Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

AU OF AIR REGULATION
FEB 04 2000
RECEIVED

February 3, 2000

9937510A/2

New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399

Attention: A.A. Linero, P.E., Administrator

RE: Palmetto Power, L.L.C.
DEP File No. 0970073-001-AC (PSD-FL-277)
Information Request

Dear Al:

This correspondence provides information requested in the Department's November 5, 1999 correspondence. The information is itemized in the same manner requested.

Gas Turbine Model

1. Department's Information Request: The application indicates that the combustion turbines will be Siemens/Westinghouse Model 501FD "or equivalent" units. However, the application also lists Siemens/Westinghouse as the "selected vendor". Has Palmetto Power entered into a contractual agreement with Siemens/Westinghouse for this project, or is it still possible to select another vendor and model of gas turbine? The Department notes that there are other vendors with similarly sized gas turbines that have much lower CO and NO_x emission rates. Please provide documentation that the CO, NO_x, PM/PM_{10}, and VOC emissions standards requested in the application are guaranteed by Siemens/Westinghouse and that these are the lowest guarantees currently offered for the Model 501FD gas turbine.

   Palmetto Power Response: The combustion turbine for the Palmetto Power Project will be the Siemens-Westinghouse Power Corporation (SWPC) Model 501FD combustion turbine for which contracts have been signed between SWPC and Dynegy (the project developer). SWPC has guaranteed the emission rates for CO, NO_x, PM/PM_{10} and VOC as shown on the attached data sheet, which was also provided in the permit application. These are the lowest emission guarantees that SWPC has provided to Dynegy. These were also the same emission guarantees provided for the Heard County Combustion Turbine Facility in Georgia. The Georgia Department of Natural Resources gave final approval for this project on October 20, 1999. A copy of the permit is attached.

2. Department's Information Request: Please provide manufacturer information on the automated gas turbine control system for this model, including a general description of the system, the input parameters monitored, and the gas turbine parameters that are controlled.

   Palmetto Power Response: Please find attached a description of the SWPC ECONOPAC Control System incorporated into the Model 501FD combustion turbine.

3. Department's Information Request: Please provide manufacturer information on the proposed evaporative inlet air cooling system, including a description of the process and the equipment to be installed.

   Palmetto Power Response: Please find attached a description of the SWPC Evaporative Cooling System that would be installed on the Model 501FD combustion turbines proposed for the project. The evaporative cooling system will increase power as well as improving efficiency (i.e., lower heat rate). At an ambient air temperature of 95°F and 60 percent relative humidity, the evaporative cooling system at 85 percent efficiency will increase power by 4.14 percent and lower heat rate by 0.84 percent. Data related to performance of the evaporative cooler is shown in Appendix A of the Air Permit Application and Prevention of Significant Deterioration Analysis.

4. Department's Information Request: Please provide emissions performance curves based on manufacturer information for:
   - CO vs. load in terms of ppmvd and pounds per hour
   - NO_x vs. load in terms of ppmvd and pounds per hour

   Palmetto Power Response: Performance curves for the project are attached.

5. Department's Information Request: Please provide information from the manufacturer regarding CO and NO_x emission levels during actual field service for at least two projects operating this model gas turbine. Summarize the initial emissions performance tests for CO, NO_x, PM/PM_{10}, and VOC as well as the continuous NO_x monitoring data for these projects.

   Palmetto Power Response: SWPC Model 501 FD combustion turbines with dry low-NO_x (DLN) combustor technology are not currently in service at this time. The design of this model is based on previous designs, but with improved DLN performance. Based on these designs, SWPC has guaranteed NO_x emissions to not exceed 15 ppmvd corrected to 15 percent oxygen. The basic DLN technology incorporated into the SWPC 501FD is similar to the principals in our vendor designs, which have achieved NO_x emissions to levels at 15 ppmvd corrected to 15 percent oxygen.

6. Department's Information Request: How many minutes does startup to 70% of base load take as well as shutdown? Please estimate the number of startups in a year based on the proposed maximum 3750 hours per year of operation. How many hours of startup and shutdown would this be? Based on the manufacturer's emission rates for startups and shutdowns, estimate the annual emissions of CO, NO_x, PM/PM_{10}, SO_2, and VOC from startups and shutdowns. The Department plans to address excess emissions in its BACT determination.

   Palmetto Power Response: Startup to achieve 70 percent load or greater requires 30 minutes. Shutdown requires about 20 minutes. The number of startup and shutdowns will vary depending upon market demand. It is estimated that up to 150 starts per year may be required. The NO_x emissions during startup are estimated at about 75 pounds per turbine for the 30-minute period. There will be no substantial change in particulate or sulfur dioxide emissions. Emissions of CO and VOCs will be variable. Given the times for startup and shutdown, the proposed facility will comply with the Department's excess emission limitations provided for in Rule 62-210.700 Florida Administrative Code (F.A.C.). Indeed, Rule 62-210.700 (1) requires Palmetto Power to operate the system properly to reasonably prevent excess emissions. Also, as indicated in the response to Item 2, the operation of the SWPC DLN combustion technology is fully automated to assure that excess emissions will be minimized.

NO_x BACT Determination

7. Department's Information Request: The requested NO_x BACT limit for this project is 15 ppmvd. What model combustor is proposed? Does the manufacturer guarantee this rate? Is this emissions rate specific to DLN combustors firing natural gas only? In other words, does the manufacturer guarantee lower emissions when firing natural gas as compared to a gas turbine with dual-fuel combustors? Is this the lowest guaranteed NO_x emissions rate offered by the manufacturer? Are other combustor types available that offer lower NO_x emissions? After achieving stable operation and emissions, does the diffusion flame burner on the DLN combustor ever completely shut off? Several recent projects have determined NO_x BACT for simple cycle operation to be 9 to 12 ppmvd. Please explain any significant differences presented by this project.

   Palmetto Power Response: The combustor type will be the SWPC 501 FD DLN combustor. SWPC has guaranteed by contract that NO_x emissions will be 15 ppmvd corrected to 15 percent O_2 during normal load operation (i.e., 70 to 100 percent load) when firing natural gas. SWPC has indicated that their dual fuel configuration combustor can achieve be 15 ppmvd corrected to 15 percent O_2 when firing natural gas. While these combustors were available to Palmetto Power, it was determined that only natural gas would be used for the project. As indicated in the response to Item 1, this is the lowest NO_x emission guarantee offered to Dynegy by SWPC. There are no other combustor types commercially available by SWPC with lower NO_x emissions. The DLN system uses a diffusion flame burner (pilot stage burner) to maintain flame stability throughout the load range. This pilot flame does not completely shut off during operation at higher loads.

Palmetto Power Response: Attached please find a recent vendor quotation for "hot SCR" at 3.5 ppmvd. The vendor quote provides for flue gas cooling to 1,025°F in the estimate. Also attached is a recalculated capital and annualized cost for "hot SCR" that incorporates the changes suggested by the Department. The cost effectiveness using the latest vendor quotation and the approach suggested by the Department is $13,635 per ton of NO_x removed. This is higher than that originally estimated (i.e., $11,850).

CO BACT Determination

10. Department's Information Request: The requested BACT limit for CO is 25 ppmvd. Page 4-10 of the application suggests that CO emissions from the Model 501FD may actually be 10 ppmvd and even calculates a cost effectiveness based on 20 ppmvd. The reason cited for the 25 ppmvd limit requested for CO standard is the "uncertainty associated with maintaining low NO_x emissions" simultaneously with low CO emissions. There does not appear to be the same degree of uncertainty associated with other competing gas turbines. In fact, several recently issued permits for similarly sized projects were permitted with CO BACT limits of 9 to 15 ppmvd. Please provide supporting information regarding the uncertainty for this model and explain any significant differences that this project may present.

    Palmetto Power Response: The CO emission rate proposed for the project reflects the SWPC guarantee for the Model 501FD. The statements in the BACT evaluation reflect actual experience with an SWPC "F" Class combustion turbine and previous design considerations by SWPC in achieving lower NO_x emissions simultaneously with low CO emissions. As described in the response to Item 7, the proposed project will fire only natural gas and have lower total emissions for NO_x, PM, SO_2, VOCs, and sulfuric acid mist. While CO emissions will be higher, the impacts are insignificant and the slightly higher emissions of CO have no other secondary environmental effects (e.g., acid rain) as the other pollutants. Indeed, the Palmetto Power Project by using only natural gas in a more efficient combustion turbine is no different in an overall environmental sense than other projects permitted by the Department.

11. Department's Information Request: Why was the cost analysis for a CO oxidation catalyst based on CO emissions of 10 ppmvd? Based on information provided for similar projects, a 90% reduction in CO emissions may be achievable with an oxidation catalyst, especially when firing natural gas only. Please explain any significant differences that this project may present.

    Palmetto Power Response: The basis of the 10 ppmvd was based the typical BACT levels that the Department had established as BACT for other projects. An oxidation catalyst can achieve 90 percent reduction. (See response to Item 12 below).

12. Department's Information Request: Please revise the cost analysis based on the following:
    - Treat the catalyst cost as part of the capital costs for the CO catalyst system and as an annualized cost for catalyst replacement - not a "recurring capital cost".
    - Remove the catalyst disposal cost or provide information from the vendor that the quoted catalyst cost does not include an exchange for spent catalyst.
    - Remove the "MW Loss Penalty" because these units are only operated 3750 hours per year.
    - Remove the fuel escalation cost.
    - Remove the 10% contingency factor for "energy costs".
    - Based on the answer to question #11, revise the "tons per year" CO emissions reduction.

    Please provide the vendor quote for this equipment including information regarding the type of catalyst quoted. Also, please provide details as to the "instrumentation" that will be provided in addition to the equipment that will be provided by the CO catalyst vendor.

    Palmetto Power Response: Attached please find a recent vendor quotation for an oxidation catalyst achieving 90 percent CO removal efficiency. Also attached is a recalculated capital and annualized cost for the oxidation catalyst that incorporates the changes suggested by the Department. The cost effectiveness using the latest vendor quotation and the approach suggested by the Department is $3,666 per ton of CO removed. This is lower than that originally estimated (i.e., $4,150).

Other Sources

13. Department's Information Request: Please provide estimates of the potential emissions from the 250 kW emergency diesel generator, the 310 hp emergency diesel fire pump, the 4.9 mmBTU per hour gas heater, and any other combustion sources that will be constructed as a result of this project. The potential emissions may be based on requested fuel consumption limits or those limits specified in the exemption criteria listed in Rule 62-210.300, F.A.C. Please identify the fuel, fuel heating value, and fuel sulfur content for each source.

    Palmetto Power Response: Attached is Table 2-3 that provides the requested information on the natural gas heaters and emergency generators. The table contains the information on typical performance, stack parameters and emissions. The natural gas heater will use only natural gas while the diesel generators will use transportation diesel with a sulfur content of 0.05 percent. The annual emissions for heater was based on 800 hours/year as identified in the application. The annual emissions for the diesels were calculated based on two assumptions. The first is based on a maximum operation of 2 hours per week while the second is based on the limit in Rule 62-210.300(3)(a)20.b. of 32,000 gallons per year for emergency generators. As shown in the table, the typical maximum operation will be 12 percent of that expressed in the rule. At the maximum potential emissions for these sources, the PSD applicability does not change.

Air Quality Analysis

14. Department's Information Request: The Air Dispersion modeling protocol submitted on July 26, 1999 stated that Orlando surface and Ruskin upper air meteorological data from 1987 to 1991 would be used in the modeling analysis. However, the modeling that was submitted was based upon Orlando surface and West Palm Beach upper air meteorological data from 1987 to 1991. Please give the reason behind the change in upper air meteorological data.

    Palmetto Power Response: The ISCST input and output files incorrectly name the upper air station as West Palm Beach but show the correct station identification number as 12842 which is Ruskin. As a result, the modeling was performed using Orlando surface and Ruskin upper air meteorological data as stated in the modeling protocol.

15. Department's Information Request: Page 2-4 of the permit application states that the project proposes to operate one 250-kW diesel generator and one 310-hp emergency fire pump. Please explain why these units are exempt from modeling. Also, provide the maximum sulfur content of the fuel oil that will be used to operate these machines.

