Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

October 4, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Bernie Cumbie, Plant Manager
Crystal River Power Plant
Progress Energy Florida, Inc.
100 Central Avenue, CN77
St. Petersburg, Florida 33701

Re: Request for Additional Information
Project No. 0170004-016-AC (PSD-FL-383)
Flue Gas Desulfurization Project

Dear Mr. Cumbie:

On September 5, 2006, the Department received your application for an air construction permit regarding the following projects for Units 4 and 5 at the existing Crystal River Power Plant: install low-NOx burners, add flue gas desulfurization systems, add alkali injection systems, upgrade the existing electrostatic precipitator, add a carbon burnout unit, authorize additional coal blends (Powder River Basin Coal and petroleum coke), revise the specified maximum heat input rate from 6665 to 7200 MMBtu/hour, and authorize a fuel additive. The project is subject to PSD review for emissions of carbon monoxide, particulate matter, sulfuric acid mist, and volatile organic compounds. 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 items below require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

Potential and Baseline Emissions

1. For Units 4 and 5, the application identifies the potential emissions as well as the allowable and baseline emissions. In the application pages (Field 3), potential annual emissions are calculated based on an 85% capacity factor for each unit. To be used in the calculation of potential emissions, the annual capacity factor must be federally enforceable. Is the application requesting a federally-enforceable restriction on the annual capacity factor or an equivalent limit on the annual heat input rate? If so, then the pollutant is "synthetically limited" and Field 4 should be changed to "yes". Please comment and revise as necessary. (See Section F of the application for Units 4 and 5.)

2. Please check Tables A-1 through A-10. It appears that baseline PM_{10} emissions have been estimated as 67% of the total baseline PM emissions; however, the notes on several tables indicate that PM_{10} emissions are assumed to be equal to PM emissions. In addition, the emission factor for baseline SAM emissions is shown as 0.001 lb/MMBtu. What is the reference for this factor? The SAM Engineering Study in Appendix A-1 suggests an actual emissions factor of: (18.7 lb/hour) (hour/6845 MMBtu) = 0.0027 lb/MMBtu. Please explain the difference.

Low-NOx Burners (LNB)

3. The burner specifications identify the maximum heat input rate as 6800 MMBtu per hour based on the maximum coal firing rate (MCR). The application requests a maximum heat input rate of 7200 MMBtu per hour. Please explain the difference and identify the maximum heat input rate for any 1-hour period. In addition, the performance guarantees in the LNB specifications identify the following: maximum NOx emissions of 0.41 lb/MMBtu, maximum CO emissions of 200 ppm, excess oxygen levels of not less than 2/5% (dry volumetric), and unburned carbon in the fly ash of no greater than 5%. Identify the CO emissions guarantee in terms of lb/MMBtu and show the conversion noting any assumptions. (See Appendix B-2, page SP-168301-6.)

4. The PSD report indicates that recent CO BACT determinations for new units range from 0.1 to 0.2 lb/MMBtu, with a median average of 0.15 lb/MMBtu. Because the project includes the installation of new burners, please explain why

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Mr. Bernie Cumbie, Plant Manager
Progress Energy Florida
Crystal River Units 1&2
100 Central Avenue CN77
St. Petersburg, Florida 33701

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Mr. Bernie Cumbie, Plant Manager
Progress Energy Florida
Crystal River Units 1&2
100 Central Avenue CN77
St. Petersburg, Florida 33701

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new burners cannot be selected to achieve CO emission levels comparable to the lower range of the recent BACT determinations. (See Section 4.3.1.3.)

5. The PSD report includes the following statement regarding CO/VOC emissions, "... the overall mass emission rate is relatively constant over the entire boiler range from initial startup to full load. Therefore, the allowable emission limit representing BACT should reflect the constant mass output equal to a full load emission rate of 7200 MMBtu/hr per unit." Tables 2-2 and 2-3 do not appear to support this statement. Please explain and provide supporting information. (See Section 4.3.1.3.)

Wet Electrostatic Precipitator (WESP) / Alkali Injection Systems

6. In general, the cost estimates follow the recommendations of EPA's OAQPS Cost Manual. Please provide supporting information for: the $80 million purchased equipment cost for the WESP; and the $2.4 million engineering estimate for "maintenance materials" in the direct annual operating costs. The OAQPS Cost Manual (Section 3.4.1.2 Operating Materials) states, "Operating materials are generally not required for ESPs. An exception is the use of gas preconditioning agents for dust resistivity control." Please explain the costs associated with this estimate or revise the cost estimate accordingly.

7. If a WESP were installed, there would be a co-environmental benefit of additional particulate matter removal as stated in Section 4.3.3.2. Please quantify the reductions in particulate matter and revise the cost effectiveness calculation to include both the removal of SAM and particulate matter.

8. In Appendix B, Table B-1 summarizes the SAM emissions at various points in the systems being evaluated. In the row identified as "ESP (Ammonia Injection and ash)", there is a 23% reduction for the WESP. Please identify the mechanism for this reduction. Should this reduction also be applied to the case for ammonia injection?

