May 20, 2004

**CERTIFIED MAIL- RETURN RECEIPT REQUESTED**

Mr. M. A. Daigle, Vice President
IMC Phosphates Company
PO Box 2000
Mulberry, FL 33860

Re: Title V Renewal Request for Additional information dated April 21, 2004
Reference Permit No. 1050055-014-AV
South Pierce Facility

Dear Mr. Daigle:

On April 22, 2004, the Department received additional information for your Title V air permit application to renew your existing permit. In order to continue processing the application, the Department will need the following additional information, in addition to information that was previously requested in our letter dated November 21, 2003:

1. Emission Unit Information. You indicated in your response that Emission Units (EUs) #002, 003, 012-014, 016, 017, 027-029, 034, 044-046 have been shut down and will no longer operate at the facility. However, EUs # 034, 045, and 046 were included in the September 26, 2003 application. Please verify that you no longer want to have these units included in the renewal permit, and provide shutdown dates on each unit. Please also provide the shutdown dates for units EUs # 003, 012, 013, 014, 027, 028, and 029.

2. Maximum Achievable Control Technology (MACT) applicability. Your facility maintains it is not a major source of hazardous air pollutants. Please provide the annual amount of hazardous air pollutants emissions from the site. In particular, please quantify the annual amount of HF emissions coming from the gypsum and cooling ponds located on the property. Please provide the fluoride concentrations and pH values of the ponds, and the total acres of pond water. If applicable, please also provide information concerning the closure of these ponds.

3. Compliance Assurance Monitoring (CAM). In your April 21, 2004 response, you propose CAM as meeting the requirements for Facility Wide Condition 14. This is not acceptable. You will need to specify maximum and minimum pressure drop and flow rate for each of the units that are subject to CAM. Also, in order to satisfy the CAM submittal requirements and to approve the previously submitted CAM plans, please submit the following information that was previously requested in our letter dated November 21, 2003:

KOOGLER & ASSOCIATES
ENVIRONMENTAL SERVICES
4014 NW THIRTEENTH STREET
GAINESVILLE, FLORIDA 32609
352/377-5822 ▪ FAX/377-7158

KA 124-03-07

July 8, 2004

RECEIVED
JUL 12 2004
BUREAU OF AIR REGULATION

Mr. Bobby Bull
Florida Department of
Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Additional Information on Title V Permit Renewal
IMC Phosphates Company – South Pierce Plant
File No. 1050055-014-AV

Dear Mr. Bull:

This is a follow up to the Department's letter dated May 20, 2004, requesting additional information on the above referenced Title V renewal project. The responses are in the order of the issues raised by FDEP.

1. **<u>Emission Unit Information.</u> You indicated in your response that Emission Units (EUs) #002, 003, 012-014, 016, 017, 027-029, 034, 044-046 have been shut down and will no longer operate at the facility. However, EUs # 034, 045, and 046 were included in the September 26, 2003 application. Please verify that you no longer want to have these units included in the renewal permit, and provide shutdown dates on each unit. Please also provide the shutdown dates for units EUs # 003, 012, 013, 014, 027, 028, and 029.**

<u>RESPONSE:</u>

The units identified will no longer be operated at the facility. The units were shutdown as indicated below:

| | |
|---|---|
| EUs. 002, 003, 012, 013, 014, 016, 017, 027, 028, 029 & 046: | in 1995 |
| EUs. 034, 044 & 045: | in or before 1992 |

2. **<u>Maximum Achievable Control Technology (MACT) applicability</u>. Your facility maintains it is not a major source of hazardous air pollutants. Please provide the annual amount of hazardous air pollutants emissions from the site. In particular, please quantify the annual amount of HF emissions**

**coming from the gypsum and cooling ponds located on the property. Please provide the fluoride concentrations and pH values of the ponds, and the total acres of pond water. If applicable, please also provide information concerning the closure of these ponds.**

RESPONSE:

The facility is a minor source of HAP emissions based on the estimates presented in Attachment 1.

3. **Compliance Assurance Monitoring (CAM). In your April 21, 2004 response, you propose CAM as meeting the requirements for Facility Wide Condition 14. This is not acceptable. You will need to specify maximum and minimum pressure drop and flow rate for each of the units that are subject to CAM. Also, in order to satisfy the CAM submittal requirements and to approve the previously submitted CAM plans, please submit the following information that was previously requested in our letter dated November 21, 2003:**

**A. Phosphoric Acid Plant- A and B Train (EU 008 & 009). CAM is applicable for fluoride. The choice of scrubber pressure drop and liquid flow rate through the scrubber are acceptable indicators to monitor. However, indicator ranges must be clearly stated in the monitoring approach table. The selection of the indicator ranges must also be clearly justified and demonstrate that operation at those levels is protective of the allowable emissions limitations. The stated indicator range is non-specific and is equivalent to the permit conditions. Using these as CAM indicator ranges will result in a permit violation every time that a CAM excursion is recorded. Please provide a table of test data that correlates the pressure differentials and flow rates to the tested fluoride emission levels. From this data, provide a justification of your choices and clearly indicate a maximum and minimum pressure drop and water flow rate that will assure compliance with the emission limit.**

RESPONSE:

The requested information for the Phosphoric Acid Plants is presented in Attachment 2. Results of testing conducted in 1996, to establish a scrubber flow rate minimum of 1200 gpm for each of the systems, are also included.

**B. No. 2 Ball Mill Grinding System (EU 022). CAM is applicable for PM. The choice of pressure drop across the baghouse is an acceptable indicator to monitor. Please identify a minimum pressure drop across the baghouse that can be used as an indicator in addition to the 15" maximum pressure drop listed. Please provide a table of test data that correlates the pressure drop to the tested**

**PM emission levels. From this data, provide a justification of your choices and clearly indicate a maximum and minimum pressure drop that will assure compliance with the emission limit.**

RESPONSE:

The compliance testing routinely conducted for the bag collector consisted of Visible Emission Evaluations. A particulate matter emission test was conducted prior to the Title V permit renewal process. Based on past VE observations, it is likely that the mass emissions are low in this application. It can be assumed that if the bag collector is in compliance with the visible emissions limit, it will be in compliance with the mass emission limit. Available compliance testing information is presented in Attachment 3.

**C. GTSP Production Plant (EU 023). CAM is applicable for PM and fluoride. The choice of scrubber pressure drop and liquid flow rate through the scrubbers are acceptable indicators to monitor. However, indicator ranges must be clearly stated in the monitoring approach table. The selection of the indicator ranges must also be clearly justified and demonstrate that operation at those levels is protective of the allowable emissions limitations. The stated indicator ranges are non-specific and are equivalent to the permit conditions. Using these as CAM indicator ranges will result in a permit violation every time that a CAM excursion is recorded. Please provide a table of test data that correlates the pressure differentials and flow rates to the tested PM and fluoride emission levels. From this data, provide a justification of your choices and clearly indicate a maximum and minimum pressure drop and water flow rate for each of the scrubbers that will assure compliance with the emission limits.**

RESPONSE:

A summary of the test data for the GTSP Plant is presented in Attachment 4. The scrubbing system consists of two parallel venturi scrubbers followed by a packed scrubber, in series. The summary of test data includes each of these scrubber systems.

**D. GTSP East Storage Building (EU 024 and 025). CAM is applicable for PM and fluoride. The choice of fan amperage as an indicator range may be acceptable if a specific range is specified that can be justified by test data. If not, scrubber pressure drop and scrubber water flow might be more appropriate. Please provide a table of test data that correlates the chosen indicator range(s) to the tested fluoride and PM emission levels. From this data, provide a justification of your choices and clearly indicate specific indicator ranges that will assure compliance with the emission limits.**

RESPONSE:

A summary of the test data for the GTSP Storage Building is presented in Attachment 5. The emissions are controlled by two parallel scrubber systems consisting of two wet cyclonic scrubbers each. Thus, there are four scrubbers with two stacks. Although each of the stacks (and associated scrubber systems) are identified as the emission units by the permit, the emission limit is applied to the building which requires that compliance be determined based on the total of the emissions from both systems.

**4. Facility Regulatory Classifications. The application is blank for several items in this section. Each item must be answered yes or no.**

RESPONSE:

All the applicable items in the Facility Regulatory Classification field in the EPSAP application were completed as required. We are unaware of any additional items that would need to be completed.

The RO and PE certifications are presented in Attachment 6.

If you have any additional questions, please call Pradeep Raval.

Very truly yours,

KOOGLER & ASSOCIATES

John B. Koogler, Ph.D., P.E.

JBK:par
Encl.

C: C. D. Turley, IMC

# ATTACHMENT 1

## HAP EMISSIONS ESTIMATES

### POINT SOURCES:

The HF emissions from the A and B phosphoric acid plants can be estimated based on testing conducted on similar units. It is estimated that 3.4 percent of the fluoride emissions are HF. Based on the maximum potential fluoride emissions for each plant of 4.9 tons per year (tpy), the maximum potential HF emissions from each plant would be 0.17 tpy.

Similarly, the HF emissions from the GTSP production and storage units are estimated to be 7.8 percent of the fluoride emissions. Based on the maximum potential fluoride emissions from the GTSP production and storage units of 25.0 tpy and 34.2 tpy, respectively, the maximum potential HF emissions from each unit would be 1.95 and 2.66 tpy, respectively.

Thus, the total HF emissions from the point sources are estimated to be 4.95 tpy.

### PLANT FUGITIVE EMISSIONS:

The fugitive HF emissions from the South Pierce plant have been estimated based on emission estimates information for a similar plant. The total HF emissions from the plant fugitives are estimated to be 0.48 tpy.

### POND EMISSIONS:

Based on past studies conducted by EPA and others, an HF emission factor of 0.1 lb/acre-day has been applied to gypsum pond and cooling ponds at operating phosphate fertilizer facilities. This factor has been used for pond systems with fluoride concentrations around 10,000 ppm fluoride and a pH around 1 standard units. The total IMC South Pierce facility pond area is 238 acres with a fluoride concentration around 11,400 ppm and pH of around 1.2 standard units. Based on the pond area, the estimated HF emissions using the above emission factor are 4.34 tpy.

The combined total HF emissions from the above areas of the facility are estimated to be 9.77 tpy. This quantity is below the major source individual HAP threshold.

### OTHER HAPS:

The emissions of other HAPS, estimated based on miscellaneous material usage at the facility and based on the MSDS information, is about 1.92 tpy.

The total of all HAP emissions at the facility are estimated to be 11.69 tpy. This quantity is below the major source threshold for all HAPS.

