPOUNDS LEAKS

1. *Applicability and Principle*

1.1 Applicability. This method applies to the determination of volatile organic compound (VOC) leaks from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals.

1.2 Principle. A portable instrument is used to detect VOC leaks from individual sources. The instrument detector type is not specified, but it must meet the specifications and performance criteria contained in Section 3. A leak definition concentration based on a reference compound is specified in each applicable regulation. This procedure is intended to locate and classify leaks only, and is not to be used as a direct measure of mass emission rates from individual sources.

2. *Definitions*

2.1 Leak Definition Concentration. The local VOC concentration at the surface of a leak source that indicates that a VOC emission (leak) is present. The leak definition is an instrument meter reading based on a reference compound.

2.2 Reference Compound. The VOC species selected as an instrument calibration basis for specification of the leak definition concentration. (For example: If a leak definition concentration is 10,000 ppmv as methane, then any source emission that results in a local concentration that yields a meter reading of 10,000 on an instrument calibrated with methane would be classified as a leak. In this example, the leak definition is 10,000 ppmv, and the reference compound is methane.)

2.3 Calibration Gas. The VOC compound used to adjust the instrument meter reading to a known value. The calibration gas is usually the reference compound at a concentration approximately equal to the leak definition concentration.

2.4 No Detectable Emission. Any VOC concentration at a potential leak source (adjusted for local VOC ambient concentration) that is less than a value corresponding to the instrument readability specification of section 3.1.1(c) indicates that a leak is not present.

[Revised by 55 FR 25604, June 22, 1990]

2.5 Response Factor. The ratio of the known concentration of a VOC compound to the observed meter reading when measured using an instrument calibrated with the reference compound specified in the application regulation.

2.6 Calibration Precision. The degree of agreement between measurements of the same known value, expressed as the relative percentage of the average difference between the meter readings and the known concentration to the known concentration.

2.7 Response Time. The time interval from a step change in VOC concentration at the input of the sampling system to the time at which 90 percent of the corresponding final value is reached as displayed on the instrument readout meter.

3. *Apparatus*

3.1 Monitoring Instrument.

3.1.1 Specifications.

a. The VOC instrument detector shall respond to the compounds being processed. Detector types which may meet this requirement include, but are not limited to, catalytic oxidation, flame ionization, infra red absorption, and photoionization.

b. — e. revised and f. added by 55 FR 25604, June 22,1990]

b. Both the linear response range and the measurable range of the instrument for each of the VOC to be measured, and for the VOC calibration gas that is used for calibration, shall encompass the leak definition concentration specified in the regulation. A dilution probe assembly may be used to bring the VOC concentration within both ranges; however, the specifications for instrument response time and sample probe diameter shall still be met.

c. The scale of the instrument meter shall be readable to ±2.5 percent of the specified leak definition concentration when performing a no detectable emission survey.

d. The instrument shall be equipped with an electrically driven pump to insure that a sample is provided to the detector at a constant flow rate. The nominal sample flow rate, as measured at the sample probe tip, shall be 0.10 to 3.0 liters per minute when the probe is fitted with a glass wool plug or filter that may be used to prevent plugging of the instrument.

e. The instrument shall be intrinsically safe as defined by the applicable U.S.A. standards (e.g., National Electric Code by the National Fire Prevention Association) for operation in any explosive atmospheres that may be encountered in its use. The instrument shall, at a minimum, be intrinsically safe for Class 1, Division 1 conditions, and Class 2, Division 1 conditions, as defined by the example Code. The instrument shall not be operated with any safety device, such as an exhaust flame arrestor, removed.

f. The instrument shall be equipped with a probe or probe extension for sampling not to exceed ¼ in. in outside diameter, with a single end opening for admission of sample.

3.1.2 Performance Criteria.

[(a) and (b) revised by 55 FR 25604, June 22, 1990]

(a) The instrument response factors for each of the VOC to be measured shall be less than 10. When no instrument is available that meets this specification when calibrated with the reference VOC specified in the applicable regulation, the available instrument may be calibrated with one of the VOC to be measured, or any other VOC, so long as the instrument then has a response factor of less than 10 for each of the VOC to be measured.

(b) The instrument response time shall be equal to or less than 30 seconds. The instrument pump, dilution probe (if any), sample probe, and probe filter, that will be used during testing, shall all be in place during the response time determination.

c. The calibration precision must be equal to or less than 10 percent of the calibration gas value.

d. The evaluation procedure for each parameter is given in Section 4.4.

3.1.3 Performance Evaluation Requirements.

a. A response factor must be determined for each compound that is to be measured, either by testing or from reference sources. The response factor tests are required before placing the analyzer into service, but do not have to be repeated at subsequent intervals.

b. The calibration precision test must be completed prior to placing the analyzer into service, and at subsequent 3-month intervals or at the next use whichever is later.

c. The response time test is required prior to placing the instrument into service. If a modification to the sample pumping system or flow configuration is made that would change the response time, a new test is required prior to further use.

3.2 Calibration Gases. The monitoring instrument is calibrated in terms of parts per million by volume (ppmv) of the reference compound specified in the applicable regulation. The calibration gases required for monitoring and instrument performance evaluation are a zero gas (air, less than 10 ppmv VOC) and a calibration gas in air mixture approximately equal to the leak definition specified in the regulation. If cylinder calibration gas mixtures are used, they must be analyzed and certified by the manufacturer to be within ±2 percent accuracy, and a shelf life must be specified. Cylinder standards must be either reanalyzed or replaced at the end of the specified shelf life. Alternately, calibration gases may be prepared by the user according to any accepted gaseous standards preparation procedure that will yield a mixture accurate to within ±2 percent. Prepared standards must be replaced each day of use unless it can be demonstrated that degradation does not occur during storage.

Calibrations may be performed using a compound other than the reference compound if a conversion factor is determined for that alternative compound so that the resulting meter readings during source surveys can be converted to reference compound results.

4. *Procedures*

4.1 Pretest Preparations. Perform the instrument evaluation procedures given in Section 4.4 if the evaluation requirements of Section 3.1.3 have not been met.

4.2 Calibration Procedures. Assemble and start up the VOC analyzer according to the manufacturer's instructions. After the appropriate warmup period and zero internal calibration procedure, introduce the calibration gas into the instrument sample probe. Adjust the instrument meter readout to correspond to the calibration gas value.

NOTE: If the meter readout cannot be adjusted to the proper value, a malfunction of the analyzer is indicated and corrective actions are necessary before use.

4.3 Individual Source Surveys.

4.3.1 Type I—Leak Definition Based on Concentration. Place the probe inlet at the surface of the component interface where leakage could occur. Move the probe along the interface periphery while observing the instrument readout. If an increased meter reading is observed, slowly sample the interface where leakage is indicated until the maximum meter reading is obtained. Leave the probe inlet at this maximum reading location for approximately two times the instrument response time. If the maximum observed meter reading is greater than the leak definition in the applicable regulation, record and report the results as specified in the regulation reporting requirements. Examples of the application of this general technique to specific equipment types are:

a. Valves—The most common source of leaks from valves is at the seal between the stem and housing. Place the probe at the interface where the stem exits the packing gland and sample the stem circumference. Also, place the probe at the interface of the packing gland take-up flange seat and sample the periphery. In addition, survey valve housings of multipart assembly at the surface of all interfaces where a leak could occur.

b. Flanges and Other Connections—For welded flanges, place the probe at the outer edge of the flange-gasket interface and sample the circumference of the flange. Sample other types of nonpermanent joints (such as threaded connections) with a similar traverse.

c. Pumps and Compressors—Conduct a circumferential traverse at the outer surface of the pump or compressor shaft and seal interface. If the source is a rotating shaft, position the probe inlet within 1 cm of the shaft-seal interface for the survey. If the housing configuration prevents a complete traverse of the shaft periphery, sample all accessible portions. Sample all other joints on the pump or compressor housing where leakage could occur.

d. Pressure Relief Devices—The configuration of most pressure relief devices prevents sampling at the sealing seat interface. For those devices equipped with an enclosed ex-

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

March 31, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. John P. Jones, President
Orlando CoGen Inc.
7201 Hamilton Boulevard
Allentown, Pennsylvania 18195-1501

Dear Mr. Jones:

Re: Completeness Review for Application to Construct a Combustion
Turbine and Associated Heat Recovery Steam Generator
AC 48-206720 and PSD-FL-184

The Department has reviewed the supplementary information received on March 2, 1992. Based on a technical evaluation of the material, the application package is deemed incomplete. Therefore, please submit to the Department's Bureau of Air Regulation the following information, including all calculations, assumptions and reference material, and the status will, again, be ascertained:

1. Please provide additional clarification and completed calculations for items on the page numbered as Notes-1, which were discussed in a meeting held on March 11 between Messrs. Ken Kosky (KBN) and Bruce Mitchell (FDER/BAR).
2. Please provide a floppy disk containing the data that was used to calculate and generate the information found in Tables A-1 thru A-4.

Sincerely,

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

CHF/BM/plm

cc: C. Collins, CD
D. Nester, OCEPD
G. Smallridge, Esq., DER
C. Shaver, NPS
J. Harper, EPA
D. Buff, P.E., KBN

Recycled Paper

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

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

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

Consult postmaster for fee.

3. Article Addressed to:

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

4a. Article Number
P 617 884 161

4b. Service Type
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☒ Certified ☐ COD
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7. Date of Delivery
4-6-92

5. Signature (Addressee)

6. Signature (Agent)

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

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

P 617 884 161

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UNITED STATES POSTAL SERVICE

Sent to Mr. John P. Jones, Orlando CoGen Inc.	
Street & No 7201 Hamilton Blvd.	
P.O., State & ZIP Code Allentown, PA 18195-1501	
Postage	$
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Return Receipt Showing to Whom & Date Delivered	
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Postmark or Date
Mailed: 3-31-92
Permit: AC 48-206720
PSD-FL-184

PS Form **3800**, June 1990

KBN

RECEIVED

MAR 25 1992

Bureau of
Air Regulation

March 24, 1992

Bruce Mitchell
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Bruce:

Please find attached for your consideration and use a proposed permit package for the Orlando CoGen project. I have tailored this after the recently issued Pasco and Lake Cogen permits. I have also enclosed a copy of the text on disk, both 3½ and 5¼, in both WordPerfect 5.1 and DOS files.

Sincerely,

Kennard F. Kosky
President

KFK/dmm
cc: File (2)

91134B1/R2/1

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

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

Technical Evaluation
and
Preliminary Determination

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

128-MW Combined Cycle Gas Turbine Cogeneration Facility

Permit Number: AC 48-206720
PSD-FL-184

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

April 1992

SYNOPSIS OF APPLICATION

I. NAME AND ADDRESS OF APPLICANT

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

II. REVIEWING AND PROCESS SCHEDULE

Date of Receipt of Application: December 30, 1991.

III. FACILITY INFORMATION

III.1 Facility Location

This facility is located in Orlando Central Park in Orange County, Florida. The UTM coordinates are 459.5 km East and 3,146.1 km North.

III.2 Facility Identification Code (SIC)

Major Group No. 49 - Electric, Gas and Sanitary Services.

Industry Group No. 493 - Combination Electric, Gas and Other Utility Services.

Industry Group No. 4931 - Electric and Other Services Combined.

III.3 Facility Category

The proposed facility will be classified as a major emitting facility. The proposed project will emit approximately 401 tons per year (TPY) of nitrogen oxides (NO_x), 12 TPY of sulfur dioxide (SO_2), 42 TPY of particulate matter (PM), 115 TPY of carbon monoxide, 20 TPY of volatile organic compounds (VOC), and 0.9 TPY of sulfuric acid mist.

IV. PROJECT DESCRIPTION

Orlando CoGen Limited, L.P. proposes to construct and operate a nominal 128-MW combined cycle gas turbine cogeneration facility. The unit will be located adjacent to the Air Products and Chemicals plant. The project will consist of one combustion turbine (CT), a heat recovery steam generator (HRSG) with duct burner, and a steam cycle. The combustion turbine will be capable of generating approximately 78 MW while operating in simple cycle and 128 MW when in combined cycle operation. The combined cycle HRSG will power a 50-MW steam turbine-generator. The HRSG with supplemental firing of duct burner will supply steam to an absorption chiller system which will supply chilled water to the Air Products and Chemicals Plant located adjacent to the site. The fuel will be natural gas.

V. RULE APPLICABILITY

The proposed project is subject to preconstruction review under the provisions of Chapter 403, Florida Statutes, and Chapter 17-2, Florida Administrative Code (F.A.C.).

The plant is located in an area designated attainment for all criteria pollutants in accordance with F.A.C. Rule 17-2.420.

The proposed project will be reviewed under F.A.C. Rule 17-2.500, Prevention of Significant Deterioration (PSD), because it will be a major facility. This review consists of a determination of Best Available Control Technology (BACT) and unless otherwise exempted, an analysis of the air quality impact of the increased emissions. No air quality impact analysis is required for ozone and there will not be a significant increase in VOC emissions. The review also includes an analysis of the project's impacts on soils, vegetation and visibility; along with air quality impacts resulting from associated commercial, residential and industrial growth.

This source shall be required to comply with the New Source Performance Standards (NSPS) for Gas Turbines, Subpart GG, and NSPS for Industrial Steam-Generating Units, Subpart Db, which are contained in 40 CFR 60, Appendix A and is adopted by reference in F.A.C. Rule 17-2.660. The proposed source shall also comply with applicable provisions of F.A.C. Rule 17-2.700, Stack Test Procedures, and F.A.C. Rule 17-2.630, Best Available Control Technology.

VI. SOURCE IMPACT ANALYSIS

VI.1 Emission Limitations

The operation of the combined cycle plant will produce emissions of NO_x, SO_2, CO, VOC, sulfuric acid mist, PM, and PM_{10}. The impact of these pollutant emissions are below the Florida ambient air quality standards (AAQS) and/or the acceptable ambient concentration levels (AAC). Table 1 lists each contaminant and its maximum expected emission rate, along with the proposed increase of emissions.

VI.2 Air Toxics Evaluation

The operation of this source will produce emissions of chemical compounds that may be toxic in high concentrations. The emission rates of these chemicals shall not create ambient concentrations greater than the acceptable ambient concentrations (AAC) as shown below. Determination of the AAC for these organic compounds shall be determined by Department approved dispersion modeling or ambient monitoring.

$$AAC = \frac{OEL}{\text{Safety Factor}}$$

Where,

AAC = acceptable ambient concentration

Safety Factor = 50 for category B substances and 8 hrs/day
100 for category A substances and 8 hrs/day
210 for category B substances and 24 hrs/day
420 for category A substances and 24 hrs/day

OEL = Occupational exposure level such as ACGIH, ASHA and NIOSH published standards for toxic materials.

MSDS = Material Safety Data Sheets

VI.3 Air Quality Analysis

a. Introduction

The operation of the proposed 128 MW combined cycle gas turbine system will result in emissions increases which are projected to be greater than the PSD significant emission rates for the following pollutants: CO, NO_x, PM, and PM_{10}. Therefore, the project is subject to the PSD review requirements contained in F.A.C. Rule 17-2.500 for these pollutants. Part of these requirements is an air quality impact analysis for these pollutants, which includes:

- An analysis of existing air quality;
- A PSD increment analysis (for SO_2, PM, PM_{10}, and NO_x);
- An ambient Air Quality Standards analysis (AAQS);
- An analysis of impacts on soils, vegetation, visibility and growth-related air quality impacts; and
- A Good Engineering Practice (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The PSD increment and AAQS analyses are based on air quality dispersion modeling completed in accordance with EPA guidelines.

Based on these required analyses, the Department has reasonable assurance that the combined cycle gas turbine cogeneration facility, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any PSD increment or ambient air quality standard. A brief description of the modeling methods used and results of the required analyses follow. A more complete description is contained in the permit application on file.

b. Analysis of the Existing Air Quality

Preconstruction ambient air quality monitoring may be required for pollutants subject to PSD review. However, an exemption to the monitoring requirement can be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined through air quality modeling, is less than a pollutant-specific de minimus concentration. The predicted maximum concentration increase for each pollutant subject to PSD review is given below:

	CO	TSP and PM_{10}	NO_x
PSD de minimus Concentration ($\mu g/m^3$)	575	10	14
Averaging Time	8-hr	24-hr	Annual
Maximum Predicted Impact ($\mu g/m^3$)	12.0	2.4	0.6

As shown above, the predicted impacts are all less than the corresponding de minimus concentrations; therefore, no preconstruction monitoring is required for any pollutant.

c. Modeling Method

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used by the applicant to predict the impact of the proposed project on the surrounding ambient air. All recommended EPA default options were used. Direction-specific downwash parameters were used because the stack was less than the good engineering practice (GEP) stack height. Five years of sequential hourly surface and mixing depth data from the Orlando, Florida National Weather Service (NWS) station collected during 1982 through 1986 were used in the model. Since five years for data were used, the highest-second-high short-term predicted concentrations are compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards.

d. Modeling Results

The applicant first evaluated the potential increase in ambient ground-level concentrations associated with the project to determine if these predicted ambient concentration increases would be greater than specified PSD significant impact levels for CO, NO_x, PM and PM_{10}. Dispersion modeling was performed with receptors placed along the 36 standard radial directions (10 degrees apart) surrounding the proposed source at the following downwind distances: 47; 100; 300; 600; 900; 1,200; 1,600; 2,000; 2,500; 3,000; 4,000; and 5,000 meters. Refined analyses were then performed to determine maximum impacts. The results of this modeling presented below show that the increases in ambient ground-level concentrations for all averaging times are less than the PSD significant impact levels for CO, NO_x, PM, and PM_{10}.