9. Provide a list of similar recent projects that were subject to BACT determinations for SAM emissions. What are the BACT limits and effective control efficiencies for these projects? The application proposes 0.012 lb/MMBtu as BACT for SAM emissions based on 85% reduction with alkali injection. However, the application also indicates that the proposed alkali injection system could achieve 90% reductions when "new and clean", but 85% was proposed due to equipment degradation such as plugged nozzles. This appears to be a maintenance issue. Please discuss.

10. Describe the types of mist eliminators that will be included with the FGD systems. Can this design be improved to capture more than 30% control for the remaining SAM emissions? Provide supporting information.

Electrostatic Precipitator (ESP) Upgrades

11. Based on the best available information, please provide PM_{10} emission rate estimates for Units 4 and 5. In the application, do the particulate matter emissions rates reflect "condensables"? If not, please revise to include condensables. Also, provide PM_{10} emissions data collected for any of the units at the Crystal River Plant.

12. The application indicates that the ESP will be rebuilt to a top-rapping unit, which will increase the collection area by approximately 10%. The design removal efficiency will increase from 99.82% to 99.91%. As BACT, the application proposes to reduce the current permit limit from 0.1 lb/MMBtu to of 0.03 lb/MMBtu based on the rebuilt ESP. Current ESP designs can achieve emissions rates below 0.01 lb/MMBtu. For Units 4 and 5, the Department's database generally shows tested emission rates below approximately 0.02 lb/MMBtu. With improvements to the existing ESP, it is reasonable to expect that performance will improve. For the previous 5 years of operation, provide the following information for Units 4 and 5: actual emissions rates (normal and soot blow) determined by stack testing; heat input rates during tests; and the number of active ESP fields during the test. Describe any operational or physical changes during this period that could have impacted emissions (i.e., fuel changes, ESP improvements, etc.).

13. For a recent coal project, EPA Region 4 provided the following comment, "The draft permit does not require use of a PM CEMS to assess compliance with the filterable PM/PM_{10} emissions limit. Since a PM CEMS can be used with a wet plume, we recommend that a PM CEMS be required to demonstrate compliance with the filterables limit." Please discuss the installation of a PM CEMS for this project. Identify units at other Progress Energy facilities (including other states) that include PM CEMS.

14. Recent BACT determinations for units controlled by ESPs include opacity standards of 10%. What are the actual opacity levels for Units 4 and 5 using the existing ESPs?

New Carbon Burnout (CBO) Unit

15. The application indicates that the maximum heat input rate for the CBO unit is 95 MMBtu per hour. The Department understands that the proposed CBO unit is a Model 1500 with a bed size of 1500 square feet. Please verify. Will the exhaust from the CBO unit be ducted to a dedicated stack (Unit 4 or 5) or be ducted to both stacks (Units 4 and 5)? Please explain and provide a process flow diagram.

16. In a November 10, 2003 memorandum, EPA Region 4 indicates a similar CBO unit is subject to NSPS Subpart Dc, which requires at least continuous fuel monitoring and reporting. Please comment and update the application as necessary. The document also indicates that addition of the CBO unit is a physical change of the existing coal-fired units. Please provide supporting details to show that the physical change is not a "modification" as defined by the NSPS provisions.

17. In Section 4.2 of the PSD report, the application indicates that the proposed project does not constitute a modification to existing Units 4 and 5, which are subject to NSPS Subpart D. However, in a January 20, 2006 memorandum regarding Tampa Electric Company's Big Bend Carbon Burnout Project, EPA Region 4, states, "The opinion of the Region 4 Air Permits Section is that the fluidized bed combustor within the carbon burnout project can be viewed as a physical change of the existing Big Bend Units 3 and 4 subject to the additional considerations below. Units 3 and 4 meet the regulatory definition of an electric utility steam generating unit (EUSGU)." Provide supporting information to show that the project will not result in a "modification" with regard to the applicable NSPS Subpart D provisions.

Alternate Fuel Blends – Powder River Basin (PRB) Coal and Petroleum Coke

18. In Air Permit No. 0170004-012-AC, the Department authorized a temporary trial burn of the current bituminous coal with up to 30% Powder River Basin (PRB) sub-bituminous coal by weight. As the application indicates, the coal blend actually tested during the trial burn consisted of only 18% PRB coal by weight. Tests showed increased CO emissions and marginal impacts for other pollutants. Is authorization for PRB requested immediately or after installation of the SCR, FGD, alkali injection systems, and ESP improvements? Would the requested coal blend be fired in any other units? How would the coal blends be separated?

19. The application requests authorization to fire a coal blend of up to 30% petroleum coke by weight with a maximum sulfur content of 6% for the petroleum coke. Will petroleum coke be blended with PRB coal? Will petroleum coke be blended with blends of bituminous coal/PRB coal? At what rates? Is authorization for a coal blend with petroleum coke requested immediately or after installation of the SCR, FGD, alkali injection systems, and ESP improvements? Would the requested coal blend be fired in any other units at the plant? If not, how would the coal blends be separated? The Department may require a temporary trial burn to gather emissions and operational data. Please comment.