ATTACHMENT 2

SUMMARY OF TEST DATA FOR PHOSPHORIC ACID PLANTS

## South Pierce Phosphoric Acid Plant
## A Train (008) Scrubber
## Compliance Test Results

| Run | Test Date | P2O5 Input TPH | F lb/hr | F limit lb/hr | Scrubber Total GPM | Scrubber dP |
|---|---|---|---|---|---|---|
| Testing to establish minimum flow rate of 1200 gpm | | | | | | |
| 3 run average | 08/01/96 | 44.6 | 0.11 | 0.89 | 2442 | 5.8 |
| 3 run average | 08/05/96 | 46.2 | 0.10 | 0.92 | 1014 | 5.8 |
| 2 runs | 08/07/96 | 43.1 | 0.18 | 0.86 | 1251 | 5.1 |
| 1 run | 08/08/96 | 44.6 | 0.09 | 0.89 | 1250 | 5.1 |
| | | | | | | |
| 1 | 07/20/00 | 44.8 | 0.11 | | 1386 | 5.5 |
| 2 | 07/20/00 | 44.8 | 0.12 | | 1385 | 5.5 |
| 3 | 07/20/00 | 44.8 | 0.14 | | 1385 | 5.5 |
| Test Average | 07/20/00 | 44.8 | 0.12 | 0.90 | 1385 | 5.5 |
| | | | | | | |
| 1 | 08/09/00 | 42.5 | 0.12 | | 1370 | 4.2 |
| 2 | 08/09/00 | 42.5 | 0.16 | | 1383 | 4.2 |
| 3 | 08/09/00 | 42.5 | 0.21 | | 1379 | 4.3 |
| Test Average | 08/09/00 | 42.5 | 0.16 | 0.85 | 1377 | 4.2 |
| | | | | | | |
| 1 | 04/18/01 | 44.0 | 0.09 | | 1332 | 2.6 |
| 2 | 04/18/01 | 44.0 | 0.12 | | 1298 | 2.9 |
| 3 | 04/18/01 | 44.0 | 0.13 | | 1291 | 3.3 |
| Test Average | 04/18/01 | 44.0 | 0.11 | 0.88 | 1307 | 2.9 |
| | | | | | | |
| 1 | 07/26/02 | 37.8 | 0.24 | | 2578 | 2.5 |
| 2 | 07/26/02 | 37.8 | 0.20 | | 2570 | 2.5 |
| 3 | 07/26/02 | 37.8 | 0.33 | | 2578 | 2.5 |
| Test Average | 07/26/02 | 37.8 | 0.26 | 0.76 | 2575 | 2.5 |
| | | | | | | |
| 1 | 09/04/02 | 46.6 | 0.19 | | 1700 | 7.0 |
| 2 | 09/04/02 | 46.6 | 0.13 | | 1725 | 7.1 |
| 3 | 09/04/02 | 46.6 | 0.07 | | 1730 | 7.2 |
| Test Average | 09/04/02 | 46.6 | 0.13 | 0.93 | 1718 | 7.1 |
| | | | | | | |
| 1 | 10/11/02 | 43.2 | 0.13 | | 1700 | 4.5 |
| 2 | 10/11/02 | 43.2 | 0.14 | | 1700 | 4.5 |
| 3 | 10/11/02 | 49.4 | 0.21 | | 1700 | 4.5 |
| Test Average | 10/11/02 | 45.3 | 0.16 | 0.91 | 1700 | 4.5 |
| | | | | | | |
| 1 | 01/15/03 | 45.4 | 0.17 | | 1550 | 4.0 |
| 2 | 01/15/03 | 45.4 | 0.17 | | 1550 | 4.0 |
| 3 | 01/15/03 | 45.4 | 0.20 | | 1550 | 4.0 |
| Test Average | 01/15/03 | 45.4 | 0.18 | 0.91 | 1550 | 4.0 |
| | | | | | | |
| 1 | 12/03/03 | 40.9 | 0.16 | | 2175 | 1.0 |
| 2 | 12/03/03 | 40.9 | 0.12 | | 2200 | 1.1 |
| 3 | 12/03/03 | 40.9 | 0.14 | | 2200 | 1.1 |
| Test Average | 12/03/03 | 40.9 | 0.14 | 0.82 | 2192 | 1.1 |
| | | | | | | |
| | | | | min | 1014 | 1.0 |
| | | | | max | 2578 | 7.2 |

NOTE: These are the available data, from tests conducted to establish minimum allowable values for the subject parameters, with reference to the existing Title V permit provisions.

## South Pierce Phosphoric Acid Plant
## B Train (009) Scrubber
## Compliance Test Results

| Run | Test Date | P2O5 Input TPH | F lb/hr | F limit lb/hr | Scrubber Total GPM | Scrubber dP |
|---|---|---|---|---|---|---|
| Testing to establish minimum flow rate of 1200 gpm | | | | | | |
| 3 run average | 08/09/96 | 44.5 | 0.12 | 0.89 | 2410 | 8.7 |
| 3 run average | 08/13/96 | 42.6 | 0.22 | 0.85 | 1230 | 7.4 |
| 3 run average | 08/16/96 | 45.7 | 0.22 | 0.91 | 1620 | 7.9 |
| | | | | | | |
| 1 | 05/18/99 | 40.8 | 0.34 | | 1674 | 3.4 |
| 2 | 05/18/99 | 42.1 | 0.36 | | 1374 | 3.4 |
| 3 | 05/18/99 | 42.1 | 0.16 | | 1374 | 3.4 |
| Test Average | 05/18/99 | 41.7 | 0.29 | 0.83 | 1474 | 3.4 |
| | | | | | | |
| 1 | 07/09/99 | 41.1 | 0.05 | | 2240 | 2.8 |
| 2 | 07/09/99 | 41.1 | 0.05 | | 2345 | 2.8 |
| 3 | 07/09/99 | 41.1 | 0.05 | | 2280 | 2.8 |
| Test Average | 07/09/99 | 41.1 | 0.05 | 0.82 | 2288 | 2.8 |
| | | | | | | |
| 1 | 03/16/00 | 49.9 | 0.13 | | 1933 | 5.0 |
| 2 | 03/16/00 | 49.9 | 0.25 | | 1496 | 4.9 |
| 3 | 03/16/00 | 49.9 | 0.23 | | 1510 | 4.9 |
| Test Average | 03/16/00 | 49.9 | 0.20 | 1.00 | 1646 | 4.9 |
| | | | | | | |
| 1 | 08/10/01 | 48.5 | 0.27 | | 1462 | 3.5 |
| 2 | 08/10/01 | 48.5 | 0.31 | | 1411 | 3.9 |
| 3 | 08/10/01 | 48.5 | 0.21 | | 1383 | 3.8 |
| Test Average | 08/10/01 | 48.5 | 0.26 | 0.97 | 1419 | 3.8 |
| | | | | | | |
| 1 | 07/25/02 | 43.2 | 0.16 | | 2184 | 3.7 |
| 2 | 07/25/02 | 43.2 | 0.30 | | 2180 | 3.5 |
| 3 | 07/25/02 | 43.2 | 0.15 | | 2204 | 3.8 |
| Test Average | 07/25/02 | 43.2 | 0.20 | 0.86 | 2189 | 3.7 |
| | | | | | | |
| 1 | 01/10/03 | 43.8 | 0.06 | | 2100 | 3.6 |
| 2 | 01/10/03 | 43.8 | 0.08 | | 2100 | 3.6 |
| 3 | 01/10/03 | 43.8 | 0.08 | | 2100 | 3.7 |
| Test Average | 01/10/03 | 43.8 | 0.08 | 0.88 | 2100 | 3.6 |
| | | | | | | |
| 1 | 04/29/03 | 42.5 | 0.19 | | 1683 | 2.2 |
| 2 | 04/29/03 | 42.5 | 0.17 | | 1685 | 2.2 |
| 3 | 04/29/03 | 42.5 | 0.27 | | 1652 | 2.1 |
| Test Average | 04/29/03 | 42.5 | 0.20 | 0.85 | 1673 | 2.2 |
| | | | | | | |
| | | | | min | 1230 | 2.1 |
| | | | | max | 2410 | 8.7 |
| | | | | | | |

NOTE: These are the available data, from tests conducted to establish minimum allowable values for the subject parameters, with reference to the existing Title V permit provisions.

ATTACHMENT 3

SUMMARY OF TEST DATA FOR NO. 2 BALL MILL GRINDING SYSTEM

## South Pierce No. 2 Ball Mill Grinding System (022)
## Compliance Test Results

| Run | Test Date | TPH | PM lb/hr | PM limit lb/hr | VE | VE limit | Bag Collector dP |
|---|---|---|---|---|---|---|---|
| | 02/18/99 | 50 | | | 0 | 20 | 7.0 |
| | | | | | | | |
| | 01/25/00 | 50 | | | 0 | 20 | 3.0 |
| | | | | | | | |
| | 03/20/01 | 50 | | | 0 | 20 | 1.0 |
| | | | | | | | |
| | 04/15/02 | 50 | | | 0 | 20 | 0.8 |
| | | | | | | | |
| 1 | 11/19/03 | | 0.11 | | | | |
| 2 | 11/19/03 | | 0.22 | | | | |
| 3 | 11/19/03 | | 0.28 | | | | |
| Test Average | 11/19/03 | 50 | 0.20 | 31.8 | 5.6 | 20 | 3.1 |
| | | | | | | | |
| | | | | | | min | 0.8 |
| | | | | | | max | 7.0 |
| | | | | | | | |

NOTE: These are the available data, from tests conducted to establish minimum allowable values for the subject parameters, with reference to the existing Title V permit provisions.

ATTACHMENT 4

SUMMARY OF TEST DATA FOR GTSP PRODUCTION PLANT

## South Pierce GTSP Production Plant (023)
## Compliance Test Results

| Run | Test Date | Rate TPH | PM lb/hr | PM limit lb/hr | F lb/hr | F limit lb/hr | RGCV Venturi Total GPM | RGCV Venturi dP | Dryer Venturi Total GPM | Dryer Venturi dP | Tailgas Scrubber Total GPM | Tailgas Scrubber dP |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 02/01/00 | 103.8 | 12.8 | | 3.5 | | 926 | 8.1 | 910 | 11.2 | 4658 | 6.6 |
| 2 | 02/01/00 | 103.8 | 20.1 | | 3.0 | | 926 | 8.1 | 910 | 11.2 | 4658 | 6.6 |
| 3 | 02/01/00 | 105.4 | 22.8 | | 3.0 | | 926 | 8.1 | 910 | 11.2 | 4658 | 6.6 |
| Test | 02/01/00 | 104 | 18.6 | 35 | 3.2 | 5.7 | 926 | 8.1 | 910 | 11.2 | 4658 | 6.6 |
| | | | | | | | | | | | | |
| 1 | 04/25/00 | 125.5 | 32.5 | | 1.6 | | 992 | 8.5 | 860 | 10.7 | 5018 | 6.3 |
| 2 | 04/25/00 | 125.6 | 23.2 | | 1.7 | | 982 | 8.5 | 856 | 10.9 | 4892 | 6.4 |
| 3 | 04/25/00 | 124.5 | 23.5 | | 1.7 | | 974 | 8.7 | 857 | 10.8 | 4910 | 6.5 |
| Test | 04/25/00 | 125 | 26.4 | 35 | 1.7 | 5.7 | 983 | 8.6 | 858 | 10.8 | 4940 | 6.4 |
| | | | | | | | | | | | | |
| 1 | 05/22/00 | 118 | 16.8 | | 1.2 | | 871 | 8.3 | 825 | 10.7 | 4650 | 6.3 |
| 2 | 05/22/00 | 118 | 12.9 | | 1.5 | | 817 | 8.1 | 824 | 10.7 | 4550 | 6.4 |
| 3 | 05/22/00 | 120 | 14.7 | | 1.3 | | 806 | 8.0 | 821 | 10.6 | 4518 | 6.4 |
| Test | 05/22/00 | 119 | 14.8 | 35 | 1.3 | 5.7 | 831 | 8.1 | 823 | 10.6 | 4572 | 6.4 |
| | | | | | | | | | | | | |
| 1 | 07/24/01 | 117 | 28.7 | | 1.0 | | 814 | 9.5 | 914 | 11.2 | 5020 | 8.2 |
| 2 | 07/24/01 | 119 | 32.6 | | 1.6 | | 832 | 9.6 | 925 | 11.2 | 5035 | 8.1 |
| 3 | 07/24/01 | 120 | 33.2 | | 1.3 | | 812 | 9.6 | 930 | 11.2 | 4745 | 7.9 |
| Test | 07/24/01 | 119 | 31.5 | 35 | 1.3 | 5.7 | 819 | 9.6 | 923 | 11.2 | 4933 | 8.1 |
| | | | | | | | | | | | | |
| 1 | 11/08/01 | 120 | 19.3 | | 2.6 | | 729 | 9.5 | 827 | 9.9 | 4550 | 6.2 |
| 2 | 11/08/01 | 120 | 29.6 | | 2.7 | | 739 | 9.9 | 828 | 10.0 | 4594 | 6.5 |
| 3 | 11/08/01 | 120 | 28.4 | | 3.2 | | 734 | 10.0 | 839 | 10.0 | 4594 | 6.3 |
| Test | 11/08/01 | 120 | 25.8 | 35 | 2.8 | 5.7 | 734 | 9.8 | 831 | 10.0 | 4579 | 6.3 |
| | | | | | | | | | | | | |
| 1 | 05/02/03 | 106.7 | 16.9 | | 2.0 | | 710 | 7.2 | 715 | 9.4 | 4195 | 6.1 |
| 2 | 05/02/03 | 107.7 | 21.8 | | 1.9 | | 712 | 7.8 | 713 | 9.0 | 4248 | 6.2 |
| 3 | 05/02/03 | 107.7 | 22.1 | | 1.8 | | 703 | 7.7 | 711 | 8.9 | 4234 | 6.3 |
| Test | 05/02/03 | 107 | 20.3 | 35 | 1.9 | 5.7 | 708 | 7.6 | 713 | 9.1 | 4226 | 6.2 |
| | | | | | | | | | | | | |
| 1 | 02/06/04 | 126.8 | 12.6 | | 1.5 | | 705 | 7.5 | 721 | 9.8 | 5061 | 8.4 |
| 2 | 02/06/04 | 126.7 | 11.5 | | 1.5 | | 702 | 7.5 | 717 | 9.8 | 5064 | 7.8 |
| 3 | 02/06/04 | 126.9 | 10.7 | | 1.5 | | 735 | 7.4 | 725 | 9.7 | 5044 | 8.3 |
| Test | 02/06/04 | 127 | 11.6 | 35 | 1.5 | 5.7 | 714 | 7.5 | 721 | 9.8 | 5056 | 8.2 |
| | | | | | | | | | | | | |
| 1 | 04/27/04 | 111.7 | 18.2 | | 3.7 | | 642 | 5.4 | 661 | 7.5 | 4663 | 10.2 |
| 2 | 04/27/04 | 112.4 | 16.5 | | 4.2 | | 642 | 5.4 | 674 | 7.4 | 4675 | 10.2 |
| 3 | 04/27/04 | 112.4 | 15.4 | | 4.1 | | 642 | 5.4 | 674 | 7.4 | 4675 | 10.2 |
| Test | 04/27/04 | 112 | 16.7 | 35 | 4.0 | 5.7 | 642 | 5.4 | 670 | 7.4 | 4671 | 10.2 |
| | | | | | | | | | | | | |
| | | | | | | min | 642 | 5.4 | 661 | 7.4 | 4195 | 6.1 |
| | | | | | | max | 992 | 10.0 | 930 | 11.2 | 5064 | 10.2 |

NOTE: These are the available data, from tests conducted to establish minimum allowable values for the subject parameters, with reference to the existing Title V permit provisions.

