KBN

June 20, 1991

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Division of Air Resources Management

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

Subject: Permit Applications: Lake County AC 35-196459, PSD-FL-176
Pasco County AC 51-196460, PSD-FL-177

Dear Clair:

This correspondence is submitted on behalf of Lake Cogen Limited and Pasco Cogen Limited to address questions raised in your letter dated May 31, 1991, concerning the above-referenced permit applications. The questions contained in your May 31, 1991 letter were identical for both projects. Since the technology proposed for both projects is identical, it is the intent of this correspondence to address the questions asked for both projects simultaneously. The responses presented are listed in the same numerical order as your May 31, 1991, letter.

Please call if there are any questions concerning these responses. Your efforts to expedite the issuance of the construction permits for these projects would be greatly appreciated. The generation made available by these projects will assist Florida in its growing energy demands while using the cleanest of fuels and most efficient technology.

Sincerely,

Ken Kosky/LCB

Kennard F. Kosky, P.E.
President

cc: E. Mize
E. White
K. Smith
J. Clemons
R. Zwolak
S. Marks
P. Lewis
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J. Harper, EPA
C. Shaver, NPS

90115-90116A1/1

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

RESPONSE TO COMMENTS

FDER.1a

Comment: In Table 2-1, you stated that the duct burner will only fire natural gas and operate 3500 hours/year.

Response: The duct burner will operate an equivalent of 3,500 hours per year (hr/yr) at an average heat input of 150 million British thermal units per hour (MMBtu/hr) or 525,000 million British thermal units per year (MMBtu/yr) (see Page 2-5 of the report). A permit condition specifying the maximum heat input per year, rather than a limitation on hours of operation, is requested due to the variation in steam loads of the citrus processing plants. Because the operation of the duct burner will be dependent on the steam loads of the citrus processing plants, the heat input to the duct burner will vary. In fact, recent engineering information indicates that up to 225 MMBtu/hr will be required for the Pasco County project. However, the average heat input will remain the same, i.e., 525,000 MMBtu/yr. Since the maximum heat input will increase, Table 2-1 and Tables A-1 through A-4 have been revised (see Attachment FDER.1a) for the Pasco County permit application to reflect this increase. This revision does not change the annual emissions or PSD applicability since the annual emissions will be on the same basis as the original application. Additionally, the impact analyses will not change since the modeling was performed using the worst- case fuel, i.e., distillate oil. Distillate oil will only be used when natural gas is curtailed; thus, duct firing will not occur when distillate oil is fired.

FDER.1b

Comment: You also stated that the gas turbine will fire oil 240 hours/year and gas 8520 hours/year. Why doesn't the duct burner operate the total time (8760 hours/year)?

Response: The duct burner will not operate all year because of the variation in steam load and seasonal nature of the citrus processing plants. However, duct firing may operate greater than 3,500 hr/yr but not above the requested annual heat input (i.e., 525,000 MMBtu/yr).

FDER.1c

Comment: If this duct burner will only be operated intermittently, what records will be kept on operation and emissions by pollutant?

Response: The amount of natural gas burned will be continuously monitored and recorded by an electronic control system (see response to Comment 6).

FDER.1d

Comment: Have the emissions been adjusted for the actual operating hours by fuel?

Response: The maximum annual emissions have been calculated to account for 8,520 hr/yr of gas turbine operation when firing natural gas, 240 hr/yr of gas turbine operation when firing distillate oil and 3,500 hr/yr of duct firing when firing natural gas at an equivalent average heat input of 150 MMBtu/hr. It should be noted that distillate oil will only be used if natural gas is curtailed, which is usually for only a few days.

FDER.2

Comment: Carbon monoxide emissions seem to be higher than expected (467 TPY compared to a similar combustion turbine having about 230 TPY). Please discuss reasons for higher emissions along with the relationship to NO_x emissions.

Response: The proposed carbon monoxide (CO) emission limitation reflects the level that the manufacturer of the gas turbine would guarantee for this project. The reason for this is based on the lack of experience for this new machine, i.e., the GE LM 6000. However, the CO emissions expected when the units are tested are believed to be less than one-half of the guaranteed level. This was stated on Page 4-30.

