ECT
Environmental Consulting & Technology, Inc.

July 31, 2001

SENT VIA OVERNIGHT MAIL ON JULY 31, 2001

Mr. A.A. Linero, P.E.
Administrator, New Source Review Section
Florida Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400

Re: Calpine Construction Finance Company, L.P.
DEP File No. PA 00-42 (PSD-FL-309)
Blue Heron Energy Center
Comments on Draft Permit

Dear Mr. Linero:

On behalf of Calpine Construction Finance Company, L.P. (Calpine), comments on the Department's draft Technical Evaluation and Preliminary Evaluation (TEPD), Best Available Control Technology (BACT) Determination, and Prevention of Significant Deterioration (PSD) permit for the Blue Heron Energy Center are attached for your consideration. To facilitate your review, marked up electronic versions of the Department's draft permit documents showing the requested revisions are also being sent to you via electronic mail.

Your review of these comments and continued processing of the Calpine Blue Heron Energy Center PSD permit application is appreciated. Please contact Mr. Benjamin Borsch at (813) 207-0771 or the undersigned at (352) 332-6230, Ext. 351 if there are any questions regarding these comments.

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis, P.E.
Principal Engineer

Attachments

cc: Mr. Benjamin Borsch, Calpine
Mr. David Dee, Landers & Parson
Mr. R. Douglas Neely, EPA Region 4
Mr. Leonard Koslov, FDEP Central District
M. Culpin
J. Holladay
B. Owen
H. Worley EPA
J. Bunyak, NPS

3701 Northwest
98TH Street
Gainesville, FL
32606

(352)
332-0444

FAX (352)
332-6722

Comments on FDEP Draft Permit Documents
Calpine Blue Heron Energy Center

A. Technical Evaluation and Preliminary Evaluation (TEPD)

1. Change "Calpine Construction & Finance Company, LP" to "Calpine Construction Finance Company, L.P." on TE-1.

   Basis for Revision:
   Correction of applicant name.

2. Suggest changing emission unit description of Emission Units 001 through 004 on TE-3 as follows:

   Emission Units 001 and 002

   ~~One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator~~
   One nominal 170 Megawatt Combustion Turbine Generator/Heat Recovery Steam Generator Unit. EU 001 and EU 002 and one, common nominal 200 Megawatt Steam Turbine Electrical Generator comprise one nominal 540 Megawatt Combined Cycle Power Generation System.

   Emission Units 003 and 004

   ~~One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator~~
   One nominal 170 Megawatt Combustion Turbine Generator/Heat Recovery Steam Generator Unit. EU 003 and EU 004 and one, common nominal 200 Megawatt Steam Turbine Electrical Generator comprise one nominal 540 Megawatt Combined Cycle Power Generation System.

   Basis for Revision:
   Clarifies the nominal electrical production capacities of the CTG/HRSG units and steam turbines.

3. Suggest changing project description on TE-3 to read as follows:

   The project includes: four nominal 170 MW Westinghouse 501FD combustion turbine-electrical generators (CTGs) configured in combined cycle mode, operating solely on natural gas; ~~four 260 million Btu per hour (MMBtu/hr) supplementally-fired heat recovery steam generators (HRSG)~~ four heat recovery steam generators (HRSGs), each equipped with supplemental 260 million Btu per hour (MMBtu/hr) lower heating value (LHV) heat input duct burners; two nominal 200 MW (gross output) steam turbines; ~~four stacks~~ one stack for each CTG/HRSG unit; an emergency (diesel-fired) generator; a diesel firewater pump; 2 fresh water cooling towers; one wastewater cooling tower and ancillary equipment.

The ~~turbines will~~ CTGs will each be equipped with Dry Low NO_X combustors. In addition, each HRSG will include ~~as well as~~ an SCR in order to control NO_X emissions from each CTG/HRSG unit to 3.5 ppmvd at 15% O_2. Each combination of combustion turbine and HRSG will have a maximum heat input rating of 2,265 MMBtu/hr at a lower heat value (LHV) of 20,981 Btu/lbm while operating at maximum output and 20°F (specified as case 4 in Table C-9 of the application).