    Palmetto Power Response: These units will be used for emergency purposes only and are expected to operate very infrequently (e.g., for testing and maintenance purposes). As a result, their impacts are expected to be minimal, if any, during the course of a year. The maximum sulfur content of the fuel oil for these machines will be 0.05 percent.

16. Department's Information Request: The locations of the Air Inlets and Generators input into the BPIP program do not correspond to the locations that are shown on figure 2-3. Please revise the Building Downwash Analysis so that it represents the proposed building and stack locations.

    Palmetto Power Response: The locations of the air inlet and generators are correctly shown in Figure 2-2. The orientation of the stacks is in an east-west direction not in a north-south direction shown in Figure 2-3. The modeling has been revised to reflect the plant orientation and stack locations shown in Figure 2-2. These results are presented in attached Tables 6-2, 6-3, and 6-4 that will replace those tables from the PSD application.

    The revised results are similar to those presented in the PSD application; maximum concentrations are predicted to increase by less than about 0.01 $\mu g/m^3$ for all pollutants and averaging times (there are some decreases as well). These results again show that the maximum concentrations predicted for the Project are well below the PSD significant impact levels.

    Copies of the Building Downwash analysis and ISCST input and output files are provided on Golder's FTP site (ftp.golder.com/gville/rcm/palmetto).

17. Department's Information Request: Please submit the modeling files that correspond to all of the predicted concentrations shown in figure 6-3.

Palmetto Power Response: As indicated in response to Request No. 16, the modeling files that correspond to all of the predicted concentrations are provided on Golder's FTP site (ftp.golder.com/gville/rcm/palmetto). Please note that in the original PSD application, the PM_{10} concentrations were incorrectly transferred from Table 6-2 to Table 6-3. This has been corrected with the latest tables attached to this letter.

Sincerely,

GOLDER ASSOCIATES INC.

Robert C McCann Jr for

Kennard F. Kosky
Principal

RCM/arz

Enclosures

cc: Jeffery Koerner, BAR
Starla Lacy, Palmetto Power, L.L.C.
Robert C. McCann, Jr., Golder

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cc: NPS
EPA
Central Dist.
File

Response to Question No. 1

SIEMENS Westinghouse Dynegy - Florida

Expected 501F Combustion Turbine Performance

Simple Cycle / Dry Low NOx Combustor

AEROPAC 2-95x200 / 0.90 Power Factor

CTT-1914 Rev.1

08/19/99

SITE CONDITIONS:	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7	CASE 8
FUEL TYPE	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
LOAD LEVEL	BASE	BASE	BASE	BASE	BASE	70%	70%	70%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,981	20,981	20,981	20,981	20,981	20,981	20,981	20,981
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,299	23,299	23,299	23,299	23,299	23,299	23,299	23,299
EVAPORATIVE COOLER STATUS/EFFICIENCY	OFF	85%	OFF	85%	OFF	OFF	OFF	OFF
AMBIENT DRY BULB TEMPERATURE, °F	32.0	59.0	59.0	95.0	95.0	32.0	59.0	95.0
AMBIENT RELATIVE HUMIDITY, %	50%	60%	60%	60%	60%	50%	60%	60%
BAROMETRIC PRESSURE, psia	14.643	14.643	14.643	14.643	14.643	14.643	14.643	14.643
COMPRESSOR INLET TEMPERATURE, °F	32.0	52.6	59.0	84.5	95.0	32.0	59.0	95.0
HEAT INPUT, mmBtu/hr (HHV)	1,981	1,902	1,867	1,752	1,696	1,468	1,394	1,292
GROSS POWER OUTPUT, kW	196,200	186,460	182,470	167,590	160,930	137,010	127,370	112,260

COMBUSTION TURBINE PERFORMANCE:	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7	CASE 8
GROSS POWER OUTPUT, kW	196,200	186,460	182,470	167,590	160,930	137,010	127,370	112,260
GROSS HEAT RATE, Btu/kWh (LHV)	9,095	9,190	9,215	9,415	9,495	9,650	9,855	10,370
GROSS HEAT RATE, Btu/kWh (HHV)	10,100	10,200	10,230	10,455	10,540	10,715	10,940	11,510
FUEL FLOW, lbm/hr	85,050	81,640	80,130	75,190	72,810	63,000	59,810	55,460
INJECTION RATE, lbm/hr	-	-	-	-	-	-	-	-
HEAT INPUT, mmBtu/hr (LHV)	1,784	1,713	1,681	1,578	1,528	1,322	1,255	1,164
HEAT INPUT, mmBtu/hr (HHV)	1,981	1,902	1,867	1,752	1,696	1,468	1,394	1,292
EXHAUST TEMPERATURE, °F	1,085	1,096	1,099	1,123	1,129	1,026	1,041	1,064
EXHAUST FLOW, lbm/hr	3,793,672	3,661,592	3,612,916	3,368,437	3,291,632	3,133,033	3,017,700	2,849,774
EXHAUST FLOW, MACFM	2.52	2.46	2.43	2.32	2.28	2.00	1.95	1.89
ESTIMATED AUXILIARY LOADS, kW	295	310	295	310	295	295	295	295

EXHAUST GAS COMPOSITION (BY % VOL):	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7	CASE 8
OXYGEN	12.50	12.38	12.46	11.94	12.08	13.29	13.27	13.00
CARBON DIOXIDE	3.82	3.78	3.77	3.75	3.73	3.46	3.40	3.31
WATER	7.90	8.74	8.49	11.07	10.66	7.19	7.76	9.84
NITROGEN	74.85	74.17	74.35	72.32	72.62	75.13	74.63	72.94
ARGON	0.94	0.93	0.93	0.91	0.91	0.94	0.94	0.92

NET EMISSIONS: Based on Westinghouse 21T5620 test methods	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5	CASE 6	CASE 7	CASE 8
NOx, ppmvd @ 15% O_2	15	15	15	15	15	15	15	15
NOx, lbm/hr as NO_2	111	107	105	98	95	83	79	73
NOx, lbm/MMBtu	0.056	0.056	0.056	0.056	0.056	0.057	0.057	0.056
CO, ppmvd	31	31	31	32	31	28	28	27
CO, ppmvd @ 15% O2	25	25	25	25	25	25	25	25
CO, lbm/hr	113	109	107	100	97	85	80	74
CO, lbm/MMBtu	0.057	0.057	0.057	0.057	0.057	0.058	0.057	0.057
VOC, ppmvd as CH_4	2	2	2	2	2	2	2	2
VOC, ppmvd @ 15% O2 as CH_4	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
VOC, lbm/hr as CH_4	3.7	3.6	3.5	3.3	3.2	2.8	2.6	2.5
VOC, lbm/MMBtu	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019	0.0019
PARTICULATES, lbm/hr	8.6	8.2	8.2	7.5	7.3	7.1	6.9	6.4
PARTICULATES, lbm/MMBtu	0.0043	0.0043	0.0044	0.0043	0.0043	0.0049	0.0049	0.0049
OPACITY, %	≤ 10	≤ 10	≤ 10	≤ 10	≤ 10	≤ 10	≤ 10	≤ 10

NOTES:

- The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Westinghouse is available to review permit application data upon request.
- Emissions during startup/shutdown, transient conditions, and initial startup activities during plant commissioning are exluded from emissions guarantee.
- Gas fuel must be in compliance with the latest revision of the Siemens Westinghouse Gas Fuel Spec (21T0306).
- Gas fuel composition is 98% CH4, 0.6% C2H6, 1.4% N2, and 0.2 grains of sulfur per 100 SCF.
- Liquid condensable fuels must be removed from the fuel lines.
- Gross power output is at the generator terminals.
- Expected CT Performance values are dependent upon receiving test tolerances persuant to the latest revision of SWPC EC- 93208.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.
- Actual IGV schedule may vary. Part load performance will be adjusted accordingly.
- Exhaust volumetric flow rate is at the exit to the ECONOPAC stack.
- Average temperature of the gas fuel is 59 °F.
- Performance based on new and clean condition.
- All data is expected and not guaranteed.
- Emissions exclude ambient air contributions.
- VOC's are non methane, non ethane.
- Particulates are per U.S. EPA Method 5 (front half only).
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Emission Factors are based on Heat Input, High Heating Value (HHV).

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

AIR QUALITY PERMIT

Permit No.
4911-149-0005-P-01-0

Effective Date
OCT 20 1999

In accordance with the provisions of the Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq and the Rules, Chapter 391-3-1, adopted pursuant to or in effect under that Act,

Heard County Power, LLC.
1000 Louisiana Street, Suite 5800
Houston, TX 77002

Facility location: Joe Stephens Road
Franklin, Heard County, Georgia 30217

is issued a Permit for the following: The construction and operation of three simple-cycle combustion turbines. The combustion turbines are fired using natural gas and utilize Dry Low NOx burner technology.

This Permit is conditioned upon compliance with all provisions of The Georgia Air Quality Act, O.C.G.A. Section 12-9-1, et seq, the Rules, Chapter 391-3-1, adopted or in effect under that Act, or any other condition of this Permit.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above; or for any misrepresentation made in Application No. 11348 dated March 15, 1999 supporting data entered therein or attached thereto, or any subsequent submittals or supporting data; or for any alterations affecting the emissions from this source.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached 6 pages, which pages are a part of this Permit.

Harold F. Reheis

Director
Environmental Protection Division

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

1.0 General Requirements

1.1 At all times, including periods of startup, shutdown, and malfunction, the Permittee shall to the extent practicable maintain and operate this source, including associated air pollution control equipment, in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Division which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

1.2 The Permittee shall cause to be conducted a performance test at any specified emission point when so directed by the Division. The test results shall be submitted to the Division within 30 days of the completion of testing. Any tests shall be performed and conducted using methods and procedures which have been previously approved by the Division.

1.3 The Permittee shall commence construction within 18 months of the date of issuance of this Permit. Approval to construct this facility shall become invalid if construction is not commenced by that date. For purposes of this Permit, the definition of "commence" is given in 40 CFR 52.21(b)(9). [40 CFR 52.21(r)]

1.4 Construction shall be completed by no later than December 31, 2001, otherwise this Permit shall become null and void with respect to any combustion turbine for which construction has not yet been completed. The Permit will remain in full force and effect with regard to any units for which construction was completed before said date. [40 CFR 52.21(r)(2)]

1.5 The contents of the brackets at the end of each condition denoted as 40 CFR refers to the section in Title 40 of the Code of Federal Regulations (CFR) from which the condition has been derived. If there are any discrepancies between the permit condition and the 40 CFR section, the 40 CFR section takes precedent.

2.0 Allowable Emissions

2.1 The Permittee shall comply with all applicable provisions of the New Source Performance Standards (NSPS), 40 CFR 60, Subpart A - "General Provisions" and Subpart GG - "Standards of Performance for Stationary Gas Turbines."

2.2 The Permittee shall not operate any combustion turbine for a total of more than 4,000 hours during any twelve consecutive months.
[40 CFR 52.21(j)]

2.3 The Permittee shall not discharge or cause the discharge into the atmosphere from any combustion turbine any gases which: [40 CFR 52.21(j)]

a. contain nitrogen oxides in excess of 15 ppmvd corrected to 15% oxygen.

b. contain carbon monoxide in excess 25 ppmvd corrected to 15% oxygen.

c. contain particulate matter in excess of 0.005 pounds per million Btu heat input, higher heating value (HHV).

d. exhibit greater than 10 percent opacity.

3.0 Process and Control Equipment

Not applicable.

4.0 Performance Testing

4.1 The Permittee shall provide the Division thirty (30) days prior written notice of the date of any performance test(s) to afford the Division the opportunity to witness and/or audit the test, and shall provide with the notification a test plan in accordance with Division guidelines.

4.2 The Permittee shall provide performance test ports which comply with criteria approved by the Division.

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

4.3 Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup, the Permittee shall conduct the following performance tests on each combustion turbine and furnish to the Division a written report of the results of such performance tests:

a. Performance tests for nitrogen oxides (NOx) conducted in accordance with 40 CFR 60.335.

b. Performance tests for carbon monoxide (CO) at the maximum and minimum points in the normal operating range.

c. Visible emission test.

d. Performance tests for CO and visible emissions shall be conducted concurrently. The concurrent CO and visible emissions tests will be at base load.