FDER.3

Comment: Submit a stack drawing showing location for taking stack samples.

Response: A conceptual drawing of the stack is provided as Attachment FDER.3. The stack will be identical for both projects. The locations of the sampling ports, when construction is complete, will conform with FDER Rule 17-2.700(4)(c).

FDER.4

Comment: Provide listing of similar sources already in operation including summary of stack test results on all pollutants.

Response: Data for the GE LM6000 are not available. Stack test data are available for the GE LM5000, which is an aircraft derivative machine similar to the LM6000. The test results are provided as Attachment FDER.4.

FDER.5

Comment: Provide any additional manufacturer information and brochures including a process flow diagram showing volumetric flow rates for the source.

Response: Additional manufacturer information on the LM6000 is provided as Attachment FDER.5.

FDER.6

Comment: What kind of control and monitoring equipment do you propose to use for continuously recording power generation (MWS), fuel injection rate (MMCF/hr or Gal/hr), water injection rate (Gal/hr), Co (PPMDV), SO_2 (PPMDV), and NO_x (PPMDV)?

Response: Signals for kW, fuel, and NO_x water injection flow are some of the many parameters that the electronic control system will continuously display. All of the signals within the system will be sent to the plant's data control system (DCS) via an RS232 link (updated approximately every 1 to 2 seconds) for use in the operator display screens and the plant reporting and logging systems. Also among these signals sent to the DCS are parameters like shaft speeds, pressures, and temperatures for use in algorithms to derive exhaust flow. The NO_x emissions will be determined continuously according to the requirements of 40 CFR, Part 60, Section 60.334. CO emissions are proposed to be determined using EPA Method 10 during annual compliance tests. Sulfur dioxide emissions are proposed to be determined by using the sulfur content obtained from fuel analyses and fuel input rates. The proposed methods for determining compliance with emission limitations is consistent with permits issued recently for similar sources.

FDER.7

Comment: What is the basis for the statement "CO emissions are expected to be one-half or less than those proposed..." (page 4-30)?

Response: See answer to Comment 2.

FDER.8

Comment: Table 4-7 (page 4-7) lists primary and secondary differentials when SCR is used to control NO_x emissions. Please provide additional discussion for basis of secondary emissions and how primary emissions were calculated?

Response: The primary emissions are based on emissions from the proposed sources. The particulate matter is based on the assumption that the sulfur dioxide emitted from the project would react with the ammonia and form ammonium salts. The calculation is based on the tons per year (TPY) of sulfur dioxide multiplied by the difference in molecular weight of sulfur dioxide and ammonium salts (i.e., 21 TPY SO2 x 132/64). The primary NO_x emissions are the emissions with selective catalytic reduction (SCR) at 65 percent control, which is 9 parts per million (ppm) NO_x corrected to 15 percent oxygen, dry conditions (i.e., 0.35 x 405 TPY NO_x). The ammonia emissions were based on an ammonia slip of 10 ppm emitted. This level of ammonia emissions represents the emission level being permitted for SCR systems. The emissions are calculated using the ideal gas law and the stack flow rate [i.e., 324,249 ft^3/hr x 60 min/hr x 10 ppm $NH_3/10^6$ ft^3/ppm x 2116.8 lb/ft^3 / 1,545 ft/°R x 692°R x 17 (molecular weight of ammonia) x 2 units x 4.38 TPY/lb/hr].

The secondary emissions are based on the lost energy that occurs due to the electrical requirements and turbine back pressure caused by the SCR catalyst. Since this unit will be extremely efficient, it will be run base load and have a high capacity factor. In addition, because of the unit's inherent efficiency and its cogeneration ability, it will supply electrical power at a higher priority than other power plants. The energy loss caused by the SCR system will not be available and will have to be replaced by other power plants, which will incrementally emit more air pollutants to make up for the generation loss. The air emissions caused by this loss generation is referred to as secondary emissions. The type of unit that will replace this lost energy will likely be an oil-fired unit, since they are the last placed in service by the utility system. For the purpose of this calculation, it was assumed that the hypothetical unit that replaced the loss energy has a heat rate of 10,000 British thermal units per kilowatt (Btu/kW). EPA emission factors were then used to calculate emissions. The calculations are: 58,000 kW/hr (lost energy) x 10,000 Btu/kW x million/10^6 x EF (emission factor in lb/MMBtu) x 4.38 TPY/lb/hr. The emission factors used (in lb/MMBtu) were: 0.1, 1.1, 0.55, 0.033, and 0.005 for PM, SO_2, NO_x, CO, and volatile organic compounds (VOC), respectively.