The CTG/HRSG units will be fueled by ~~fuel will be~~ pipeline quality natural gas and ~~the unit~~ may each ~~will~~ operate up to 8760 hours per year. Emission increases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (SAM), particulate matter (PM/PM_{10}), volatile organic compounds (VOC) and nitrogen oxides (NO_X). PSD review is required for CO, SO_2, SAM, PM/PM_{10}, NO_X, and VOC since emissions, per the application, will increase by more than their respective significant emissions levels.

Basis for Revision:
Clarifies the heat input rating of the duct burners and steam turbines and emission sources controlled by the proposed control systems.

Requested revisions to the TEPD have also been sent via electronic mail (file: BH TEPD – Calpine Comments.doc).

B. Best Available Control Technology Determination (BACT)

1. Correct project description on BD-1 as follows:

   The primary units to be installed are four nominal 170 MW, Siemens Westinghouse "F" Class (501FD) combustion turbine-electrical generators, fired solely with pipeline natural gas and equipped with evaporative coolers on the inlet air system. The project includes four heat recovery steam generators (HRSGs), each with a 135 ft. stack and two steam turbine-electrical generator rated at approximately 200 MW each. Duct burners will be installed in the HRSGs for supplemental firing and to achieve peak output. The project also includes three mechanical draft cooling towers, an emergency (~~gas-fired~~ diesel-fired) generator and a diesel fire pump. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated January 31, 2001, accompanying the Department's Intent to Issue.

   Basis for Revision:
   Applicant request.

2. Change lower range of CTG load from 70% to 60%, add requested low load CO BACT limits, and correct wastewater cooling tower drift loss rate on BD-1 as follows:

   The application was received on December 5, 2000 and included a proposed BACT proposal prepared by the applicant's consultant, Environmental Consulting & Technology, Inc (ECT). The proposal is summarized in the table below (MW loads are assumed to be at ~~70%~~ 60% or higher unless otherwise noted).

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 9 ppmvd Ammonia Slip
SO_2 / SAM	Pipeline Natural Gas	1.5 grains S / 100 scf
CO	Pipeline Natural Gas Good Combustion	10 ppmvd 15.6 ppmvd with Duct Burners on (DB) 25 ppmvd during power augmentation (PA) 38.5 ppmvd during DB plus PA 50.0 ppmvd at 60% to 70% load w/o DB or PA
VOC	Pipeline Natural Gas Good Combustion	1.2 ppmvd 6.6 ppmvd during DB plus PA
NO_X	DLN & SCR	3.5 ppmvd @ 15% O_2
PM (Main cooling towers; N & S)	High efficiency drift eliminators	0.002% drift loss
PM (Wastewater cooling tower)	High efficiency drift eliminators	~~0.005%~~ 0.0005% drift loss

   Basis for Revision:
   Applicant request.

3. Clarify duct burner capacity on BD-5 as follows:

   Figure A (below) is an example of an in-line duct burner arrangement. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Furthermore the duct burner size is only 260 MMBtu/hr (LHV) compared with the turbine that can accommodate a heat input greater than 1700 MMBtu/hr (LHV). The duct burner will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

   Basis for Revision:
   Applicant request.

4. Correct control technology description on BD-7 as follows:

   Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. Certain manufacturers, such as Engelhard, market ~~an SCNR~~ a non-selective catalytic reduction (NSCR) control technology for NOX control within

the temperature ranges for which this project will operate (700 – 1400°F). However, the NSCR process also requires a low oxygen content in the exhaust stream in order to be effective. Given that a top-down review leads one to an SCR in this application, SNCR and NSCR do ~~does~~ not merit further consideration.

Basis for Revision:
Clarifies NO_x control technologies.

5. Comment on XONON™ technology on BD-8:

   The Department's discussion of XONON™ technology indicates that "The technology has been demonstrated on combustors on the same order of size as SCONOx™ has." SCONOx™ technology has been demonstrated on 32-MW combustion turbines. Calpine is not aware of any demonstration of the XONON™ technology on combustion turbines larger than 1.4 MW.

6. Change text on BD-9 as follows:

   The applicant has identified PM emissions of up to 107.9 TPY from the (main) fresh-water cooling towers, and an additional 5.7 TPY of PM emissions from the wastewater-cooling tower. Accordingly, drift eliminators shall be installed on all three cooling towers to reduce PM/PM10. The drift eliminators shall be designed and maintained to reduce drift to 0.002 percent of the circulating water flow rate for the main cooling towers and ~~0.005~~ 0.0005 percent for the wastewater cooling tower. No PM testing is required because the Department's Emission Monitoring Section has determined that there is no appropriate PM test method for these types of cooling towers.