Request to Revise the Maximum Heat input Rate from 6665 to 7200 MMBtu/hour

20. The application requests an 8% increase in the maximum heat input rate from 6665 MMBtu per hour to 7200 MMBtu per hour. The application indicates that Units 4 and 5 have always been capable of achieving the requested value, but did not pursue a change to the maximum heat input rate specified in the Title V permit because of the current permitting note. Progress Energy understood that the permitting note was originally included not as a continuous limit, but to ensure that testing was conducted at, "... the worst case (maximum) operating levels."

    a. During the original Title V permitting process, EPA objected to several proposed utility permits because the unit capacity had not been identified. As mentioned, the issue was resolved by applicants identifying "... the worst case (maximum) operating levels ..." under which emissions testing would occur. Describe the method Progress Energy used for Units 4 and 5 to identify the "maximum" operating levels for the 3-hour emissions tests.

    b. Does Progress Energy consider the request to identify a higher heat input rate as an "increase on paper" only? Because of the many changes (burners, fuels, etc.) requested, it is important to document the current capabilities of the existing units. Based on fuel feed rate and fuel analysis method requested, provide five actual operating data sets for Units 4 and 5 over the last 5 years showing continuous operation at 6800 MMBtu per hour (at least 24-hours) and peak operation at 7200 MMBtu per hour (at least 1-hour). For Units 4 and 5, provide the original "contract data sheets" indicating the boiler, fuel, and operating specifications.

Air Quality Modeling Analysis

21. Currently, Units 4 and 5 are limited by NSPS Subpart D to an SO_2 emissions standard of 1.2 lb/MMBtu based on any 3-hour average. The application requests an allowable emissions limit for SO_2 of 0.27 lb/MMBtu based on a 30-day

rolling average. Please provide a table of the maximum SO_2 emission rates (lb/hour, lb/MMBtu and grams/second) used in the air quality modeling analyses for each averaging period (3-hour, 24-hour, and annual). Show how these emissions rates were calculated. Short term emissions limits may be necessary to ensure compliance with the PSD increments and ambient air quality standards.

22. The electronic modeling files were not included with the application, but were received on September 28, 2006 (AERMOD) and October 3, 2006 (CALPUFF). Therefore, the Department will request additional information regarding the air quality modeling before November 2, 2006.

Miscellaneous

23. The application indicates that a process flow diagram is provided in Figure 2-1; however, this is a site plan. Provide a detailed process flow diagram for each unit identifying the boiler and equipment, fuel feeds, pollution controls, injection points, CBO unit, stacks, CEMS, exhausts, and solid/liquid discharges. (See Field 1 in Section I of the application form.)

24. The application requests authorization to use a fuel additive to improve unit performance and reduce emissions as well as LOI. The Department intends to allow for a temporary trial period to conduct tests to validate emissions impacts. Please comment.

25. The application proposes to install a new stack with two liners having a larger exit diameter, which will decrease the exhaust velocity and is intended to reduce stack rain-out. Will the existing stacks remain or be dismantled? Is there any scenario where the existing stacks would be used as bypass stacks? Will new CEMS be installed or will the existing CEMS be removed from the existing stacks and installed/certified on the new stack/liners? If so, describe how the CEMS will be modified to monitor the lower emissions levels.

26. In the portion of the application regarding burner specifications, it is stated that natural gas in not available at the site. Page 18 of the emissions unit section identifies natural gas as an available fuel and the Title V permit identifies natural gas as a startup fuel. Is natural gas available at this site? Is natural gas fired in Units 4 and 5? (See Appendix B-2, pages SP-168301-5 and 6.)

27. Section F of the application indicates a 5-year monitoring period for SO_2, but the PSD report indicates that NOx and SO_2 emissions will be reported for a 10-year period. The Department agrees that a 10-year reporting period is required. Please correct as necessary.

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. For any material changes to the application, please include a new certification statement by the authorized representative or responsible official. You are reminded that Rule 62-4.055(1), F.A.C. requires applicants to respond to requests for information within 90 days or provide a written request for an additional period of time to submit the information.

If you have any questions regarding this matter, please call me at 850/921-9536.

Sincerely,

Jeffery F. Koerner, P.E.
BAR - Air Permitting North

On October 4, 2006, this request for additional information was sent by electronic mail to the following parties:

Mr. Bernie Cumbie, Progress Energy Florida, Inc. (BERNIE.CUMBIE@PGNMAIL.COM)
Mr. Dave Meyer, Progress Energy Florida, Inc. (DAVE.MEYER@PGNMAIL.COM)
Mr. Scott Osbourn, Golder Associates Inc. (SOSBOURN@GOLDER.COM)
Ms. Mara Nasca, SWD Office (MARA.NASCA@DEP.STATE.FL.US)
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