FDER.9

<u>Comment</u>: In the PSD analysis the maximum Class I PM and NO_x PSD increment consumption at the Chassahowitzka National Wilderness Area was determined for the proposed facility alone. However, there are no PSD significant impact levels for Class I areas. Please perform a cumulative Class I increment analysis which includes all increment consuming sources in the airshed impacting the Chassahowitzka Wilderness Area.

<u>Response</u>: Particulate matter (PM-TSP) and NO_x emission inventories for the Chassahowitzka Wilderness Area prevention of significant deterioration (PSD) Class I modeling were provided to KBN by the Florida Department of Environmental Regulation (FDER). The inventory included all PSD increment consuming sources of NO_x and PM-TSP within the PSD Class I airshed. PM-increment-consuming sources for Florida Power Corporation (FPC) Crystal River was included in the inventory from a recent PSD permit application. The modeling was performed with the Industrial Source Complex Short-Term (ISCST) model using a 5-year meteorological record. For the Lake County facility, a 5-year record (1982-1986) from Orlando/Ruskin was used. For the Pasco County facility, a 5-year record (1982-1986) from Tampa/Ruskin was used. Nine screening receptors covering the outer boundary of the Chassahowitzka Wildlife Refuge were provided to KBN by FDER. Four additional receptors were added to cover the northern boundary of the PSD Class I area. The average distance between receptors is approximately 2.5 kilometers.

The NO_x and PM-TSP PSD Class I modeling results for the proposed Lake County facility are presented in Table FDER.9-1 (see Attachment FDER.9). These results indicate that the maximum NO_x increment consumption of 0.13 micrograms per cubic meter ($\mu g/m^3$) is below the allowable Class I increment of 2.5 $\mu g/m^3$. The PM modeling results indicate that the maximum annual and 24-hour PM increment consumptions are 0.40 and 2.72 $\mu g/m^3$, respectively. These concentrations are considerably below the allowable PSD Class

I increments of 5 and 10 $\mu g/m^3$, respectively, for the annual and 24-hour averaging times. They are also below the proposed PM10 PSD Class I increments of 4 and 8 $\mu g/m^3$, respectively, for those same two averaging times.

The NO_x and PM-TSP PSD Class I modeling results for the proposed Pasco County facility are presented in Table FDER.9-2. These results indicate that the maximum NO_x increment consumption of 0.13 $\mu g/m^3$ is below the allowable Class I increment of 2.5 $\mu g/m^3$. The PM modeling results indicate that the maximum annual and 24-hour PM increment consumptions are 0.41 and 2.22 $\mu g/m^3$, respectively. These concentrations are considerably below the allowable PSD Class I increments of 5 and 10 $\mu g/m^3$, respectively, for the annual and 24-hour averaging times. They are also below the proposed PM10 PSD Class I increments of 4 and 8 $\mu g/m^3$, respectively, for those same two averaging times.

A printed copy and a disk copy of the input and output file are provided in Attachment FDER.9.

ATTACHMENT FDER.1a

Table 2-1. Stack, Operating, and Emission Data for the Proposed Cogeneration Facility (Maximum at ISO Conditions)

	Fuel Type		
	Fuel Oil[a]	Natural Gas	
Parameter	Gas Turbine	Gas Turbine[b]	Duct Burner[c]
Stack Data (ft)			
Height	100	100	d
Diameter	11	11	d
Operating Data			
Temperature (°F)	232	232	d
Velocity (ft/sec)	56.9	56.2	d
Building Data (ft)			
Height	51	51	d
Length	124	124	d
Width	80	80	d
Maximum Hourly Emission Data (lb/hr) for Each Emission Unit/Fuel Type			
SO_2	40.0	1.15	0.68
PM	10.0	2.5	1.35
NO_x	68.5	39.4	22.5
CO	75.5	40.3	45.0
VOC	4.15	1.65	6.75
Sulfuric acid mist	3.2	Neg	Neg
Pb	0.0034	—	—
Annual Potential Emission Data (TPY) for Each Emission Unit/Fuel Type			
SO_2	4.8	5.05	0.79
PM	1.2	11.0	1.58
NO_x	8.2	172.4	26.3
CO	9.1	176.6	52.5
VOC	0.5	7.2	7.9
Sulfuric Acid Mist	0.4	Neg	Neg
Pb	0.0004	Neg	Neg