   Basis for Revision:
   Corrects drift loss rate for wastewater cooling tower.

7. CO concentration for Case 20 on BD-9:

   The Department uses a value of 33.4 ppmvd @ 15% O_2 for Case 20 (100% load, 95°F ambient air temperature, evaporative cooling, steam power augmentation, and duct burner firing) mode of operation. As indicated in the submitted permit application, this operating mode results in a calculated CO exhaust concentration of 38.5 ppmvd @ 15% O_2. The CO exhaust concentration of 38.5 ppmvd @ 15% O_2 was calculated based on a CO mass emission rate of 177.3 lb/hr and exhaust flow rate of 1,056,308 ft^3/min, dry corrected to 68°F and 15% O_2. The capacity of the duct burner for the Blue Heron Energy Center Project (260 MMBtu/hr, LHV) is slightly larger than the one planned for the Calpine Osprey Energy Center (250 MMBtu/hr, LHV).

Use of the 38.5 ppmvd @ 15% O_2 concentration results in a CO limit of 17.4 ppmvd, which remains the same as the Department's value of 17 ppmvd.

Suggested revision to text on BD-9 are is follows:

(b) 17 ppmvd based upon a 24-hour block average {rationale: 10 ppmvd x 16/24 hours plus 15.6 ppmvd x 2/24 hours plus 25 ppmvd x 2/24 hours plus ~~33.4~~[1] 38.5 ppmvd x 2/24 hours plus 50 ppmvd x 2/24 hours}
[1]~~Note: Value lowered for consistency with Calpine's Osprey Energy Center.~~

Basis for Revision:
Corrects CO concentration for Case 20 conditions.

8. Proposed BACT limits on BD-10:

The Department proposes an ammonia slip rate of 5 ppmvd. Calpine notes that there have been a number of recent BACT determinations nationally which allow up to 10 ppmvd ammonia slip. The ammonia slip limit issued by the Department for the Calpine Osprey Project is 9.0 ppmvd. It is therefore requested that the Department reconsider Calpine's request for a 9 ppmvd ammonia slip emission limit.

The proposed BACT limits for VOC include two operating modes: (a) 100% load with the duct burner off [1.2 ppmvd VOC], and (b) 100% load with the duct burner on and with steam power augmentation [6.6 ppmvd VOC]. As noted in the permit application, permit limits are also requested for two additional cases: (a) 100% load with the duct burner on [3.4 ppmvd VOC], an (b) 60% – 70% load with out duct burner firing or steam power augmentation [3.0 ppmvd VOC].

The proposed BACT limits for CO include limits of 10 ppmvd and 43 lb/hr for operating modes without duct burner firing or steam power augmentation. As noted in the permit application, the maximum CO mass emission rate for this operating mode is projected to be 46 lb/hr at 20°F ambient temperature.

The proposed BACT limits for NO_x include a separate limit of 0.1 lb/MW-hr for the duct burners. Calpine requests deletion of the separate NO_x BACT limit for the duct burners as a redundant limit since the 3.5 ppmvd and 31.9 lb/hr BACT NO_x limits include duct burner operations. The recent revisions to NSPS Subpart Da allow for testing at the HRSG outlet stack (with both the CTG and duct burner operating) to demonstrate duct burner compliance with Subpart Da; reference the April 10, 2001 Federal Register. Having a separate BACT limit for the duct burner would eliminate this testing option.

Drift loss rate for the wastewater tower should be shown as 0.0005 percent.