4.4 Performance and compliance tests shall be conducted and data reduced in accordance with applicable procedures and methods specified in the Division's *Procedures for Testing and Monitoring Sources of Air Pollutants*. Specific applicable test methods included in the above reference or as otherwise referenced are as follows:

a. Method 1 for sample point location.

b. Method 2 for determination of velocity and gas flow rate.

c. Method 3A for determination of gas stream molecular weight and excess air correction factor.

d. Method 5 for emission rate of particulate matter and associated moisture content. For Method 5, the minimum sampling time for each run shall be 120 minutes.

e. Method 9 and the procedures of Section 1.3 for the determination of opacity.

f. Method 10 for concentration of carbon monoxide.

g. Method 20 for the concentration of nitrogen oxides.

Minor modifications of these methods and procedures may be specified or may be approved by the Director or his designee when necessitated by process variables, changes in facility design, or improvements or corrections which in his opinion render those methods and procedures thereof more reliable.

5.0 Monitoring Requirements

5.1 The Permittee shall monitor the sulfur content of natural gas by the recordkeeping of a semi-annual analysis of the gas as obtained from the supplier. [40 CFR 60.334(b)]

5.2 Periods of excess emissions from each combustion turbine are defined as any one-hour period in which the average NOx concentration exceeds 15 ppmvd at 15% oxygen, dry basis.

5.3 The Permittee shall comply with all applicable requirements of the continuous monitoring rule in 40 CFR 75. The Permittee by meeting these requirements shall be considered as meeting the requirements in 40 CFR 60.334(b) and shall be considered to be complying with the requirement for having a custom fuel monitoring schedule under 40 CFR 60.334(b)(2).

5.4 The Permittee shall install, calibrate, maintain, and operate continuous monitoring systems for measuring nitrogen oxides emissions from each combustion turbine. The monitoring systems shall include oxygen monitors and shall meet the applicable specifications of Performance Specification 2 and 3 contained in the Division's *Procedures for Testing and Monitoring Sources of Air Pollutants*. The one-hour average nitrogen oxides emissions rates shall be recorded and shall be expressed in terms of parts per million (ppm), corrected to 15 percent oxygen, and pound per million Btu heat input. [40 CFR 75]

5.5 The Permittee shall install, calibrate, operate and maintain on each combustion turbine, devices for measuring the quantity of natural gas, in cubic feet, burned in the turbine, and the hours of operation of the turbine.

5.6 Any monitoring system installed by the Permittee shall be in continuous operation except during calibration checks, zero and span adjustments or periods of maintenance or repair. Maintenance or repair shall be conducted in the most expedient manner to minimize the period during which the system is out of service.

5.7 A spare parts inventory for all emission monitoring systems installed at the facility shall be maintained by the Permittee. The contents of this list are subject to the approval of the Division.

6.0 Ambient Monitoring

Not Applicable

7.0 Fugitive Emissions

7.1 The Permittee shall take all reasonable precautions with any operation, process, handling, transportation, or storage facilities to prevent fugitive emissions of air contaminants.

8.0 Notification, Reporting, and Recordkeeping

8.1 The Permittee shall maintain daily records of natural gas usage and hours of operation for each combustion turbine. The records shall be in a form suitable for inspection and/or submittal to the Division. The records shall be retained for at least five years following the date of entry.

8.2 The Permittee shall submit a quarterly report within thirty (30) days following each calendar quarter unless otherwise approved by the Division. The report shall be prepared from records retained in Conditions 5.4, 5.5 and 8.1, submitted in a manner suitable to the Division and contain:

a. Quantity of natural gas burned monthly in each turbine.

b. Monthly hours of operation of each turbine.

c. The date and time frame for which the NOx monitor was inoperative with an explanation of any system repairs or adjustments.

8.3 In accordance with 40 CFR 60.334(c), the Permittee shall submit a written report of excess emissions, as defined by Condition 5.2 of this Permit, to the Division for every calendar quarter. If there are no excess emissions during the quarter, the Permittee shall submit a report stating that no excess emissions occurred during the quarterly reporting period. All reports shall be postmarked by the 30th day following the end of the reporting period.

8.4 The Permittee shall furnish the Division written notification as follows:

a. The actual date of initial startup of this source within 15 days after such date.

b. Certification that a final inspection has shown that construction has been completed in accordance with the application, plans, specifications and supporting documents submitted in support of this permit.

9.0 Modifications

9.1 The Permittee shall give written notification to the Division when there is any modification to this source. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the plant before and after the change; and the anticipated completion date of the change.

10.0 Circumvention

10.1. The Permittee shall not build, erect, install or use any article, machine, equipment or process the use of which conceals an emission which would otherwise constitute a violation of an applicable emission standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged into the atmosphere.

11.0 Special Conditions

11.1 The Permittee shall install and operate, as BACT for NO_X on each combustion turbine, dry low NO_X combustors. [40 CFR 52.21(j)]

11.2 At any time that the Division determines that additional control of emissions from the facility may reasonably be needed to provide for the continued protection of public health, safety and welfare, the Division reserves the right to amend the provisions of this Permit pursuant to the Division's authority as established in the Georgia Air Quality Act and the rules adopted pursuant to that Act.

Response to Question No. 2

ECONOPAC Control System

ECONOPAC CONTROL SYSTEM

INTRODUCTION

Control, protection, and monitoring functions for the combustion turbine and ECONOPAC systems are performed by a microprocessor-based distributed control system that has the flexibility to accommodate a wide range of plant configurations and interface options.

SYSTEM DESCRIPTION

The ECONOPAC control system is a microprocessor-based distributed control system. The core of the system is the computer processing unit which performs all of the control and logic functions. The base system configuration has two non-redundant processors. A redundant configuration can be provided, in which a second processor would run in a backup mode such that, if a failure of the primary processor is detected control would be bumplessly transferred to the backup processor. For the redundant option a backup processor power supply is also provided.

The input/output signal cards provide the interface to the field instrumentation and control devices and can accommodate a wide range of signal types. A selective amount of redundancy is provided on critical input signals. A dual redundant auctioneered Input/Output (I/O) power supply is provided as part of the base system configuration.

A CRT-based computer display system is provided in the electrical package and serves as the human-machine interface (HMI) device for the system. This is both the system programming device as well as the operator interface. All control and monitoring functions can be performed from this panel. A set of standard graphic displays is provided for all operational and monitoring functions. The HMI computer also performs the logging function. A standard set of logs is provided for documenting combustion turbine operational performance. The logs are a combination of periodically generated logs and event driven logs which capture information on start-ups and shutdowns. An additional feature of the logger is sequence of event (SOE) recording. The SOE time resolution is 10 milliseconds. Sixteen SOE points are available as part of the standard system configuration. The HMI computer is configured to function as a general purpose historical storage and retrieval unit. With this feature any data within the computer control system can be captured and stored for later retrieval and plotting.

The local equipment panel in the Electrical Package houses other control related equipment such as the vibration monitoring system, trip push-button, and other ancillary equipment.

The control system processors and the operator interface (Human Machine Interface - HMI) are interconnected on the computer network system. This is a high level, high speed communication network that allows all devices to communicate with each other and share a global information database. The HMI computer is also interfaced to the network. The network consists of coaxial cable and is fault tolerant. A fiber optic network can be provided as an option.

For a single stand-alone ECONOPAC system, the network is fairly small and is contained within the electrical package. For multi-unit systems the data highway can be extended to the control systems of other units in a simple building block manner. The value of this is that the units can share information, and the operator interface stations in each unit can serve as a backup to each other.

A further evolution of a multi-unit plant configuration is one in which a central control room is provided. For the base configuration, all of the man-machine interface units are removed from the electrical packages and are clustered together in the control room. Adding operator interface HMI units back into the electrical packages is another option to this configuration. The control system can be expanded further to include additional control processors on the network in the central control room to accommodate common balance-of-plant functions such as switchyard monitoring, SCADA interface, etc. This process of expanding the control system through processor building blocks on the network can be continued to support a plant configuration of varying complexity up to and including a complete combined cycle plant.

Interfaces between the ECONOPAC control system and other computer control systems can also be accommodated. This is usually accomplished through a combination of hardwired input/output signals and some form of computer interface datalink. The hardwired signals are for direct control commands. The information on the datalink would be status and monitoring data. A number of options are available for the digital interface, the most common being a simple serial datalink. More sophisticated interfaces can be supported, such as Ethernet communication through a human interface workstation.

OPERATION

An operational example of a typical dual fuel combustion turbine start is presented below. This example assumes the turbine is on turning gear and all auxiliaries are operating.

Step One:

The operator calls up (pushes a button) the start up overview graphic and selects from the following pre-start options:

1. Fuel Type for Starting, Gas or Distillate Oil

2. Voltage Regulator Mode, Auto or Manual

3. Synchronizer Mode, Auto or Manual

   NOTE: Regulator in manual forces synchronizer to manual.

4. Spin Hold, Set or Clear

   Spin hold set will hold the turbine at ignition speed but withhold permissive for fuel and igniters until spin hold is clear.

5. Sync Speed Hold, Set or Clear

   Sync speed hold set will hold the turbine at synchronous speed but withhold permissive to synchronizer until sync speed hold is clear.

6. Load Control Mode or Base Load

   In load control mode the turbine will load the generator to minimum load after breaker closure. From this point generator load is controlled by the operator via the selection of the MW target and rate. In base load mode the turbine will increase generator load automatically until the maximum allowed turbine exhaust temperature is reached.

Step Two:

The operator verifies "Ready to Start" is indicated and presses the START push-button. Note: if a "Not Ready to Start" is indicated, the operator selects another graphic page which provides details on the ready to start logic.

Step Three:

From this point to base load, the following automatic steps are taken:

1. Overlay start sequence display window over pre-start selects.
2. Test emergency lube oil pump, alarm on fault.
3. Engage start device.
4. Verify minimum cranking speed, trip on fault.
5. Disengage turning gear, enable vibration monitor.
6. Verify ignition speed, trip on fault.
7. Open overspeed fuel isolation valve, trip on fault.
8. Igniters on, open fuel isolation valve, start light off verification timer.
9. Verify ignition, trip on fault, overlay start sequence display window with fuel flow and speed trend window.
10. Engage start ramp, trigger acceleration event log.

11. Engage acceleration monitor, alarm on low acceleration, trip on extra low acceleration.

12. Accelerate turbine.

13. Engage blade path spread monitor, alarm on high spread and trip on extra high spread.

14. Transition from start ramp to speed reference control, continue acceleration on closed loop speed control.

15. Close bleed valves.

16. Close generator field breaker.

17. Synchronous speed achieved, trigger synchronous speed log.

18. Disengage acceleration monitor.

19. Synchronization can be accomplished either automatically or manually, whichever is selected by the operator. Manual synchronization can only be performed from the electrical package.

20. Generator breaker closes, enable megawatt control function to pick up minimum load, trigger loading event log.

21. Minimum load achieved. If load control mode is selected, the operator enters the MW rate and target selections . If base load mode is selected, load will increase until the exhaust temperature limit is reached.

Turbine shutdown is also initiated with a single push button operation. When normal stop is selected, the control system will reduce generator load at the designated load rate. When minimum load is reached with normal stop selected, the generator breaker is opened and the turbine is held at synchronous speed for a three-minute cool-down period. After the cool-down period, all fuel valves (throttling and isolation) are closed and the turbine coasts to stop, at which time the turning gear is engaged. Normal stop can be cleared at any time by pressing the GO push button.