Pollutant	Averaging Time	PSD Significance Level ($\mu g/m^3$)	Ambient Concentration Increase ($\mu g/m^3$)
CO	8-hour	500	47.0
	1-hour	2000	12.0
NO_2	Annual	1.0	0.61
PM/PM_{10}	Annual	1.0	0.07
	24-hour	5.0	2.44

Therefore, further dispersion modeling for comparison with AAQS and PSD increment consumption were not required in this case.

The applicant performed dispersion modeling to determine the predicted ambient concentration increases in the Class I Chassahowitzka National Wilderness Area located 121 km away for the pollutants with Class I increments. The maximum predicted PM increases are 0.001 $\mu g/m^3$ for the annual averaging time and 0.02 for the 24-hr averaging time. The maximum predicted NO_2 increase is 0.01 $\mu g/m^3$ for the annual averaging time. These predicted values are all much less than the corresponding Class I increments and the EPA Class I significant impact levels.

e. Additional Impacts Analysis

The emissions from the Orlando CoGen Limited, L.P., facility are not expected to affect the visibility in the Chassahowitzka National Wilderness area located 121 km away because of the very small maximum predicted impacts. Because the impacts from the proposed pollutants are predicted to be less than PSD significance levels, no harmful effects on soils and vegetation is expected. In addition, the proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

VII. CONCLUSION

Based on the information provided by Orlando CoGen Limited, L.P., the Department has reasonable assurance that the proposed installation of the 128 MW combined cycle gas turbine system, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapter 17-2 of the Florida Administrative Code.

State of Florida
Department of Environmental Regulation
Notice of Intent to Issue

The Florida Department of Environmental Regulation hereby gives notice of its intent to issue a permit to Orlando CoGen Limited, L.P., 7201 Hamilton Boulevard, Allentown, PA 18195-1501, to construct and operate a nominal 128-MW combined cycle gas turbine cogeneration facility located in Orange County, Florida. A determination of Best Available Control Technology (BACT) was required. The Class I PM_{10} PSD increment consumed is 0.02 vs. 8 allowable 24-hour average and 0.001 vs. 4 allowable annual average, in micrograms per cubic meter. The Class I nitrogen dioxide increment consumed is 0.01 vs. 2.5 allowable annual average, in micrograms per cubic meter. The maximum predicted increases in ambient concentrations for the above three pollutants for all averaging times are less than significant in the Class II area surrounding the plant, thus no increment consumption was calculated. The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

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

The Petition shall contain the following information:

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

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

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

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

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

Department of Environmental Regulation
Central District
3319 Maguire Blvd.
Orlando, Florida 32803-3767

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

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

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

In the Matter of
Application for Permit by:

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

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

INTENT TO ISSUE

The Department of Environmental Regulation hereby gives notice of its intent to issue an air construction permit (copy attached) for the proposed project as detailed in the application specified above. The Department is issuing this Intent to Issue for the reasons stated in the attached Technical Evaluation and Preliminary Determination.

The applicant, Orlando CoGen Limited, L.P., applied on December 30, 1991, to the Department of Environmental Regulation for a permit to construct and operate a nominal 128-MW cogeneration facility consisting of one combined cycle gas turbine generator and associated steam cycle.

The Department has permitting jurisdiction under Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. The project is not exempt from permitting procedures. The Department has determined that an air construction permit is required for the proposed work.

Pursuant to Section 403.815, F.S. and DER Rule 17-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permit. The notice shall be published one time only within 30 days, in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. The applicant shall provide proof of publication to the Department, at the address specified within seven days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

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

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

Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, Florida Statutes.

The Petition shall contain the following information:

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

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

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

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

Copies furnished to:

Charles Collins, CD
Jewell Harper, EPA

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this NOTICE OF INTENT TO ISSUE and all copies were mailed before the close of business on ________________.

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

_________________ _________
Clerk Date

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

The applicant proposes to install a combustion turbine generator at its facility in Orange County. The generator system will consist of one nominal 78-megawatt (MW) combustion turbine, with exhaust through heat recovery steam generator (HRSG) which will be used to power nominal 50-MW steam turbine. The HRSG will be supplementary fired to produce sufficient steam at higher operating temperatures.

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

Pollutant	Potential Emissions (TPY)	PSD Significant Emission Rate (TPY)
NO_x	400.9	40
SO_2	12.02	40
PM	41.67	25
PM_{10}	41.67	15
CO	114.6	100
VOC	19.8	40
H_2SO_4	0.92	7
Be	Neg.	0.0004
Hg	Neg.	0.1
Pb	Neg.	0.6

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

Date of Receipt of a BACT Application

December 30, 1991

BACT Determination Requested by the Applicant

Pollutant	Determination
NO_x	25 ppmvd @ 15% O_2 (natural gas burning)--CT 0.1 lb/10^6 Btu--duct burner
CO	Combustion control
PM and PM_{10}	Combustion control

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-2, Air Pollution, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the top-down approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, than the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

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

- Combustion Products (e.g., particulates). Controlled generally by good combustion of clean fuels.
- Products of Incomplete Combustion (e.g., CO). Control is achieved largely by proper combustion techniques.
- Acid Gases (e.g., NO_x). Controlled generally by gaseous control devices.

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

Combustion Products

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

A PM/PM_{10} emissions limitations of 0.011 lb/MMBtu from the CT when firing natural gas is reasonable as BACT for the Orlando CoGen facility. The duct burner PM/PM_{10} emission rate of 0.01 lb/MMBtu is reasonable as BACT.

Products of Incomplete Combustion

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

A review of the BACT/LAER clearinghouse indicates that several of the combustion turbines using dry low-NO_x combustion technology to control NO_x to 25 ppmvd (corrected to 15 percent O_2) have been permitted with CO limitations that are higher than those proposed by the applicant. The applicant has stated that the CT is a new design, and CO margins must be higher. The majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, additional control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions). In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing gas turbine applications have been limited to smaller cogeneration facilities burning natural gas.

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

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

Acid Gases

The emissions of nitrogen oxides represent a significant proportion of the total emissions and need to be controlled if deemed appropriate.

The applicant has stated that BACT for nitrogen oxides will be met by using dry low-NO_x combustion to limit emissions to 25 ppmvd at 15% oxygen when burning natural gas.

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

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

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

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

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

Based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions with dry low-NO_x combustion from the Orlando CoGen facility will be 401 tons/year. Assuming that SCR would reduce the NO_x emissions to a level of 9 ppmvd when firing natural gas, about 141 tons of NO_x would be emitted annually. When this reduction is taken into consideration with the total levelized annual cost of $1,903,000, the cost per ton of controlling NO_x is $7,319. This calculated cost is higher than has previously been approved as BACT.

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

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

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

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

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing operation NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 75 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases.

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

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

Environmental Impact Analysis

The predominant environmental impacts associated with this proposal are related to the use of SCR for NO_x control. The use of SCR results in emissions of ammonia, which may increase with increasing levels of NO_x control. In addition, some catalysts may contain substances which are listed as hazardous waste, thereby creating an additional environmental burden. Also, air emissions result from the lost generations that must be replaced. The lost generation is due to the back pressure on the turbine covered by the catalyst. Although the use of SCR does have some environmental impacts, the disadvantages may outweigh the benefit which would be provided by reducing nitrogen oxide emissions by 80 percent or greater. The benefit of NO_x control by using SCR is substantiated by the fact that nearly one half of all BACT determinations have established SCR as the control measure for nitrogen oxides over the last 5 years.

In addition to the criteria pollutants, the impacts of toxic pollutants associated with the combustion of natural gas have been evaluated. Toxics are expected to be emitted in minimal amounts, with the total emissions combined to be less than 0.1 TPY.

Although the emissions of the toxic pollutants could be controlled by particulate control devices such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of the toxic pollutants associated with the firing of natural gas.

Potentially Sensitive Concerns

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

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

2. SCR could result in the release of unreacted quantities of ammonia to the atmosphere.
3. SCR would require handling of ammonia by plant operators. Since it is a hazardous material, there is a concern about safety and productivity of operators.
4. SCR results in contaminated catalyst from flue gas trace elements which could be considered hazardous. Safety of operators and disposal of spent catalyst is a concern.

The combustion turbine proposed for the project (ABB 11N-EV) is a heavy-frame machine that is highly efficient and uses advanced dry low-NO_x combustion technology. Information supplied by the applicant indicates that actual emissions will be 25 ppmvd or lower on a continuous basis. The manufacturer's guarantee is 25 ppm; the Department, the applicant, and the manufacturer expect lower emissions.

BACT Determination by DER

NO_x Control

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

The information that the applicant presented and Department calculations indicates that the incremental cost of controlling NO_x ($7,319/ton) is high compared to other BACT determinations which require SCR. Furthermore, actual NO_x levels are expected to be less than the 25 ppm guarantee which would increase the cost effectiveness of SCR. Based on the information presented by the applicant and the studies conducted, the Department believes that the use of SCR for NO_x control is not justifiable as BACT. Therefore, the Department is willing to accept for NO_x control when firing natural gas.

The emissions of NO_x from the duct burners will be limited to 0.1 lb/MMBtu which has been the BACT limit established for similar facilities. Duct firing will be used for supplying steam and limited to an equivalent to 4,500 hours/year at 100 MMBtu/hr.

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

Pollutant	Emission Limit CT (Natural Gas Firing)	Duct Burner[a]
NOx	25 ppmvd @ 15% O_2	0.1 lb/MMBtu
CO	10 ppmvd	0.1 lb/MMBtu
PM & PM10	0.011 lb/MMBtu	0.01 lb/MMBtu

[a] Natural gas will be used only for supplemental firing for no greater than 4,500 full-load equivalent hours at 100 MMBtu/hr on a total annual Btu basis.

Details of the Analysis May Be Obtained by Contacting:

Bruce Mitchell, P.E., BACT Coordinator
Department of Environmental Regulation
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

______________________ 1992
Date

Approved by:

Carol M. Browner, Secretary
Dept. of Environmental Regulation

______________________ 1992
Date

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 ppmvd at 15% O_2	95.7	400.9
	DB	NG	BACT: 0.1 lb/MMBtu	12.2	
CO	CT	NG	BACT: 10 ppmvd	22.3	114.6
	DB	NG	BACT: 0.1 lb/MMBtu	12.2	
PM/PM_{10}	CT	NG	BACT: 0.011 lb/MMBtu	11.0	41.67
	DB	NG	BACT: 0.01 lb/MMBtu	1.22	
VOC	CT	NG	Proposed by Applicant	3.18	19.75
	DB	NG	Proposed by Applicant	3.7	

[a] CT = combustion turbine
DB = duct burner

[b] NG = natural gas

PERMITTEE:
Orlando CoGen Limited, L.P.
7201 Hamilton Blvd.
Allentown, PA 18195-1501

Permit Number: AC 48-206720
Expiration Date: June 1, 1994
County: Orange
Latitude/Longitude: 28°26'23"N
81°24'28"W
Project: 128-MW Combined Cycle
Gas Turbine

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

For the construction of a 128-MW combined cycle gas turbine cogeneration facility to be located in Orlando Central Park and supply steam to the adjacent Air Products and Chemicals plant in Orange County, Florida. The UTM coordinates are 459.5 km East and 3,146.1 km North.

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

Attachments are listed below:

1. Orlando CoGen Limited's application dated December 19, 1991.
2. Department's sufficiency request dated January 28, 1992.
3. Letter from KBN Engineering and Applied Science, Inc., dated February 27, 1992, to supply additional information.

GENERAL CONDITIONS:

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

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

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

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

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

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

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

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

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

GENERAL CONDITIONS:

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

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

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

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

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

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

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

10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

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

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

13. This permit also constitutes:

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

GENERAL CONDITIONS:

14. The permittee shall comply with the following:

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

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

c. Records of monitoring information shall include:

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

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

SPECIFIC CONDITIONS:

Emission Limits

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

2. Unless the Department has determined other concentrations are required to protect public health and safety, predicted acceptable ambient air concentrations (AAC) of the following pollutants shall not be exceeded:

PERMITTEE:
Orlando CoGen Limited, L.P.

Permit Number: AC 48-206720
Expiration Date: June 1, 1994

SPECIFIC CONDITIONS:

Pollutant	Acceptable Ambient Concentrations $\mu g/m^3$ 8 Hours	24 Hours	Annual
Beryllium	0.02	0.005	0.0004
Lead	1.5	0.36	0.09
Mercury: allyl compounds	0.1	0.024	-
• all forms of vapor except allyl	0.5	0.12	-
• allyl & organic compounds	1	0.24	

3. Visible emissions shall not exceed 10% opacity.

Operating Rates

4. This source is allowed to operate continuously (8,760 hours per year).

5. This source is allowed to use natural gas as the primary fuel.

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

- Maximum heat input shall not exceed 829.6 MMBtu/hr/CT (gas) at ISO conditions.
- Duct firing shall be limited to natural gas firing only with a maximum heat input of 122 MMBtu/hr.
- Duct firing shall be limited to 450,000 MMBtu/year/HRSG-duct burner, which is an equivalent to 4,500 hours at 100 MMBtu/hour.

7. Any change in the method of operation, equipment or operating hours shall be submitted to the DER's Bureau of Air Regulation and Central District offices.

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

Compliance Determination

9. Compliance with the NO_x, CO, and visible emission standards shall be determined by the following reference methods as described in 40 CFR 60, Appendix A (July 1, 1990) and adopted by reference in F.A.C. Rule 17-2.700.

SPECIFIC CONDITIONS:

- Method 1. Sample and Velocity Traverses
- Method 2. Volumetric Flow Rate
- Method 3. Gas Analysis
- Method 9. Determination of the Opacity of the Emissions from Stationary Sources
- Method 10. Determination of the Carbon Monoxide Emission from Stationary Sources
- Method 20. Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines

10. An initial compliance test shall be performed using natural gas.

11. Compliance with the SO_2 emission limit can also be determined by calculations based on fuel analysis from the natural gas supplier.

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

13. During performance tests,, to determine compliance with the proposed NO_x standard, measured NO_x emission at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

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

where:

NO_x = Emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x\ obs}$ = Measured NO_x emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{AMB} = Temperature of ambient air at test.

SPECIFIC CONDITIONS:

14. Test results will be the average of 3 valid runs. The Central District office will be notified at least 30 days in advance of the compliance test. The source shall operate between 90% and 100% of permitted capacity as adjusted for ambient temperature during the compliance test. Compliance test results shall be submitted to the Central District office no later than 45 days after completion.

15. Dry low-NO_x combustion shall be utilized for NO_x control. The NO_x emissions shall be continuously monitored using procedures specified in 40 CFR Part 60.

Rule Requirements

16. This source shall comply with all applicable provisions of Chapter 403, Florida Statutes and Chapters 17-2 and 17-4, Florida Administrative Code.

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

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

19. This source shall comply with F.A.C. Rule 17-2.700, Stationary Point Source Emission Test Procedures.

20. Pursuant to F.A.C. Rule 17-2.210(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur, nitrogen content and lower heating value of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual reports shall be sent to the Department's Southwest District office.

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

PERMITTEE: Orlando CoGen Limited, L.P.	Permit Number: AC 48-206720 Expiration Date: June 1, 1994

SPECIFIC CONDITIONS:

22. An application for an operation permit must be submitted to the Central District office at least 90 days prior to the expiration date of this construction permit or within 45 days after completion of compliance testing, whichever occurs first. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rule 17-4.220).

Issued this _______ day
of _______________, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
Carol M. Browner, Secretary

CONTACT REPORT

DATE: 3-23-92 **ORIGINATOR:** Heather V. Rooney

CONTACT BY: _X_ TELEPHONE ____ MEETING OTHER: __________

NAME, TITLE, AND ORGANIZATION

Mr. Preston Lewis
Florida Department of Environmental Regulation

ADDRESS AND TELEPHONE NUMBER

Mr. Preston Lewis
Florida Department of Environmental Regulation
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400
(904)488-1344

CONTACT SUMMARY

Mr. Lewis was contacted to request cooperation in identifying and supplying the following information: state and local regulations for stationary gas turbines and the basis of those regulations; general emission test data for stationary gas turbines; and copies of permits for stationary gas turbines.

Mr. Lewis stated that the state emission regulations for Florida are more stringent than the Federal regulations. The majority of the turbines are utilized for utility power generation and are regulated through a BACT review. BACT determinations are decided on a case by case basis for those turbines over 250,000 Btu/hr. The BACT determinations for Florida have primarily been combustion controls either with or without wet injection. In addition, many of the determinations require the facilities to ensure that the necessary space is available for future SCR installation if it is deemed necessary. The BACT NOx emission limits are 25 ppm for gas and 42 ppm for oil. In addition a CO catalyst may be required if CO emission levels exceed 42 ppm. Mr. Lewis stated that CO levels have been more favorable with dry Low NOx combustor controls than with wet Low NOx combustor controls.

Mr. Lewis also stated that compliance testing is required shortly after the turbine is operational and then either once a year or every three years depending on the permitting requirements. The compliance tests require monitoring of criteria pollutants and air toxics. Continuous Emission Monitors (CEMs) are required for monitoring NOx and SO2 for the major sources.

Confirmation Signature and Date

Add. Af 2/27/03 / [illegible]

KBN

February 27, 1992

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

Subject: Orange County - A.P.
Orlando CoGen Limited, L.P.
Combustion Turbine and Heat Recovery Steam Generator
AC 48-206720 and PSD-FL-184

RECEIVED
MAR 03 1992
Division of Air
Resources Management

Attention: Bruce Mitchell

Dear Bruce:

This correspondence provides the information requested in the Department's letter dated January 28, 1992. A discussion of the items is presented in the same order as listed in the January 28th letter.