Requested changes to the Department BACT Determination are as follows:

POLLUTANT	CONTROL TECHNOLOGY	BACT DETERMINATION
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion Inlet Air Filtering	10 Percent Opacity 26.0 lb/hr during DB plus PA ~~5~~ 9 ppmvd Ammonia Slip
SO_2 / SAM	Pipeline Natural Gas	1.5 grains S / 100 scf
VOC	Pipeline Natural Gas Good Combustion	1.2 ppmvd 6.6 ppmvd during DB plus PA 3.4 ppmvd with DB and w/o PA 3.0 ppmvd at 60-70% loads w/o DB and PA
CO	Pipeline Natural Gas Good Combustion	10 ppmvd – 24 hour block average, or 17 ppmvd – 24 hour block average; and 10 ppmvd and ~~43~~ 46 lb/hr w/o DB plus PA
NO_X (all operating modes)	DLN & SCR	3.5 ppmvd (SCR) – 3 hour block average ~~DB limited to 0.1 lb/MW-hr~~ 31.9 lb/hr during DB plus PA ~~5~~ 9 ppm ammonia slip
PM (Main cooling towers; N & S)	High efficiency drift eliminators	0.002% drift loss
PM (Wastewater cooling tower)	High efficiency drift eliminators	~~0.005%~~ 0.0005% drift loss

Basis for Revision:
Applicant request.

9. Proposed Compliance Procedures on BD-11:

   Calpine requests addition of Reference Test Methods 5B and 17 to the list of available methods for initial PM testing. Requested changes are as follows:

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
PM/Visible Emissions	Methods 5, 5B, or 17 (initial test only) and Method 9 (annually)
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	CEMS plus annual method 10 during operation at capacity without use of duct burners and power augmentation
NO_X 3-hr block average	NO_X CEMS, O_2 or CO_2 diluent monitor, and exhaust flow monitor~~device~~ as needed
NO_X (performance)	Annual Method 20 or 7E
Ammonia Slip	CTM-027 initial and annual (The test and analyses shall be conducted so that the minimum detection limit is 1 ppmvd)

Basis for Revision:
Applicant request.

Requested revisions to the BACT Determination have also been sent via electronic mail (file: BH BACT – Calpine Comments.doc).

C. Draft PSD Permit

1. Facility Description, Page 2 of 14

   Delete reference to emergency diesel engines since these emission sources are exempt from Chapter 62-212 permitting pursuant to Rule 62-210.300(3(a)21., F.A.C. Suggest changing emission unit description of Emission Units 001 through 004 as follows:

This permit addresses the following emissions units:

EMISSIONS UNIT	SYSTEM	Emission Unit Description
001	Power Generation	~~One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator~~ One nominal 170 Megawatt Combustion Turbine Generator/Heat Recovery Steam Generator Unit. EU 001 and EU 002 and one, common nominal 200 Megawatt Steam Turbine Electrical Generator comprise one nominal 540 Megawatt Combined Cycle Power Generation System.
002	Power Generation	~~One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator~~ One nominal 170 Megawatt Combustion Turbine Generator/Heat Recovery Steam Generator Unit. EU 001 and EU 002 and one, common nominal 200 Megawatt Steam Turbine Electrical Generator comprise one nominal 540 Megawatt Combined Cycle Power Generation System.
003	Power Generation	~~One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator~~ One nominal 170 Megawatt Combustion Turbine Generator/Heat Recovery Steam Generator Unit. EU 003 and EU 004 and one, common nominal 200 Megawatt Steam Turbine Electrical Generator comprise one nominal 540 Megawatt Combined Cycle Power Generation System.
004	Power Generation	~~One nominal 270 Megawatt Combined Cycle Gas Combustion Turbine/HRSG Electrical Generator~~ One nominal 170 Megawatt Combustion Turbine Generator/Heat Recovery Steam Generator Unit. EU 003 and EU 003 and one, common nominal 200 Megawatt Steam Turbine Electrical Generator comprise one nominal 540 Megawatt Combined Cycle Power Generation System.

005	Water Cooling	North Main Fresh Water Cooling Tower
006	Water Cooling	South Main Fresh Water Cooling Tower
007	Water Cooling	Wastewater Cooling Tower
~~xxx~~	~~Miscellaneous~~	~~Emergency Generator and Diesel Fire Pump~~

Basis for Revision:
Rule 62-210.300(3(a)21., F.A.C., applicant request.

2. Regulatory Classification, Page 3 of 14

   Project is subject to PSD review for sulfuric acid mist. Suggest revision to first paragraph as follows:

   This facility is within an industry (fossil fuel-fired steam electric plant) included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of SO_2 and NO_X, 25/15 TPY of PM/PM_{10}, 100 TPY of CO, 7 TPY of H_2SO_4, and 40 TPY of VOC's. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

   Basis for Revision:
   Table 62-212.400-1, F.A.C.