ATTACHMENT 5

SUMMARY OF TEST DATA FOR GTSP EAST STORAGE BUILDING

# South Pierce GTSP East Storage Building
# North (024) and South (025) Scrubbers
# Compliance Test Results

| Eu ID | Run | Test Date | Rate TPH | TPD Loaded | PM lb/hr | PM limit lb/hr | F lb/hr | F limit lb/hr | No 1 Fan Amps | No 2 Fan Amps |
|---|---|---|---|---|---|---|---|---|---|---|
| 024 | 1 | 09/29/99 | 70 | 2880 | 6.5 | | 2.6 | | 13 | 22 |
| 024 | 2 | 09/29/99 | 102 | 2880 | 7.5 | | 2.8 | | 13 | 22 |
| 024 | 3 | 09/29/99 | 105 | 2880 | 5.7 | | 3.8 | | 13 | 22 |
| | Test Average | 09/29/99 | 92 | 2880 | 6.6 | | 3.1 | | 13 | 22 |
| 025 | 1 | 09/29/99 | 70 | 2880 | 4.0 | | 3.1 | | 20 | 19 |
| 025 | 2 | 09/29/99 | 102 | 2880 | 4.6 | | 3.6 | | 20 | 19 |
| 025 | 3 | 09/29/99 | 105 | 2880 | 3.0 | | 5.3 | | 20 | 19 |
| | Test Average | 09/29/99 | 92 | 2880 | 3.9 | | 4.0 | | 20 | 19 |
| | Compliance Result: | | 92 | 2880 | 10.4 | 40.1 | 7.1 | 7.8 | | |
| | | | | | | | | | | |
| 024 | 1 | 03/07/00 | 100 | 3744 | 3.6 | | 4.4 | | 17 | 20 |
| 024 | 2 | 03/07/00 | 100 | 3744 | 5.4 | | 3.7 | | 17 | 20 |
| 024 | 3 | 03/07/00 | 102 | 3744 | 5.4 | | 3.1 | | 17 | 20 |
| | Test Average | 03/07/00 | 101 | 3744 | 4.8 | | 3.7 | | 17 | 20 |
| 025 | 1 | 03/10/00 | 106 | 3744 | 5.7 | | 2.0 | | 19 | 20 |
| 025 | 2 | 03/10/00 | 106 | 5136 | 4.6 | | 2.0 | | 19 | 20 |
| 025 | 3 | 03/10/00 | 109 | 5088 | 5.6 | | 2.2 | | 19 | 20 |
| | Test Average | 03/10/00 | 107 | 4656 | 5.3 | | 2.0 | | 19 | 20 |
| | Compliance Result: | | 104 | 4200 | 10.2 | 40.1 | 5.8 | 7.8 | | |
| | | | | | | | | | | |
| 024 | 1 | 05/01/00 | 118 | 5400 | 4.6 | | 1.2 | | 19 | 20 |
| 024 | 2 | 05/01/00 | 118 | 5400 | 6.5 | | 0.9 | | 19 | 20 |
| 024 | 3 | 05/01/00 | 118 | 4200 | 3.5 | | 1.5 | | 19 | 20 |
| | Test Average | 05/01/00 | 118 | 4992 | 4.8 | | 1.2 | | 19 | 20 |
| 025 | 1 | 05/02/00 | 118 | 5400 | 5.1 | | 5.9 | | 17 | 19 |
| 025 | 2 | 05/02/00 | 118 | 4200 | 2.9 | | 5.5 | | 17 | 19 |
| 025 | 3 | 05/02/00 | 118 | 3600 | 2.1 | | 4.8 | | 17 | 19 |
| | Test Average | 05/02/00 | 118 | 4400 | 3.4 | | 5.4 | | 17 | 19 |
| | Compliance Result: | | 118 | 4696 | 8.2 | 40.1 | 6.6 | 7.8 | | |
| | | | | | | | | | | |
| 024 | 1 | 09/18/01 | 105 | 4152 | 2.7 | | 1.0 | | 20 | 22 |
| 024 | 2 | 09/18/01 | 105 | 4704 | 1.5 | | 0.7 | | 20 | 22 |
| 024 | 3 | 09/18/01 | 105 | 4944 | 1.6 | | 0.4 | | 20 | 22 |
| | Test Average | 09/18/01 | 105 | 4608 | 2.0 | | 0.7 | | 20 | 22 |
| 025 | 1 | 09/20/01 | 109 | 5280 | 9.1 | | 3.0 | | 22 | 20 |
| 025 | 2 | 09/20/01 | 112 | 4128 | 3.0 | | 3.4 | | 22 | 20 |
| 025 | 3 | 09/20/01 | 112 | 5280 | 6.2 | | 3.2 | | 22 | 20 |
| | Test Average | 09/20/01 | 111 | 4896 | 6.1 | | 3.2 | | 22 | 20 |
| | Compliance Result: | | 108 | 4752 | 8.1 | 40.1 | 3.9 | 7.8 | | |
| | | | | | | | | | | |
| 024 | 1 | 12/04/01 | 123 | 4248 | 3.2 | | 3.1 | | 23 | 21 |
| 024 | 2 | 12/04/01 | 123 | 6048 | 5.9 | | 3.4 | | 23 | 21 |
| 024 | 3 | 12/04/01 | 123 | 6048 | 7.3 | | 3.5 | | 23 | 21 |
| | Test Average | 12/04/01 | 123 | 5448 | 5.5 | | 3.3 | | 23 | 21 |
| 025 | 1 | 12/04/01 | 123 | 4248 | 6.7 | | 0.7 | | 23 | 21 |
| 025 | 2 | 12/04/01 | 123 | 6048 | 3.9 | | 1.0 | | 23 | 21 |
| 025 | 3 | 12/04/01 | 123 | 5448 | 2.8 | | 0.7 | | 23 | 21 |
| | Test Average | 12/04/01 | 123 | 5248 | 4.4 | | 0.8 | | 23 | 21 |
| | Compliance Result: | | 123 | 5348 | 9.9 | 40.1 | 4.1 | 7.8 | | |
| | | | | | | | | | | |

## South Pierce GTSP East Storage Building
## North (024) and South (025) Scrubbers
## Compliance Test Results

| Eu ID | Run | Test Date | Rate TPH | TPD Loaded | PM lb/hr | PM limit lb/hr | F lb/hr | F limit lb/hr | No 1 Fan Amps | No 2 Fan Amps |
|---|---|---|---|---|---|---|---|---|---|---|
| 024 | 1 | 09/18/03 | 60 | 6600 | 1.2 | | 0.9 | | 24 | 25 |
| 024 | 2 | 09/18/03 | 60 | 3600 | 1.8 | | 1.1 | | 24 | 25 |
| 024 | 3 | 09/18/03 | 60 | 6600 | 0.4 | | 1.8 | | 24 | 25 |
| | Test Average | 09/18/03 | 60 | 5592 | 1.1 | | 1.2 | | 24 | 25 |
| 025 | 1 | 09/18/03 | 60 | 6600 | 4.1 | | 1.8 | | 24 | 25 |
| 025 | 2 | 09/18/03 | 60 | 3600 | 2.7 | | 1.9 | | 24 | 25 |
| 025 | 3 | 09/18/03 | 60 | 6600 | 2.8 | | 3.1 | | 24 | 25 |
| | Test Average | 09/18/03 | 60 | 5592 | 3.2 | | 2.3 | | 24 | 25 |
| | Compliance Result: | | 60 | 5592 | 4.3 | 40.1 | 3.5 | 7.8 | | |
| | | | | | | | | | | |
| 024 | 1 | 11/05/03 | 112 | 5160 | 10.0 | | 2.5 | | 24 | 23 |
| 024 | 2 | 11/05/03 | 108 | 7368 | 5.5 | | 2.4 | | 23 | 24 |
| 024 | 3 | 11/05/03 | 112 | 4608 | 4.2 | | 2.7 | | 24 | 24 |
| | Test Average | 11/05/03 | 110 | 5400 | 6.6 | | 2.5 | | 24 | 24 |
| 025 | 1 | 11/10/03 | 110 | 5928 | 3.8 | | 0.8 | | 24 | 24 |
| 025 | 2 | 11/10/03 | 110 | 3504 | 3.3 | | 0.7 | | 24 | 24 |
| 025 | 3 | 11/10/03 | 110 | 6744 | 4.1 | | 0.8 | | 24 | 24 |
| | Test Average | 11/10/03 | 110 | 5400 | 3.7 | | 0.8 | | 24 | 24 |
| | Compliance Result: | | 110 | 5400 | 10.3 | 40.1 | 3.3 | 7.8 | | |
| | | | | | | | | | | |
| | | | | | | | | min | 13 | 19 |
| | | | | | | | | max | 24 | 25 |

NOTE: These are the available data, from tests conducted to establish minimum allowable values for the subject parameters, with reference to the existing Title V permit provisions.

# COMPLIANCE ASSURANCE MONITORING PLAN
# (CAM PLAN)

**FOR**

## Crystal River Plant

**Progress Energy Florida**
**Citrus County, Florida**

**June, 2004**

# I. EMISSION UNITS REQUIRING CAM PLANS

## *A. CAM Rule Applicability Definition*

Progress Energy Florida (Progress) was issued a Title V Air Operation Permit (Permit No. 0170004-004-AV) that was effective January 1, 2000 for their Crystal River Plant. The current permit, unless renewed through submittal of an application to the Florida Department of Environmental Protection (FDEP), expires on December 31, 2004. To be considered timely and sufficient, as defined in Rule 62-4.090 of the Florida Administrative Code, a renewal application must be submitted no later than 180 days prior to the expiration date of the permit.

As part of these Title V renewal applications, EPA, through regulations adopted in Title 40, Part 64 of the Code of Federal Regulations (40 CFR 64), is requiring submittal of Compliance Assurance Monitoring (CAM) Plans. This regulation has been incorporated by reference by FDEP in Rule 62-204.800 and implemented in Rule 62-213.440.

CAM plans are required for all Title V permitted emission units using control devices to meet federally enforceable emission limits or standards with pre-control emissions greater than "major" source thresholds. The term "major" is defined as in the Title V Regulations (40 CFR 70), but applied on a source-by-source basis. However, there are some specific exemptions to the applicability of the CAM Rule.

Specifically exempted from the CAM Rule are emissions units subject to requirements under Stratospheric Ozone Regulations (40 CFR 82), the Acid Rain Program (40 CFR 72), or that are part of an emission cap included in the Title V Permit. Also exempt are emission units subject to New Source Performance Standards (40 CFR 60) and National Emission Standards for Hazardous Air Pollutants (40 CFR 63) promulgated after 11/15/1990, as these sources have equivalent monitoring requirements included as part of the standard.

## *B. Emissions Units Requiring CAM Plans*

A review of emission units at Crystal River was conducted to determine the applicability of the CAM Rule. This evaluation was conducted for each emission unit and pollutant. First, the

existence of a "control device" as defined by the CAM Rule was determined on a source-by-source basis for each pollutant. Those emission units without control devices were eliminated from further consideration. The remaining emission units were then evaluated on a pollutant-by-pollutant basis to determine if a control device was used to meet a federally enforceable emission limit or standard. Each pollutant without a federally enforceable emission limit or standard, emitted from a given emission unit, was eliminated from further consideration. Uncontrolled annual emissions were then calculated for each remaining source-pollutant combination. If uncontrolled emissions for a pollutant emitted from a given emission unit source were below major source thresholds as defined by the CAM Rule, that pollutant was not further considered. This evaluation process resulted in a determination that Units 1, 2, 4 and 5 (DEP Permit Nos. 001, 002, 004 and 003, respectively) are subject to the CAM requirements. Specific exemptions to the applicability of the CAM Rule were also considered in this evaluation.