1. As described in the introduction to Appendix A, all emission calculations are performed on a Lotus 1-2-3 spreadsheet. A printout showing all equations was also presented. This printout was annotated to show the source of all data not calculated. Presented in an updated Appendix A are example calculations for 20°F condition. Calculations for other temperatures are the same as shown on the printout. Included in the updated Appendix A are the emission factors used for POM and formaldehyde. All other emissions were calculated based on the manufacturer's specifications. During the review of the spreadsheets, it was noted that the sulfuric acid mist emission was incorrect. The relevant tables in the report have been updated to reflect the correct emissions. This change does not affect PSD applicability.

2. Tables 4-5, 4-6, and 4-7 were also generated in Lotus 1-2-3. These tables have been annotated to include equations as well as the origin of data. The revised tables are enclosed. It was also noticed that the cost for interest during construction in Table 4-5 included an additional cost that was not correct. This cost has been corrected and included on the annotated tables.

   The cost to modify the heat recovery steam generator (HRSG) to incorporate space for SCR has been estimated by the HRSG manufacturer to range from $500,000 to $750,000 which is higher than the estimate in Table 4-5 of $303,000. The manufacturer's estimate is higher due to the need to split the boiler into two sections, move boiler tubes, and add additional structural steel for support of the steam drums. Also, an additional $500,000 (not accounted for in Table 4-5) is required to expand the turbine/boiler building. These costs were not added to the capital costs since the cost analysis contains contingency funds to account for project-specific cost differences. Nonetheless, the Department should consider this total cost,

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

i.e. about \$1,000,000 to \$1,250,000, in establishing any permit condition that may require the installation of a duct module for SCR.

3. The low-NO_x combustor in the ABB 11N-EV is currently available and in use in the United States. There is no separate model number for the combustor. Information on the proposed machine is attached. The ABB 11N-EV with the low-NO_x combustor can achieve lower NO_x emissions than 25 ppmvd corrected to 15 percent oxygen; however, the guaranteed NO_x emission rate is based on 25 ppmvd (corrected).

4. Information on the ABB dry low-NO_x combustor is attached. The information includes:
    a. ABB literature on low-NO_x combustor.
    b. Letter (2/14/92) from ABB describing performance of dry low-NO_x combustor.
    c. Test results from the Midland Michigan unit.
    d. ASME technical paper on the ABB dry low-NO_x combustor.

    This information clearly indicates that the combustion turbine selected for the project can achieve NO_x emission levels well below 25 ppmvd (corrected to 15 percent oxygen). However, the guaranteed emission rate is 25 ppmvd (corrected to 15 percent oxygen).

5. SCR is not currently incorporated into the design of the proposed facility. The cost to provide this space has been estimated to be from \$1,000,000 to \$1,250,000. Although SCR could be installed at a future date if sufficient duct space were left in the HRSG, it does not appear practical to require such space in light of the actual performance data from ABB. Based on actual performance data from the Midland, Michigan unit, NO_x levels are expected to be in the 15 ppmvd range (corrected to 15 percent oxygen) for the proposed project. At an actual emission level of 15 ppmvd, the cost effectiveness of SCR would be approximately \$12,000/ton of NO_x removed.

Please call if you have any questions.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President and Principal Engineer

KFK/dmpm

Enclosures

cc: John P. Jones, Orlando CoGen Limited, L.P.
Gary Kinsey, Air Products
File (2)
C. Holladay
C. Collins
D. Nester
C. Shaver
J. Harper

91134C2/2

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)	$1.04\text{x}10^{-3}$	$9.56\text{x}10^{-4}$	$9.25\text{x}10^{-4}$	$8.59\text{x}10^{-4}$	$1.36\text{x}10^{-4}$
(TPY)	$4.56\text{x}10^{-3}$	$4.19\text{x}10^{-3}$	$4.05\text{x}10^{-3}$	$3.76\text{x}10^{-3}$	$2.51\text{x}10^{-4}$
Formaldehyde (lb/hr)	$8.25\text{x}10^{-2}$	$7.57\text{x}10^{-2}$	$7.33\text{x}10^{-2}$	$6.80\text{x}10^{-2}$	$1.08\text{x}10^{-2}$
(TPY)	$3.61\text{x}10^{-1}$	$3.31\text{x}10^{-1}$	$3.21\text{x}10^{-1}$	$2.98\text{x}10^{-1}$	$1.99\text{x}10^{-2}$

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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)
```

```
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)
```

```
A:A75: [W22] '  TPY
A:B75: (F2) [W16] (B74*8760/2000)
A:C75: (F2) [W16] (C74*8760/2000)
A:D75: (F2) [W16] (D74*8760/2000)
A:E75: (F2) [W16] (E74*8760/2000)
A:F75: (F2) [W16] (F74*3688.5/2000)
A:G75: [W6] (G74+1)
A:A76: [W22] '  ppm
A:B76: (,1) [W16] 10
A:C76: (,1) [W16] 10
A:D76: (,1) [W16] 10
A:E76: (,1) [W16] 10
A:G76: [W6] (G75+1)
A:G77: [W6] (G76+1)
A:A78: [W22] 'VOC's:
A:G78: [W6] (G77+1)
A:A79: [W22] '  Basis
A:B79: (,1) [W16] "3 ppm+
A:C79: (,1) [W16] "3 ppm+
A:D79: (,1) [W16] "3 ppm+
A:E79: (,1) [W16] "3 ppm+
A:F79: (,1) [W16] "0.03 lb/MMBtu
A:G79: [W6] (G78+1)
A:A80: [W22] '  lb/hr
A:B80: (F2) [W16] (B82*(1-B26/100)*B22*2116.8*12*60/(1545*(460+B25)*1000000)) . . . . . . . . . . . . . See Note C
A:C80: (F2) [W16] (C82*(1-C26/100)*C22*2116.8*12*60/(1545*(460+C25)*1000000))
A:D80: (F2) [W16] (D82*(1-D26/100)*D22*2116.8*12*60/(1545*(460+D25)*1000000))
A:E80: (F2) [W16] (E82*(1-E26/100)*E22*2116.8*12*60/(1545*(460+E25)*1000000))
A:F80: (F2) [W16] ($F$13*0.03) . . . . . . . . . . . . . . . . . . . . . . . . . . Emission Factor * Heat Input
A:G80: [W6] (G79+1)
A:A81: [W22] '  TPY
A:B81: (,1) [W16] (B80*8760/2000)
A:C81: (,1) [W16] (C80*8760/2000)
A:D81: (,1) [W16] (D80*8760/2000)
A:E81: (,1) [W16] (E80*8760/2000)
A:F81: (F2) [W16] (F80*3688.5/2000)
A:G81: [W6] (G80+1)
A:A82: [W22] '  ppm
A:B82: (,1) [W16] 3
A:C82: (,1) [W16] 3
A:D82: (,1) [W16] 3
A:E82: (,1) [W16] 3
A:G82: [W6] (G81+1)
A:G83: [W6] (G82+1)
A:A84: [W22] 'Lead:
A:G84: [W6] (G83+1)
A:A85: [W22] '  Basis
A:G85: [W6] (G84+1)
A:A86: [W22] '  lb/hr
A:B86: (S2) [W16] "NA
A:C86: (S2) [W16] "NA
A:D86: (S2) [W16] "NA
A:E86: (S2) [W16] "NA
A:F86: (S2) [W16] "NA
A:G86: [W6] (G85+1)
A:A87: [W22] '  TPY
A:B87: (S2) [W16] "NA
A:C87: (S2) [W16] "NA
A:D87: (S2) [W16] "NA
A:E87: (S2) [W16] "NA
A:F87: (S2) [W16] "NA
A:G87: [W6] (G86+1)
A:A88: [W22] \_
A:B88: [W16] \_
A:C88: [W16] \_
A:D88: [W16] \_
A:E88: [W16] \_
```

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A:F88: [W16] \_
A:G88: [W6] (G87+1)
A:G89: [W6] (G88+1)
A:A90: [W22] '* corrected to 15% 02 dry conditions
A:G90: [W6] (G89+1)
A:A91: [W22] '+ corrected to dry conditions
A:G91: [W6] (G90+1)
A:A92: [W22] 'Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr.  Annual emissions for
A:G92: [W6] (G91+1)
A:A93: [W22] '      duct burner based on 450,000 MM Btu/year operation; i.e., 4,500 hours at 100 MM Btu/hr.
A:G93: [W6] (G92+1)
A:A94: [W22] '      Duct burner will only be operated when ambient temperature is greater than 72oF.
A:G94: [W6] (G93+1)
```

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A:A96: [W22] 'Table A-3.  Maximum Other Regulated Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G96: [W6] 96
A:A97: [W22] '          Cogeneration Project
A:G97: [W6] (G96+1)
A:A98: [W22] \_
A:B98: [W16] \_
A:C98: [W16] \_
A:D98: [W16] \_
A:E98: [W16] \_
A:F98: [W16] \_
A:G98: [W6] (G97+1)
A:G99: [W6] (G98+1)
A:A100: [W22] ^Pollutant
A:B100: [W16] "Gas Turbine
A:C100: [W16] "Gas Turbine
A:D100: [W16] "Gas Turbine
A:E100: [W16] "Gas Turbine
A:F100: [W16] "Duct Burner
A:G100: [W6] (G99+1)
A:B101: [W16] "Natural Gas
A:C101: [W16] "Natural Gas
A:D101: [W16] "Natural Gas
A:E101: [W16] "Natural Gas
A:F101: [W16] "Natural Gas
A:G101: [W6] (G100+1)
A:A102: [W22] ^A
A:B102: [W16] "20oF - B
A:C102: [W16] "59oF - C
A:D102: [W16] "72oF - D
A:E102: [W16] "102oF - E
A:F102: [W16] "90oF - F
A:G102: [W6] (G101+1)
A:A103: [W22] \_
A:B103: [W16] \_
A:C103: [W16] \_
A:D103: [W16] \_
A:E103: [W16] \_
A:F103: [W16] \_
A:G103: [W6] (G102+1)
A:G104: [W6] (G103+1)
A:A105: [W22] '  As (lb/hr)
A:B105: [W16] "NEG.
A:C105: [W16] "NEG.
A:D105: [W16] "NEG.
A:E105: [W16] "NEG.
A:F105: [W16] "NEG.
A:G105: [W6] (G104+1)
A:A106: [W22] '     (TPY)
A:B106: [W16] "NEG.
A:C106: [W16] "NEG.
A:D106: [W16] "NEG.
A:E106: [W16] "NEG.
A:F106: [W16] "NEG.
A:G106: [W6] (G105+1)
A:G107: [W6] (G106+1)
A:A108: [W22] '  Be (lb/hr)
A:B108: [W16] "NEG.
A:C108: [W16] "NEG.
A:D108: [W16] "NEG.
A:E108: [W16] "NEG.
A:F108: [W16] "NEG.
A:G108: [W6] (G107+1)
A:A109: [W22] '     (TPY)
A:B109: [W16] "NEG.
A:C109: [W16] "NEG.
A:D109: [W16] "NEG.
A:E109: [W16] "NEG.
```

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A:F109: [W16] "NEG.
A:G109: [W6] (G108+1)
A:G110: [W6] (G109+1)
A:A111: [W22] '  Hg (lb/hr)
A:B111: [W16] "NEG.
A:C111: [W16] "NEG.
A:D111: [W16] "NEG.
A:E111: [W16] "NEG.
A:F111: [W16] "NEG.
A:G111: [W6] (G110+1)
A:A112: [W22] '     (TPY)
A:B112: [W16] "NEG.
A:C112: [W16] "NEG.
A:D112: [W16] "NEG.
A:E112: [W16] "NEG.
A:F112: [W16] "NEG.
A:G112: [W6] (G111+1)
A:G113: [W6] (G112+1)
A:A114: [W22] '  F (lb/hr)
A:B114: [W16] "NEG.
A:C114: [W16] "NEG.
A:D114: [W16] "NEG.
A:E114: [W16] "NEG.
A:F114: [W16] "NEG.
A:G114: [W6] (G113+1)
A:A115: [W22] '    (TPY)
A:B115: [W16] "NEG.
A:C115: [W16] "NEG.
A:D115: [W16] "NEG.
A:E115: [W16] "NEG.
A:F115: [W16] "NEG.
A:G115: [W6] (G114+1)
A:G116: [W6] (G115+1)
A:A117: [W22] '  H2SO4 (lb/hr)
A:B117: (S2) [W16] (B63*0.05*3.06/2)  . . . . . . . . . . . . . .   SO2 Emission * 0.05 (%H2SO4 Formed) * MWH2SO4/MWSO2
A:C117: (S2) [W16] (C63*0.05*3.06/2)
A:D117: (S2) [W16] (D63*0.05*3.06/2)
A:E117: (S2) [W16] (E63*0.05*3.06/2)
A:F117: (S2) [W16] (F63*0.05*3.06/2)
A:G117: [W6] (G116+1)
A:A118: [W22] '    (TPY)
A:B118: (S2) [W16] (B117*8760/2000)
A:C118: (S2) [W16] (C117*8760/2000)
A:D118: (S2) [W16] (D117*8760/2000)
A:E118: (S2) [W16] (E117*8760/2000)
A:F118: (F2) [W16] (F117*3688.5/2000)
A:G118: [W6] (G117+1)
A:G119: [W6] (G118+1)
A:A120: [W22] \_
A:B120: [W16] \_
A:C120: [W16] \_
A:D120: [W16] \_
A:E120: [W16] \_
A:F120: [W16] \_
A:G120: [W6] (G119+1)
A:G121: [W6] (G120+1)
A:A122: [W22] 'Sources: EPA, 1988; EPA, 1980
A:G122: [W6] (G121+1)
```