PROTECTION

The ECONOPAC control system provides machine protection by two methods. The first method is alarm condition annunciation, which implies operator intervention. Alarms of this priority indicate operational faults which are not severe enough to warrant automatic adjustment of the current operation point. The second method has automated actions which affect the current operation point. The severity of the fault determines the type of action to be activated. Typical conditions requiring alarms and or trips include the following conditions:

1. Overfuel at ignition (Gas or Oil as applicable).
2. High CT vibration
3. Bleed valves are not in the requested position.
4. CT low acceleration during sequenced start-up, ignition, or acceleration phases.
5. A fire is detected.
6. Gas purge manifold purge space pressure is high (running on gas fuel only). Applicable to dual fuel designs only.
7. An auto unload condition exists prior to reaching synch speed.
8. Critical monitoring of inputs indicates not good quality
9. The master trip relay de-energizes.
10. The CT fails to ignite.
11. CT overspeed.
12. CT underspeed.
13. CT load exceeds maximum MW setpoint.
14. Lube oil pressure is low.
15. Lube oil reservoir level is low.
16. Blade path spread is high.
17. A Load dump fault does not self-reset within 10 seconds of a load rejection.
18. Fuel oil discharge pump suction pressure low while oil fuel is selected.
19. Lube oil temperature is high.
20. Blade path differential is high.
21. A normal stop is initiated prior to reaching synch speed.
22. Exhaust pressure high (applies only with HRSG applications)
23. DLN set of trips unique to DLN combustor system applied as required
24. Individual blade path temperature high (only on501F with oil fuel only)
25. Generator and Generator Auxiliary System Trips

26. Control System Failures

27. Operator Initiated manual trips

    a) Hard wired push button in CT Electrical Package

    b) Hard wired push button in CT Mechanical Package

    c) Other hard wired remote trip push buttons as required

    d) Soft manual trip through CRT display work stations

28. Purchaser Trips provided and wired by purchaser

These identified conditions are offered as a base design. Many other status or alarm conditions can be made available depending upon the options and modes provided with the turbine generator system. Detailed meetings are welcome to discuss special requirements.

Response to Question No. 3

Evaporative Cooling

Evaporative Cooling

Siemens Westinghouse offers an evaporative cooler as an option to lower the compressor inlet air temperature and increase performance. The evaporative cooler comes complete with 85% efficient evaporative cooling media, water sump, distribution header, piping, and pump. Downstream of the evaporative cooler there are mist eliminators that avoid water carryover. The coolers are integral with the inlet system and are located in the filter housing. The cooler media is 12" deep utilizing the Munters Celdek cellulose base cooler media. The evaporator design utilizes the following materials:

Evap Cooler Media Housing	304 Stainless Steel
Media Holding Frames & Structure	304 Stainless Steel
Drain Sump Housing	304 Stainless Steel
Mist Eliminator Media	PVC
Supply & Drain Piping	PVC Piping

A local flow meter and manual flow regulating valve are used to adjust the water flow across each cooler module. Another local flow meter and manual regulating valve are used on the bleed off to maintain the appropriate number of water concentrations assuming that the combustion turbine is operating at base load. The system flow rates are set when the unit is commissioned and usually do not require readjustment during operation. Makeup water flow is controlled by a sump level control (float type) valve. The sump has drain and overflow connections. A flow switch provides confirmation that the water is feeding the cooler media when the pump is running.

The system is started by starting the circulating water pump. When the pump is shut off, the system stops operating.

Make up water consumption rates are a summation of the blowdown rate and the evaporation rate. The calculation of blowdown rate is based upon the cycles of concentration which in turn is dependent upon the specific water chemistry at each Site. The highest evaporation rate, however, occurs at the highest ambient temperature but at the lowest relative humidity. Therefore, it is responsibility of the customer to provide Siemens Westinghouse with this data to insure that the make up water provision is adequate for all operating conditions.

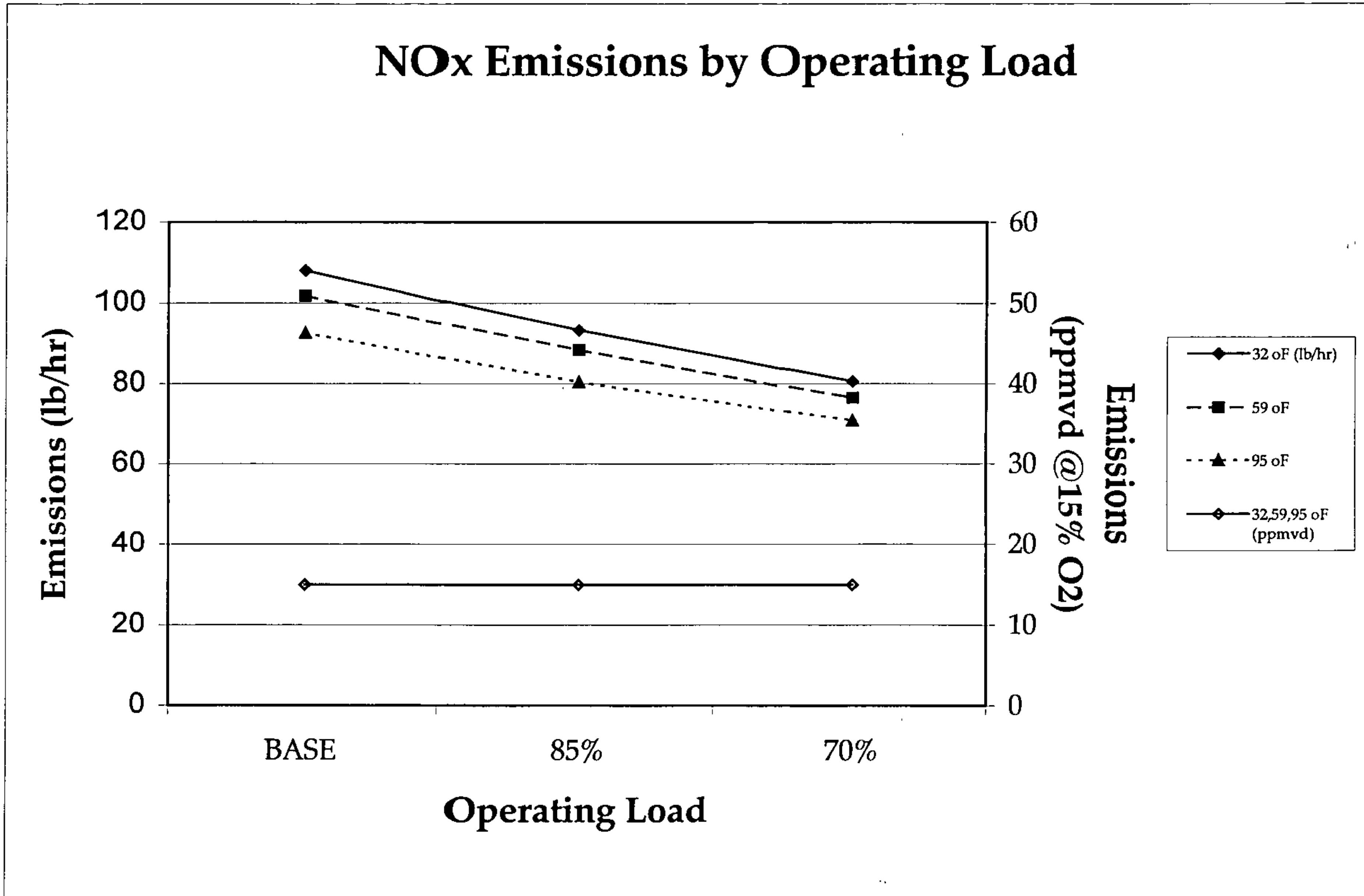
For make up water chemistry on most applications, it is recommended that the use of potable water for the evaporative cooler feedwater be used. A typical water chemistry of the feedwater is shown below. As a general guideline, this water chemistry, that meets the guidelines as shown, can be utilized at two (2) to six (6) cycles of concentrations in a recirculating evaporative cooler.

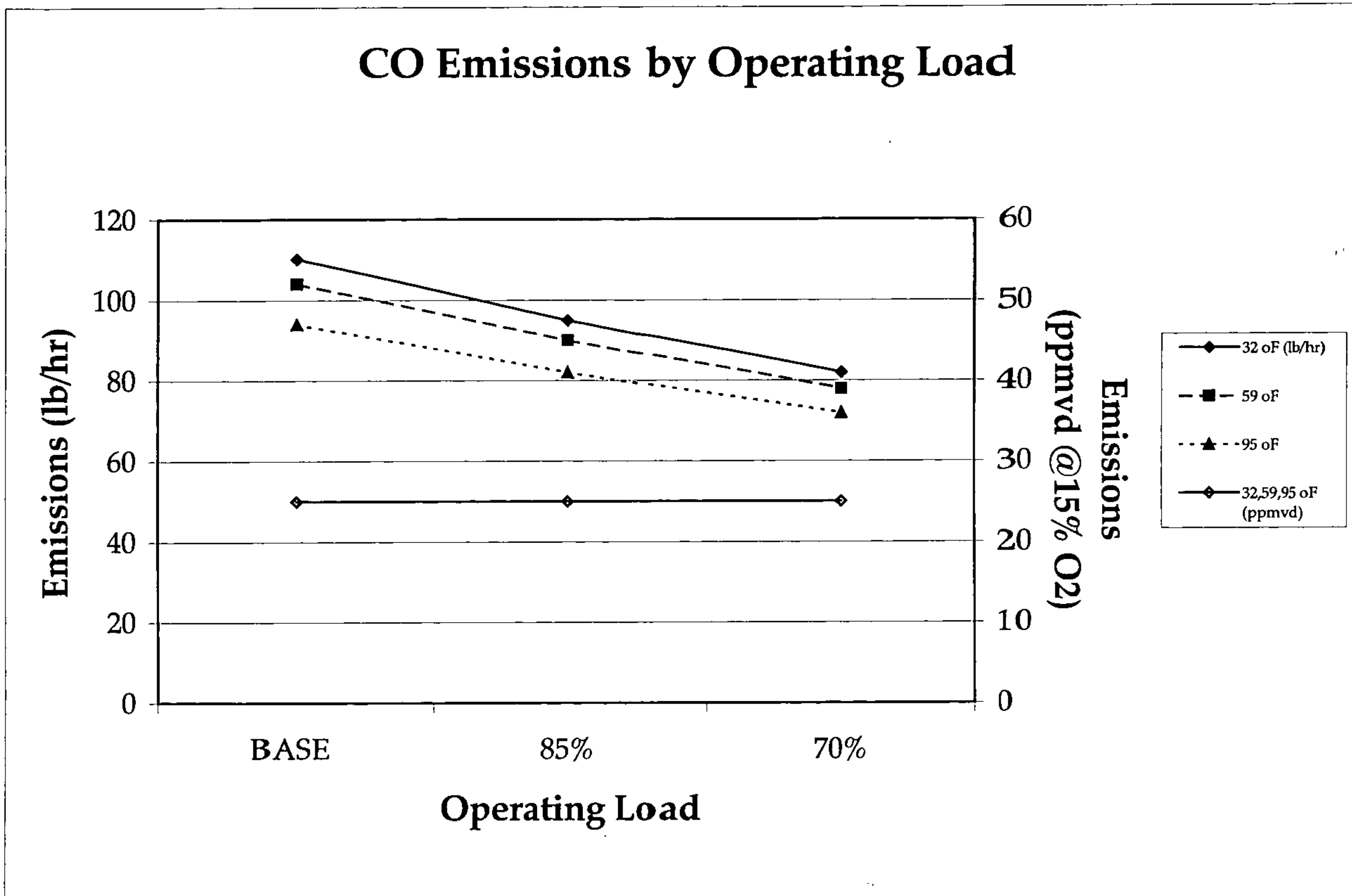
Constituent	PPM ±10%
Calcium Hardness (as $CaCO_3$)	50 - 150
Total Alkalinity (as $CaCO_3$)	50 - 150
Chlorides (as Cl)	< 50
Silica (as SiO)	< 25
Iron	< 0.2
Oil & Grease	< 2.0
Total Dissolved Solids	< 500
Suspended Solids	< 5
pH	7.0-8.5
Conductivity	______