**Crystal River Unit 1 (E.U. ID No. 001)**

Fossil Fuel Steam Generator Unit 1 is a tangentially fired pulverized coal dry bottom unit. The unit is rated at 440.5 MW and 3,750 MMBtu/hr while burning bituminous coal or a bituminous coal and bituminous coal briquette mixture. Distillate fuel oil may be burned as a startup fuel. This unit may also burn oily flyash. Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc. Emissions are exhausted through a 499 ft. stack.

This emission unit is regulated under Acid Rain, Phase I and II and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input, and Power Plant Siting Certification PA 77-09 conditions. Fossil fuel fired steam generator Unit 1 began commercial operation in 1966.

**Crystal River Unit 2 (E.U. ID No. 002)**

Fossil Fuel Steam Generator, Unit 2 is a tangentially fired pulverized coal dry bottom unit. The unit is rated at 523.8 MW and 4,795 MMBtu/hr while burning bituminous coal or a bituminous

coal and bituminous coal briquette mixture. Distillate fuel oil may be burned as a startup fuel. . This unit may also burn oily flyash. Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc. Emissions are exhausted through a 502 ft. stack

This emission unit is regulated under Acid Rain, Phase I and II and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input, and Power Plant Siting Certification PA 77-09 conditions. Fossil fuel fired steam generator Unit 2 began commercial operation in 1969.

**Crystal River Unit 4 (E.U. ID No. 004)**

Fossil Fuel Steam Generator, Unit 4 is a pulverized coal dry bottom wall-fired unit. The unit is rated at 760 MW and 6,665 MMBtu/hr while burning bituminous coal, a bituminous coal and bituminous coal briquette mixture, and used oil, with distillate fuel oil as a startup fuel, and natural gas as a startup and low-load flame stabilization fuel. Emissions are controlled with a high efficiency electrostatic precipitator, manufactured by Combustion Engineering. Emissions are exhausted through a 600 ft. stack

This emission unit is regulated under Acid Rain, Phase I and II and Rule 62-210.300, F.A.C., 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971; and, Power Plant Siting Certification PA 77-09 conditions. Fossil fuel fired steam generator Unit 4 began commercial operation in 1982.

**Crystal River Unit 5 (E.U. ID No. 003)**

Fossil Fuel Steam Generator, Unit 5 is a pulverized coal dry bottom wall-fired unit. The unit is rated at 760 MW and 6,665 MMBtu/hr while burning bituminous coal, a bituminous coal and bituminous coal briquette mixture, and used oil, with distillate fuel oil as a startup fuel, and natural gas as a startup and low-load flame stabilization fuel. Emissions are controlled with a

high efficiency electrostatic precipitator, manufactured by Combustion Engineering. Emissions are exhausted through a 600 ft. stack

This emission unit is regulated under Acid Rain, Phase I and II and Rule 62-210.300, F.A.C., 40 CFR 60 Subpart D, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971; and, Power Plant Siting Certification PA 77-09 conditions. Fossil fuel fired steam generator Unit 5 began commercial operation in 1984.

## II. CAM PLAN FOR PARTICULATE EMISSIONS

### *A. Emissions Units Background*

Compliance testing is required annually for particulates and for visible emissions (VE) for these four units. In addition, a continuous opacity monitoring system (COMS) is required to be used to record the opacity of the stack flue gas. The COMS must be properly calibrated, operated, and maintained in accordance with Rule 62-297.520, F.A.C. In addition, the current TV permit contains language (Condition A.19) that correlates opacity with periodic monitoring requirements as follows:

*<u>COMS for Periodic Monitoring</u>:*

*a. Periodic monitoring for opacity shall be COMS, which are maintained and operated in conformance with 40 CFR Part 75.*

*b. Periodic monitoring for particulate matter shall be COMS. For any calendar quarter in which more than five percent of the COMS readings show 20% or greater opacity for Units 2, 4, and 5 and 30% or greater opacity for Unit 1 (excluding startup, shutdown, and malfunction periods), a steady-state particulate matter stack test shall be performed within the following calendar quarter. Due to the allowed opacity level of 60% for sootblowing and load changing periods for Units 1 and 2, periods of sootblowing and load changing shall also be excluded for those units. The stack test shall comply with all of the testing and reporting requirements contained in the preceding specific conditions and, where practicable, shall be performed while operating at conditions representative of those showing greater than 20% opacity (30% for Unit 1). Units are not required to be brought on-line solely for the purpose of performing this special test. If the unit does not operate in the following quarter, the special test may be postponed until the unit is brought back on-line. In such cases, the special test shall be performed within 30 days.*

### *B. Emissions Units Correlations*

To develop the indicator ranges, opacity readings were compared with stack test results of particulate matter (PM) emissions for each unit over the last 5 years. PM emissions (lb/MMBtu) were plotted versus the average of the opacity readings for each of the three 1-hour runs that comprise each annual stack test. Linear curves were then applied to the data to develop a relationship between opacity and PM (lb/MMBtu) emissions (see Figures 1 through 4). As shown, there is almost no correlation between opacity and PM (lb/MMBtu). Attempts to derive opacity trigger levels from the correlations developed resulted in values in excess of the current opacity standards. This is partly due to the fact that most of the PM emissions data are very low and extrapolating to PM values close to the allowable 0.1 lb/MMBtu limit results in a correspondingly high opacity value. Based on the correlation and nature of the data, more test data for these units will likely not result in a better correlation. In addition, PM emissions for Unit 1 were compared with total ESP power (kW) to determine if a correlation could be made. As shown in Figure 5, no correlation exists, in fact the trend indicates increased PM emissions with increased power. Historic ESP power values are not normally maintained by the site, so data available to evaluate correlations at the other units is very limited.

Since a good correlation based on test data does not exist, an approach to CAM based on operating experience and current procedures is proposed. Operational experience has indicated that an increase of VE beyond 40 percent for Unit 1 and beyond 20 percent for Units 2, 4 and 5 could indicate impaired performance of the particulate control device.

*C. Monitoring Approach- Tables 1A through 1D (Units 1, 2, 4 and 5, respectively)*

| **Table 1A** | **Indicator Unit No. 1** |
|---|---|
| Indicator | Opacity via a COMS. |
| Measurement Approach | 40 CFR 60, Appendix B, Performance Specification 1 |
| Indicator Range | An excursion is defined as a VE (3-hour block averaging time) greater than 36%.<br><br>Excluding periods of startup, shutdown, malfunction and soot blowing pursuant to Rule 62-210.700.<br>An excursion will trigger an evaluation of operation of the power boiler and ESP. Corrective action will be taken as necessary. Any excursion will trigger recordkeeping and reporting requirements. |
| Data Representativeness | VE measurements are made in the stack. |
| Verification of Operational Status | NA |
| QA/QC Practices and Criteria | The COMS is automatically calibrated every 24 hours. Calibration information is recorded through a data acquisition system (DAS). A neutral density filter test is performed quarterly as well as preventative maintenance items; replace filters, clean optics, etc., as prescribed by the manufacturer. |
| Monitoring Frequency | Opacity is monitored continuously. |
| Data Collection Procedures | Six-minute averages are recorded through the DAS. Daily reports with all six-minute averages are generated. |
| Averaging Period | The averaging period for opacity observations is a six-minute block average. |

| Table 1B | Indicator Unit No. 2 |
|---|---|
| Indicator | Opacity via a COMS. |
| Measurement Approach | 40 CFR 60, Appendix B, Performance Specification 1 |
| Indicator Range | An excursion is defined as a VE (3-hour block averaging time) greater than 18%.<br><br>Excluding periods of startup, shutdown, malfunction and soot blowing pursuant to Rule 62-210.700.<br><br>An excursion will trigger an evaluation of operation of the power boiler and ESP. Corrective action will be taken as necessary. Any excursion will trigger recordkeeping and reporting requirements. |
| Data Representativeness | VE measurements are made in the stack. |
| Verification of Operational Status | NA |
| QA/QC Practices and Criteria | The COMS is automatically calibrated every 24 hours. Calibration information is recorded through a data acquisition system (DAS). A neutral density filter test is performed quarterly as well as preventative maintenance items; replace filters, clean optics, etc., as prescribed by the manufacturer. |
| Monitoring Frequency | Opacity is monitored continuously. |
| Data Collection Procedures | Six-minute averages are recorded through the DAS. Daily reports with all six-minute averages are generated. |
| Averaging Period | The averaging period for opacity observations is a six-minute block average. |

| Table 1C | Indicator Unit No. 4 |
|---|---|
| Indicator | Opacity via a COMS. |
| Measurement Approach | 40 CFR 60, Appendix B, Performance Specification 1 |
| Indicator Range | An excursion is defined as a VE (3-hour block averaging time) greater than 18%.<br><br>Excluding periods of startup, shutdown, malfunction and soot blowing pursuant to Rule 62-210.700.<br><br>An excursion will trigger an evaluation of operation of the power boiler and ESP. Corrective action will be taken as necessary. Any excursion will trigger recordkeeping and reporting requirements. |
| Data Representativeness | VE measurements are made in the stack. |
| Verification of Operational Status | NA |
| QA/QC Practices and Criteria | The COMS is automatically calibrated every 24 hours. Calibration information is recorded through a data acquisition system (DAS). A neutral density filter test is performed quarterly as well as preventative maintenance items; replace filters, clean optics, etc., as prescribed by the manufacturer. |
| Monitoring Frequency | Opacity is monitored continuously. |
| Data Collection Procedures | Six-minute averages are recorded through the DAS. Daily reports with all six-minute averages are generated. |
| Averaging Period | The averaging period for opacity observations is a six-minute block average. |

| Table 1D | Indicator Unit No. 5 |
|---|---|
| Indicator | Opacity via a COMS. |
| Measurement Approach | 40 CFR 60, Appendix B, Performance Specification 1 |
| Indicator Range | An excursion is defined as a VE (3-hour block averaging time) greater than 18%.<br><br>Excluding periods of startup, shutdown, malfunction and soot blowing pursuant to Rule 62-210.700.<br><br>An excursion will trigger an evaluation of operation of the power boiler and ESP. Corrective action will be taken as necessary. Any excursion will trigger recordkeeping and reporting requirements. |
| Data Representativeness | VE measurements are made in the stack. |
| Verification of Operational Status | NA |
| QA/QC Practices and Criteria | The COMS is automatically calibrated every 24 hours. Calibration information is recorded through a data acquisition system (DAS). A neutral density filter test is performed quarterly as well as preventative maintenance items; replace filters, clean optics, etc., as prescribed by the manufacturer. |
| Monitoring Frequency | Opacity is monitored continuously. |
| Data Collection Procedures | Six-minute averages are recorded through the DAS. Daily reports with all six-minute averages are generated. |
| Averaging Period | The averaging period for opacity observations is a six-minute block average. |

### *D. Corrective Action Procedures Summary – Table 2 (Units 1, 2, 4 and 5)*

| | | *Description* |
|---|---|---|
| I. | Initiation of Corrective Action Procedures | Corrective action shall be initiated with the discovery of a three-hour block average of opacity greater than the levels that define an excursion (as defined in Tables 1A through 1D). The plant staff that made the discovery shall immediately notify the responsible official. This action describes a corrective action trigger. |
| II. | Time of Completion of Corrective Action Procedures | As soon as practically possible. |
| III. | Corrective Action | The Shift Supervisor or responsible official will implement the following as a corrective action.<br><br>• Perform operational diagnostics to identify cause of the excursion;<br>• If operational diagnostics indicate a malfunction of the ESP, the reason for failure will be identified;<br>• ESP operation will be restored to ensure opacity below excursion levels; and<br>• In the event of the need for load reductions or unit shutdown to bring opacity to below excursion levels, the task will be undertaken utilizing best operational practices to minimize emissions.<br><br>Regardless of the failure mechanism, ESP operation will be restored such that the cause of excursion is identified and appropriate actions taken to ensure opacity below excursion levels. |

## *E. Justification*

### 1. Background

The pollutant specific emission units are Crystal River Units 1, 2, 4 and 5 which are primarily fired on coal. Particulate emissions are controlled by high efficiency ESPs.