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A:A125: [W22] 'Table A-4.  Maximum Non-Regulated Pollutant Emissions for Orlando CoGen Limited, L.P.
A:G125: [W6] 125
A:A126: [W22] '           Cogeneration Project
A:G126: [W6] (G125+1)
A:A127: [W22] \_
A:B127: [W16] \_
A:C127: [W16] \_
A:D127: [W16] \_
A:E127: [W16] \_
A:F127: [W16] \_
A:G127: [W6] (G126+1)
A:G128: [W6] (G127+1)
A:A129: [W22] ^Pollutant
A:B129: [W16] "Gas Turbine
A:C129: [W16] "Gas Turbine
A:D129: [W16] "Gas Turbine
A:E129: [W16] "Gas Turbine
A:F129: [W16] "Duct Burner
A:G129: [W6] (G128+1)
A:B130: [W16] "Natural Gas
A:C130: [W16] "Natural Gas
A:D130: [W16] "Natural Gas
A:E130: [W16] "Natural Gas
A:F130: [W16] "Natural Gas
A:G130: [W6] (G129+1)
A:A131: [W22] ^A
A:B131: [W16] "20oF - B
A:C131: [W16] "59oF - C
A:D131: [W16] "72oF - D
A:E131: [W16] "102oF - E
A:F131: [W16] "90oF - F
A:G131: [W6] (G130+1)
A:A132: [W22] \_
A:B132: [W16] \_
A:C132: [W16] \_
A:D132: [W16] \_
A:E132: [W16] \_
A:F132: [W16] \_
A:G132: [W6] (G131+1)
A:G133: [W6] (G132+1)
A:A134: [W22] '  Manganese (lb/hr)
A:B134: [W16] "NEG.
A:C134: [W16] "NEG.
A:D134: [W16] "NEG.
A:E134: [W16] "NEG.
A:F134: [W16] "NEG.
A:G134: [W6] (G133+1)
A:A135: [W22] '     (TPY)
A:B135: [W16] "NEG.
A:C135: [W16] "NEG.
A:D135: [W16] "NEG.
A:E135: [W16] "NEG.
A:F135: [W16] "NEG.
A:G135: [W6] (G134+1)
A:G136: [W6] (G135+1)
A:A137: [W22] '  Nickel (lb/hr)
A:B137: [W16] "NEG.
A:C137: [W16] "NEG.
A:D137: [W16] "NEG.
A:E137: [W16] "NEG.
A:F137: [W16] "NEG.
A:G137: [W6] (G136+1)
A:A138: [W22] '     (TPY)
A:B138: [W16] "NEG.
A:C138: [W16] "NEG.
A:D138: [W16] "NEG.
A:E138: [W16] "NEG.
```

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A:F138: [W16] "NEG.
A:G138: [W6] (G137+1)
A:G139: [W6] (G138+1)
A:A140: [W22] '  Cadmium (lb/hr)
A:B140: [W16] "NEG.
A:C140: [W16] "NEG.
A:D140: [W16] "NEG.
A:E140: [W16] "NEG.
A:F140: [W16] "NEG.
A:G140: [W6] (G139+1)
A:A141: [W22] '     (TPY)
A:B141: [W16] "NEG.
A:C141: [W16] "NEG.
A:D141: [W16] "NEG.
A:E141: [W16] "NEG.
A:F141: [W16] "NEG.
A:G141: [W6] (G140+1)
A:G142: [W6] (G141+1)
A:A143: [W22] '  Chromium (lb/hr)
A:B143: [W16] "NEG.
A:C143: [W16] "NEG.
A:D143: [W16] "NEG.
A:E143: [W16] "NEG.
A:F143: [W16] "NEG.
A:G143: [W6] (G142+1)
A:A144: [W22] '    (TPY)
A:B144: [W16] "NEG.
A:C144: [W16] "NEG.
A:D144: [W16] "NEG.
A:E144: [W16] "NEG.
A:F144: [W16] "NEG.
A:G144: [W6] (G143+1)
A:G145: [W6] (G144+1)
A:A146: [W22] '  Copper (lb/hr)
A:B146: [W16] "NEG.
A:C146: [W16] "NEG.
A:D146: [W16] "NEG.
A:E146: [W16] "NEG.
A:F146: [W16] "NEG.
A:G146: [W6] (G145+1)
A:A147: [W22] '    (TPY)
A:B147: [W16] "NEG.
A:C147: [W16] "NEG.
A:D147: [W16] "NEG.
A:E147: [W16] "NEG.
A:F147: [W16] "NEG.
A:G147: [W6] (G146+1)
A:G148: [W6] (G147+1)
A:A149: [W22] '  Vanadium (lb/hr)
A:B149: [W16] "NEG.
A:C149: [W16] "NEG.
A:D149: [W16] "NEG.
A:E149: [W16] "NEG.
A:F149: [W16] "NEG.
A:G149: [W6] (G148+1)
A:A150: [W22] '     (TPY)
A:B150: [W16] "NEG.
A:C150: [W16] "NEG.
A:D150: [W16] "NEG.
A:E150: [W16] "NEG.
A:F150: [W16] "NEG.
A:G150: [W6] (G149+1)
A:G151: [W6] (G150+1)
A:A152: [W22] '  Selenium (lb/hr)
A:B152: [W16] "NEG.
A:C152: [W16] "NEG.
A:D152: [W16] "NEG.
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A:E152: [W16] "NEG.
A:F152: [W16] "NEG.
A:G152: [W6] (G151+1)
A:A153: [W22] '    (TPY)
A:B153: [W16] "NEG.
A:C153: [W16] "NEG.
A:D153: [W16] "NEG.
A:E153: [W16] "NEG.
A:F153: [W16] "NEG.
A:G153: [W6] (G152+1)
A:G154: [W6] (G153+1)
A:A155: [W22] '  POM (lb/hr)
A:B155: (S2) [W16] (B13*0.48*2.324/1000000) . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-161
A:C155: (S2) [W16] (C13*0.48*2.324/1000000)
A:D155: (S2) [W16] (D13*0.48*2.324/1000000)
A:E155: (S2) [W16] (E13*0.48*2.324/1000000)
A:F155: (S2) [W16] (F13*0.48*2.324/1000000)
A:G155: [W6] (G154+1)
A:A156: [W22] '    (TPY)
A:B156: (S2) [W16] (B155*8760/2000)
A:C156: (S2) [W16] (C155*8760/2000)
A:D156: (S2) [W16] (D155*8760/2000)
A:E156: (S2) [W16] (E155*8760/2000)
A:F156: (S2) [W16] (F155*3688.5/2000)
A:G156: [W6] (G155+1)
A:G157: [W6] (G156+1)
A:A158: [W22] '  Formaldehyde (lb/hr)
A:B158: (S2) [W16] (B13*38*2.324/1000000) . . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-156
A:C158: (S2) [W16] (C13*38*2.324/1000000)
A:D158: (S2) [W16] (D13*38*2.324/1000000)
A:E158: (S2) [W16] (E13*38*2.324/1000000)
A:F158: (S2) [W16] (F13*38*2.324/1000000)
A:G158: [W6] (G157+1)
A:A159: [W22] '    (TPY)
A:B159: (S2) [W16] (B158*8760/2000)
A:C159: (S2) [W16] (C158*8760/2000)
A:D159: (S2) [W16] (D158*8760/2000)
A:E159: (S2) [W16] (E158*8760/2000)
A:F159: (S2) [W16] (F158*3688.5/2000)
A:G159: [W6] (G158+1)
A:A160: [W22] \_
A:B160: [W16] \_
A:C160: [W16] \_
A:D160: [W16] \_
A:E160: [W16] \_
A:F160: [W16] \_
A:G160: [W6] (G159+1)
A:G161: [W6] (G160+1)
A:G162: [W6] (G161+1)
A:G165: [W6] 165
A:G166: [W6] (G165+1)
A:G167: [W6] (G166+1)
A:G168: [W6] (G167+1)
A:G169: [W6] (G168+1)
A:G170: [W6] (G169+1)
A:G171: [W6] (G170+1)
A:G172: [W6] (G171+1)
A:G173: [W6] (G172+1)
A:G174: [W6] (G173+1)
A:G175: [W6] (G174+1)
A:G176: [W6] (G175+1)
A:G177: [W6] (G176+1)
A:G178: [W6] (G177+1)
A:G179: [W6] (G178+1)
A:G180: [W6] (G179+1)
A:G181: [W6] (G180+1)
A:G182: [W6] (G181+1)
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A:G183: [W6] (G182+1)
A:G184: [W6] (G183+1)
A:G185: [W6] (G184+1)
A:G186: [W6] (G185+1)
A:G187: [W6] (G186+1)
A:G188: [W6] (G187+1)
A:G189: [W6] (G188+1)
A:G190: [W6] (G189+1)
A:G191: [W6] (G190+1)
```

NOTE A

Volume is calculated based on ideal gas law:

$$PV = mRT/M$$

where:
P = pressure = 2116.8 lb/ft^2
m = mass flow of gas (lb/hr)
R = universal gas constant = 1545
M = molecular weight of gas
T = temperature (K)

NOTE B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

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

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

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

Substituting:

$$\begin{aligned} V_{NOx\ Act} &= V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9 \\ &= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9 \\ &= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9 \end{aligned}$$

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

NOTE C

Same as D except only moisture correction is used:

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

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

ORLANDO COGEN LIMITED
EXAMPLE CALCULATIONS - 20°F CONDITIONS

ROWS listed below correspond to the ROW listed in Table.

Table A-1: (Note: all other data not calculated)

ROW 13--Heat Input (10^6 Btu/hr):

Power (kW) x Heat Rate (10^6 Btu/kWh)

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

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

Heat Input (10^6 Btu/hr) ÷ 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) ÷ Heat content (Btu/cf)

$933.9 \times 10^6 \div 946 = 987{,}186.5$ cf/hr

ROW 21--Volume Flow (acfm) - See Note A:

$V = mRT/PM$

$2{,}631{,}000 \text{ lb/hr} \times 1{,}545 \times (941 + 460°\text{K}) \div (28 \times 2{,}116.8 \text{ lb/ft}^2) \div 60(\text{min/hr})$

$= 1{,}601{,}395$ 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 ÷ 2,000 lb/ton

= 2.25 ton/year

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

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

= 2.82 lb/hr

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

25 ppm x [20.9 ÷ 5.9 (1 - 6.1/100) - 14.4] x 2,116.8 lb/ft^2 x 1,601,395 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (941 + 460°K) x 10^6 (adjust for ppm)]

= 95.7 lb/hr

ROW 74--CO Emissions (lb/hr):

Same as NO_x except ppm and molecular weight changed; confirmation calculation:

95.7 lb/hr NO_x x 10/25 x 28/46

= 23.3 lb/hr

ROW 80--VOC Emissions (lb/hr) - See Note C:

3 ppm x (1-6.1/100) x 1,601,395 acfm x 2,116.8 lb/ft^2 x 12 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (941 + 460) x 10^6)

= 3.18 lb/hr

Table A-3:

ROW 117--H_2SO_4 Mist Emissions (lb/hr):

Based on 5 percent SO_2 converted to acid mist

2.82 lb SO_2/hr x 0.05 x 98 ÷ 64 (or a ratio 3.06/2)

$= 2.16 \times 10^{-1}$

Table A-4:

ROW 155--POM Emissions (lb/hr):

EPA emission factor as noted in printout:

933.9 (MMBtu) x 0.48 pg/J x 2.324 lb/10^{12} Btu/pg/J ÷ 10^6 (to adjust to 10^{12} Btu)

$= 1.04 \times 10^{-4}$ lb/hr

ROW 158--Formaldehyde Emissions (lb/hr):

EPA emission factor as noted in printout.

Same calculation as ROW 155.

REVISIONS TO TABLE 2-1 AND 3-3

REFLECTING MINOR CHANGES
(i.e., H_2SO_4 AND ANNUAL EMISSIONS)

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

Parameter	Maximum Emissions			
		CT/Duct Burner		
	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

Pollutant	Emissions (TPY)		
	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
<u>Indirect Annual Costs</u>		
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)
<u>Total Indirect Annual Costs</u>	1,214,200	Sum of all indirect annual costs
<u>Total Annual Costs</u>	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			Project Without SCR	
	Primary	Secondary[a]	Total	CT/DB	Difference[b]
Particulate	24 [c]	2.06	26	0	26
Sulfur Dioxide	0	22.64	23	0	23
Nitrogen Oxides	141 [d]	11.32	152	401	(249)
Carbon Monoxide	0	0.68	1	0	1
Volatile Organic Compounds	0	0.10	0	0	0
Ammonia	64 [e]	0.00	64	0	64
Total	229	36.81	266	401	(135)
Carbon Dioxide[f]	--	3,535	3,535	--	3,535

Note: Btu/kWh = British thermal units per kilowatt-hour.
CT = combustion turbine.
DB = duct burner.
MW = megawatt.
% = percent.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Lost energy of 0.47 MW from heat rate penalty and electrical for 8,760 hours per year operation (0.5% of 78.83 MW plus 0.080 MW). Assumes Florida Power Corp. baseloaded oil-fired unit would replace lost energy. EPA emission factors used for 1% sulfur fuel oil and an assumed heat rate of 10,000 Btu/kWh. Emission factors use were (lb/10^6 BTU): PM = 0.1; SO_2 = 1.1; NO_x = 0.55, CO = 0.033 and VOC = 0.005. Example calculation for PM - 0.47 MW x 10,000 BTU/kwh x 1,000 kw/MW x 8,760 hr/yr x 0.1 lb pm/10^6 BTU ÷ 2,000 lb/ton = 2.06 TPY.

[b] Difference = Total with SCR minus project without SCR.

[c] Assume sulfur reacts with ammonia; 11.65 TPY SO_2 x 132 (MW of ammonia salt) ÷ 64 (MW of SO_2).

[d] 9 ppm NO_x emissions.

[e] 10 ppm ammonia slip (ideal gas law at actual flow rate from stack): 726,343 acfm x 60 m/hr x 10 ppm/10^6 x 2,116.8 lb/ft^2 ÷ 1,545 x 17 (molecular weight of NH_3) ÷ (460 +230) x 8,760 ÷ 2,000.

[f] Reflects differential emissions due to lost energy efficiency with SCR (i.e., 0.47 MW CO_2 calculated based on 85.7% carbon in fuel oil and 18,300 BTU/lb).

INFORMATION ON DRY LOW-NO_x COMBUSTOR FOR ABB GT 11N-EV

DRY LOW NOx EMISSIONS

ABB's second generation "EV" Burners, proposed to Air Products for the Orlando Cogeneration Project, when operated on natural gas, require no introduction of steam or water to maintain low NOx emissions.

ABB guarantees to achieve a Dry Low NOx emission level for the unit proposed, equipped with the "EV" burner, of 25ppmvd, (15% O_2 corrected) when operating at base load on the natural gas fuel specified.

EXPERIENCE

ABB pioneered development of Dry Low NOx combustor technology in 1984. Our first generation "lean pre-mix" burner achieved 36ppmvd (15% corrected) on a model 13B gas turbine located in Germany.

Since that time ABB has placed in operation or has on order, nine (9) first generation "lean pre-mix burners" and twelve (12) second generation "EV burners" (as proposed for the GT 11N's for Air Products). The total accumulated operating hours ABB has now exceeds over 80,000 hours.

The following is a list of installations, type of burner, (first or second generation) accumulated operating hours, and measured or anticipated NOx levels.

ABB
ASEA BROWN BOVERI

Gas Turbine and Combined Cycle Power Plants

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:

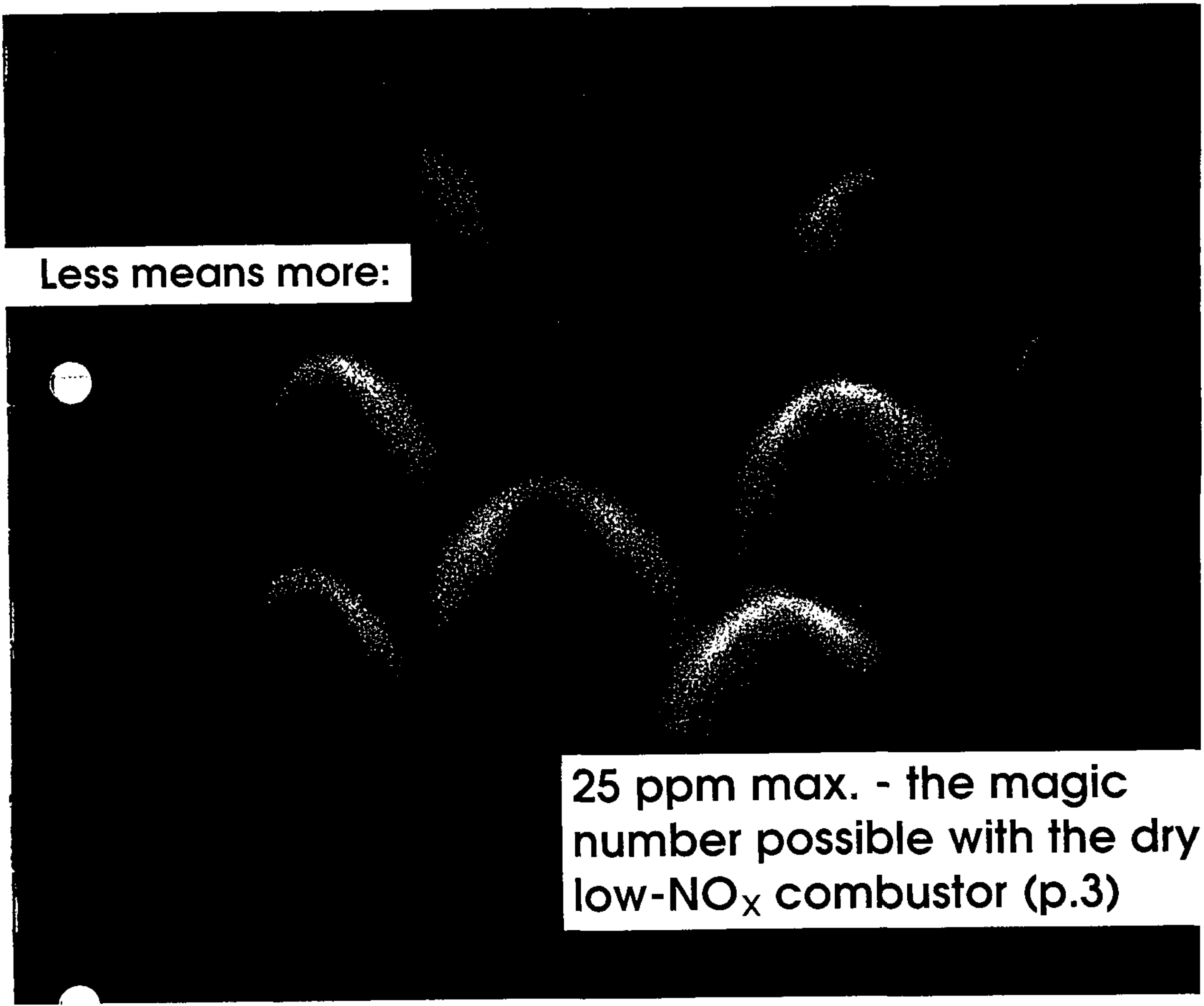
- Successful ignition and light-off
- Successful achievement of Dry Low NO_x of less than 25 ppmvd at full load
- Demonstrated achievement of part load low NO_x levels
- Demonstrated reliability
- Completion of work to schedule

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)

Less means more: 25 ppm max. - the magic number possible with the dry low-NOx combustor

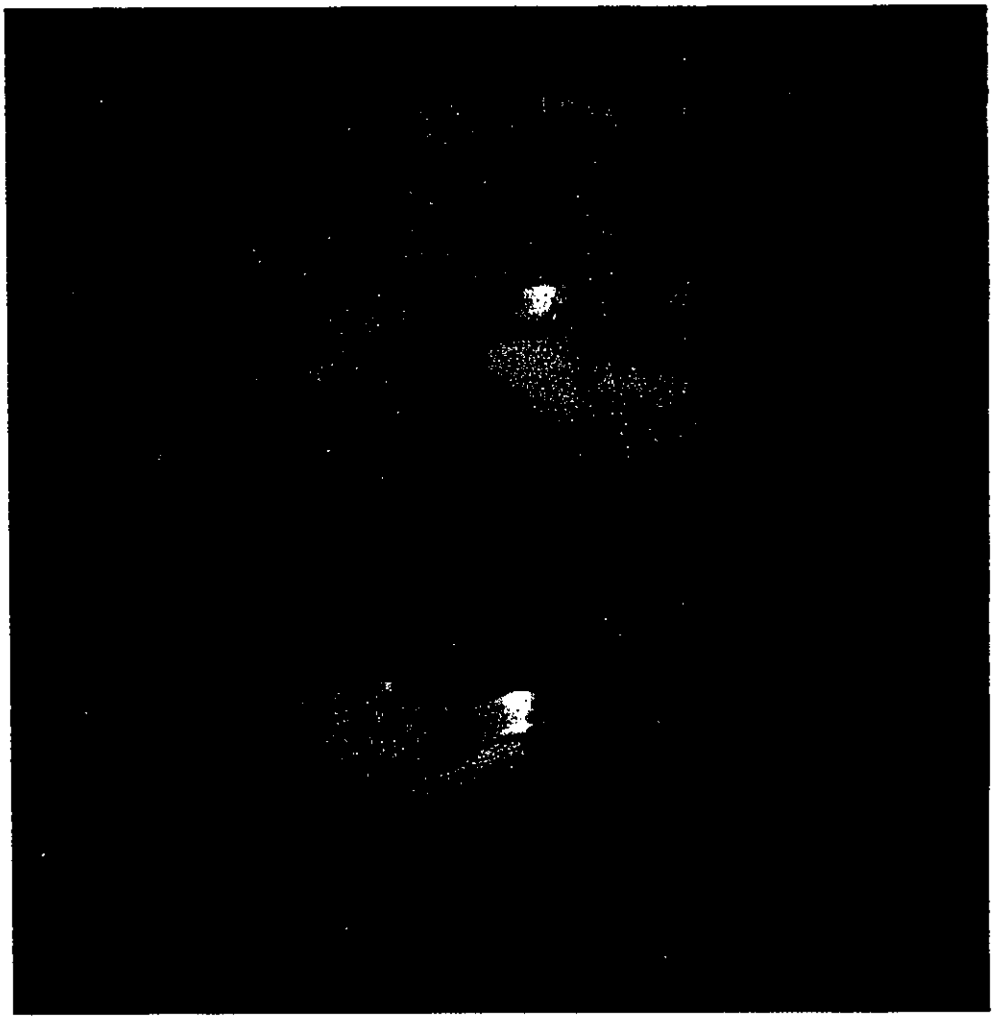
The production of nitrogen oxides that accompanies fossil fuel combustion is one of the key problems the power generation industry will have to resolve if pollutant emissions are to be reduced. Research into new combustor technologies is currently the most important activity in the gas turbine sector that is addressing this problem.