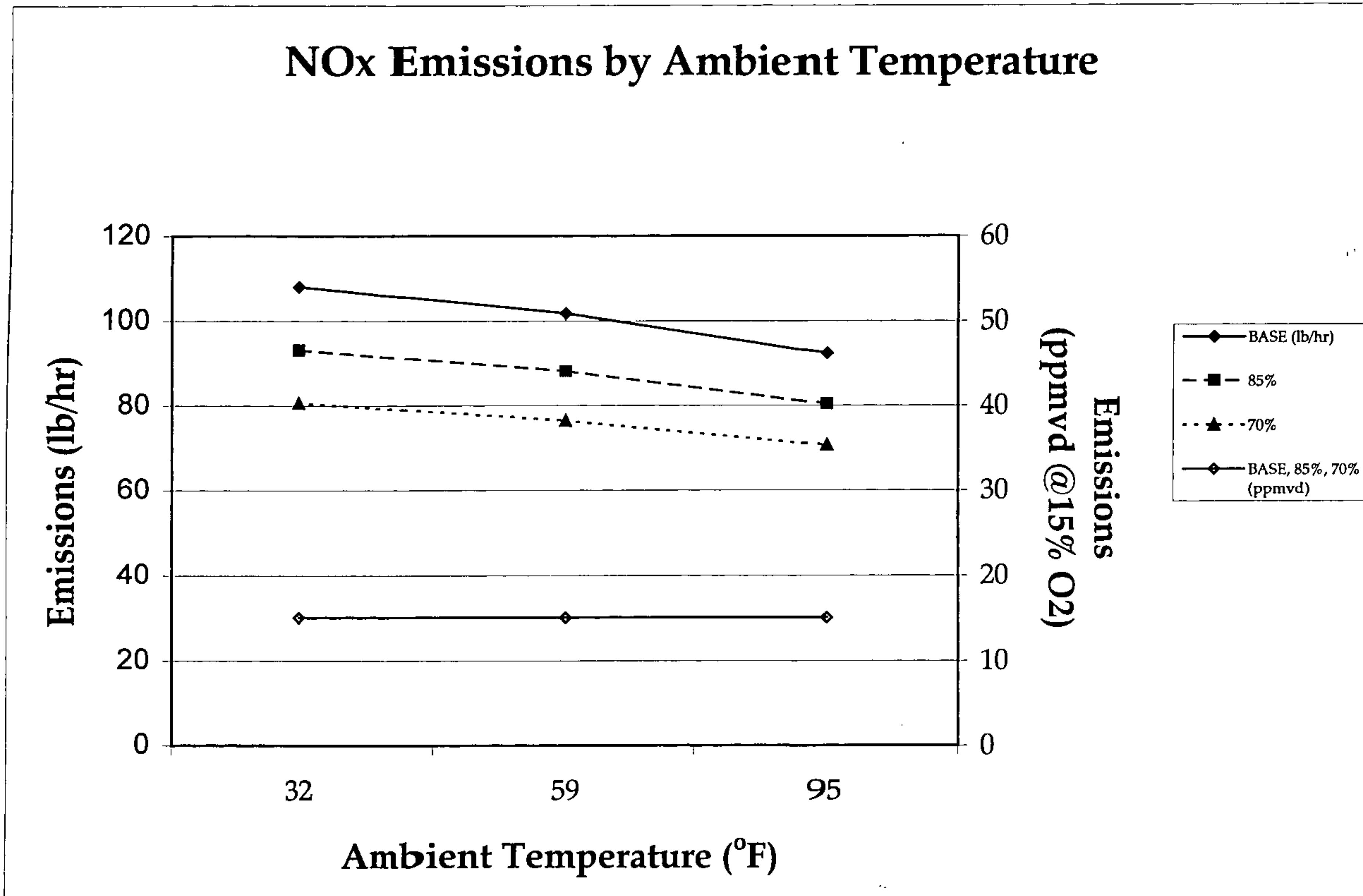
Recommended Evaporative Cooler Feedwater Guideline

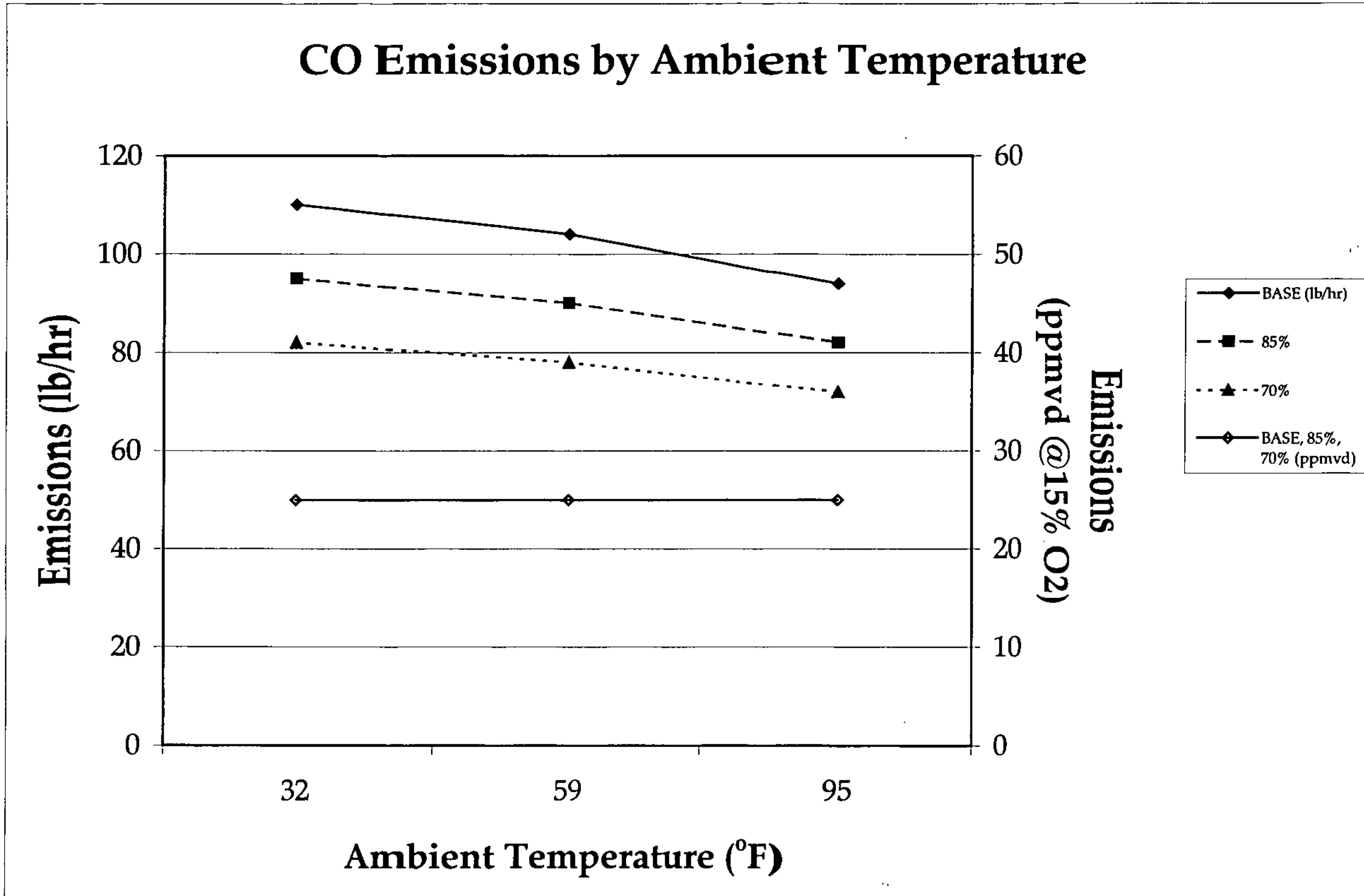
Note: High purity water from a reverse osmosis system or a demineralized water system is not recommended as the sole source of evaporative cooler water. A blended water system should be employed in these cases.

Response to Question No. 4


NOx Emissions by Operating Load
120
100
80
60
40
20
0
Emissions (lb/hr)
60
50
40
30
20
10
0
Emissions (ppmvd @15% O2)
BASE
85%
70%
Operating Load
32 oF (lb/hr)
59 oF
95 oF
32,59,95 oF (ppmvd)


CO Emissions by Operating Load
Emissions (lb/hr)
120
100
80
60
40
20
0
Emissions (ppmvd @15% O2)
60
50
40
30
20
10
0
BASE
85%
70%
Operating Load
32 oF (lb/hr)
59 oF
95 oF
32,59,95 oF (ppmvd)


NOx Emissions by Ambient Temperature
Emissions (lb/hr)
Emissions (ppmvd @15% O2)
Ambient Temperature (°F)
120
100
80
60
40
20
0
60
50
40
30
20
10
0
32
59
95
BASE (lb/hr)
85%
70%
BASE, 85%, 70% (ppmvd)


CO Emissions by Ambient Temperature
Emissions (lb/hr)
120
100
80
60
40
20
0
Emissions (ppmvd @15% O2)
60
50
40
30
20
10
0
32
59
95
Ambient Temperature (°F)
BASE (lb/hr)
85%
70%
BASE, 85%, 70% (ppmvd)

Response to Question No. 9

ENGELHARD

Golder Assoc.
Westinghouse 501D and GE 7FA - Simple and Combined Cycle
CAMET® CO Oxidation Catalyst System
VNX™ / ZNX™ SCR Catalyst System
Engelhard Budgetary Proposal EPB99639
December 13, 1999

Westinghouse 501D – Simple Cycle

ASSUMED AMBIENT	59
GIVEN TURBINE EXHAUST TEMPERATURE, F	1,100
GIVEN TURBINE EXHAUST FLOW, lb/hr	3,600,000
ASSUMED TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	75.23
O2	12.61
CO2	3.63
H2O	7.60
Ar	0.93
AMBIENT AIR FLOW, lb/hr	307,337
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	3,907,337
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	75.70
O2	13.09
CO2	3.35
H2O	7.01
Ar	0.86
CALCULATED AIR + GAS MOL. WT.	28.48
GIVEN: TURBINE CO, ppmvd @ 15% O2	25.0
CALC.: TURBINE CO, lb/hr	100.6
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	15.0
CALC.: TURBINE NOx, lb/hr	99.2
CALC.: CO, ppmvd @ 15% O2 - AT CATALYST FACE	24.4
CALC.: NOx, ppmvd @ 15% O2 - AT CATALYST FACE	14.6
FLUE GAS TEMP. @ SCR CATALYST, F	1,025
DESIGN REQUIREMENTS	
CO CATALYST CO CONVERSION, %	90%
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5
NH3 SLIP, ppmvd @ 15% O2	9
SCR PRESSURE DROP, "WG - Max.	4"
GUARANTEED PERFORMANCE DATA	
CO CATALYST CO CONVERSION, % - Min.	90.0%
CO OUT, lb/hr - Max.	10.1
CO OUT, ppmvd @ 15% O2 - Max.	2.4
CO PRESSURE DROP, "WG - Max.	1.5
SCR CATALYST NOx CONVERSION, % - Min.	76.7%
NOx OUT, lb/hr - Max.	23.1
NOx OUT, ppmvd@15%O2 - Max.	3.4
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	181
NH3 SLIP, ppmvd@15%O2 - Max.	9
SCR PRESSURE DROP, "WG - Max.	4.0
REQUIRED CROSS SECTION - INSIDE LINER - A x B, sq ft	**1900.0**
CO SYSTEM	**$995,000**
REPLACEMENT CO CATALYST MODULES	**$775,000**
SCR SYSTEM	**$3,409,000**
REPLACEMENT SCR CATALYST MODULES	**$1,956,000**

Table B-3-rev1. Capital Cost for Selective Catalytic Reduction for Westingouse Frame 501F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$3,409,000	Vendor Estimate
Ammonia Storage Tank	$128,156	$35 per 1,000 lb mass flow developed from vendor quotes
Flue Gas Ductwork	$66,758	Vatavauk,1990
Instrumentation	$50,000	Additional NO_x Monitor and System
Taxes	$204,540	6% of SCR Associated Equipment and Catalyst
Freight	$170,450	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$4,028,904	
Direct Installation Costs		
Foundation and supports	$322,312	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$564,047	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$161,156	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$80,578	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$40,289	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$40,289	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$15,000	Engineering Estimate
Total Direct Installation Costs (TDIC)	$1,228,671	
Recurring Capital Costs (RCC)	$0	Catalyst; Vendor Based Estimate
Total Capital Costs (TCC)	$5,257,575	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$525,757	10% of Total Capital Costs; OAQPS Cost Control Manual
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$262,879	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$525,757	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$105,151	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$52,576	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$157,727	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$1,679,848	
Total Direct, Indirect and Recurring Capital Costs (TDIRCC)	$6,937,423	Sum of TCC and TInCC
Mass Flow of Combustion Turbine	4,518,595 lb/hr	"G"
	3,661,592 lb/hr	"F"