### 2. Rationale for Selection of Performance Indicators

Opacity was selected as the performance indicator because it is indicative of good operation and maintenance of the ESP. When the ESPs are operating properly, there will be very little opacity or visible emissions (VE) from the ESP exhaust. Operational experience has indicated that an increase of VE beyond 40 percent opacity for Unit 1 and 20 percent opacity for Units 2, 4 and 5 could indicate impaired performance of the particulate control device; therefore, VE is used as the performance indicator. These indicator levels were referenced earlier as already contained in Condition A.19 of the current TV permit. Condition A.19 was for purposes of periodic monitoring and related to the number of times the indicator level was exceeded (5 percent) in a quarter. As the CAM Plan trigger levels are based on a different averaging time and frequency of occurrence, the respective opacity values recommended below are slightly different.

### 3. Rationale for Selection of Indicator Ranges

The selected indicator ranges are as follows (all are in 3-hour block averages):

- 36 % for Unit 1
- 18 % for Unit 2
- 18 % for Unit 4
- 18 % for Unit 5

These indicator ranges were selected because they provide a margin on those opacity values that could be reflective of impaired ESP performance and an associated increase in particulate emissions from the ESP outlet. Initially, to develop the indicator ranges, opacity readings were compared with stack test results of PM emissions over the last 5 years for each Unit. PM emissions (lb/MMBtu) were plotted versus the average of the opacity readings for each of the

three 1-hour runs comprising each annual stack test. Linear curves were then applied to the data to develop a relationship between opacity and PM (lb/MMBtu) emissions (see Figures 1 through 4). As shown, there is almost no correlation between opacity and PM (lb/MMBtu). Based on the correlation and nature of the data, more test data for these units will likely not result in a better correlation. In addition, PM emissions for Unit 1 were compared with total ESP power (kW) to determine if a correlation could be made. As shown in Figure 5, no correlation exists, in fact the trend indicates increased PM emissions with increased power. Historic ESP power values are not normally maintained by the site, so data available to evaluate correlations at the other units is very limited.

Since a good correlation based on test data does not exist, an approach to CAM based on operating experience and current procedures is proposed. Operational experience has indicated that an increase of VE beyond 40 percent opacity for Unit 1 and 20 percent for Units 2, 4 and 5 could indicate impaired performance of the particulate control device. The trigger levels selected provide for an operating margin over these values. Current experience suggests that, if these trigger levels are not exceeded, reasonable assurance will be provided that the corresponding PM emissions standards will be met. When an excursion occurs, corrective action will be initiated as described in Table 2, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported.