The approach adopted by the business area PGT (Power Generation Gas Turbines) at the time new combustor concepts were being considered was both logical and simple: as the nitrogen oxides are produced during the combustion process, it was in the combustor that technical improvements would have to be introduced to reduce them.

Although a simple deduction, its realization involves a highly complex technology with limits imposed by physical and chemical conditions.

Stoichiometry as an interference factor

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



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

mixture exhibits a concentration gradient within which the very hot stoichiometric mixture is produced. As the formation of nitrogen oxides depends on a high temperature and a certain residence time, conventional burners (i.e. the diffusion type) produce large amounts of nitrogen oxide as a matter of course.

In contrast to the oil firing used to heat private households, gas turbines bring far larger quantities of air into contact with the fuel than would be required for the theoretically necessary stoichiometric mixture. Combustion begins at the high stoichiometric flame temperature of 2000 °C or above, and ends at a far lower turbine inlet temperature. However, due to the high flame temperature in the combustor's primary zone NOx formation is generally too high. It is therefore necessary to drastically reduce the flame temperature from the beginning.

A paradox shows the way: cold flames

There have been many approaches to solving this dilemma. However, all of them were directed at reducing the formation of nitrogen oxides by lowering the flame temperature.

Fire and water: diffusion flames with wet control

By injecting water or steam directly into the flame, it is possible to lower the temperature and consequently reduce nitrogen oxide emissions to values of 25 to 150 ppm. This method is used widely throughout the world, and has the desirable byproduct of generating more power. This is possible as a larger volume of gas is forced through the turbine than in conventional combustion without water injection.

A less desirable "byproduct" is the drop in efficiency in plants with a heat recovery facility with steam turbine (combined cycle power plants) that results from the poorer utilization of injected steam in the gas turbine.

The "dry" approach

Improved efficiency and a further reduction in nitrogen oxide emissions, particularly for the combined cycle power plant - the current No. 1 on the list of clean plants - was and still is the driving force behind the development of dry low-NOx burner concepts.

This type of burner has special benefits for plants operated non-stop. Since their first-time costs make up only approximately 6 % of the total running costs over their lifetime, it pays to invest more in improving their efficiency. In a combined cycle plant, efficiencies 1 to 2 % higher than with wet control are possible with this method.

PGT developed three concepts along these lines:

- The first-generation lean premix burner
- The ring combustor
- The second-generation lean premix burner

The third-named concept was based on preliminary work carried out at the ABB Research Centre in Dättwil and subsequent joint development for its application in ABB gas turbines.

Lean Premix Burner

This concept is based on the simple principle of premixing air and fuel, with the maximum amount of excess air, before combustion. The amount of air used is about twice the theoretical amount required for combustion, thus giving the method its name "lean premix". From the outset, the flame temperature is at least 500 °C lower than in the earlier method. The hot yellow flame is replaced by a blue flame which is much colder and produces less NOx.

ABB première

Such burners were first deployed in 1984 on a Type 13 gas turbine. The father of this low-NOx development, the engineer Hans Koch, replaced the turbine's diffusion burner by a bundle of lean premix burners.

One difficulty he had to overcome was caused by the premixed flames exhibiting a much smaller range of stability than the conventional diffusion flames, where the stabilizing element was simply the boundary between the air and fuel. Small, central diffusion flames were added to try and achieve better stabilization, but these caused the pollutant emissions to increase again.

A second difficulty to be overcome involved the machine's control with these low-pollutant air fuel mixtures. The amount of fuel needed to control the machine varies widely with the load (in the ratio of 1:4). A lean premix burner

Less means more: 25 ppm max. - the magic number possible with the dry low-NOx combustor

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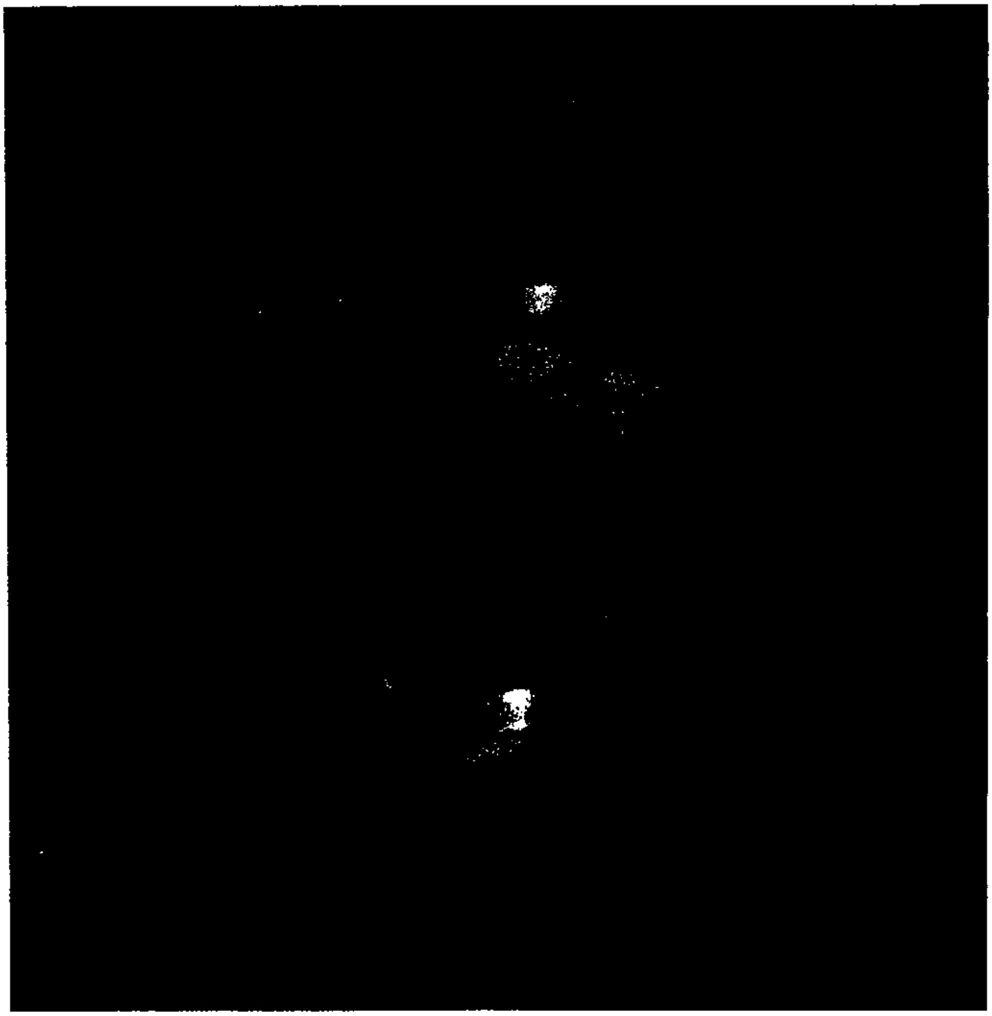

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A second difficulty to be overcome involved the machine's control with these low-pollutant air fuel mixtures. The amount of fuel needed to control the machine varies widely with the load (in the ratio of 1:4). A lean premix burner would be extinguished 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

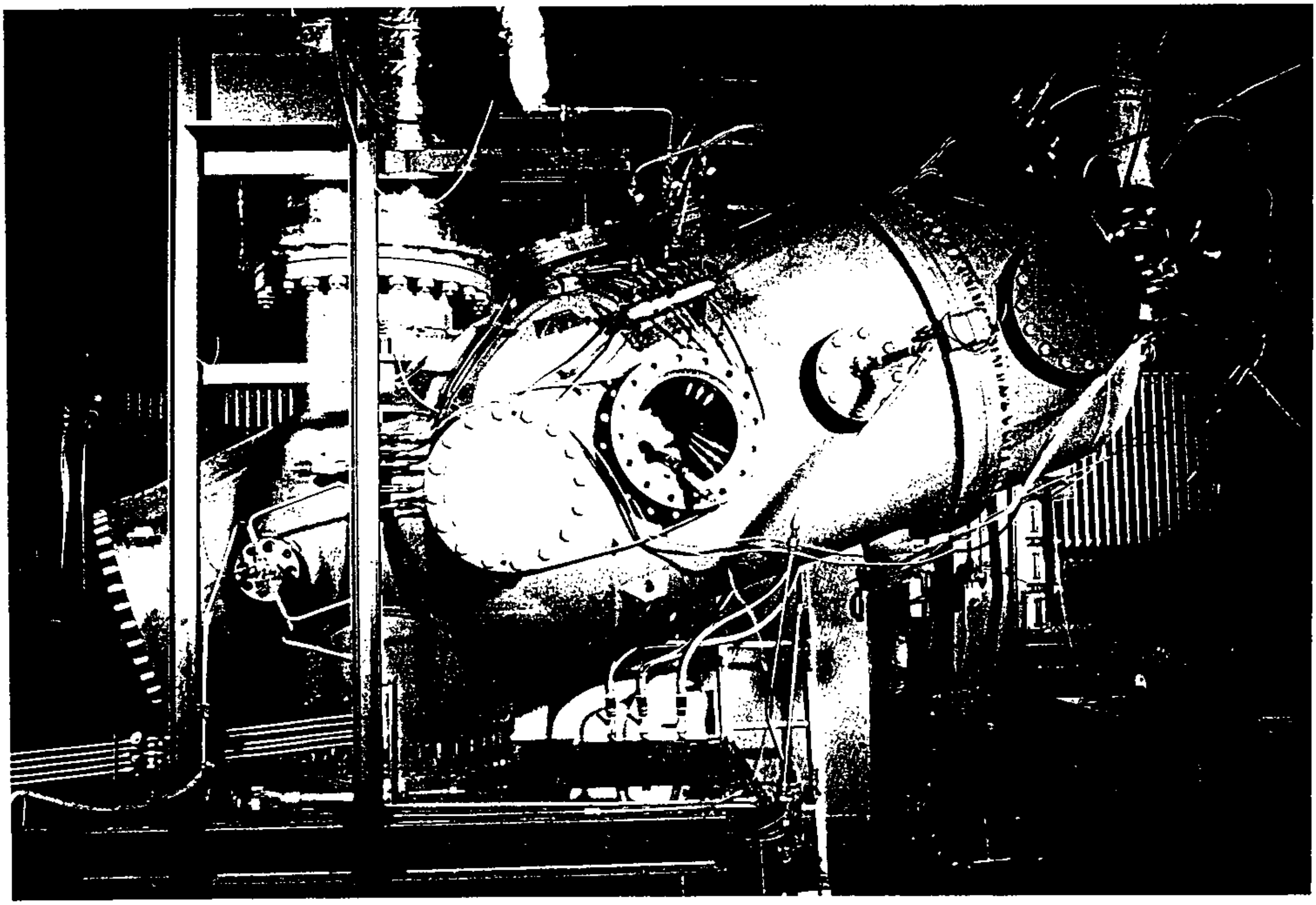
In the second concept a number of small burners are arranged in a circle. This arrangement resulted in a drastic reduction in the size of the combustor. The first such combustor was installed in a GT 8 in 1987 and is still operating today.

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.

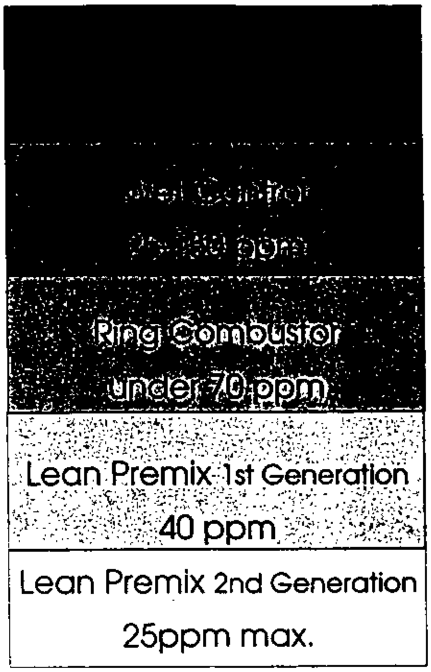
2. The premix flames are no longer stabilized by central diffusion flames, but by adjacent burners of the same type, however operated in another premix mode.

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.

The 1989
Energy Conservation
Award
For outstanding achievement by industry in
optimizing use of our energy resources
Awarded by Power International to:
UNA Amsterdam
Hemweg Station

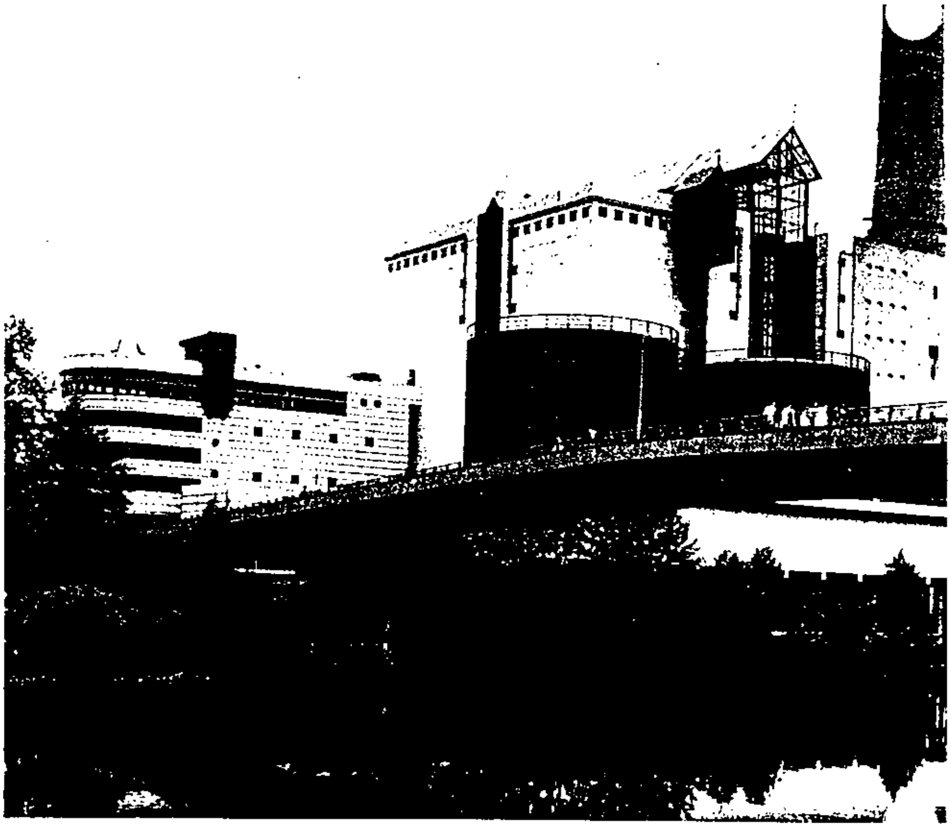
This flag represents the international concern for
protection of our energy resources.

Editor

The 1989
Environmental Protection
Award
For outstanding achievement by industry in
optimizing use of our natural environment
Awarded by Power International to:
Stadtwerke Saarbrücken AG
Römerbrücke Station

The "E" stands for Environment and is a symbol
of concern for the purity of our world's air and water.

Editor



Römerbrücke
Stadtwerke Saarbrücken's Römerbrücke district heating power plant was supplied turnkey by ABB

ABB
ASEA BROWN BOVERI

February 14, 1992

Mr. Jack Kindt
Environmental/Energy Division
Air Products and Chemicals, Inc.
7201 Hamilton Blvd.
Allentown, PA 18195-1501

Subject: ABB GT11N, EV Combustor

cc. Chris Allevik

Dear Mr. Kindt,

ABB has proven in Midland, Mi that their GT11N-EV can reach NOx emission values of less than 25 ppmvd (15%O2) when firing natural gas. As you can see from the attached press release, the GT11N has actually run as low as 9 ppm, even though the continuous operating level as of now is 13 ppmvd (15%O2) with CO levels below 8 ppm. Please be aware that these values are below the actual air permit requirement for Midland and that they are based on long-term testing on-site. More than 1500 operating hours have been accumulated at Midland.

Included is also a graph which shows NOx measurements by ABB as well as a third-party company (CONSUMERS POWER) at a certain point within the test period. The burner air to fuel ratio can be adjusted to show different NOx levels. Here they show values of less than 25 ppmvd (15%O2) over a load range from 60% to 100%

I have also attached a copy of the ASME paper 90-GT-308 which shows burner tests under full-engine conditions. The paper summarizes the effect of pressure, temperature and air to fuel ratio on NOx formation for the ABB EV burner. NOx values of less than 25 ppmvd (15%O2) were measured at full load.