3. General and Administrative Requirements, Page 4 of 14

   Request deletion of Condition No. 7 language regarding future plant conversions and phased construction. The reference to future plant conversions is not applicable because the Blue Heron Energy Center combustion turbines will initially include HRSGs. Calpine also requests the addition of language regarding when a BACT reassessment will be required. Suggested revisions are as follows:

   BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21 (j) and 40 CFR 51.166(j), the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate ~~in the event of a plant conversion.~~ This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." A BACT reassessment will also be conducted for this

project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes that result in a significant net emissions increase. [40 CFR 52.21(j), 40 CFR 51.166(j) and Rule 62-4.070 F.A.C.]

Basis for Revision:
Deleted text is not applicable to the Blue Heron Energy Project. Allow for Department flexibility in determining whether a BACT reassessment will be required for project changes.

4. Applicable Standards and Regulations, Page 6 of 14

   Request revision of Condition No. 4 to clarify applicability of Subpart Da as follows:

   ARMS Emissions Units 001 through 004. Direct Power Generation, each consisting of a nominal 170 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). Additionally, each Emissions Unit consists of a supplementally-fired heat recovery steam generator equipped with a natural gas fired 260 MMBTU/hr duct burner (LHV) and combined with two each 200 MW steam electrical generators. These duct burners shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.

   Basis for Revision:
   Clarify NSPS Subpart Da applicability.

5. General Operation Requirements, Page 7 of 14

   Revise Condition No. 18. as follows:

   Drift eliminators shall be installed on the cooling towers to reduce PM/PM10 emissions. A manufacturer's certification following installation (and prior to startup) shall be submitted that the drift eliminators were installed and that the installation is capable of meeting 0.002 gallons/100 gallons recirculation water flowrate for the main towers and ~~0.005~~ 0.0005 gallons/100 gallons for the wastewater cooling tower.

   Basis for Revision:
   Clarify certification requirements, correct drift loss rate for the wastewater cooling tower.

6. General Operation Requirements, Page 7 of 14

   Section III of the draft permit does not include a Condition No. 19.

7. Emission Limits and Standards, Page 8 of 14

   Revise Condition No. 20. as follows:

   Nitrogen Oxides (NO_X) Emissions:

   The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating and the duct burner on or off, shall not exceed 3.5 ppmvd @15% O_2 on a ~~3-hr~~ 24-hour block average. This limit shall apply whether or not the unit is operating with duct burner on and/or in power augmentation mode. Compliance shall be determined by the continuous emission monitor (CEMS). [BACT Determination]

   The emissions of NO_X shall not exceed 31.9 lb/hr ~~(at 18°F ambient temperature)~~ per unit while operating in the power augmentation mode with the duct burner on, to be demonstrated by annual stack test. [BACT Determination]

   ~~Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS (see Specific Condition 29 for compliance procedures). [Applicant Request, Rule 62-4.070 and 62-204.800(7), F.A.C.]~~

   The concentration of ammonia in the exhaust gas from each CT/HRSG shall not exceed ~~5.0~~ 9.0 ppmvd @15% O_2. The compliance procedures are described in Specific Conditions 29 and 45. [BACT, Rules 62-212.400 and 62-4.070, F.A.C.]

   Basis for Revisions:
   Change averaging time to be consistent with Department PSD permit for the Osprey Energy Center.

   Delete reference to an ambient temperature with respect to mass emission rate to simplify annual stack testing procedures.

   Delete separate BACT emission limit for duct burners as a redundant limit since the 3.5 ppmvd and 31.9 lb/hr BACT NO_x limits include duct burner operations. The recent revisions to NSPS Subpart Da allow for testing at the HRSG outlet stack (with both the CTG and duct burner operating) to demonstrate duct burner compliance with Subpart Da; reference the April 10, 2001 Federal Register. Having a separate BACT limit for the duct burner would eliminate this testing option.

   Change ammonia slip limit to be consistent with the Department's Calpine Osprey Energy Center PSD permit.