**Figure 1.**
**Unit 1 - PM Emissions vs. COMS Opacity**

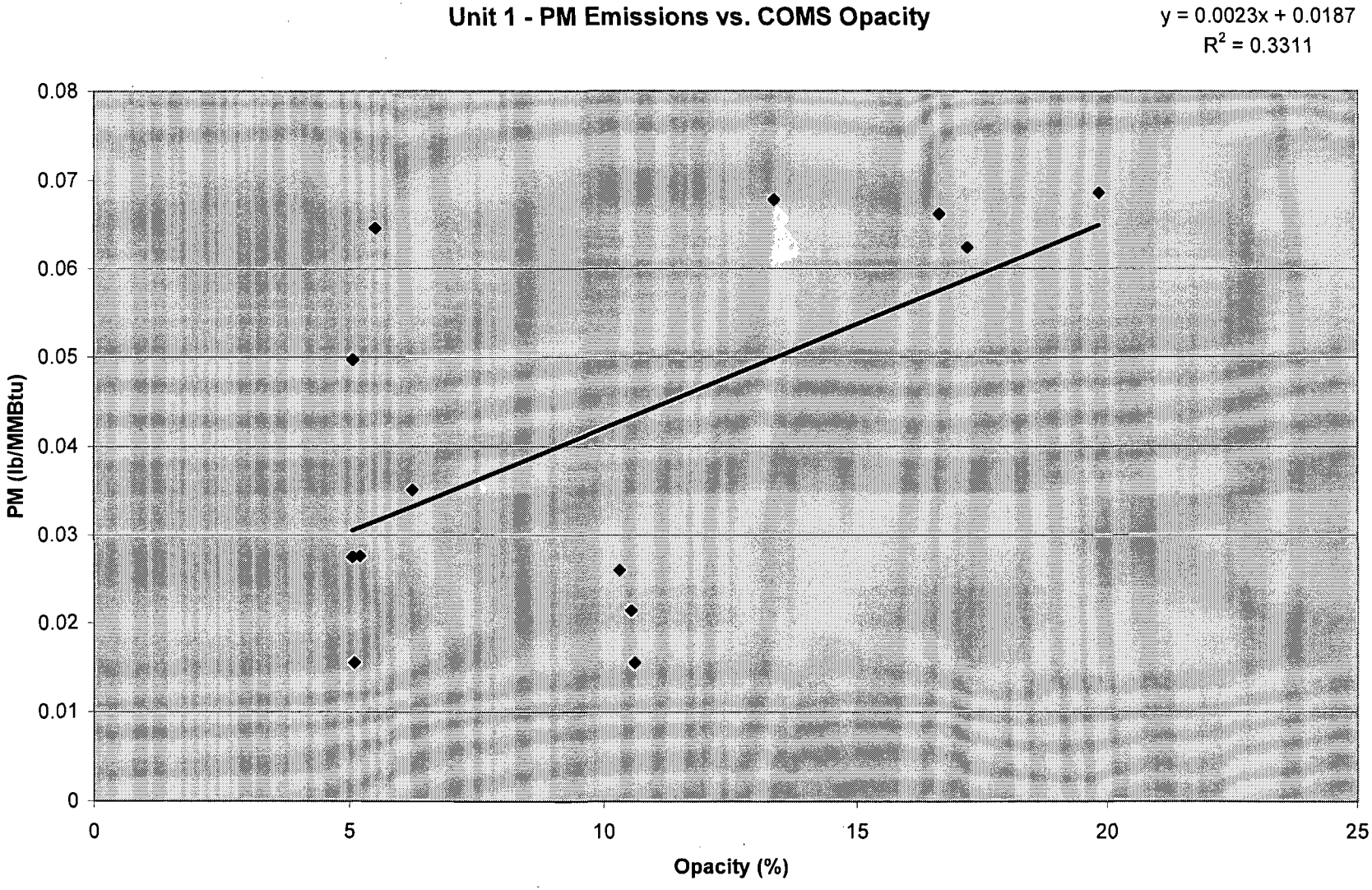


**Figure 2.**
**Unit 2 - PM Emissions vs. COMS Opacity**

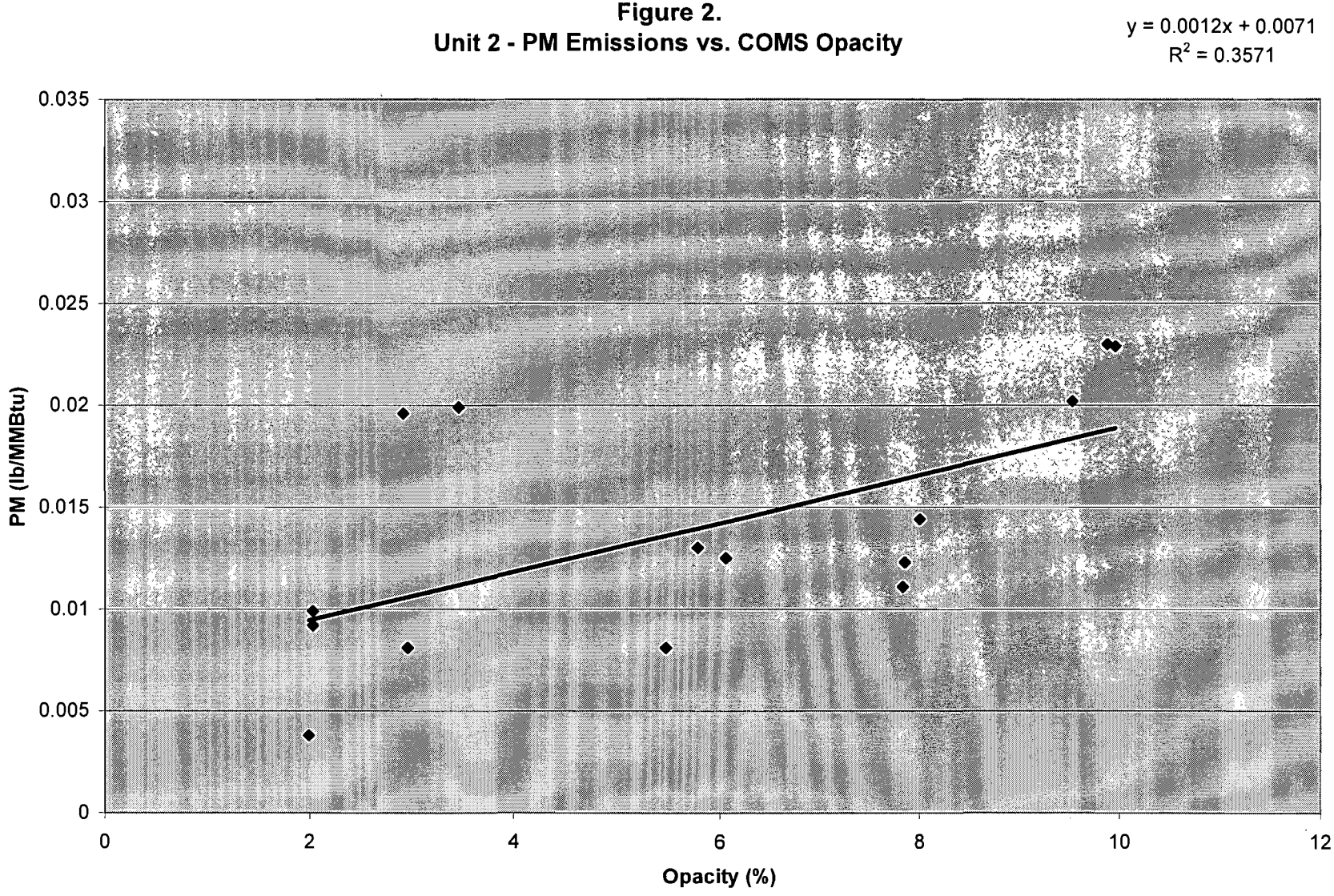


**Figure 3.**
**Unit 4 - PM Emissions vs. COMS Opacity**

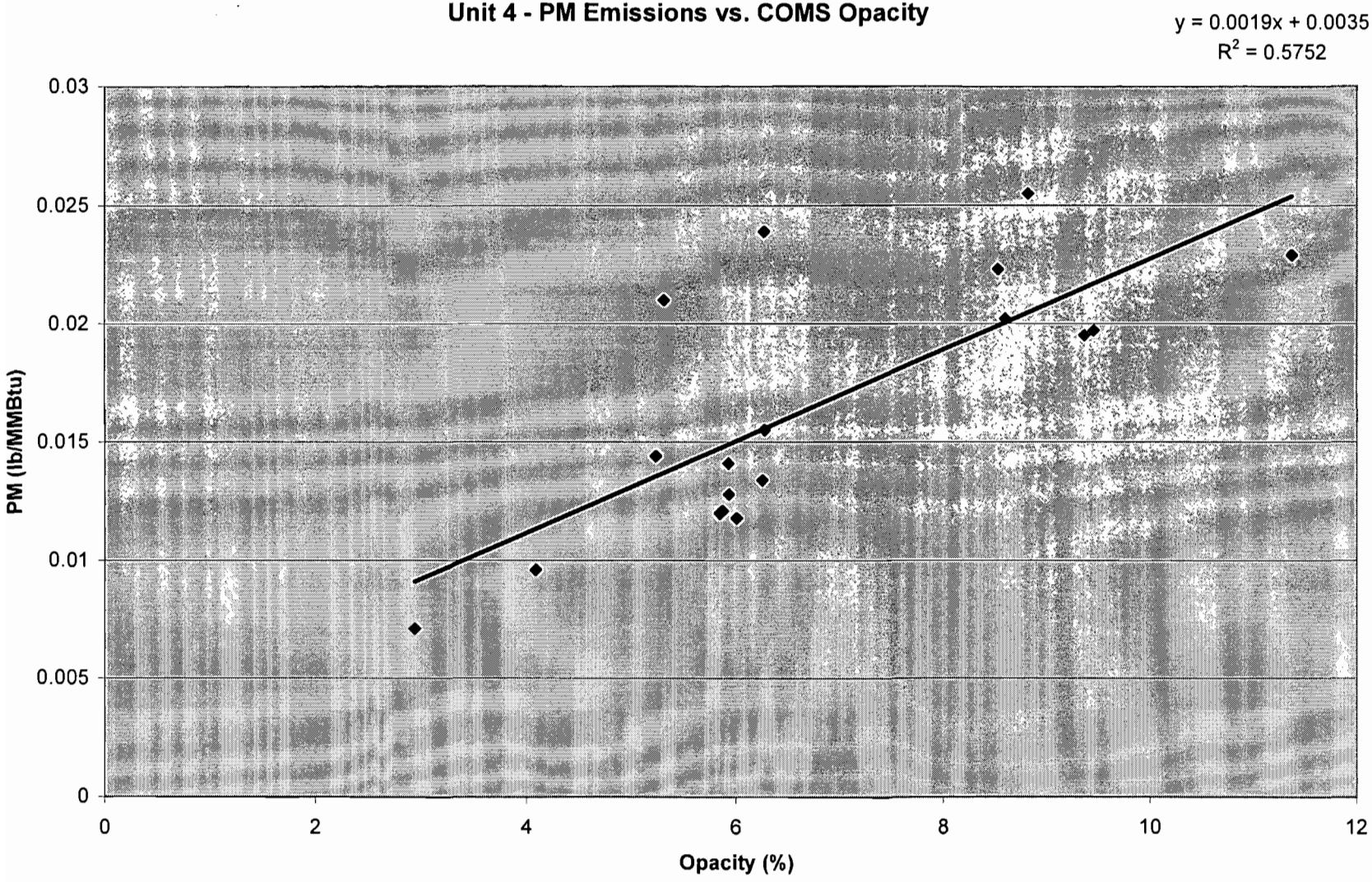


**Figure 4.**
**Unit 5 - PM Emissions vs. COMS Opacity**

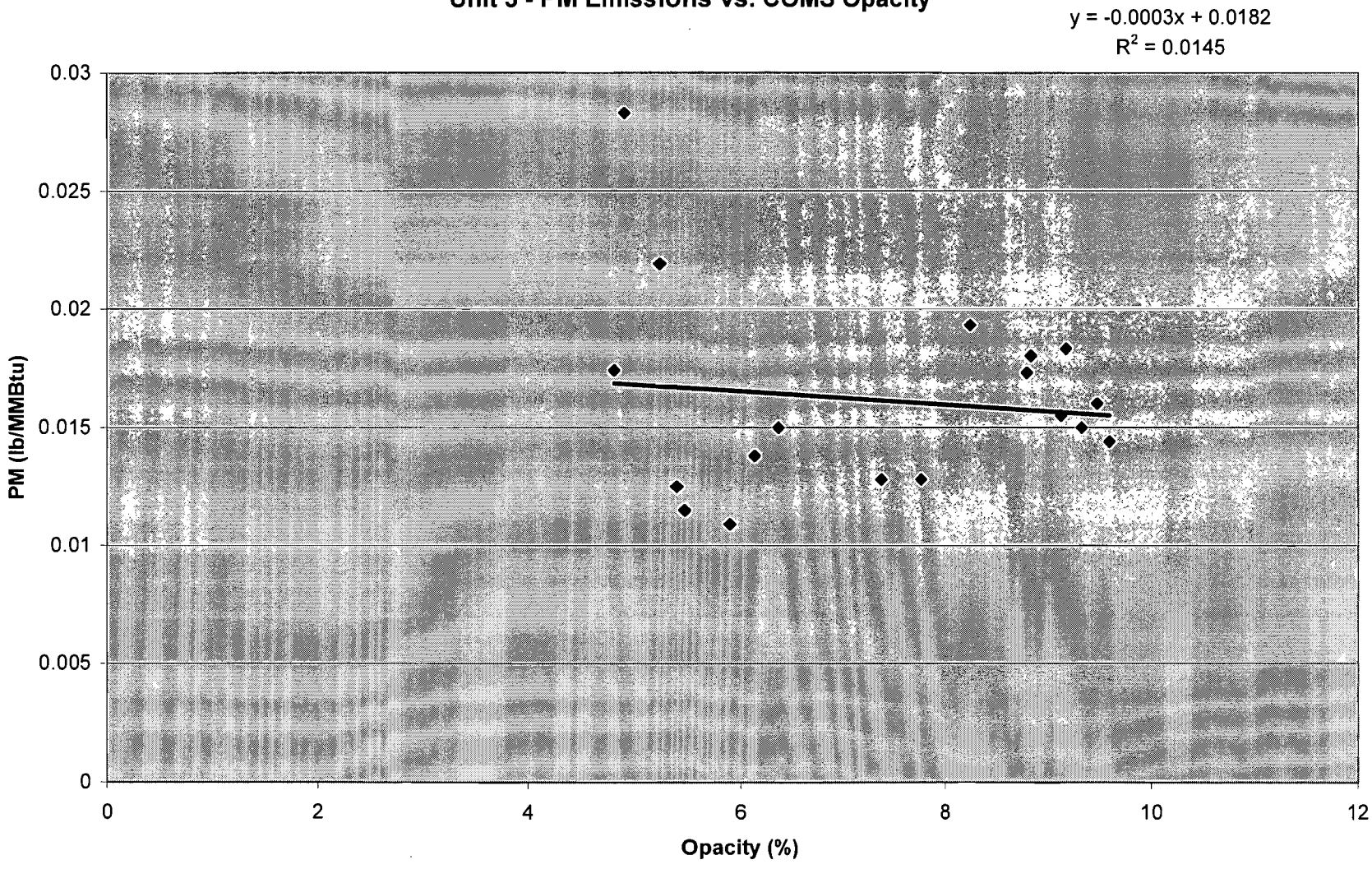
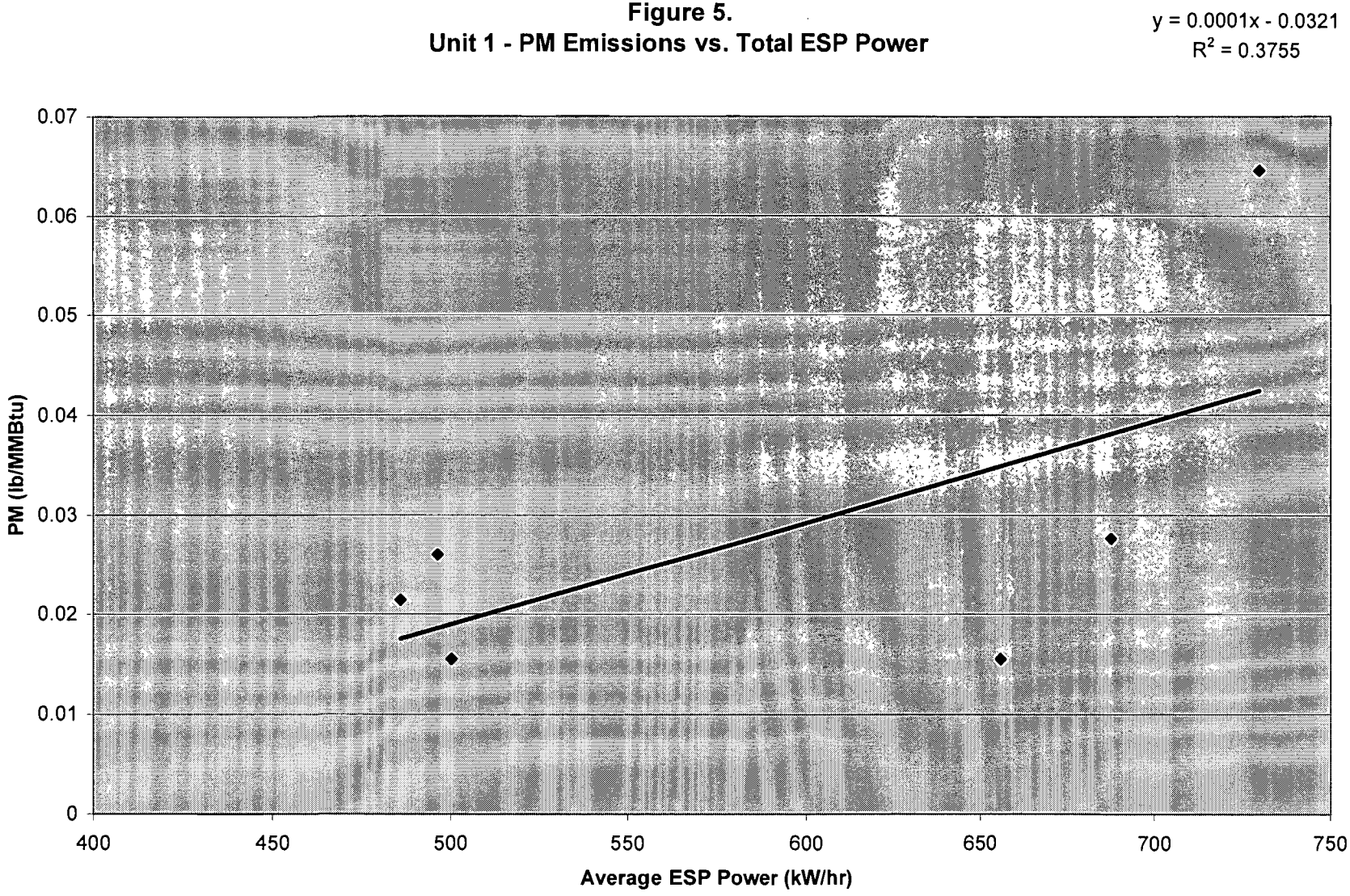


**Figure 5.**
**Unit 1 - PM Emissions vs. Total ESP Power**



## Mitchell, Bruce

**From:** Vielhauer, Trina
**Sent:** Monday, October 11, 2004 12:51 PM
**To:** Gibson, Victoria; Mitchell, Bruce
**Cc:** Pennington, Jim
**Subject:** RE: Received today a Request for Extension of time on Gainesville Regional Util.

Vickie,

I think I misspoke-

As long as they have published their notice in the newspaper, third party timeframes to challenge the permit have started. These 3rd parties will have 14 days from date of publication to challenge the permit. To preserve their rights to be a "party" should any 3rd party file a challenge, the company would also need to challenge their own permit. So, I'd say it makes sense to allow them just enough time to see if a third party has, indeed, challenged the permit. We need them to withdraw their extensions by NO later than November 15 [and preferably earlier so we can get proposed to EPA]. Maybe extend until November 1?

-----Original Message-----
**From:** Gibson, Victoria
**Sent:** Monday, October 11, 2004 12:17 PM
**To:** Vielhauer, Trina; Mitchell, Bruce
**Subject:** Received today a Request for Extension of time on Gainesville Regional Util.
**Importance:** High

Hi,

Received a request for extension of time today from:

Gainesville Regional Utilities - Deerhaven Generating Station 0010006-003-AV

They have requested just about 60 days -- the hard date is 12/6/04.

Should we grant their request....and for how long?

Thank you.

*Vickie*

Victoria Gibson, Administrative Secretary
Bureau Chief's Office
DEP/Bureau of Air Regulation
victoria.gibson@dep.state.fl.us
850-921-9504

Seminole

XXV. Modification of Conditions

The conditions of this certification may be modified in the following manner:

A. The Board hereby delegates to the Secretary the authority to modify, after notice and opportunity for hearing, any conditions pertaining to monitoring, testing and evaluation programs, sampling, groundwater, mixing zones, zones of discharge or variances to water quality standards, or location of transmission line corridors within areas already approved at the land use hearing.

B. This certification shall be automatically modified to conform to any subsequent amendments, modifications, or renewals made by DEP under a federally delegated or approved program to any separately issued Prevention of Significant Deterioration (PSD) permit, Title V Air Permit, or National Pollutant Discharge Elimination System (NPDES) permit for the certified facility. SECI shall send each party to the original certification proceedings (at the party's last known address as shown in the record of such proceeding notice of requests submitted by SECI for modifications or renewals of the above listed permits if the request involves a relief mechanism (e.g., mixing zone, variance, etc.) From state standards, a relaxation of conditions included in the permit due to state permitting requirements, or the inclusion of less restrictive air emission limitations in the air permits. DEP shall notify all parties to the certification proceeding of any intent to modify conditions under this section prior to taking final agency action.

C. All other modifications shall be made in accordance with Section 403.516, Florida Statutes.

FINAL DETERMINATION

**Seminole Electric Cooperative Incorporated**

Modification of Permit No. PSD-FL-018(A)
**Seminole Palatka Power Plant Units 1 and 2**

An Intent to Issue an air construction permit modification for Seminole Electric Cooperative, Inc., Palatka Power Plant Units No. 1 & 2 located in Palatka, Putnam County, Florida was distributed on February 10, 1997. The Notice of Intent was published in the Palatka Daily News on February 18, 1997. Copies of the modification were available for public inspection at the Department offices in Jacksonville and Tallahassee.