If you have any questions, please don't hesitate to call me at 908-932-6368.

Very truly yours,

Gregor Gnaedig
Performance Engineer
Gas Turbine Engineering

ABB Power Generation Inc.

Gas Turbine Power Division
1460 Livingston Avenue
North Brunswick, New Jersey 08902
Telephone: 908-932-6000
Telefax: 908-932-6194

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ASEA BROWN BOVERI

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 NOX 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.

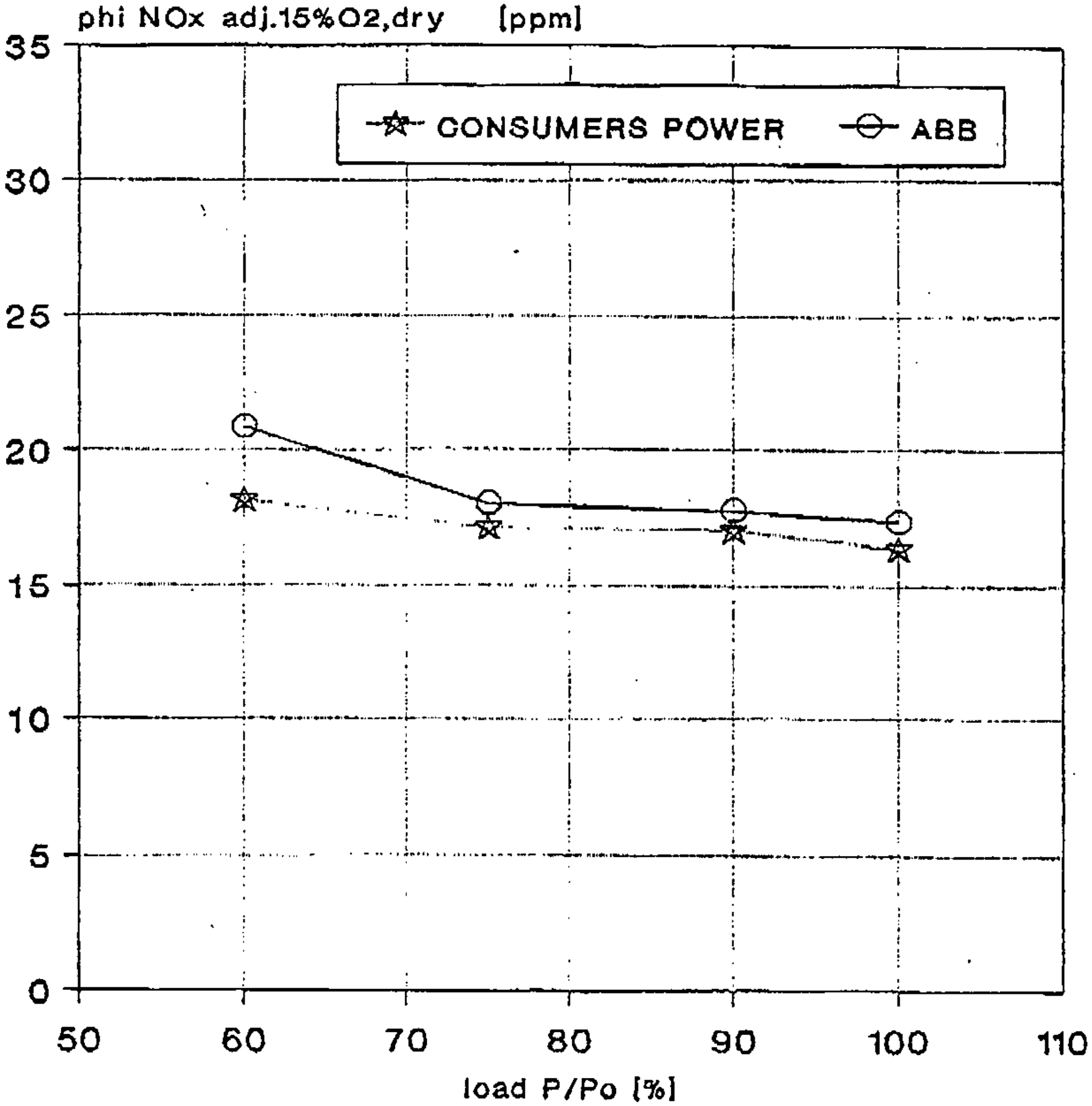
(more)

ABB's Gas Turbine Power Division is part of ABB Power Generation Inc. and supplies a complete range of gas turbines for peaking, baseload and combined cycle operations from its North Brunswick, New Jersey headquarters. ABB Power Generation Inc. offers equipment and services for steam and gas turbine generators, combined cycle and hydro-electric power plants. ABB, with approximately $6 billion sales and some 30,000 employees in the United States, provides products and services for power, automation, environmental control, transit and other markets.

# # #

GT11N-EV

phi NOx adj.15%O2,dry = f (P/Po)



stable load conditions
fuel : natural gas

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New York, N.Y. 10017

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Printed in USA.

Second Generation Low-Emission Combustors for ABB Gas Turbines: Burner Development and Tests at Atmospheric Pressure

TH. SATTELMAYER, M. P. FELCHLIN, J. HAUMANN, J. HELLAT, D. STYNER
ABB Corporate Research Center, Aerodynamics Department
CH-5405 Baden, Switzerland

ABSTRACT:

Based on fundamental research concerning swirling flows, including the vortex breakdown phenomenon, as well as on stability considerations of premixed flames, a second generation of low emission burners has been developed.

The lean premixing technique provides NOx-emissions below 25ppmv for natural gas. For liquid fuels the oxides of nitrogen are limited to 42ppmv (oil no. 2).

The novel burner technology will be applied to the well-known ABB silo combustor. As a first step the Conical Premix Burner will be used to retrofit the ABB type 11N. For the ABB gas turbine type 8 the design of a novel fully annular combustor is in progress.

Most of the conceptual work concerning burner aerodynamics and burner-burner interaction has been carried out on scaled-down burner- and combustor-models. For a second step a sector of the combustor in 1:1 scale has been tested at atmospheric pressure. Additional high pressure tests provide information about the combustor performance at engine conditions.

The present paper summarizes the results of the first two steps beginning with the early ideas in the conceptual phase up to the 1:1 tests which prove the low-NOx capability for both gaseous and liquid fuels under atmospheric pressure conditions.

NOMENCLATURE:

b	width of air inlet slot (conical premix burner)
c	air velocity
cf	fuel concentration
D	burner diameter
$\dot{m}$	mass flow rate
r	radius
T_{air}	air temperature upstream of burner
T_p	calculated primary zone temperature
T_{Burner}	burner temperature
T_c	gas temperature on burner centerline
u	axial air velocity
v	radial air velocity
w	tangential air velocity
x	axial coordinate
y	coordinate (combustor height)
z	coordinate (combustor width)
α_c	cone angle (Fig. 9)
α_w	angle of flow near burner wall (Fig.9)
Φ_{burner}	equivalence ratio fuel/air of burner
Φ_{main}	equivalence ratio fuel/air of main burner
Φ_{pilot}	equivalence ratio fuel/air of pilot burner
λ_{burner}	excess air coefficient of burner
λ_{comb}	excess air coefficient of combustor

GOAL OF THE CONTINUING COMB DEVELOPMENT PROGRAM AT ABB

In 1984 the first Dry-Low-NOx combustor of ABB w service in Lausward (FRG). The cluster of burners is show 1. Combustion air and gaseous fuel are mixed in an arra before the mixture enters a large tubular combustor via ai NOx-emissions below 40ppmv have been measured at c pressures up to 14.5 bars and inlet temperatures up to 380° the large residence times in the combustor, very high co efficiencies are obtained above approximately 40% load [1]. Using the experience gained from six units (total GT o MW) with more than 63000 hours of operation, the first g investigation of low emission combustion is to imp performance of ABB silo combustors by replacing the prese including the mixing tubes (FIG. 2). For this purpose a no fuel burner of considerably simpler design has been de Additionally, several kinds of burner staging have been inv to simplify the fuel supply and control system. In order to reliability of the present silo combustor technology, on changes are made to parts of the hot gas path downstrea burners.

Due to the NOx-limitation of 25ppmv, the percentage of air for combustion increases with increasing pressure ratio and temperature of the compressor. Simultaneously, more air i for wall cooling, as long as the basic combustor design and cooling technique remain unchanged. The air consumption cooling can be minimized by reducing the overall surface o gas path from burner to turbine inlet. As a consequence, turbines with very high pressure ratios (e.g. ABB type 8), combustor is of a fully annular design (FIG. 3) and will be with 18 main burners and 18 alternately distributed smal burners. All burners are of the same type.

*Presented at the Gas Turbine and Aeroengine Congress and Exposition—June 11-14, 1990—Brussels, Belgium
This paper has been accepted for publication in the Transactions of the ASME
Discussion of it will be accepted at ASME Headquarters until September 30, 1990

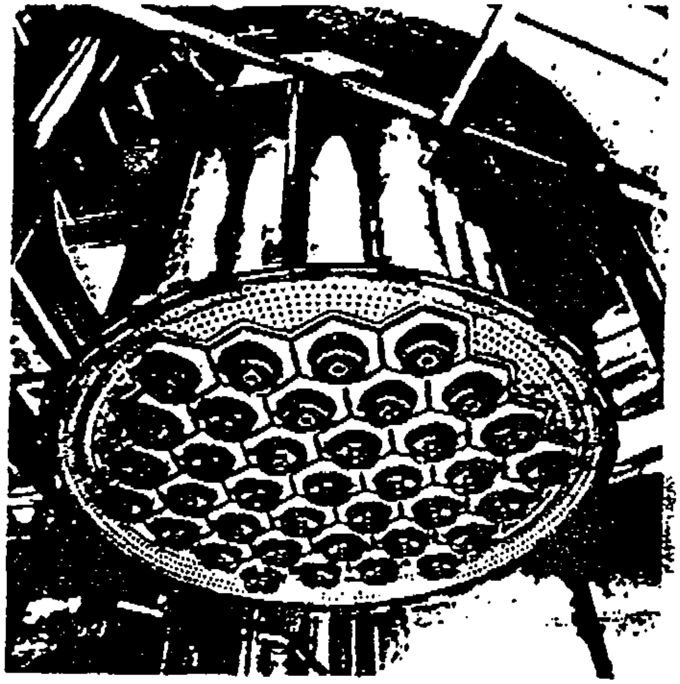


FIG. 1: 1st GENERATION OF LOW NOx-COMBUSTORS (CLUSTER OF PREMIX BURNERS)

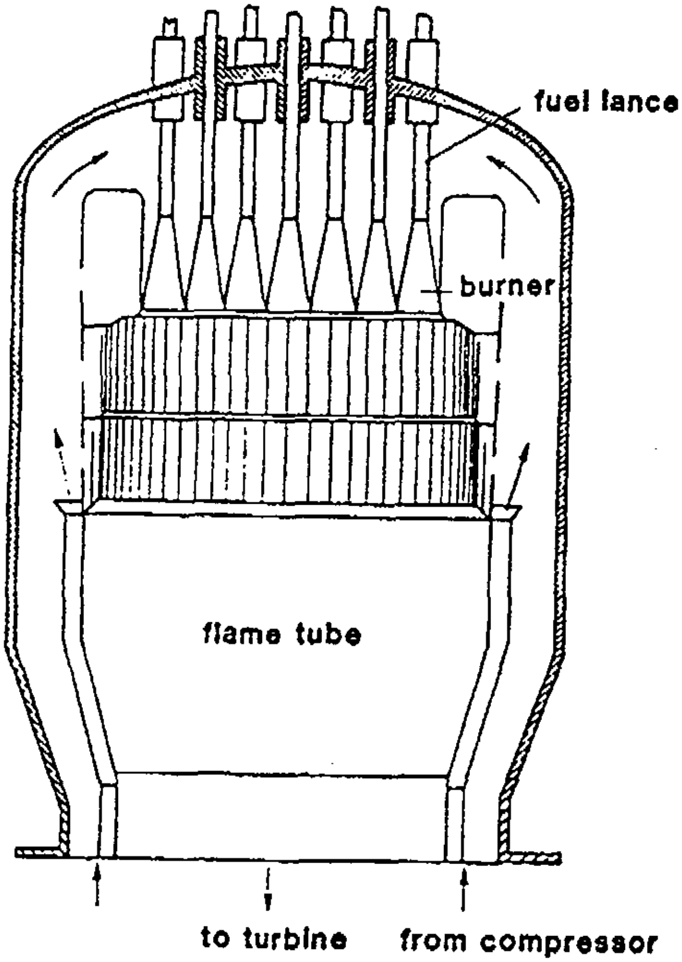


FIG. 2: SILO-COMBUSTOR EQUIPPED WITH CONICAL PREMIX BURNERS (e.g. GT11N)

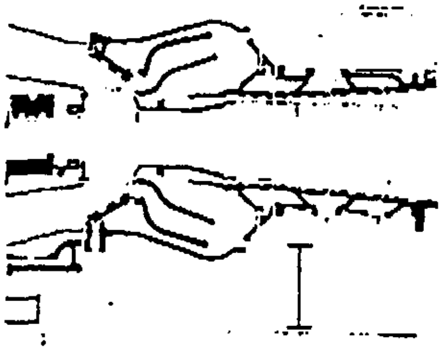


FIG. 3: ANNULAR COMBUSTOR EQUIPPE
PREMIX BURNERS (e.g. GT8)

PREMIX BURNER DEVELOPMENT DOWN MODELS

A unique property of the Conical Premix Burne
stabilization in free space near the burner outle
breakdown of a swirling flow [2]. The swir
simple design (FIG. 5) consists of two halves
shifted to form two air inlet slots of constant w
tube known from conventional burner desig
Gaseous or liquid fuels can be burnt. The operat
cases is shown in FIG. 4. Gaseous fuels a
combustion air by means of fuel distribution n
rows of small holes perpendicular to the inlet
Complete mixing of fuel and air is obtained shor
distributing the holes along the inlet slots
concentration profile in the burner exit plane car
fuels are injected at the burner tip using a pn
assisted atomizer. Due to the flame stabiliza
premixing and combustion chambers can be
mixing and complete evaporation is achieved dc
swirler before the recirculation zone is approache
the mixture takes place near the flow stagnation
perfectly nonluminescent oil flame is obtained.
more conventional premix burner designs, no diff
is needed to improve the stability of the premixed
equipped with Conical Premix Burners always
premixed mode. Due to the fact that neither gasec
present upstream of the swirler exceptional relia
obtained. Since the zone of ignition is significantly
burner walls, the heat transfer to the burner sectio

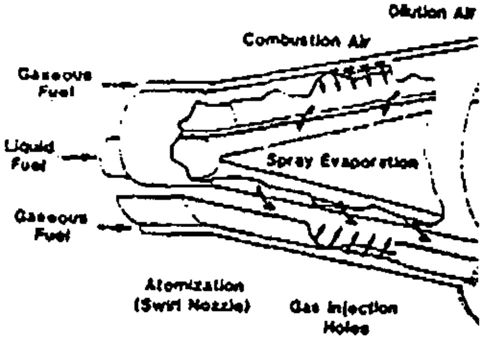


FIG 4: OPERATING PRINCIPLE OF THE CC
BURNER

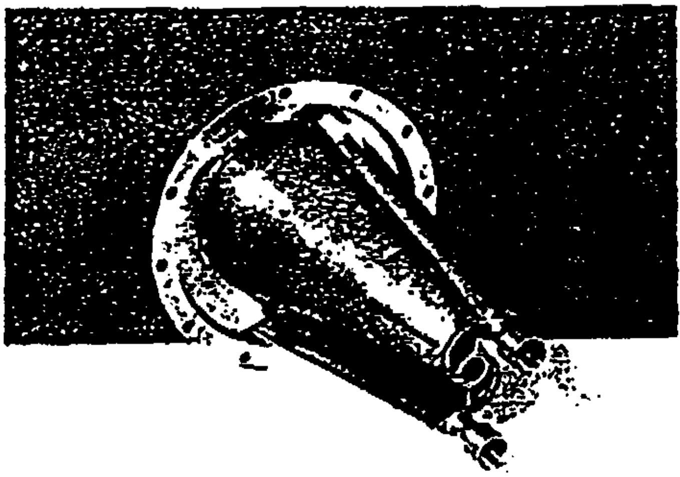


FIG 5: PROTOTYPE BURNER FOR HIGH PRESSURE TESTS

Frequently, severe stability problems occur with premixed flames in gas turbine combustors. An important property of the burner flow field is how strong the disturbances originating from combustion will influence the local position of the ignition zone near the stagnation point. A weak characteristic causes fluctuating local heat release and destabilizes the combustion process.

Vortex breakdown theory [2] clearly indicates that the most stable transition from a supercritical closed vortex flow into an annular form with recirculation on the axis is obtained only for swirling flows without a deficit in axial velocity on the burner axis, as known from flows generated from e.g. radial swirler configurations.

For the Conical Premix Burner it can easily be shown that an analytical solution can be given for potential flow between the burner tip and the zone of vortex breakdown.

The solution does not depend on the axial burner coordinate:

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

The parameter β is a function of the cone angle and the width of the inlet slots:

$$\beta = Const. \cdot (\tan \alpha / b)$$

FIG. 6 shows the theoretical velocity field for a prototype burner with an orifice diameter of 100mm near the exit plane.

The existence of an analytical solution leads to a high degree of understanding without using any elaborate numerical computer codes. Fuel concentration or spray penetration and evaporation calculations, for example, can be easily performed.