8. Emission Limits and Standards, Page 8 of 14

   Revise Condition No. 21. as follows:

   Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas shall exceed neither 10 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS for those days when no valid hour includes the use of duct burner firing, power augmentation or 60-70% operation (otherwise, the limit is 17 ppmvd @15% O_2 on a 24-hr block average to be demonstrated by CEMS); and neither 10 ppmvd @15% O_2 nor ~~43~~ 46 lb/hr per unit at 100% output with the duct burner off and no power augmentation to be demonstrated by annual stack test using EPA Method 10 or through annual RATA testing. [BACT, Rule 62-212.400, F.A.C.]

   Basis for Revisions:
   The proposed BACT limits for CO include limits of 10 ppmvd and 43 lb/hr for operating modes without duct burner firing or steam power augmentation. As noted in the permit application, the maximum CO mass emission rate for this operating mode is projected to be 46 lb/hr at 20°F ambient temperature.

9. Emission Limits and Standards, Page 8 of 14

   Revise Condition No. 22. as follows:

   Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas ~~(baseload at ISO conditions)~~ with the combustion turbine operating on gas shall not exceed ~~neither~~: (a) 1.2 ppmvd @15% O_2 per unit, baseload with the duct burner off and without steam power augmentation, (b) 3.4 ppmvd @15% O_2 per unit, baseload with the duct burner on and without steam power augmentation, (c) 3.0 ppmvd @15% O_2 per unit between 60 and 70 percent load *with the duct burner off and without steam power augmentation, and* (d) ~~neither~~ 6.6 ppmvd @15% O_2 per unit, baseload with the duct burner on and operating in the power augmentation mode to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [BACT, Rule 62-212.400, F.A.C.]

   Basis for Revisions:
   Applicant request.

10. Emission Limits and Standards, Page 8 of 14

    Revise Condition No. 23. as follows:

    Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content not greater than 1.5 grains per 100 standard cubic foot). Compliance with this requirement in conjunction with implementation of the

Custom Fuel Monitoring Schedule in Specific Condition 42 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. Note: This will effectively limit the combined SO_2 emissions for EU-001 through EU-004 at ~~36.3~~ 145.0 tons per year. [BACT, 40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

Basis for Revisions:
Correction of annual SO_2 emission rate.

11. Excess Emissions, Page 9 of 14

Revise Condition No. 25. as follows:

Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to and shutdowns from combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. Operation below 60% output per turbine shall otherwise be limited to 2 hours in any 24-hour period, unless CO CEMS data demonstrates that the emission limits specified in Specific Condition No. 21. are being met. [Rule 62-210.700, F.A.C.].

Basis for Revisions:
Allows for operation below 60% load if BACT CO emission limits, confirmed by CO CEMS data, are not exceeded.

12. Excess Emissions, Page 9 of 14

Revise Condition No. 26. as follows:

Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the ~~3-hr~~ 24-hr average for NO_X and the 24-hr average for CO.

Basis for Revisions:
Applicant request.

13. Excess Emissions, Page 9 of 14

Revise Condition No. 27. as follows:

Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, and using the monitoring methods listed in Specific Conditions 40 through 45, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 20 and 21 ~~through 24~~. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

Basis for Revisions:
Specific Conditions Nos. 22, 23, and 24 address VOC, SO_2, and PM/PM_{10} emission rates, respectively. Stack testing for VOC, SO_2, and PM/PM_{10} emission rates is not required nor practical during startups, shutdowns, and malfunctions.

14. Compliance Determination, Page 10 of 14

Revise Condition No. 29. as follows:

EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (EPA Reference method 10 or RATA test data may be used to demonstrate compliance for annual test requirement) (I, A)

EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines" (EPA reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" or RATA test data may be used to demonstrate compliance for annual test requirement); Initial test for compliance with 40CFR60 Subpart GG; Initial (only) NO_X compliance test for the duct burners (Subpart Da) shall be accomplished in accordance with the testing procedures specified in Subpart Da ~~via testing with duct burners "on" as compared to "off" and computing the difference~~.

Basis for Revisions:
Allows use of RATA for CO testing and for duct burner testing as specified in the April 10, 2001 Federal Register revisions to NSPS Subpart Da.