[a] Performance based on NO_x emissions of 42 ppmvd (corrected to 15 percent O_2); SO_2 emissions based on an average sulfur content of 0.1 percent sulfur; annual emission data based on 240 hr/yr (10 days/year).
[b] Performance based on NO_x emissions of 25 ppmvd (corrected to 15 percent O_2); annual emissions data based on 8,760 hours/year (365 days/yr) operation.
[c] Performance based on a maximum of 225 x 10^6 Btu/hour heat input per HRSG and an average of 150 x 10^6 Btu/hr for 3,500 hours per year operation.
[d] Same as gas turbine natural gas; duct burners will not fire No. 2 oil.

pollutants, regulated noncriteria pollutants, and nonregulated pollutants from each CT are presented in Tables A-1 through A-5 of Appendix A.

Supplemental firing with natural gas will take place in the duct between each CT and its associated HRSG. The supplemental firing, at a maximum rate of 225 million British thermal units per hour (x 10^6 Btu/hr), will allow the HRSG to produce additional steam and therefore allow greater electrical power generation in the steam turbine/generator. The firing of natural gas will produce additional air emissions, as shown in Tables 2-1 and 2-2, for the maximum firing rate. These emissions will combine with the CT exhaust gases only during natural gas firing and exhaust through the HRSG stack. Supplemental firing will be limited to an equivalent of 3,500 hours per year at an average capacity of 150 x 10^6 Btu/hr capacity (i.e., 525,000 x 10^6 Btu).

Table A-1. Design Information and Stack Parameters for Cogeneration Project

Data A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
General:			
Power (kW)[a]	42,044.0	NA	41,917.0
Heat Rate (Btu/kwh)[a]	9,112.0	NA	9,232.0
Heat Input (MMBtu/hr)	383.1	225.0[c]	387.0
Fuel Oil (lb/hr)	18,533.4	10,884.4[c]	21,031.4
(cf/hr)	403,268.3	236,842.1[c]	
Fuel:			
Heat Content - (LHV)	20,671 Btu/lb	20,671 Btu/lb	18,400 Btu/lb
Sulfur	1 gr/100cf	1 gr/100cf	0.1
CT Exhaust:			
Volume Flow (acfm)	593,208		590,922
Volume Flow (scfm)	247,404		244,711
Mass Flow (lb/hr)[b]	1,079,779		1,081,322
Temperature (°F)	806		815
Moisture (% Vol.)	11.00		9.30
Oxygen (% Vol.)	13.36		13.46
Molecular Weight	28.03		28.38
Water Injected (lb/hr)	19,061		21,793
HRSG Stack:			
Volume Flow (acfm)	324,249		320,720
Temperature (°F)	232		232
Diameter (ft)	11.0		11.0
Velocity (ft/sec)	56.9		56.2

Source: General Electric and Stewart and Stevenson, 1991.
Note: All data shown on this table and subsequent tables are for each combustion turbine and duct burner.

[a] Represents ISO conditions, which produces maximum potential emissions; actual operating power and heat rate will produce lower heat input.
[b] A 5% margin added to maximize emissions since machine is new and the operating history in industrial applications has not yet been developed.
[c] Represents maximum heat input; average heat input will be 150 MMBtu/hr; 7.256.5 lb/hr and 157,894.7 ft^3/hr.