Table B-4-rev1. Annualized Cost for Selective Catalytic Reduction for Westinghouse Frame 501F Simple Cycle Operation

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	18,720	24 hours/week at $15/hr
Supervision	2,808	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	66,898	$300 per ton for Aqueous NH_3
PSM/RMP Update	15,000	Engineering Estimate
Inventory Cost	71,590	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Cost	652,000	3 years catalyst life; Based on Vendor Budget Estimate
Contingency	24,810	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	851,826	
Energy Costs		
Electrical	42,000	80kW/h for SCR 200kW/h for cooling fan @ $0.04/kWh times Capacity Factor
MW Loss and Heat Rate Penalty	246,833	0.5% of MW output; EPA, 1993 (Page 6-20)
Capacity Loss	0	
Fuel Escalation	0	
Contingency	0	0% of Energy Costs
Total Energy Costs (TEC)	288,833	
Indirect Annual Costs		
Overhead	$53,056	60% of Operating/Supervision Labor and Ammonia
Property Taxes	$69,374	1% of Total Capital Costs
Insurance	$69,374	1% of Total Capital Costs
Annualized Total Direct Capital	$761,729	10.98% Capital Recovery Factor of 7% over 15 years times sum of TDCC, TDIC and TInCC
Annualized Total Direct Recurring	$0	38.11% Capital Recovery Factor of 7% over 3 years times RCC
Total Indirect Annual Costs (TIAC)	$953,533	
Total Annualized Costs	$2,094,192	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$13,635	NO_x Reduction Only
	$20,178	Net Emission Reduction

Response to Question No. 12

Table B-6-rev1. Direct and Indirect Capital Costs for CO Catalyst, Westinghouse 501F Simple Cycle Mode

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$995,000	Vendor Quote
Flue Gas Ductwork	$66,758	Vatavauk,1990
Instrumentation	$99,500	10% of SCR Associated Equipment
Sales Tax		6% of SCR Associated Equipment/Catalyst
Freight	$49,750	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$1,211,008	
Direct Installation Costs		
Foundation and supports	$96,881	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$169,541	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$48,440	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$24,220	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$12,110	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$12,110	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$368,302	
Recurring Capital Costs (RCC)	$0	Catalyst; Vendor Based Estimate
Total Capital Costs	$1,579,310	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$157,931	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$78,966	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$157,931	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$31,586	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$15,793	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$47,379	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$489,586	
Total Direct, Indirect and Recurring Capital Costs (TDIRCC)	$2,068,897	Sum of TCC and TInCC
Mass Flow of Combustion Turbine	4,518,595 lb/hr	"G"
	3,661,592 lb/hr	"F"

Table B-7-rev1. Annualized Cost for CO Catalyst, Simple Cycle Mode

Cost Component	Cost	Basis of Cost Estimate
Diirect Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$258,333	3 year catalyst life; base on Vendor Budget Quote
Inventory Cost	$28,365	Capital Recovery (10.98%) for 1/3 catalyst
Catalyst Disposal Cost	$0	$28/1,000 lb/hr mass flow over 3 yrs; developed from vendor quotes
Contingency	$8,816	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	302,691	
Energy Costs		
Heat Rate Penalty	$98,733	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs
MW Loss Penalty	$0	2 days replacement energy costs @ $0.01 kWh each three period
Fuel Escalation	$0	Escalation of fuel over inflation; 3% of energy costs
Contingency	$0	0% of Energy Costs
Total Energy Costs (TDEC)	$98,733	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$20,689	1% of Total Capital Costs
Insurance	$20,689	1% of Total Capital Costs
Annualized Total Direct Capital	$227,165	10.98% Capital Recy Factor of 7% over 15 yrs times sum of TDCC, TDIC,& TInCC
Annualized Total Direct Recurring	$0	38.11% Capital Recovery Factor of 7% over 3 years times RCC
Total Indirect Annual Costs	$272,848	
Total Annualized Costs	$674,272	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$3,666	Simple CycleCombustion Turbine
	$3,761	Net Emission Reduction

Response to Question No. 13

Table 2-3. Performance, Stack Parameters and Emissions for Natural Gas Heater, Emergency Diesel Generator and Diesel Fire Pump
Palmetto Power

	Natural Gas Heater	Diesel Generator	Diesel Fire Pump	Total
Performance				
Fuel Usage (scf/hr-gas; gallons/hr-diesel)	4,798	18.99	17.56	
Rating (kW-generator or hp-fire pump)	NA	250	310	
Heat Input (mmBtu/hr-HHV)	4.90	2.63	2.43	
Hours per Year (diesels = 2 hours/week)	800	104	104	
Typical Fuel Usage (mmscf/yr; gallons/yr)	3.84	1,975	1,826	
Maximum Fuel Usage (mmscf/yr; gallons/yr)[a]		16,000	16,000	
Number of Units	1	1	1	
Stack Parameters				
Diameter (ft)	1	0.5	0.5	
Height (ft)	23	6	6	
Temperature (°F)	713	770	770	
Velocity (ft/sec)	26	83	62	
Flow (acfm)	2,426	1,951	1,456	
Emissions				
SO_2 -Basis (grains S/100 scf-gas; %S diesel)[b]	1	0.05%	0.05%	
(lb/hr)	0.014	0.137	0.126	
(tpy) - typical maximum	0.005	0.007	0.007	0.019
(tpy) - maximum[a]	NA	0.058	0.058	0.121
NO_x - (lb/mmBtu)[c]	0.120	4.410	4.410	
(lb/hr)	0.588	11.576	10.704	
(tpy)	0.235	0.602	0.557	1.394
(tpy) - maximum[a]	NA	4.877	4.877	9.989
CO - (lb/mmBtu)[c]	0.050	0.950	0.950	
(lb/hr)	0.245	2.494	2.306	
(tpy)	0.098	0.130	0.120	0.348
(tpy) - maximum[a]	NA	1.051	1.051	2.199
VOC - (lb/mmBtu)[c]	0.260	0.350	0.350	
(lb/hr)	1.274	0.919	0.850	
(tpy)	0.510	0.048	0.044	0.602
(tpy) - maximum[a]	NA	0.387	0.387	1.284
PM/PM10 - ($lb/10^6 ft^3$)[d]	6.200	0.310	0.310	
(lb/hr)	0.030	0.814	0.752	
(tpy)	0.012	0.042	0.039	0.093
(tpy) - maximum[a]	NA	0.343	0.343	0.698

Notes:

a - Rule 62-210.300(3)(a)20.b. F.A.C.

b - Typical maximum for pipeline natural gas; distillate fuel oil

c - vendor for gas heater and Table 3.3-1 in AP-42

d - AP-42 Table 1.4-2 Filterable PM; higher factor used for small heater; Table 3.3-1 PM-10

Response to Question No. 16

Table 6-2. Maximum Predicted Pollutant Concentrations For One Simple-Cycle Combustion Turbine
Screening Analysis, 501D Combustion Turbine, Natural Gas- Fired
Palmetto Power, L.L.C. Project

	Maximum Emission Rates (lb/hr) by Operating Load and Air Inlet Temperature							Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Inlet Temperature (1)					
	Base Load			70% Load			Averaging	Base Load			70% Load		
Pollutant	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F	Time	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Generic	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.017	0.017	0.017	0.018	0.018	0.018
(10 g/s)							24-Hour	0.181	0.184	0.193	0.231	0.235	0.241
							8-Hour	0.484	0.494	0.516	0.608	0.618	0.632
							3-Hour	0.877	0.897	0.944	1.227	1.328	1.333
							1-Hour	1.950	1.983	2.076	2.489	2.551	2.613
PM10	8.6	8.2	7.5	7.1	6.9	6.4	Annual	0.0018	0.0018	0.0016	0.0016	0.0015	0.0014
							24-Hour	0.020	0.019	0.018	0.021	0.020	0.019
NO_x	111.2	106.8	98.4	83.0	78.8	72.9	Annual	0.024	0.023	0.021	0.019	0.018	0.016
CO	113.0	109.0	100.0	85.0	80.0	74.0	8-Hour	0.69	0.68	0.65	0.65	0.62	0.59
							1-Hour	2.8	2.7	2.6	2.7	2.6	2.4

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations in Orlando and West Palm Beach, Florida, respectively.

Pollutant concentrations were based on a modeled or generic concentration predicted using a modeled emission rate of 79.37 lb/hr [10(g/s)]. Specific pollutant concentrations were estimated by multiplying the modeled concentration (at 10 g/s) by the ratio of the specific pollutant emission rate to the modeled emission rate of 10 g/s.

Table 6-3. Maximum Pollutant Concentrations Predicted for Three Simple Cycle Combustion Turbines Compared to EPA Significant Impact and Deminimis Monitoring Levels- Screening Analysis Palmetto Power, L.L.C. Project

ollutant	Averaging Time	Maximum Predicted Concentrations (ug/m^3) by Operating Load and Air Inlet Temperature (1)						EPA Significant Impact Levels (ug/m^3)	EPA Deminimis Levels (ug/m^3)
		Base Load			70% Load				
		32 °F	59 °F	95 °F	32 °F	59 °F	95 °F		
PM10	Annual	0.0055	0.0053	0.0049	0.0048	0.0046	0.0043	1	NA
	24-Hour	0.059	0.057	0.054	0.062	0.061	0.058	5	10
NO_2	Annual	0.072	0.069	0.064	0.056	0.053	0.049	1	14
CO	8-Hour	2.1	2.0	2.0	2.0	1.9	1.8	500	575
	1-Hour	8.3	8.2	7.8	8.0	7.7	7.3	2,000	NA

(1) Concentrations are based on highest predicted concentrations using five years of meteorological for 1987 to 1991 of surface and upper air data from the National Weather Service stations in Orlando and West Palm Beach, Florida, respectively.

Table 6-4. Summary of Maximum Pollutant Concentrations Predicted for Three SimpleCycle Combustion Turbines Compared to EPA Significant Impact and Deminimis Monitoring Levels
Palmetto Power, L.L.C. Project

ollutant	Averaging Time	Maximum Predicted Concentrations (ug/m³)	EPA Significant Impact Levels (ug/m³)	EPA Deminimis Levels (ug/m³)	PSD ClassII Increments (ug/m³)	AAQS (ug/m³)
PM10	Annual	0.0055 (1)	1	NA	17	50
	24-Hour	0.076 (2)	5	10	30	150
NO_2	Annual	0.072 (1)	1	14	25	100
CO	8-Hour	2.1 (1)	500	575	NA	10,000
	1-Hour	8.4 (1)	2,000	NA	NA	40,000

NA= not applicable

(1) Based on operating conditions at 100 percent load and ambient inlet temperature of 32 °F.
(2) Based on operating conditions at 70 percent load and ambient inlet temperature of 32 °F.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 5, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Rick A. Bowen, Executive V.P.
Palmetto Power, L.L.C
1000 Louisiana Street, Suite 5800
Houston, TX 77002

Re: Request for Additional Information
DEP File No. 0970073-001-AC (PSD-FL-277)
Three Simple Cycle, 182 MW Combustion Turbines Osceola County

Dear Mr. Bowen:

On October 15, 1999, the Department received your application with sufficient fee for an air construction permit for three simple cycle, 182 MW combustion turbines to be located in Osceola County, Florida. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Gas Turbine Model

1. The application indicates that the combustion turbines will be Siemens/Westinghouse Model 501FD "or equivalent" units. However, the application also lists Siemens/Westinghouse as the "selected vendor". Has Palmetto Power entered into a contractual agreement with Siemens/Westinghouse for this project, or is it still possible to select another vendor and model of gas turbine? The Department notes that there are other vendors with similarly sized gas turbines that have much lower CO and NOx emission rates. Please provide documentation that the CO, NOx, PM/PM_{10}, and VOC emissions standards requested in the application are guaranteed by Siemens/Westinghouse and that these are the lowest guarantees currently offered for the Model 501FD gas turbine.
2. Please provide manufacturer information on the automated gas turbine control system for this model, including a general description of the system, the input parameters monitored, and the gas turbine parameters that are controlled.
3. Please provide manufacturer information on the proposed evaporative inlet air cooling system, including a description of the process and the equipment to be installed.
4. Please provide emissions performance curves based on manufacturer information for:
   - CO vs. load in terms of ppmvd and pounds per hour
   - NOx vs. load in terms of ppmvd and pounds per hour
5. Please provide information from the manufacturer regarding CO and NOx emission levels during actual field service for at least two projects operating this model gas turbine. Summarize the initial

emissions performance tests for CO, NOx, PM/PM_{10}, and VOC as well as the continuous NOx monitoring data for these projects.