No comments were submitted by the National Park Service or the U.S. Environmental Protection Agency. A comment was submitted by the applicant concerning the maximum weight of the petroleum coke that shall be burned. The Department concurs with the applicant's comment.

The final action of the Department will be to issue the permit modification as noted above.

FINAL DETERMINATION

**Seminole Electric Cooperative Incorporated**

Modification of Permit No. PSD-FL-018(A)
**Seminole Palatka Power Plant Units 1 and 2**

An Intent to Issue an air construction permit modification for Seminole Electric Cooperative, Inc., Palatka Power Plant Units No. 1 & 2 located in Palatka, Putnam County, Florida was distributed on February 10, 1997. The Notice of Intent was published in the Palatka Daily News on February 18, 1997. Copies of the modification were available for public inspection at the Department offices in Jacksonville and Tallahassee.

No comments were submitted by the National Park Service or the U.S. Environmental Protection Agency. A comment was submitted by the applicant concerning the maximum weight of the petroleum coke that shall be burned. The Department concurs with the applicant's comment.

The final action of the Department will be to issue the permit modification as noted above.

| | |
|---|---|
| $P_S$ | = potential $SO_2$ combustion concentration (unwashed coal without emission control systems) as defined by NSPS Subpart Da; lb $SO_2$/MMBtu, 30-day rolling average |
| $\% R_0$ | = overall percent $SO_2$ reduction from Equation 19-21 of EPA Reference Method 19. Per NSPS Subpart Da, $\% R_0$ must not be less than 90%, 30-day rolling average |
| 0.74 | = historical 2-year annual average $SO_2$ emission rate for Unit 1; lb/MMBtu |
| 0.72 | = historical 2-year annual average $SO_2$ emission rate for Unit 2; lb/MMBtu |

Compliance with the lb/MMBtu heat input emission limitations and percent reduction requirement shall be determined on a 30-day rolling average basis.

Item 2 - Nitrogen Oxide Emissions

a) 0.60 lb/MMBtu heat input, and 35 percent of the potential combustion concentration (65 percent reduction). Compliance with the lb/MMBtu heat input emission limitation and percent reduction requirement shall be determined on a 30-day rolling average basis. Compliance with the 0.60 lb/MMBtu heat input emission limitation shall also constitute compliance with the 65 percent reduction requirement; and

b) 0.50 lb/MMBtu heat input determined on an annual average basis, when subject to the 40 CFR §76.8 Early Election Program for Group 1, Phase II Boilers or in any year when petcoke is burned.

Item 3 - Particulate Matter Emissions

0.03 lb/MMBtu heat input, and one percent of the potential combustion concentration (99 percent reduction). Compliance with the 0.03 lb/MMBtu heat input emission limitation shall also constitute compliance with the 99 percent reduction requirement.

Item 4 - Carbon Monoxide Emissions

The Permittee shall maintain and submit to the Department, on an annual basis for a period of five years from the date the units begin firing petroleum coke, test results demonstrating that the operational changes did not result in a significant emissions increase of the pollutant when compared to past emissions while firing coal. The carbon monoxide emissions shall be based on test results using EPA Method 10.

Item 5 - Sulfuric Acid Mist Emissions

The Permittee shall maintain and submit to the Department on an annual basis for a period of five years from the date the units begin firing petroleum coke, test results demonstrating that the operational changes did not result in a significant emissions increase of the pollutant when compared to past emissions while firing coal. The sulfuric acid mist emissions shall be based on test results using EPA Method 8.

Item 6 - Fuel Specifications

Fuels fired shall consist of coal and petroleum coke blends containing a maximum of 30 percent petroleum coke by weight. The maximum weight of the petroleum coke burned shall not exceed 186,000 pounds per hour (averaged over 24 hours). The petroleum coke sulfur content shall not exceed 7.0 percent by weight, dry basis.

Item 7 - Reporting and Recordkeeping

| | |
|---|---|
| $P_S$ | = potential $SO_2$ combustion concentration (unwashed coal without emission control systems) as defined by NSPS Subpart Da; lb $SO_2$/MMBtu, 30-day rolling average |
| $\% R_0$ | = overall percent $SO_2$ reduction from Equation 19-21 of EPA Reference Method 19. Per NSPS Subpart Da, $\% R_0$ must not be less than 90%, 30-day rolling average |
| 0.74 | = historical 2-year annual average $SO_2$ emission rate for Unit 1; lb/MMBtu |
| 0.72 | = historical 2-year annual average $SO_2$ emission rate for Unit 2; lb/MMBtu |

Compliance with the lb/MMBtu heat input emission limitations and percent reduction requirement shall be determined on a 30-day rolling average basis.

Item 2 - Nitrogen Oxide Emissions

a) 0.60 lb/MMBtu heat input, and 35 percent of the potential combustion concentration (65 percent reduction). Compliance with the lb/MMBtu heat input emission limitation and percent reduction requirement shall be determined on a 30-day rolling average basis. Compliance with the 0.60 lb/MMBtu heat input emission limitation shall also constitute compliance with the 65 percent reduction requirement; and

b) 0.50 lb/MMBtu heat input determined on an annual average basis, when subject to the 40 CFR §76.8 Early Election Program for Group 1, Phase II Boilers or in any year when petcoke is burned.

Item 3 - Particulate Matter Emissions

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The Permittee shall maintain and submit to the Department, on an annual basis for a period of five years from the date the units begin firing petroleum coke, test results demonstrating that the operational changes did not result in a significant emissions increase of the pollutant when compared to past emissions while firing coal. The carbon monoxide emissions shall be based on test results using EPA Method 10.

Item 5 - Sulfuric Acid Mist Emissions

The Permittee shall maintain and submit to the Department on an annual basis for a period of five years from the date the units begin firing petroleum coke, test results demonstrating that the operational changes did not result in a significant emissions increase of the pollutant when compared to past emissions while firing coal. The sulfuric acid mist emissions shall be based on test results using EPA Method 8.

Item 6 - Fuel Specifications

Fuels fired shall consist of coal and petroleum coke blends containing a maximum of 30 percent petroleum coke by weight. The maximum weight of the petroleum coke burned shall not exceed 186,000 pounds per hour (averaged over 24 hours). The petroleum coke sulfur content shall not exceed 7.0 percent by weight, dry basis.

Item 7 - Reporting and Recordkeeping

a) Documentation verifying that the coal and petroleum coke fuel blends combusted in Units 1 and 2 have not exceeded the 30 percent maximum petroleum coke by weight limit specified by Condition of Approval, Section D, Item 6 shall be maintained and submitted to the Department's Northeast District office with each annual report; and

b) The Permittee shall maintain and submit to the Department, on an annual basis for a period of five years from the date the units begin firing petroleum coke, data demonstrating that the operational change associated with the use of petroleum coke did not result in a significant emission increase pursuant to Rule 62-210.200(12)(d), F.A.C.

Item 8 - Handling of Petroleum Coke

All prior conditions of approval that address coal handling shall also apply to the handling of petroleum coke.

E. FOR THE ELECTRIC UTILITY STEAM GENERATING UNITS WHEN BURNING NO 2 FUEL OIL

Use of No. 2 fuel oil is authorized for startups, flame stabilization and required emergency electric reserve capacity. It is also authorized for normal continuous operation when coal quality, process conditions, and/or burner equipment prevent meeting demand with solid fuels only.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Sincerely,

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/sa/hh

# Department of
# Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

February 7, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. M. P. Opalinski
Director of Environmental Affairs
Seminole Electric Cooperative Incorporated
16313 North Dale Mabry Highway
Tampa, Florida 33688

Re: DRAFT Permit Modification: PSD-FL-018(A), PA 78-10
Seminole Power Plants, Palatka, Units 1 & 2
Petroleum Coke Co-firing

Dear Mr. Opalinski:

Enclosed is one copy of the Draft Permit Modification to the PSD permit for the Seminole Power Plants located in Palatka, Putnam County. The Department's Intent to Issue Permit Modification and the "PUBLIC NOTICE OF INTENT TO ISSUE PERMIT MODIFICATION" are also included.

The "PUBLIC NOTICE OF INTENT TO ISSUE PERMIT MODIFICATION" must be published within 30 (thirty) days of receipt of this letter. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit modification.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Mr. Syed Arif or Mr. Linero at 904/488-1344.

Sincerely,

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

CHF/sa/hh

Enclosures

## PUBLIC NOTICE OF INTENT TO ISSUE PERMIT MODIFICATION

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

File No.: PSD-FL-018(A), PA 78-10
Seminole Palatka Power Plant Units 1 & 2
Putnam County

The Department of Environmental Protection (Department) gives notice of its intent to issue a modification of Permit PSD-FL-018 to Seminole Electric Cooperative, Inc. (SECI) to allow co-firing of petroleum coke (petcoke) with coal and to allow increased use of No. 2 fuel oil at its Palatka Power Plant Units No. 1 & 2 in Putnam County. A Best Available Control Technology (BACT) determination was not required pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21, Prevention of Significant Deterioration (PSD). The modification will not result in a significant increase in sulfur dioxide, particulate matter, carbon monoxide, nitrogen oxides, or any other PSD pollutant from the facility, and will not cause a violation of any state or federal ambient air quality standards or increments. The applicant's name and address are: Seminole Electric Cooperative Incorporated, 16313 N. Dale Mabry Highway, Tampa, Florida 33688.

Units 1 and 2 are 714 megawatt (design) electrical power generating units, equipped with sulfur dioxide scrubbers, mist eliminators, and electrostatic precipitators. In accordance with the PSD permit issued by EPA in August, 1979, coal may be burned continuously while fuel oil may be used for startups and flame stabilization. The modification will permit co-firing of 30 percent, by weight, petcoke with coal. It will also permit use of the existing fuel oil system to generate up to 45 megawatts of electrical power in order to meet required reserve capacity and maintain electrical capacity when coal quality, conditions and/or processing or burner equipment prevents meeting demand with coal only. SECI conducted performance tests of coal/petcoke fuel blends December, 1995, and January, 1996. Based on the performance test results and additional control measures (increased use of underutilized sulfur dioxide scrubbing capability) proposed by SECI, the Department determined that PSD review is not applicable to this permit modification request.

The Department will issue the FINAL Permit Modification, in accordance with the conditions of the DRAFT Permit Modification unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed DRAFT Permit Modification issuance action for a period of 30 (thirty) days from the date of publication of this Notice. Any written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in this DRAFT Permit Modification, the Department shall issue a Revised DRAFT Permit Modification and require, if applicable, another Public Notice.

The Department will issue FINAL Permit Modification with the conditions of the DRAFT Permit Modification unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S. or a party requests mediation as an alternative remedy under Section 120.573 before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 904/488-9370, fax: 904/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by petitioner, if any; (e) A

statement of the facts that the petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement identifying the rules or statutes that the petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take with respect to the Department's action or proposed action addressed in this notice of intent.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A person whose substantial interests are affected by the Department's proposed permitting decision, may elect to pursue mediation by asking all parties to the proceeding to agree to such mediation and by filing with the Department a request for mediation and the written agreement of all such parties to mediate the dispute. The request and agreement must be filed in (received by) the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, by the same deadline as set forth above for the filing of a petition.

A request for mediation must contain the following information: (a) The name, address, and telephone number of the person requesting mediation and that person's representative, if any; (b) A statement of the preliminary agency action; (c) A statement of the relief sought; and (d) Either an explanation of how the requester's substantial interests will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that the requester has already filed, and incorporating it by reference.

The agreement to mediate must include the following: (a) The names, addresses, and telephone numbers of any persons who may attend the mediation; (b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time; (c) The agreed allocation of the costs and fees associated with the mediation; (d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation; (e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen; (f) The name of each party's representative who shall have authority to settle or recommend settlement; and (g) The signatures of all parties or their authorized representatives.

As provided in Section 120.573 F.S., the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57 F.S. for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57 F.S. remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 904/488-1344
Fax: 904/922-6979

Department of Environmental Protection
Site Certification Section
2720 Blair Stone Road, Suite H
Tallahassee, Florida 32301
Telephone: 904/487-0472

Department of Environmental Protection
Northeast District
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida 32256-7577
Telephone: 904/448-4310

The complete project file includes the Draft Permit Modification, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 904/488-1344, for additional information.