Table A-2. Maximum Criteria Pollutant Emissions for Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
Particulate:			
Basis	Manufacturer	0.006 lb/MMBtu	Manufacturer
lb/hr	2.50	1.35	10.0
TPY	10.95	1.58	1.2
Sulfur Dioxide:			
Basis	1 gr/100 cf	1 gr/100 cf	0.1% Sulfur
lb/hr	1.15	0.68	39.96
TPY	5.05	0.79	4.8
Nitrogen Oxides:			
Basis	25 ppm[a]	0.1 lb/MMBtu	42 ppm[a]
lb/hr	39.4	22.5	68.5
TPY	172.37	26.3	8.2
ppm	25.0	NA	42.0
Carbon Monoxide:			
Basis	42 ppm[b]	0.2 lb/MMBtu	78 ppm[b]
lb/hr	40.3	45.0	75.5
TPY	176.58	52.5	9.1
ppm	42.0	NA	78.0
VOCs:			
Basis	4 ppm[b]	0.03 lb/MMBtu	10 ppm[b]
lb/hr	1.65	6.75	4.15
TPY	7.2	7.9	0.5
ppm	4.0	NA	10.0
Lead:			
Basis			EPA(1988)
lb/hr	NA	NA	3.44E-03
TPY	NA	NA	4.13E-04

[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 hr/yr and 240 hr/yr for fuel oil firing. Annual emissions for duct burners based on 3,500 hr/yr at an average heat imput of 150 MMBtu/hr.

Table A-3. Maximum Other Regulated Pollutant Emissions for Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
As (lb/hr)	NEG.	NEG.	0.0016253065248
(TPY)	NEG.	NEG.	1.95E-04
Be (lb/hr)	NEG.	NEG.	0.00096744436
(TPY)	NEG.	NEG.	1.16E-04
Hg (lb/hr)	NEG.	NEG.	1.16E-03
(TPY)	NEG.	NEG.	1.39E-04
F (lb/hr)	NEG.	NEG.	0.01257677668
(TPY)	NEG.	NEG.	1.51E-03
H2SO4 (lb/hr)	8.81E-03	5.18E-03	3.22E+00
(TPY)	3.86E-02	6.04E-03	3.86E-01

Sources: EPA, 1988; EPA, 1980

Table A-4. Maximum Non-Regulated Pollutant Emissions for Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Manganese (lb/hr)	NEG.	NEG.	2.49E-03
(TPY)	NEG.	NEG.	2.99E-04
Nickel (lb/hr)	NEG.	NEG.	6.58E-02
(TPY)	NEG.	NEG.	7.89E-03
Cadmium (lb/hr)	NEG.	NEG.	4.06E-03
(TPY)	NEG.	NEG.	4.88E-04
Chromium (lb/hr)	NEG.	NEG.	1.84E-02
(TPY)	NEG.	NEG.	2.21E-03
Copper (lb/hr)	NEG.	NEG.	1.08E-01
(TPY)	NEG.	NEG.	1.30E-02
Vanadium (lb/hr)	NEG.	NEG.	2.70E-02
(TPY)	NEG.	NEG.	3.24E-03
Selenium (lb/hr)	NEG.	NEG.	9.08E-03
(TPY)	NEG.	NEG.	1.09E-03
POM (lb/hr)	4.27E-04	2.51E-04	1.08E-04
(TPY)	1.87E-03	2.93E-04	1.30E-05
Formaldehyde (lb/hr)	3.38E-02	9.11E-02	1.57E-01
(TPY)	1.48E-01	1.06E-01	1.88E-02

ATTACHMENT FDER.4

Table FDER.4-1. Comparison of Tested and Permitted Emissions for Tropicana and Reedy Creek Energy Services