6. How many minutes does startup to 70% of base load take as well as shutdown? Please estimate the number of startups in a year based on the proposed maximum 3750 hours per year of operation. How many hours of startup and shutdown would this be? Based on the manufacturer's emission rates for startups and shutdowns, estimate the annual emissions of CO, NOx, PM/PM_{10}, SO_2, and VOC from startups and shutdowns. The Department plans to address excess emissions in its BACT determination.

NOx BACT Determination

7. The requested NOx BACT limit for this project is 15 ppmvd. What model combustor is proposed? Does the manufacturer guarantee this rate? Is this emissions rate specific to DLN combustors firing natural gas only? In other words, does the manufacturer guarantee lower emissions when firing natural gas as compared to a gas turbine with dual-fuel combustors? Is this the lowest guaranteed NOx emissions rate offered by the manufacturer? Are other combustor types available that offer lower NOx emissions? After achieving stable operation and emissions, does the diffusion flame burner on the DLN combustor ever completely shut off? Several recent projects have determined NOx BACT for simple cycle operation to be 9 to 12 ppmvd. Please explain any significant differences presented by this project.

8. For the NOx BACT analysis, why was the DLN system at 15 ppmvd compared to a hot SCR system at 4.5 ppmvd? There are many BACT determinations in other states establishing SCR BACT limits of 2 to 3.5 ppmvd? Why wouldn't a comparable hot SCR system for this project be able to achieve 3.5 ppmvd of NOx?

9. Please revise the cost analysis based on the following:

   - Treat the catalyst cost as part of the capital costs for SCR and as an annualized cost for catalyst replacement - not a "recurring capital cost".
   - Remove the catalyst disposal cost or provide information from the vendor that the quoted catalyst cost does not include an exchange for spent catalyst.
   - Remove the "Capacity Loss" because the gas turbines are only operated 3750 hours per year.
   - Remove the fuel escalation cost.
   - Remove the 10% contingency factor for "energy costs".

   Please provide the vendor quote for this equipment including information regarding the type of catalyst recommended for this exhaust temperature and the need for gas cooling. Also, please provide details as to the "instrumentation" that will be provided in addition to the equipment that will be provided by the SCR vendor.

CO BACT Determination

10. The requested BACT limit for CO is 25 ppmvd. Page 4-10 of the application suggests that CO emissions from the Model 501FD may actually be 10 ppmvd and even calculates a cost effectiveness based on 20 ppmvd. The reason cited for the 25 ppmvd limit requested for CO standard is the "uncertainty associated with maintaining low NOx emissions" simultaneously with low CO emissions. There does not appear to be the same degree of uncertainty associated with other competing gas turbines. In fact, several recently issued permits for similarly sized projects were

Is your **RETURN ADDRESS** completed on the reverse side?

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

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

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

Consult postmaster for fee.

3. Article Addressed to:
Rick Bowen, Ex, VP
Palmetto Power, LLC
1000 Louisiana St
Houston, TX
77002

4a. Article Number
Z 031 392 002

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

7. Date of Delivery
NOV 5 1999

5. Received By: *(Print Name)*

6. Signature: *(Addressee or Agent)*
X Robert Salazar

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

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

Z 031 392 002

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do ~~not use for~~ International Mail *(See reverse)*

Sent to Rick Bowen	
Street & Number Palmetto Power	
Post Office, State, & ZIP Code Houston TX	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date 11-4-99	

C97CC73-001-AC
P30-F1-277

PS Form **3800**, April 1995

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 5, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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1000 Louisiana Street, Suite 5800
Houston, TX 77002

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2. Please provide manufacturer information on the automated gas turbine control system for this model, including a general description of the system, the input parameters monitored, and the gas turbine parameters that are controlled.
3. Please provide manufacturer information on the proposed evaporative inlet air cooling system, including a description of the process and the equipment to be installed.
4. Please provide emissions performance curves based on manufacturer information for:
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   - NOx vs. load in terms of ppmvd and pounds per hour
5. Please provide information from the manufacturer regarding CO and NOx emission levels during actual field service for at least two projects operating this model gas turbine. Summarize the initial

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NOx BACT Determination

7. The requested NOx BACT limit for this project is 15 ppmvd. What model combustor is proposed? Does the manufacturer guarantee this rate? Is this emissions rate specific to DLN combustors firing natural gas only? In other words, does the manufacturer guarantee lower emissions when firing natural gas as compared to a gas turbine with dual-fuel combustors? Is this the lowest guaranteed NOx emissions rate offered by the manufacturer? Are other combustor types available that offer lower NOx emissions? After achieving stable operation and emissions, does the diffusion flame burner on the DLN combustor ever completely shut off? Several recent projects have determined NOx BACT for simple cycle operation to be 9 to 12 ppmvd. Please explain any significant differences presented by this project.

8. For the NOx BACT analysis, why was the DLN system at 15 ppmvd compared to a hot SCR system at 4.5 ppmvd? There are many BACT determinations in other states establishing SCR BACT limits of 2 to 3.5 ppmvd? Why wouldn't a comparable hot SCR system for this project be able to achieve 3.5 ppmvd of NOx?

9. Please revise the cost analysis based on the following:

   - Treat the catalyst cost as part of the capital costs for SCR and as an annualized cost for catalyst replacement - not a "recurring capital cost".
   - Remove the catalyst disposal cost or provide information from the vendor that the quoted catalyst cost does not include an exchange for spent catalyst.
   - Remove the "Capacity Loss" because the gas turbines are only operated 3750 hours per year.
   - Remove the fuel escalation cost.
   - Remove the 10% contingency factor for "energy costs".

   Please provide the vendor quote for this equipment including information regarding the type of catalyst recommended for this exhaust temperature and the need for gas cooling. Also, please provide details as to the "instrumentation" that will be provided in addition to the equipment that will be provided by the SCR vendor.

CO BACT Determination

10. The requested BACT limit for CO is 25 ppmvd. Page 4-10 of the application suggests that CO emissions from the Model 501FD may actually be 10 ppmvd and even calculates a cost effectiveness based on 20 ppmvd. The reason cited for the 25 ppmvd limit requested for CO standard is the "uncertainty associated with maintaining low NOx emissions" simultaneously with low CO emissions. There does not appear to be the same degree of uncertainty associated with other competing gas turbines. In fact, several recently issued permits for similarly sized projects were

permitted with CO BACT limits of 9 to 15 ppmvd. Please provide supporting information regarding the uncertainty for this model and explain any significant differences that this project may present.

11. Why was the cost analysis for a CO oxidation catalyst based on CO emissions of 10 ppmvd? Based on information provided for similar projects, a 90% reduction in CO emissions may be achievable with an oxidation catalyst, especially when firing natural gas only. Please explain any significant differences that this project may present.

12. Please revise the cost analysis based on the following:

 - Treat the catalyst cost as part of the capital costs for the CO catalyst system and as an annualized cost for catalyst replacement - not a "recurring capital cost".
 - Remove the catalyst disposal cost or provide information from the vendor that the quoted catalyst cost does not include an exchange for spent catalyst.
 - Remove the "MW Loss Penalty" because these units are only operated 3750 hours per year.
 - Remove the fuel escalation cost.
 - Remove the 10% contingency factor for "energy costs".
 - Based on the answer to question #11, revise the "tons per year" CO emissions reduction.

 Please provide the vendor quote for this equipment including information regarding the type of catalyst quoted. Also, please provide details as to the "instrumentation" that will be provided in addition to the equipment that will be provided by the CO catalyst vendor.

<u>Other Sources</u>

13. Please provide estimates of the potential emissions from the 250 kW emergency diesel generator, the 310 hp emergency diesel fire pump, the 4.9 mmBTU per hour gas heater, and any other combustion sources that will be constructed as a result of this project. The potential emissions may be based on requested fuel consumption limits or those limits specified in the exemption criteria listed in Rule 62-210.300, F.A.C. Please identify the fuel, fuel heating value, and fuel sulfur content for each source.

<u>Air Quality Analysis</u>

14. The Air Dispersion modeling protocol submitted on July 26, 1999 stated that Orlando surface and Ruskin upper air meteorological data from 1987 to 1991 would be used in the modeling analysis. However, the modeling that was submitted was based upon Orlando surface and West Palm Beach upper air meteorological data from 1987 to 1991. Please give the reason behind the change in upper air meteorological data.

15. Page 2-4 of the permit application states that the project proposes to operate one 250-kW diesel generator and one 310-hp emergency fire pump. Please explain why these units are exempt from modeling. Also, provide the maximum sulfur content of the fuel oil that will be used to operate these machines.

16. The locations of the Air Inlets and Generators input into the BPIP program do not correspond to the locations that are shown on figure 2-3. Please revise the Building Downwash Analysis so that it represents the proposed building and stack locations.

17. Please submit the modeling files that correspond to all of the predicted concentrations shown in figure 6-3.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Material changes to the application should also be accompanied by a new certification statement by the authorized representative or responsible official. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please contact the project engineer, Jeff Koerner, at 850/850/414-7268. Questions regarding the air quality analysis should be directed to Chris Carlson (meteorologist) at 850/921-9537.

Sincerely,

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/jfk

Enclosure

cc: Ms. Starla Lacy, Palmetto Power LLC
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Len Kozlov, DEP - Central District Office
Ken Kosky, Golder Associates

Golder Associates Inc.

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

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BUREAU OF AIR REGULATION

January 26, 2000

A.A. Linero, P.E., Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399

RE: Palmetto Power, L.L.C.
DEP File No. 0970073-001-AC (PSD-FL-277)
Information Request

Attention: Mr. Jeffery F. Koerner, P.E.

Dear Jeff:

This correspondence is submitted on behalf of Palmetto Power, L.L.C. to request an additional 14 days to submit the information requested in the Department's November 5, 1999 letter. Consulting with the manufacturer and the holidays have taken us a little more time than normally expected to prepare a response. We appreciate your patience.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal

cc: Starla Lacy, Dynegy, Inc.
Bob McCann, Golder Associates

INTEROFFICE MEMORANDUM

Date: 19-Jan-2000 06:52pm
From: Kosky, Ken
KKosky@GOLDER.com
Dept:
Tel No:

To: jeff.koerner (jeff.koerner@dep.state.fl.us)
CC: ssla (ssla@dynegy.com)

Subject: Palmetto Power

Jeff: We be sending a response early next week by the latest. The holidays slowed us down since we also had to get information from Westinghouse.
Regards, Ken

RFC-822-headers:
Delivery-receipt-to: KKosky@GOLDER.com
Received: from epic50.dep.state.fl.us ([199.73.195.8])
by mail.epic1.dep.state.fl.us (PMDF V5.2-32 #37976)
with ESMTP id <01JKWDOGXSD80051LZ@mail.epic1.dep.state.fl.us> for
KOERNER_J@a1.epic1.dep.state.fl.us (ORCPT rfc822;jeff.koerner@dep.state.fl.us)
; Wed, 19 Jan 2000 18:52:34 EST
Received: from seainternet.golder.com ([157.208.11.254])
by mail.epic50.dep.state.fl.us (PMDF V5.2-32 #31508)
with ESMTP id <01JKWDN8DTA2001SPA@mail.epic50.dep.state.fl.us> for
KOERNER_J@a1.epic1.dep.state.fl.us (ORCPT rfc822;jeff.koerner@dep.state.fl.us)
; Wed, 19 Jan 2000 18:51:35 -0500 (EST)
Received: by seainternet.golder.com with Internet Mail Service (5.5.2448.0)
id <D1KX4VVS>; Wed, 19 Jan 2000 15:58:38 -0800
X-Mailer: Internet Mail Service (5.5.2448.0)

Dynegy Inc.
1000 Louisiana Street, Suite 5800
Houston, Texas 77002
Phone 713.507.6400

facsimile

DYNEGY

To: Alan Linero, P.E.