Theoretical considerations lead to the result that vortex breakdown near the burner exit plane will occur when parameter β exceeds a certain minimum value βmin. Burners with lower values of β violate the vortex breakdown criterion and lead to flow fields completely unsuitable for combustion purposes. .

FIG. 7 shows Laser-Doppler-Anemometer measurements for a burner geometry fulfilling the theoretical criterion for vortex breakdown. The appropriate profiles within the burner are generated as predicted. The transition from a closed vortex flow with high velocities on the axis to its annular flow state with stagnation on the axis takes place within a short distance close to the burner outlet.

Satisfactory agreement between calculated (see FIG. 6) and measured velocity profiles is obtained in the region upstream of vortex breakdown (FIG. 8). The breakdown of the vortex flow occurs slightly upstream of the burner exit plane. As a consequence, only low swirl velocities are measured near the burner axis at the burner outlet due to the recirculation zone.

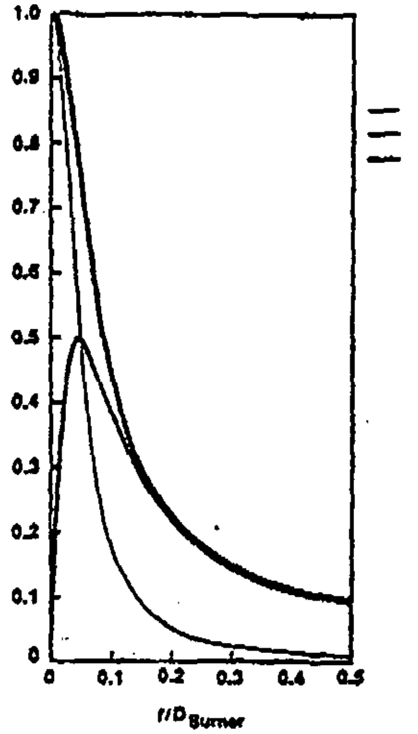


FIG.6: VELOCITY DISTRIBUTION WITH
(POTENTIAL FLOW WITHOUT BREAKDOWN)

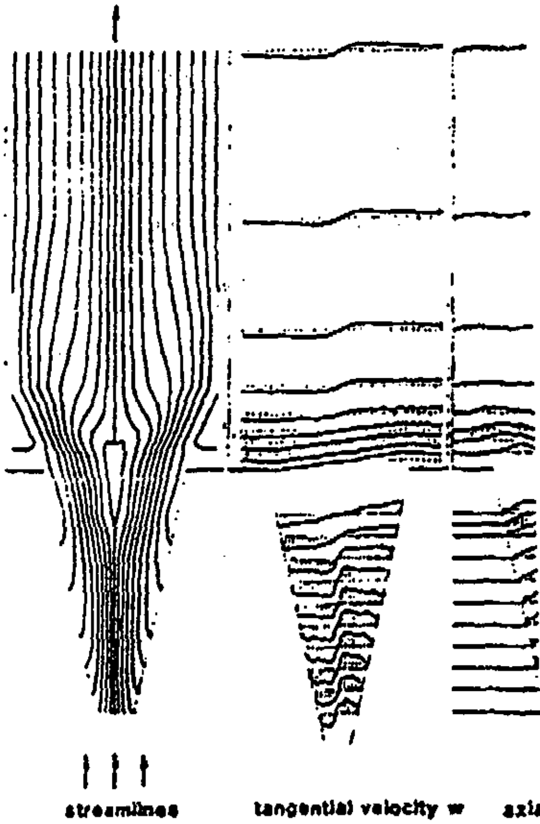


FIG 7: VELOCITY DISTRIBUTION (LDA-MEAS
NON-REACTING FLOW)

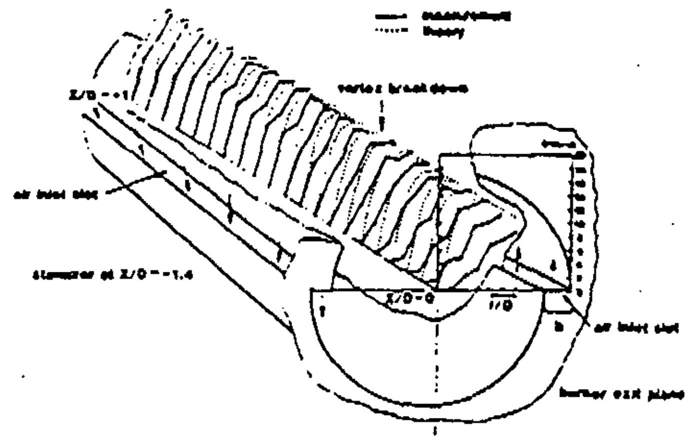


FIG. 8: COMPARISON OF PREDICTED AND MEASURED SWIRL PROFILES

The flow direction near the burner wall depends on the distance between burner wall and burner centerline. Therefore, different curves are obtained for the three circumferential positions of measurement depicted in FIG. 9. Only in the region of vortex breakdown can major differences between prediction and measurement be seen.

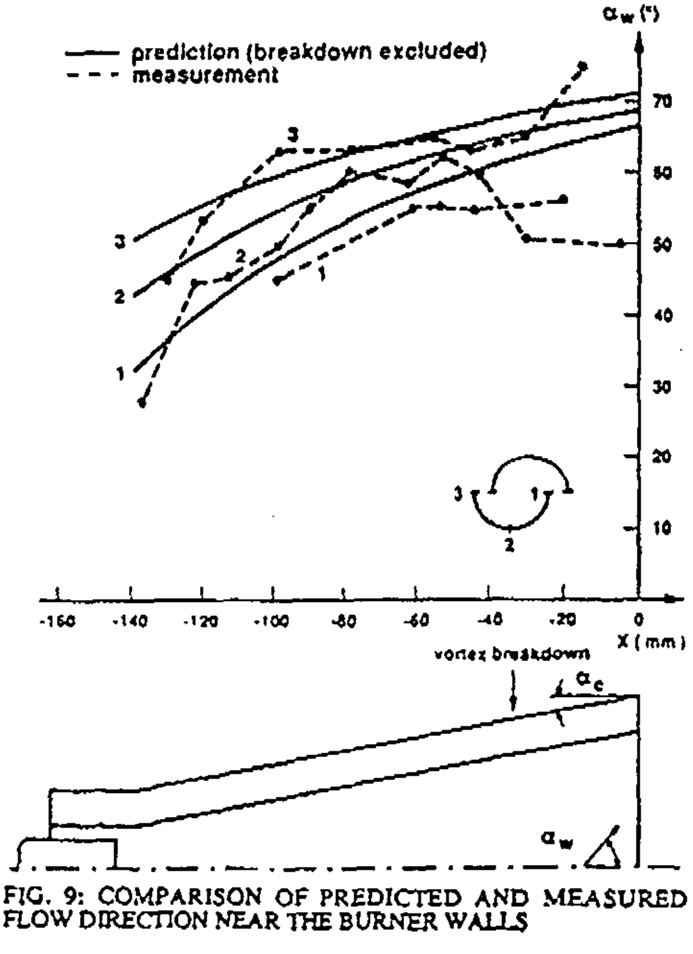


FIG. 9: COMPARISON OF PREDICTED AND MEASURED FLOW DIRECTION NEAR THE BURNER WALLS

Temperature profile measurements on the burner axis provide information about the flame position in the case of reacting flow. FIG.10 reveals that the air in the upstream part of the burner remains cold and that the temperature rise due to combustion takes place near the stagnation point found for cold flow. The beginning of the temperature rise depends weakly on the air preheat temperature.

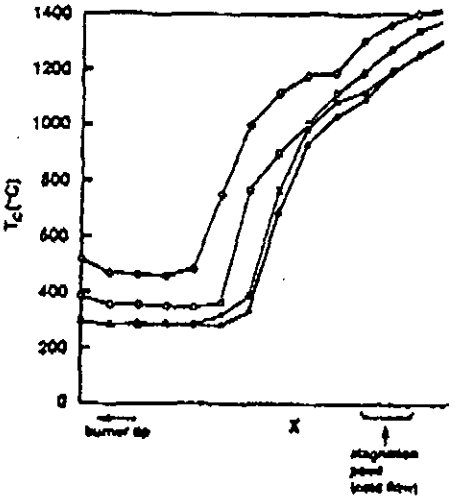


FIG 10: POSITION OF TEMPERATURE
AXIS

In a first approach, completely homogeneous m
desirable to abate the formation of nitrogen o
profile with a slightly lower mixture strength i
recirculation (FIG. 11) yields ultra low em
Conical Premix Burner.

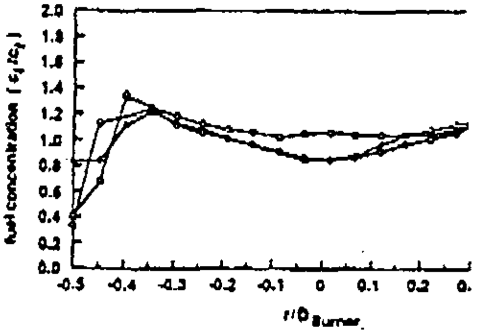


FIG. 11: FUEL DISTRIBUTION IN BUR
(NONREACTING GAS FLOW, TRACER
TRACER: CO)

Typical results of emission measurements for 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 rer
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 s
droplet evaporation within the burner. FIG. 13
of nozzle position on burner performance for two
which differ slightly from each other in terms
spray angle. Generally, the nozzle position wh
emissions are measured also yields minimum

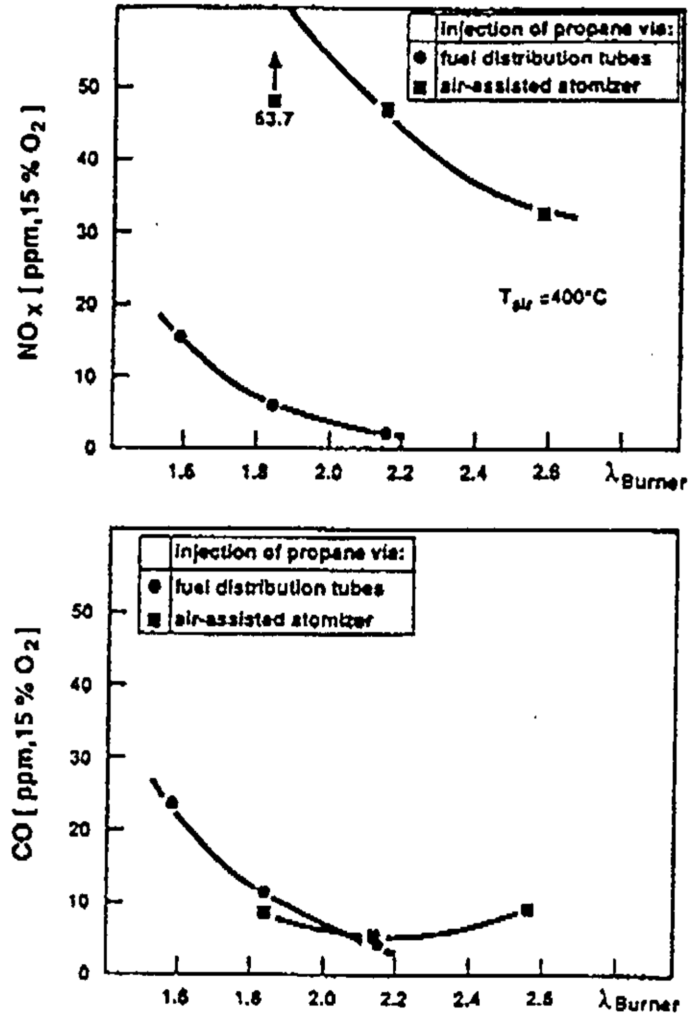


FIG. 12: NOx- AND CO- EMISSIONS OF PROTOTYPE BURNER (GASEOUS FUEL)

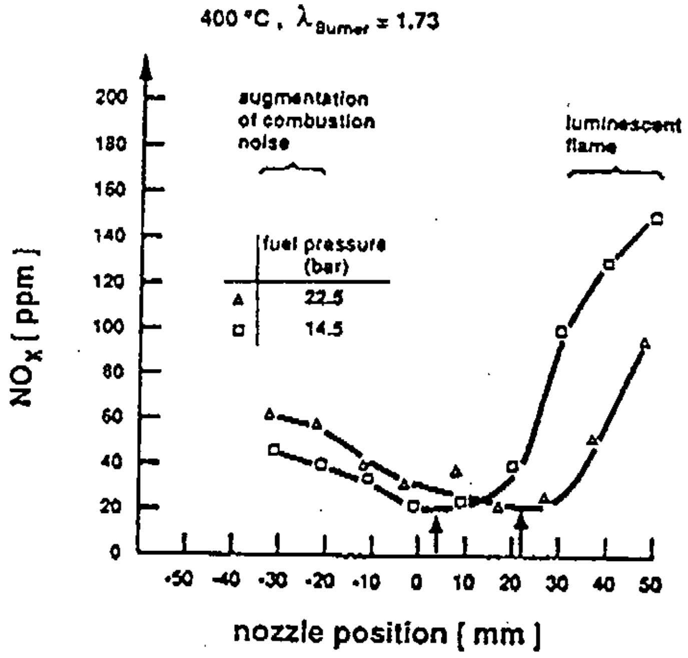


FIG 13: INFLUENCE OF NOZZLE POSITION ON NOx-EMISSIONS (PRESSURIZED NOZZLES)

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 i burner exit plane is obtained, which augments NOx generation i 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.FIG proves the low-NOx capability of the Conical Premix Burn atmospheric pressure. The lowest NOx-emissions measured fo (λBurner=2) are approximately twice as high as those measure propane if the data is compared on the basis of the burner equival ratio.

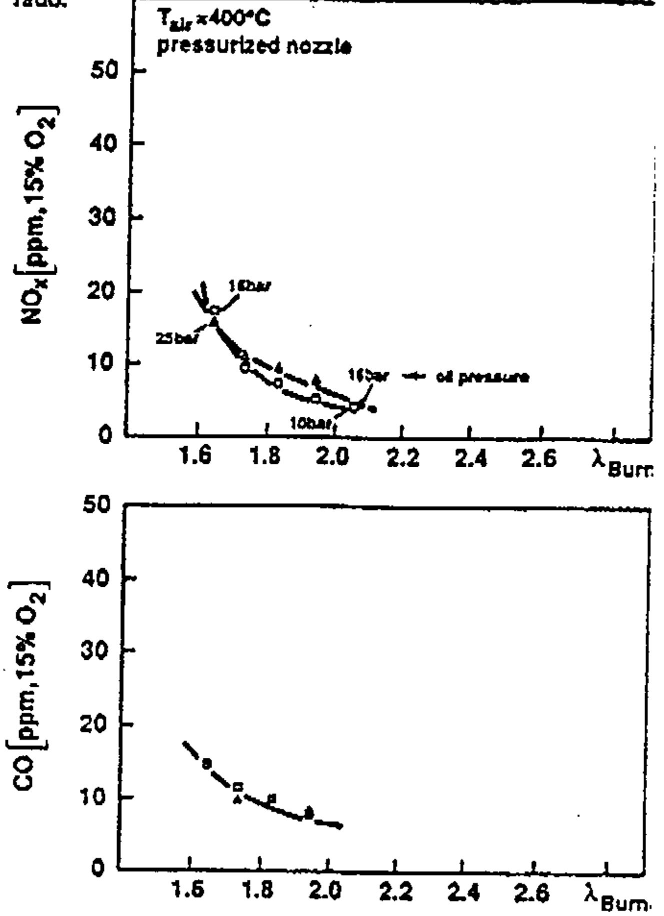
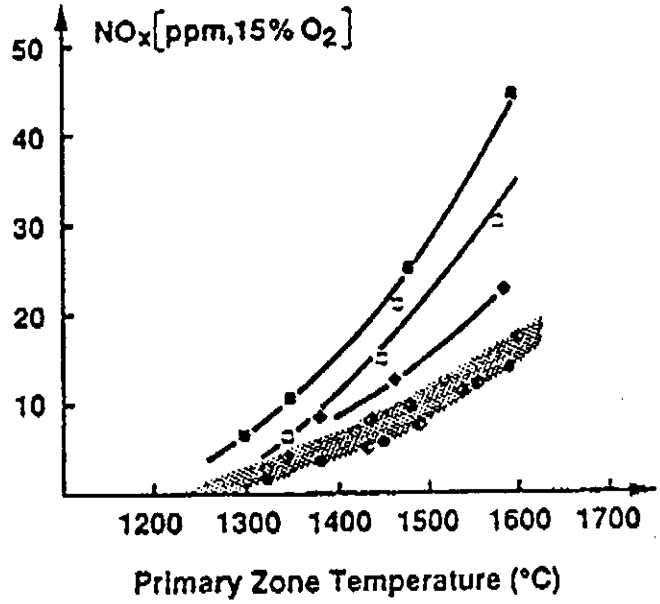


FIG. 14: NOx- AND CO- EMISSIONS OF PROTOTYPE BURN (LIQUID FUEL, FUEL BOUND NITROGEN NEGLIGIBLE)

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 the optimum nozzle configuration for oil (pressurized nozzle, sp angle 30 deg.) yields similar emissions to those measured propane at different air inlet temperatures. Since the NOx-generat of premixed flames is mainly governed by the flame temperature can be concluded that a high degree of premixing is obtained even the case of liquid fuels as long as the combustion air is stron preheated. Tests using air-assisted atomizers reveal that deterioration of droplet evaporation at lower air inlet temperatu leads to a remarkable increase in NOx-formation at constant fla temperature.



	burner type	fuel	spray angle	fuel or atomization air pressure (bar)	T_{air} (°C)	nozzle
○	prototype for gaseous fuel only	propane			20	
●	prototype for gaseous or liquid fuel	-			400	
◈		oil	30	10 - 15	-	pressurized
◇		-	30	15 - 25	-	
◆		-	60	10 - 15	-	
■		-	22	0.2	-	air-assisted
□		-	32	0.2	-	

FIG. 15: INFLUENCE OF PRIMARY ZONE TEMPERATURE ON NOx-EMISSIONS

BURNER STAGING PRINCIPLE

For single shaft gas turbines running with constant speed, the fuel consumption changes by approximately a factor of 3 from idling to full load. Modern premix burners, however, must be operated at almost constant equivalence ratio if a certain NOx-limitation is not to be exceeded. An advantage of ABB silo combustors is that this is achieved by burner (fuel) staging: In principle, purely premixed combustion can be maintained down to very low load by concentrating the fuel flow on an appropriate number of burners in the centre of the combustor.
Since the same procedure for can combustors will lead to unsatisfactory temperature profiles at the turbine inlet, additional diffusion stages are required, which exhibit an augmentation of NOx-emissions below full load.