Parameter	Units	Tropicana[a] Test Results	Tropicana[a] Permit Limits	Reedy Creek[b] Test Results	Reedy Creek[b] Permit Limits
Gas Turbine	**(GT):**				
Capacity	kW	39.76	45.4[c]	30.18	30.8[f]
Heat Input	MMBtu/hr	373.40[d]	425.5[c]	314.97	345.0[f]
Nitrogen Oxides	lb/hr	37.20	62.6	54.00[h]	77.0[g]
Carbon Monoxide	lb/hr	2.93	9.1	3.90[h]	11.0[g]
Vol. Org. Compds	lb/hr	0.00	3.6	0.00[i]	6.0[g]
Particulates	lb/hr	1.84	1.5	0.65[i]	0.8[g]
Visible Emissions	%	0.00	10	0.00[i]	5.0[g]
Gas Turbine with Duct Burners (GT/DB):					
Capacity	kW	37.69	45.4[c]	30.18	30.8[f]
Heat Input - CT	MMBtu/hr	356.92[d]	425.5[c]	316.90	322.0
- DB	MMBtu/hr	95.97[d]	104	21.90	23.0
Nitrogen Oxides - Total	lb/hr	40.69	73	54.70[i]	77.0[g]
- CT	lb/hr	35.49[e]	62.6	54.00[h]	--
- DB	lb/hr	5.20	10.4	0.70[j]	--
Carbon Monoxide - Total	lb/hr	13.50	23.66	5.10[i]	11.0[g]
- CT	lb/hr	2.80[e]	9.1	3.90[h]	--
- DB	lb/hr	10.70	14.56	1.20[j]	--
VOCs - Total	lb/hr	1.24	7.76	0.00[i]	6.0[g]
- CT	lb/hr	0.00[e]	3.6	--	--
- DB	lb/hr	1.24	4.16	--	--
Particulate - Total	lb/hr	1.34	1.75	0.65[i]	0.8[g]
- CT	lb/hr	1.76[e]	1.5	--	--
- DB	lb/hr	-0.42	0.25	--	--
Visible Emissions	%	0.00	10	0.00[i]	5.0[g]

[a] Tropicana gas turbine and heat recovery steam generator (HRSG) (AC41-157745).
[b] Reedy Creek Energy Services gas turbine and HRSG (AO48-170280).
[c] Summer design conditions are 37.9 MW and 373.7 MMBtu/hr and autumn design conditions are 41.7 MW and 408.9 MMBtu/hr.
[d] Based on the average high heating value (HHV) of gas, 1,024 Btu/ft.
[e] Calculated based on heat input for GT and emissions from GT only test.
[f] Maximum permitted limit for both the gas turbine and duct burners.
[g] Annual average limits for both GT and HRSG when firing natural gas.
[h] Stack test result from firing gas turbine only.
[i] Stack test result from firing both gas turbine and duct burners.
[j] Calculated by subtracting (h) from (i).

ATTACHMENT FDER.9

Table FDER.9-1. Maximum Predicted PSD Class I Impacts for the Proposed Lake Cogeneration Facility

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] UTM-E (m)	Receptor Location[a] UTM-N (m)	Day/ Period
Nitrogen Oxides (NO_x)					
Annual					
	1982	0.13	340300	3165700	- / -
	1983	0.13	340300	3167700	- / -
	1984	0.11	340300	3165700	- / -
	1985	0.11	340300	3165700	- / -
	1986	0.12	340300	3165700	- / -
Particulates (PM-TSP)					
Annual					
	1982	0.40	334000	3183400	- / -
	1983	0.35	334000	3183400	- / -
	1984	0.35	340700	3171900	- / -
	1985	0.30	340300	3165700	- / -
	1986	0.34	340300	3165700	- / -
24-Hour[b]					
	1982	2.50	334000	3183400	343/ 1
	1983	2.32	336500	3183400	342/ 1
	1984	1.92	343700	3178300	342/ 1
	1985	1.82	331500	3183400	298/ 1
	1986	2.72	341100	3183400	11/ 1

Note: Allowable PSD Class I increments are (in $\mu g/m^3$):
- NO_x
  - Annual--2.5
- PM-TSP
  - Annual--5
  - 24-Hour--10

Proposed PM10 PSD Class I increments are:
- Annual--4
- 24-Hour--8

[a]Receptor locations are in UTM coordinate system (m).
[b]All short-term concentrations indicate highest, second-highest (HSH) predicted concentrations.