Fax: 850-922-6979

Subject: Palmetto Power Project

From: John Sousa

Pages: 4

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Please see attached. Thank you.

NR99-32

Dynegy Inc
1000 Louisiana Street, Suite 5800
Houston, Texas 77002
Phone 713.507.6400 · Fax 713.507.3871
http://www.dynegy.com

news release

DYNEGY

Release Dec. 6, 1999

Contact **Media:** John Sousa
(713) 507-3936

Analyst: Margaret Nollen
(713) 767-8707

DYNEGY DEVELOPING POWER PLANT NEAR ORLANDO

Palmetto Power Project Targets Commercial Operations in 2002

HOUSTON (Dec. 6, 1999) – Dynegy Inc. today announced plans to develop its first merchant power plant in the state of Florida. The 500-megawatt (MW) natural gas-fired peaking facility will be located in Osceola County, approximately 30 miles southeast of Orlando. Dynegy will sell the power generated at the Palmetto Power Project in the wholesale electricity market to public utilities, electric cooperatives and municipalities throughout Florida when commercial operations begin in the summer of 2002.

"Florida is one of the most attractive markets in the country for new power plant development," said Steve Bergstrom, president and chief operating officer of Dynegy Inc. "A constrained transmission network, coupled with strong wholesale load growth opportunities, provides excellent opportunities for market participants with regional experience developing, building and operating power generation facilities. Combined with our national power trading and fuel supply capabilities, the Palmetto Power Project will allow us to provide full service to the wholesale markets in Florida."

The Palmetto Power Project will occupy a rural 150-acre site in northeast Osceola County that Dynegy has secured for the facility. The power plant will include three advanced technology combustion turbines operating in simple-cycle. Natural gas delivered through the Florida Gas

-more-

Transmission gas pipeline will be used as fuel to generate electricity, and a 230-kilovolt interconnection with Florida Power Corp. and Florida Power & Light will provide transmission access for power transactions.

The Palmetto Power Project will create approximately 150 new construction jobs. After full commercial operation is achieved, the facility will require up to six new permanent employees.

"As we work through the development process, input will be sought from the community and citizens will be kept informed throughout all phases of the project," said Rick Bowen, executive vice president of project development, Dynegy Marketing and Trade. "It's our goal to balance the need for power with the interests of the community and its residents."

Dynegy's 34 U.S. generation plants currently operating or under construction total more than 7,000 gross MW. This includes the recently announced 100-MW expansion of the Rocky Road Power Plant, a natural gas-fired peaking facility in East Dundee, Ill., and the Calcasieu Generation Project, a 155-MW natural gas-fired peaking facility near Lake Charles, La. Dynegy began construction on an 800-MW natural gas-fired power plant in Rockingham County, N.C. in July 1999.

Dynegy and Illinova Corp. announced the execution of definitive agreements for a merger on June 14, 1999. The merger creates a $7.5 billion book value company, which is expected to own an interest in plants which total more than 14,000 MW of gross domestic generating capacity. The combined company will average North American natural gas sales of 9.1 billion cubic feet per day and serve more than 950,000 retail customers. The company will be named Dynegy Inc. and Illinova subsidiary Illinois Power will remain headquartered in Decatur, Ill.

Dynegy Inc. (NYSE: DYN) is one of the country's leading marketers of energy products and services. Through its leadership position in gathering, processing, transportation, power generation, and marketing of energy, the company provides energy solutions to its customers primarily in North America and the United Kingdom. Dynegy's primary business segments are wholesale gas and power and natural gas liquids. Dynegy Marketing and Trade, the company's power generation and natural gas and power marketing and trading subsidiary, focuses on

-more-

NR99-32

DYNEGY DEVELOPING POWER PLANT NEAR ORLANDO
3-3-3-3-3

energy convergence – the marketing, trading and arbitrage opportunities that exist among natural gas, power and coal that can be enhanced by the control and optimization of related physical assets. Dynegy's natural gas liquids subsidiary, Dynegy Midstream Services, Limited Partnership, includes North American midstream liquids operations, global natural gas liquids transportation and marketing operations.

This press release includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Although Dynegy believes that its expectations are reasonable, it can give no assurance that these expectations will prove to have been correct. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include fluctuations in commodity prices for natural gas, electricity, natural gas liquids, crude oil, or coal; competitive practices in the industries in which Dynegy competes; operations and systems risks; environmental liabilities, which are not covered by indemnity or insurance; software, hardware or third-party failures resulting from Year 2000 issues; general economic and capital market conditions, including fluctuations in interest rates; and the impact of current and future laws and governmental regulations (particularly environmental regulations) affecting the energy industry in general, and Dynegy's operations in particular.

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For more information about Dynegy, please visit its web site at www.dynegy.com

INTEROFFICE MEMORANDUM

Sensitivity: COMPANY CONFIDENTIAL

Date: 23-Nov-1999 03:03pm
From: Alvaro Linero TAL
LINERO_A
Dept: Air Resources Management
Tel No: 850/921-9523

To: Jeff Koerner TAL (KOERNER_J)

Subject: FWD: Fwd:Re:Palmetto Power

F.Y.I. Al.

INTEROFFICE MEMORANDUM

Date: 23-Nov-1999 12:06pm
From: Ellen_Porter
Ellen_Porter@nps.gov
Dept:
Tel No:

Subject: Fwd:Re:Palmetto Power

Al, please see Don Shepherd's comments below on Palmetto Power. What do you think?

____________________Forward Header____________________
Subject: Re:Palmetto Power
Author: Don Shepherd
Date: 11/22/1999 4:30 PM

Ellen,

I have looked at the Palmetto application and, as far as Siemens-Westinghouse 501FD gas turbines go, this is right in there with the rest of them at 15 ppm. However, a larger question is, should an applicant be allowed to emit higher levels of pollution just because they purchase an inherently dirtier machine. I see no reason (other than $$ and perhaps availability) why Palmetto could not have purchased a GE Frame 7 and come in at 9 ppm. Seems to me that all simple cycle turbines should be required to meet some reasonably tight limit, say 12 ppm max, and let the vendors tweak their machines to meet that limit. Right now, the vendors of the dirtier machines are getting a break, just like if I were to buy some old clunker automobile and then get relief on its tailpipe limit. I wonder what FDEP thinks of this situation?

Don

____________________Reply Separator____________________
Subject: Palmetto Power
Author: Ellen Porter
Date: 11/3/99 1:44 PM

Although this source is far (175 km) from CHAS, I thought you might want to peruse their proposed BACT - 15 ppm NOx for 3 Westinghouse SCTs. All gas, no oil. FDEP isn't even sure they can meet 15 ppm.

I put the application on your chair.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

January 26, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Rick A. Bowen, Executive V.P.
Palmetto Power, L.L.C
1000 Louisiana Street, Suite 5800
Houston, TX 77002

Re: Request for Additional Information No. 2
DEP File No. 0970073-001-AC (PSD-FL-277)
Three Simple Cycle, 182 MW Combustion Turbines Osceola County

Dear Mr. Bowen:

On October 15, 1999, the Department received your application with sufficient fee for a permit to construct three simple cycle, 182 MW combustion turbines to be located in Osceola County, Florida. On November 5, 1999, the Department requested additional information needed to complete the application. On January 26, 2000, the Department received a request from Golder Associates on behalf of Palmetto Power for an additional 14 days to submit the additional information. In accordance with Rule 62-4.055(1), F.A.C., the Department grants an additional 90 days to provide this information. The Department will resume processing your application after receipt of the requested information. A copy of the requested additional information is attached.

If you have any questions, please contact me at 850/414-7268.

Sincerely,

Jeffery F. Koerner

Jeffery F. Koerner, P.E.
New Source Review Section

AAL/jfk

Enclosure

cc: Ms. Starla Lacy, Palmetto Power LLC
Ken Kosky, Golder Associates
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Len Kozlov, DEP - Central
District Office

Fold at line over top of envelope to

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

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

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

Consult postmaster for fee.

3. Article Addressed to:
Rick Bowen
Palmetto Power, LLC
1000 Louisiana St.
Ste 16
Houston, TX 77002

4a. Article Number
Z 031 391 922

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

7. Date of Delivery

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6. Signature: *(Addressee or Agent)*
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Special Delivery Fee	
Restricted Delivery Fee	
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PS Form **3800**, April 1995

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TO THE ORDER OF
Florida Dept of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahasse FL 32399-2400

DYNEGY POWER CORP.

VICE PRESIDENT - TREASURER
AUTHORIZED SIGNATURE

⑈0000504172⑈ ⑆031100283⑆ 09 46842⑈

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permitted with CO BACT limits of 9 to 15 ppmvd. Please provide supporting information regarding the uncertainty for this model and explain any significant differences that this project may present.

11. Why was the cost analysis for a CO oxidation catalyst based on CO emissions of 10 ppmvd? Based on information provided for similar projects, a 90% reduction in CO emissions may be achievable with an oxidation catalyst, especially when firing natural gas only. Please explain any significant differences that this project may present.

12. Please revise the cost analysis based on the following:
    - Treat the catalyst cost as part of the capital costs for the CO catalyst system and as an annualized cost for catalyst replacement - not a "recurring capital cost".
    - Remove the catalyst disposal cost or provide information from the vendor that the quoted catalyst cost does not include an exchange for spent catalyst.
    - Remove the "MW Loss Penalty" because these units are only operated 3750 hours per year.
    - Remove the fuel escalation cost.
    - Remove the 10% contingency factor for "energy costs".
    - Based on the answer to question #11, revise the "tons per year" CO emissions reduction.

    Please provide the vendor quote for this equipment including information regarding the type of catalyst quoted. Also, please provide details as to the "instrumentation" that will be provided in addition to the equipment that will be provided by the CO catalyst vendor.

Other Sources

13. Please provide estimates of the potential emissions from the 250 kW emergency diesel generator, the 310 hp emergency diesel fire pump, the 4.9 mmBTU per hour gas heater, and any other combustion sources that will be constructed as a result of this project. The potential emissions may be based on requested fuel consumption limits or those limits specified in the exemption criteria listed in Rule 62-210.300, F.A.C. Please identify the fuel, fuel heating value, and fuel sulfur content for each source.

Air Quality Analysis

14. The Air Dispersion modeling protocol submitted on July 26, 1999 stated that Orlando surface and Ruskin upper air meteorological data from 1987 to 1991 would be used in the modeling analysis. However, the modeling that was submitted was based upon Orlando surface and West Palm Beach upper air meteorological data from 1987 to 1991. Please give the reason behind the change in upper air meteorological data.

15. Page 2-4 of the permit application states that the project proposes to operate one 250-kW diesel generator and one 310-hp emergency fire pump. Please explain why these units are exempt from modeling. Also, provide the maximum sulfur content of the fuel oil that will be used to operate these machines.

16. The locations of the Air Inlets and Generators input into the BPIP program do not correspond to the locations that are shown on figure 2-3. Please revise the Building Downwash Analysis so that it represents the proposed building and stack locations.

17. Please submit the modeling files that correspond to all of the predicted concentrations shown in figure 6-3.

The Department will resume processing your application after receipt of the requested information. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Material changes to the application should also be accompanied by a new certification statement by the authorized representative or responsible official. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please contact the project engineer, Jeff Koerner, at 850/850/414-7268. Questions regarding the air quality analysis should be directed to Chris Carlson (meteorologist) at 850/921-9537.

Sincerely,

A. A. Linero

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/jfk

Enclosure

cc: Ms. Starla Lacy, Palmetto Power LLC
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Len Kozlov, DEP - Central District Office
Ken Kosky, Golder Associates