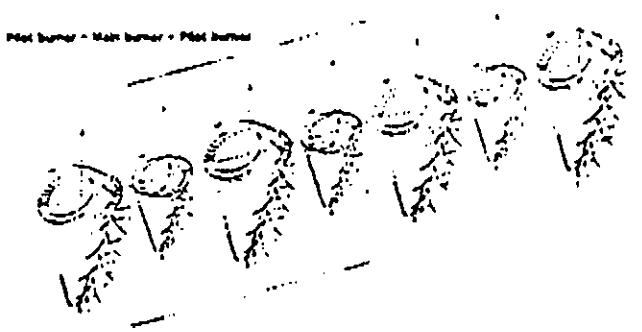


FIG. 16: MAIN- AND PILOT-BURNER CONFIGURATION OF THE ANNULAR COMBUSTOR

A novel piloting technique has been realized in the ABB combustor (FIG. 16). Pilot- and main-burners are alte distributed and have the same direction of swirl.Stable com from idling to full load is obtained as long as the pilot burners in self-stabilized mode. The fuel flow is split to obtain the equivalence ratios of the pilot burner independent of the output of the combustor. Supplementary fuel is fed to th burners. At low load the mixture obtained from the main bu too lean to ignite at the burner outlet. Nevertheless, high com efficiencies and uniform temperature profiles at the turbine 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 con performance, the self-stabilized mode of the main burners is near full load.

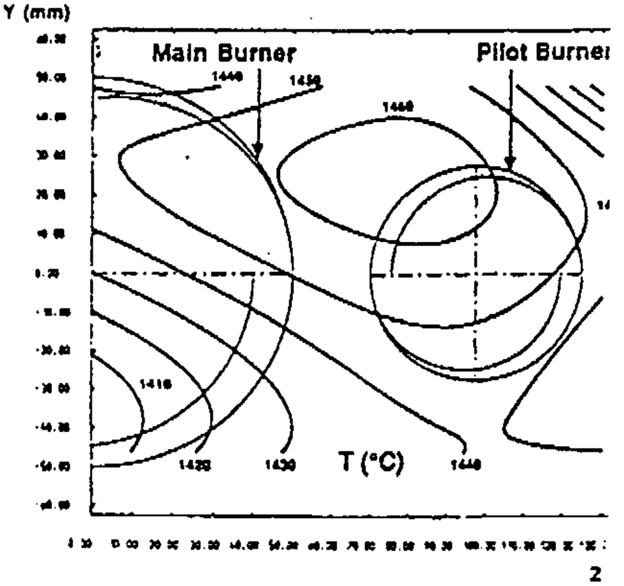


FIG. 17: TEMPERATURE DISTRIBUTION AT HIGH
(X=400MM,Φ_{pilot}=Φ_{main}=0.56)

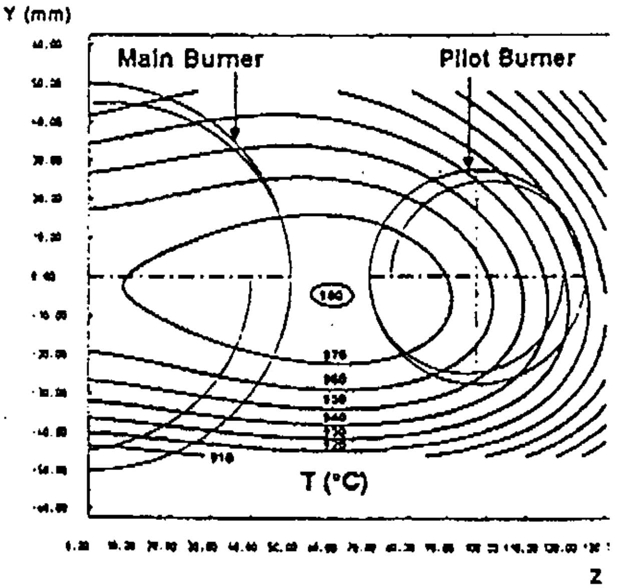


FIG. 18: TEMPERATURE DISTRIBUTION AT LOW
(X=400MM,Φ_{pilot}=0.56,Φ_{main}=0)

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.

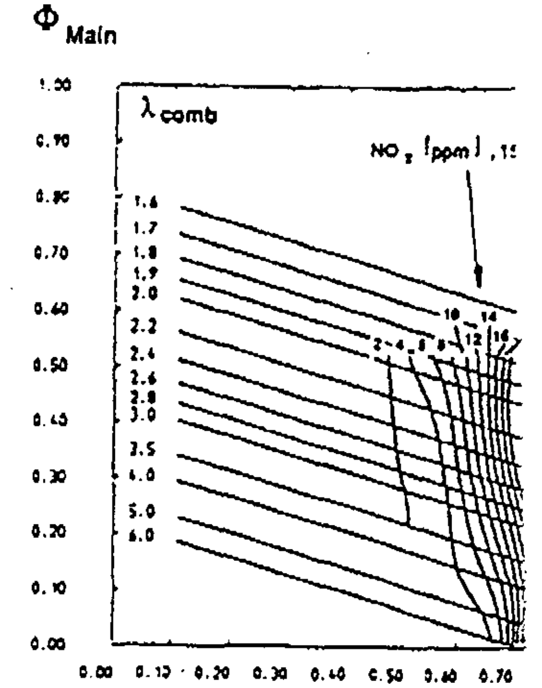


FIG. 20: NOx-EMISSION CHART (400°C, PROP

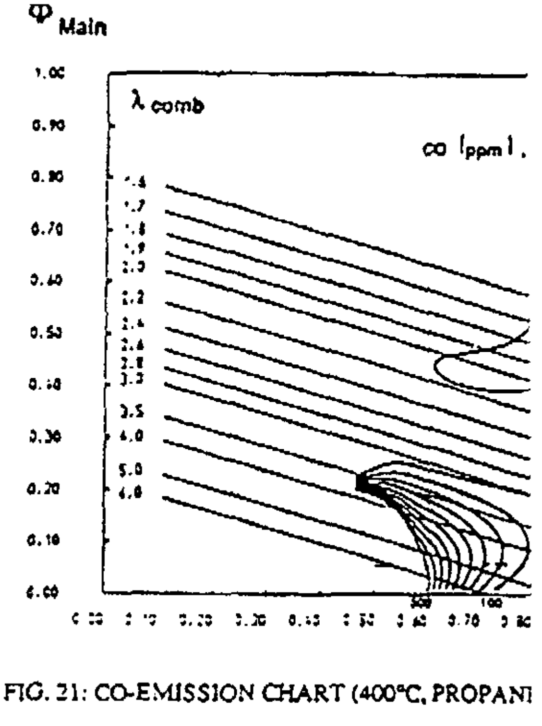


FIG. 21: CO-EMISSION CHART (400°C, PROPAN

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 regin to those /obtained for burner staging in silo combustor

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 comb (test rig comprising 2 pairs of burners). The NOx-en high load regime (main burners) are shown in FIG. 2 problems of flame stability, ultra low emissions ar

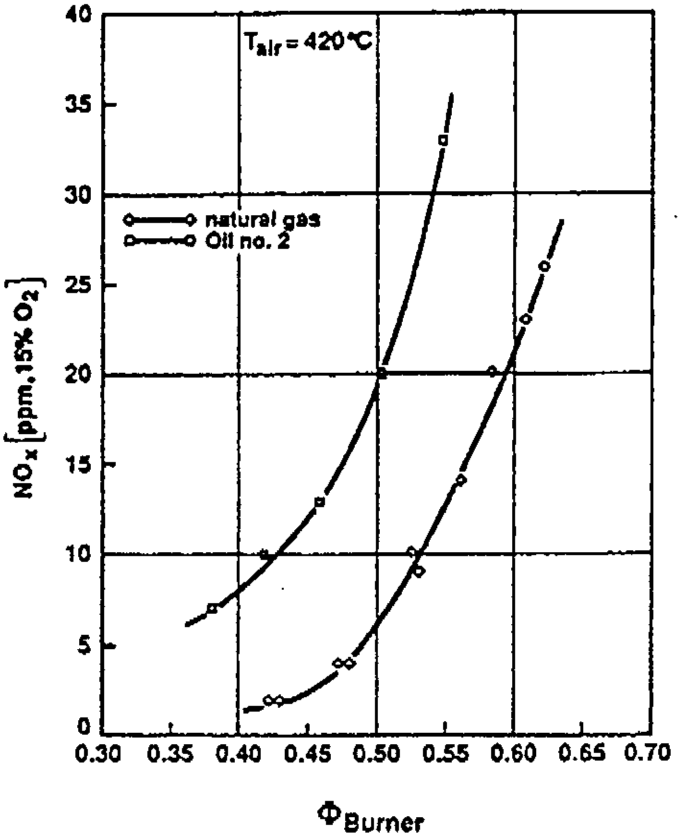


FIG. 22: OPTIMUM PERFORMANCE OF THE MAIN BURNER AT ENGINE SIZE AND ATMOSPHERIC PRESSURE (420°C)

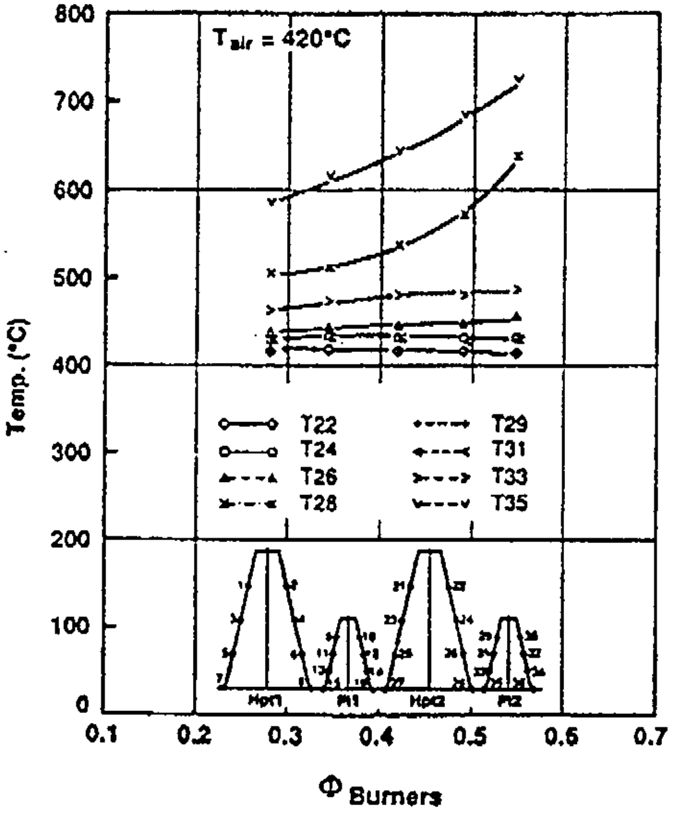


FIG. 23: BURNER TEMPERATURES (ϕ_p=2.2·ϕ_{burner}, ϕ_m=0.65·ϕ_{burner})

natural gas. For oil no. 2 the emissions obtained from t down models cannot be fully validated. Beside the effects o from fuel bound nitrogen, which can clearly be detected. t performance at 1:1 scale is due to the influence of burne droplet spray penetration. The calculation of the spir evaporation of droplets for the three cases:

1. scaled down burner operated at atmospheric pressure
2. burner of engine size operated at atmospheric pressure
3. burner of engine size under engine conditions

predicts the desired homogeneous fuel concentration only in 1 and 3. Tests at engine size but at atmospheric pressure (cas to a high concentration of the fuel vapour in the outer pa burner exit plane, generated from the droplets with an initia size greater than the mass median diameter of the spray. 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 ad

Φ_{Burner}=0.44, full load emissions for natural gas will not ex NOx-target even in the case of a scaling law NOx~$p_{combust}$ 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) d significantly exceed the temperature of the air. O thermocouples at the burner exit plane (28 and 35) record temperatures. since the impingement cooling of the combus panel was not present in the tests at atmosperic pressure.

CONCLUSIONS

Compared to the first generation of ABB low-NOx bur Conical Premix Burner exhibits several advantages:

- simple design
- no fuel upstream from burner (flashback impossible)
- no premixing tube
- simple oil injection technique

The following results have been obtained during the test pr ambient pressure:

a.) burner models:

- zone of recirculation in free space (vortex breakdow acts as a flameholder
- excellent stability of premixed flame
- ignition near burner exit plane
- zone of reaction displaced from burner walls
- low-NOx-capability for gaseous as well as liquid fuel

b.) partial load performance:

- simple piloting concept for the annular combustor
- only two burner groups (pilot burners and main burner
- excellent temperature profile without mixing zone
- low NOx-emissions as well as complete burnout abo load

c.) combustor segment (1:1 scale):

- natural gas: validation of results from model experiment
- natural gas: NOx-emissions extremely low: less than 25 engine conditions
- oil no. 2: NOx-emissions somewhat higher than i experiments
- low burner temperatures

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to be published: ASME Gas Turbine Conference, 1990, Brussels

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Florida Department of Environmental Regulation
Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

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

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to be able to install/retrofit one at a later date and, in the interim, meet the proposed 25 ppmvd (corrected to 15% oxygen) or possible lower BACT (best available control technology) limit?

4. On page 4-12, under the heading "Dry Low-NOx Combustor", it is stated that the proposed unit can achieve less than the proposed 25 ppmvd, when firing natural gas. Please provide the levels of NOx emissions that have been achieved by this unit to date; also, and if available, provide a copy of the synopsis page of any test data.

5. Can a selective catalytic reduction (SCR) system be retrofitted to the proposed source under its current design configuration? If not, please explain in detail.

If there are any questions, please call Bruce Mitchell at 904-488-1344 or write to me at the above address.

Sincerely,

A Preston Lewis
For
C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/BM/plm

c: C. Collins, CD
D. Nester, OCEPD
G. Smallridge, Esq., DER
C. Shaver, NPS
J. Harper, EPA
D. Buff, P.E., KBN

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

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

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

Consult postmaster for fee.

3. Article Addressed to:

Mr. John P. Jones, President
Orlando CoGen Inc.
7201 Hamilton Boulevard
Allentow, Pennsylvania 18195-1501

4a. Article Number
P 832 538 770

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

7. Date of Delivery
2-4-92

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

P 832 538 770

Certified Mail Receipt

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

Sent to
Mr. John P. Jones, Orlando CoGen Inc.

Street & No.
7201 Hamilton Blvd.

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

Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$

Postmark or Date
Mailed: 1-28-92
Permit: AC 48-206720
PSD-FL-184

PS Form **3800**, June 1990

To Bruce Mitchell

Date 1/22/92 Time 10:44

WHILE YOU WERE OUT

Mr. Bud Rolofson

of Nat'l Park Service

Phone

Area Code Number Extension

☒	TELEPHONED	☐	PLEASE CALL
☐	CALLED TO SEE YOU	☐	WILL CALL AGAIN
☐	WANTS TO SEE YOU	☐	URGENT
	☐	RETURNED YOUR CALL	

Message Have no Comments on Cat. Co-Dev Exampled

MS
Operator

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 10, 1992

Mr. Dennis Nester
Air Program Supervisor
Orange County Environmental
Protection Department
2002 E. Michigan Avenue
Orlando, Florida 32806

Dear Mr. Nester:

RE: Orlando CoGen Limited
Orange County, PSD-FL-184

The Department has received the above referenced PSD application package. Please review this package for completeness by January 27, 1992, and forward your comments to the Department's Bureau of Air Regulation. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact Bruce Mitchell or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

/pa

Enclosures

Recycled Paper

KBN

Letter of Transmittal

RECEIVED
JAN 9 1992
Division of Air
Resources Management

Date: January 8, 1992

Project No.: 91134/0200

To: C.H.Fancy, P.E.
Chief, Bureau of Air Regulation
FDER
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Orlando CoGen

The following items are being sent to you: ☐ *with this letter* ☐ *under separate cover*

Copies	*Description*
3	PSD Permit Application for Orlando CoGen Limited, L.P. Cogeneration Project

These are transmitted:

☒ *As requested*

☐ *For review*

☐ *For review and comment*

☐ *For approval*

☐ *For your information*

☐

Remarks:

Sender: Jan Wyckoff

Copy to: Project File (2)
Dave Buff

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

AF1/LOT1 (07/91)

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 7, 1992

Mrs. Chris Shaver, Chief
Permit Review and Technical Support Branch
National Park Service-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Dear Mrs. Shaver:

RE: Orlando CoGen Limited
Orange County, PSD-FL-184

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Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

/pa

Enclosure

Florida Department of Environmental Regulation
Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

January 7, 1992

Ms. Jewell A. Harper, Chief
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30308

Dear Mrs. Harper:

RE: Orlando CoGen Limited
Orange County, PSD-FL-184

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Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

/pa

Enclosures