Table FDER.9-2. Maximum Predicted PSD Class I Impacts for the Proposed Pasco Cogeneration Facility

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] UTM-E (m)	UTM-N (m)	Day/ Period
Nitrogen Oxides (NOx)					
Annual					
	1982	0.13	340300	3165700	- / -
	1983	0.12	340300	3165700	- / -
	1984	0.10	340300	3165700	- / -
	1985	0.12	340300	3165700	- / -
	1986	0.13	340300	3165700	- / -
Particulates (PM-TSP)					
Annual					
	1982	0.39	340300	3165700	- / -
	1983	0.38	340300	3165700	- / -
	1984	0.41	340300	3165700	- / -
	1985	0.37	340300	3165700	- / -
	1986	0.40	340700	3171900	- / -
24-Hour[b]					
	1982	1.98	342000	3174000	255/ 1
	1983	2.17	331500	3183400	107/ 1
	1984	2.22	334000	3183400	317/ 1
	1985	2.11	334000	3183400	279/ 1
	1986	1.99	342000	3174000	353/ 1

Note: Allowable PSD Class I increments are (in $\mu g/m^3$):
NO_x
Annual--2.5
PM-TSP
Annual--5
24-Hour--10
Proposed PM10 PSD Class I increments are:
Annual--4
24-Hour--8

[a]Receptor locations are in UTM coordinate system (m)
[b]All short-term concentrations indicate highest, second-highest (HSH) predicted concentrations.

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

May 31, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Earnest L. Mize, VP
Lake Cogen Limited
535 North Ferncreek Avenue
Orlando, Florida 32803

Dear Mr. Mize:

Re: Permit Application AC 35-196459, PSD-FL-176

This is to provide notice that the following additional information is required for preliminary review of the above application:

1) In Table 2-1, you stated that the duct burner will only fire natural gas and operate 3500 hours/year. You also stated that the gas turbine will fire oil 240 hours/year and gas 8520 hours year. Why doesn't the duct burner operate the total time (8760 hours/year)? If this duct burner will only be operated intermittently, what records will be kept on operation and emissions by pollutant? Have the emissions been adjusted for the actual operating hours by fuel?

2) Carbon monoxide emissions seem to be higher than expected (467 TPY compared to a similar combustion turbine having about 230 TPY). Please discuss reasons for higher emissions along with the relationship to NOx emissions.

3) Submit a stack drawing showing location for taking stack samples.

4) Provide listing of similar sources already in operation including summary of stack test results on all pollutants.

5) Provide any additional manufacturer information and brochures including a process flow diagram showing volumetric flow rates for the source.

6) What kind of control and monitoring equipment do you propose to use for continuously recording power generation (MWS), fuel injection rate (MMCF/hr or Gal/hr), water injection rate (Gal/hr), CO (PPMDV), SO_2 (PPMDV), and NOx (PPMDV)?

7) What is the basis for the statement "CO emissions are expected to be one-half or less than those proposed..." (page 4-30)?

8) Table 4-7 (page 4-7) lists primary and secondary differentials when SCR is used to control NOx emissions. Please provide additional discussion for basis of secondary emissions and how primary emissions were calculated?

9) In the PSD analysis the maximum Class I PM and NOx PSD increment consumption at the Chassahowitzka National Wilderness Area was determined for the proposed facility alone. However, there are no PSD significant impact levels for Class I areas. Please perform a cumulative Class I-increment analysis which includes all increment consuming sources in the airshed impacting the Chassahowitzka Wilderness Area.

When the requested information is received, processing of this application will resume. If you have any questions, please call Preston Lewis at 904-488-1344.

Sincerely,

C H Fancy/GPL

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

CHF/PL/plm

c: C. Collins, C. Dist.
J. Harper, EPA
K. Kosky, KBN

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3. Article Addressed to: Mr. Ernest L. Mize Lake Cogen Limited 535 North Ferncreek Avenue Orlando, Florida 32803	4. Article Number P 407 852 712
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PS Form **3811**, Apr. 1989 ★U.S.G.P.O. 1989-238-815 **DOMESTIC RETURN RECEIPT**

P 407 852 712

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PS Form 3800, June 1985

Florida Department of Environmental Regulation

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

Lawton Chiles, Governor

Carol M. Browner, Secretary

May 8, 1991

Mrs. Christine Shaver, Chief
Permit Review and Technical Support Branch
National Park Service-Air Quality Division
P. O. Box 25287
Denver, Colorado 80225

Dear Mrs. Shaver:

RE: Lake Cogen Limited, PSD-FL-176
Pasco Cogen Limited, PSD-FL-177

Enclosed for your review and comment are the above referenced PSD permit applications. If you have any comments or questions, please contact Preston Lewis or Cleve Holladay at the above address or at (904)488-1344.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

/pa

Enclosure