15. Compliance Determination, Page 10 of 14

Revise Condition No. 32. as follows:

Compliance with CO emission limit: An initial and annual test for CO shall be conducted at 100% capacity with the duct burners off and without steam power augmentation. The NO_X and CO test results shall be the average of three valid one-hour runs. Annual RATA testing for the CO and NO_X CEMS shall be required pursuant to 40 CFR 75. (EPA Reference method 10 or RATA test data may be used to demonstrate compliance for annual test requirement)

Basis for Revisions:
Makes testing basis consistent with Specific Condition No. 21. CO emission limit.

16. Monitoring Requirements, Page 11 of 14

Revise Condition No. 40. to include option for an oxygen (O_2) diluent monitor as an alternative to a carbon dioxide (CO_2) diluent monitor and a 24-hour block average for NO_x. Delete total limit of 4 hours per day for all startups, shutdowns, and malfunctions since this would prohibit a cold startup and any other startup or shutdown from occurring in the same 24-hour period.

Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the emissions of NO_x and CO from these emissions units, and the Oxygen (O_2) or Carbon Dioxide (CO2) content of the flue gas at the location where NO_x and CO are monitored, in a manner sufficient to demonstrate compliance with the emission limits of this permit. The CEM system shall be used to demonstrate compliance with the emission limits for NO_x and CO established in this permit. ~~Compliance with the emission limits for NO_x shall be based on a 3-hour block average. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values.~~ Compliance with the emission limits for CO and NO_x shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average shall be calculated from 24 consecutive hourly average emission rate values. Each hourly value shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour. If the CEM system measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a

dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEM system shall be expressed as ppmvd, corrected to 15% oxygen.

The NO_x monitor shall be certified and operated in accordance with the following requirements. The NO_x monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of 40 CFR Part 75, Subparts B and C. For purposes of determining compliance with the emission limits specified within this permit, missing data shall not be substituted. Instead the block average shall be determined using the remaining hourly data in the 24 hour block. Record keeping and reporting shall be conducted pursuant to 40 CFR Part 75, Subparts F and G. The RATA tests required for the NO_x monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_x monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

The CO monitor and O_2 or CO_2 monitor shall be certified and operated in accordance with the following requirements. The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. The O_2 or CO_2 monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 3. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of section 7 shall be made each calendar quarter, and reported semi-annually to the Department's Central District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 20 ppm, and the span for the upper range shall not be greater than 100 ppm, as corrected to 15% O_2. The RATA tests required for the O_2 or CO_2 monitor shall be performed using EPA Method 3B, of Appendix A of 40 CFR 60.

NO_x, CO and O_2 or CO_2 emissions data shall be recorded by the CEM system during episodes of startup, shutdown and malfunction. NO_x and CO emissions data recorded during these episodes may be excluded from the block average calculated to demonstrate compliance with the emission limits specified within this permit. Periods of data excluded for startup shall not exceed two hours in any block 24-hour period except for "cold startup." A cold startup is defined as a startup following a complete shutdown lasting a minimum of 48 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period. Periods of data excluded for shutdown shall not exceed two hours in any

24 hour block period. Periods of data excluded for malfunctions shall not exceed two hours in any 24-hour block period. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. ~~Periods of data excluded for all startup, shutdown or malfunction episodes shall not exceed four hours in any 24-hour block period.~~ The owner or operator shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented.

Best operational practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown and malfunction. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

A summary report of duration of data excluded from the block average calculation, and all instances of missing data from monitor downtime, shall be reported to the Department's Central District office semi-annually, and shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined as the hourly emissions which are recorded by the CEM system during periods of data excluded for episodes of startup, shutdown and malfunction, allowed above. The duration of excess emissions shall be the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than semi-annually, including semi-annual periods in which no data is excluded or no instances of missing data occur.

Upon request from the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

Basis for Revisions:
40 CFR Part 75.10(a)(2) specifies that either an O_2 or CO_2 diluent monitor may be used with a NO_x CEMS. Appendix G of 40 CFR Part 75 provides an optional alternative procedure for determining CO_2 emissions in lieu of a CO_2 CEMS monitoring. Requested NO_x averaging time is consistent with Department PSD permit for the Osprey Energy Center. Enable flexibility in plant operations by allowing for a cold startup and a shutdown or any other startup to occur within the same 24 hour period.

Requested revisions to the Draft Permit have also been sent via electronic mail (file: BH PERMIT – Calpine Comments.doc).