In the Matter of an
Application for Permit Modification by:

Mr. M. P. Opalinski
Director of Environmental Affairs
Seminole Electric Cooperative Inc.
16313 North Dale Mabry Highway
Post Office Box 27200
Tampa, Florida 33688

File No.: PSD-FL-018(A), PA 78-10
Seminole Power Plant Units 1 & 2
Putnam County

## INTENT TO ISSUE PERMIT MODIFICATION

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit modification (copy of DRAFT Permit modification attached) for the proposed project, as detailed in the application specified above, for the reasons stated below.

The applicant, Seminole Electric Cooperative Incorporated (SECI), submitted a request on November 12, 1996, to the Department for a modification of the Conditions of Approval contained in the Final Determination (PSD permit) issued August 9, 1979 by EPA for Seminole Power Plant Units 1 and 2, U.S. Highway North, Palatka, Putnam County. The modification is to allow co-firing of petcoke and coal in fuel blends containing up to 30 percent by weight petcoke and to allow increased use of No. 2 fuel oil.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a permit modification is required to commence or continue operations at the described facility.

The Department intends to issue this permit modification based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed "PUBLIC NOTICE OF INTENT TO ISSUE PERMIT MODIFICATION". The notice shall be published one time only within 30 (thirty) days in the legal advertisement section of a newspaper of general circulation in the area affected. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 904/488-1344; Fax 904/ 922-6979) within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit modification pursuant to Rule 62-103.150 (6), F.A.C.

The Department will issue the FINAL Permit Modification, in accordance with the conditions of the enclosed DRAFT Permit Modification unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed DRAFT Permit Modification issuance action for a period of 30 (thirty) days from the date of publication of "PUBLIC NOTICE OF INTENT TO ISSUE PERMIT MODIFICATION." Any written comments should be provided to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in

this DRAFT Permit Modification, the Department shall issue a Revised DRAFT Permit Modification and require, if applicable, another Public Notice.

The Department will issue the permit modification with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., or a party requests mediation as an alternative remedy under Section 120.573 F.S. before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for petitioning for a hearing are set forth below, followed by the procedures for requesting mediation.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative hearing in accordance with Sections 120.569 and 120.57 F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, telephone: 904/488-9730, fax: 904/487-4938. Petitions must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition (or a request for mediation, as discussed below) within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-5.207 of the Florida Administrative Code.

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

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice of intent. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A person whose substantial interests are affected by the Department's proposed permitting decision, may elect to pursue mediation by asking all parties to the proceeding to agree to such mediation and by filing with the Department a request for mediation and the written agreement of all such parties to mediate the dispute. The request and agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000, by the same deadline as set forth above for the filing of a petition.

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The agreement to mediate must include the following: (a) The names, addresses, and telephone numbers of any persons who may attend the mediation; (b) The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time; (c) The agreed allocation of the costs

and fees associated with the mediation; (d) The agreement of the parties on the confidentiality of discussions and documents introduced during mediation; (e) The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen; (f) The name of each party's representative who shall have authority to settle or recommend settlement; and (g) The signatures of all parties or their authorized representatives.

As provided in Section 120.573 F.S., the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57 F.S. for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57 F.S. remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

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

## CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE PERMIT MODIFICATION (including the PUBLIC NOTICE, and DRAFT permit modification) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2-10-97 to the person(s) listed:

Mr. M .P. Opalinski, SECI *
Mr. Tom W. Davis, P.E., ECT
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Hamilton Oven, DEP
Mr. Chris Kirts, NED

Clerk Stamp

**FILING AND ACKNOWLEDGMENT FILED**, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kimi Deber 2-10-97
(Clerk) (Date)

DRAFT

March XX, 1997

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. M. P. Opalinski
Director of Environmental Affairs
Seminole Electric Cooperative Incorporated
16313 North Dale Mabry Highway
Tampa, Florida 33688

Re: Seminole Power Plants, Palatka, Units 1 & 2
Modification of Final Determination - PSD-FL-018(A), PA 78-10

Dear Mr. Opalinski:

The Department hereby amends the Conditions of Approval related to emissions, fuel use, recordkeeping and reporting in the subject Final Determination (dated August 13, 1979) pursuant to 40 CFR 52.21 - Prevention of Significant Deterioration (PSD Permit). The PSD permit is amended as follows:

D. FOR THE ELECTRIC UTILITY STEAM GENERATING UNITS WHEN BURNING COAL AND PETROLEUM COKE FUEL BLENDS

Stack emissions from Units 1 and 2 shall comply with the following conditions when burning blends of coal and petroleum coke:

Item 1 - Sulfur Dioxide Emissions

a) Unit 1:

$$E_{SO2} = [ ( \%C_{HI} / 100 ) * (P_S ) * ( 1 - ( \% R_o / 100 )) ] + [ ( 1 - ( \%C_{HI} / 100 )) * ( 0.74 \text{ lb } SO_2 / \text{MMBtu} )] \quad \text{(Eqn. 1)}$$

b) Unit 2:

$$E_{SO2} = [ ( \%C_{HI} / 100 ) * ( P_S ) * ( 1 - ( \% R_o / 100 ))] + [ ( 1 - ( \%C_{HI} / 100 )) * ( 0.72 \text{ lb } SO_2 / \text{MMBtu} )] \quad \text{(Eqn. 2)}$$

where:

$E_{SO2}$ = allowable $SO_2$ emission rate; lb $SO_2$/MMBtu, 30-day rolling average

| | |
|---|---|
| $\%C_{HI}$ | = percent of coal used on a heat input basis |
| $P_S$ | = potential $SO_2$ combustion concentration (unwashed coal without emission control systems) as defined by NSPS Subpart Da; lb $SO_2$/MMBtu, 30-day rolling average |
| $\% R_o$ | = overall percent $SO_2$ reduction from Equation 19-21 of EPA Reference Method 19. Per NSPS Subpart Da, $\% R_o$ must not be less than 90%, 30-day rolling average |
| 0.74 | = historical 2-year annual average $SO_2$ emission rate for Unit 1; lb/MMBtu |
| 0.72 | = historical 2-year annual average $SO_2$ emission rate for Unit 2; lb/MMBtu |

Compliance with the lb per million Btu heat input emission limitations and percent reduction requirement shall be determined on a 30-day rolling average basis.

Item 2 - Nitrogen Oxide Emissions

a) 0.60 lb. per million Btu heat input, and 35 percent of the potential combustion concentration (65 percent reduction). Compliance with the lb. per million Btu heat input emission limitation and percent reduction requirement shall be determined on a 30-day rolling average basis. Compliance with the 0.60 lb. per million Btu heat input emission limitation shall also constitute compliance with the 65 percent reduction requirement; and

b) 0.50 lb. per million Btu heat input determined on an annual average basis, when subject to the 40 CFR §76.8 Early Election Program for Group 1, Phase II Boilers or in any year when petcoke is burned.

Item 3 - Particulate Matter Emissions

0.03 lb. per million Btu heat input, and 1 percent of the potential combustion concentration (99 percent reduction). Compliance with the 0.03 lb. per million Btu heat input emission limitation shall also constitute compliance with the 99 percent reduction requirement.

Item 4 - Carbon Monoxide Emissions

The Permittee shall maintain and submit to the Department, on an annual basis for a period of five years from the date the units begin firing petroleum coke, test results demonstrating that the operational changes did not result in a significant emissions increase of the pollutant when compared to the past actual coal levels. The carbon monoxide emissions shall be based on test results using EPA Method 10.

Item 5 - Sulfuric Acid Mist Emissions

The Permittee shall maintain and submit to the Department on an annual basis for a period of five years from the date the units begin firing petroleum coke, test results demonstrating that the operational changes did not result in a significant emissions increase of the pollutant when compared to the past actual coal levels. The sulfuric acid mist emissions shall be based on test results using EPA Method 8.

Item 6 - Fuel Specifications

Fuels fired shall consist of coal and petroleum coke blends containing a maximum of 30 percent petroleum coke by weight. The maximum weight of the petroleum coke burned shall not exceed 125,000 pounds per hour (averaged over 24 hours). The petroleum coke sulfur content shall not exceed 7.0 percent by weight, dry basis.

Item 7 - Reporting and Recordkeeping

a) Documentation verifying that the coal and petroleum coke fuel blends combusted in Units 1 and 2 have not exceeded the 30 percent maximum petroleum coke by weight limit specified by Condition of Approval, Section D., Item 6 shall be maintained and submitted to the Department's Northeast District Office with each annual report; and

b) The Permittee shall maintain and submit to the Department, on an annual basis for a period of five years from the date the units begin firing petroleum coke, data demonstrating that the operational change associated with the use of petroleum coke did not result in a significant emission increase pursuant to Rule 62-210.200(12)(d), F.A.C.

Item 8 - Handling of Petroleum Coke

All prior conditions of approval that address coal handling shall also apply to the handling of petroleum coke.

E. FOR THE ELECTRIC UTILITY STEAM GENERATING UNITS WHEN BURNING NO 2 FUEL OIL

Use of No. 2 fuel oil is authorized for startups, flame stabilization and required emergency electric reserve capacity. It is also authorized for normal continuous operation when coal quality, process conditions, and/or burner equipment prevent meeting demand with solid fuels only.

A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Sincerely,

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/sa/hh

Enclosures

DIVISION OF AIR RESOURCES MANAGEMENT
BUREAU OF AIR REGULATION
NEW SOURCE REVIEW SECTION
Telephone (904) 488-1344
Fax (904) 922-6979

# TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

Seminole Electric Cooperative, Incorporated
Seminole Power Plant
Units 1 & 2
Palatka, Putnam County, Florida

Electric Utility Steam Generating Units
Solid and Liquid Fuel-Fired Boilers
714.6 MW/unit

Permit No. PSD-FL-018
PA 78-10

February 7, 1997

## 1. Applicant

Seminole Electric Cooperative, Inc.
16313 North Dale Mabry Highway
Tampa, Florida 33618-1342

## 2. Source Name and Location

Seminole Power Plant
Units 1 & 2
Palatka, Florida 32177

## 3. Source Description

The Seminole Electric Cooperative, Inc. (Seminole) power plant located in Palatka, Putnam County, Florida, is a baseload coal-fired steam electric utility generating facility. The Seminole Power Plant consists of two steam boilers (Units 1 and 2); two steam turbines; a recirculating cooling water system; coal, limestone, fly ash, and bottom ash handling equipment, a flue gas desulfurization (FGD) sludge stabilization facility; fuel oil storage tanks; water treatment facilities; a railcar maintenance facility; and other ancillary support equipment. Each boiler is equipped with electrostatic precipitators (ESPs), low-nitrogen oxide ($NO_X$) burners, and a FGD system to control emissions of particulate matter (PM), $NO_X$, and sulfur dioxide ($SO_2$), respectively. Units 1 and 2 each have a maximum electrical load rating of 714.6 megawatt (MW). The boilers are presently coal-fired with No. 2 fuel oil used for startups and flame stabilization.

## 4. Current Permit and Major Regulatory Program Status

Operation of the Seminole Power Plant is currently authorized by United States Environmental Protection Agency (EPA) Prevention of Significant Deterioration (PSD) Permit No. PSD-FL-018 and Florida Power Plant Siting Act (PPSA) Certification No. PA 78-10. In June 1996, Seminole submitted an application for a Title V operation permit; this application is presently undergoing Department review.

The initial construction of Units 1 and 2 was authorized pursuant to the PSD New Source Review (NSR) regulatory permitting program. Units 1 and 2 are subject to New Source Performance Standard (NSPS) Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The Seminole Power Plant boilers are also subject to the Federal Acid Rain Program requirements applicable to Phase II units.

An amendment to Permit PSD-FL-018 (Attachment 1) was issued on December 11, 1995 following publication of the Department's Notice of Intent. This permit amendment authorized Seminole to conduct performance tests on Unit 1 while firing various blends of coal and petroleum coke (petcoke). The petcoke test burns were conducted during December 1995 and January 1996.

Seminole submitted a comprehensive report of the petcoke test burn results to the Department in February 1996.

## 5. Permit Amendment Request

On November 12, 1996, Seminole Electric Cooperative, Inc. (Seminole) submitted a request (Attachment 2) for an amendment to Permit PSD-FL-018 originally issued by EPA on August 13, 1979. The requested amendments are as follows:

i. Allow co-firing of petcoke and coal in fuel blends containing up to 30 percent by weight petcoke as an alternate method of operation; and

ii. Allow use of No. 2 fuel oil to generate electric power during statewide emergency energy shortages to meet Florida Public Service Commission (FPSC) reserve and maximum continuous electric load requirements if coal quality, process conditions, and/or burner equipment prevents meeting demand with solid fuels only.

Following an initial review of the submitted material, the Department requested additional information in a letter to Seminole dated November 25, 1996. A meeting attended by Department staff and Seminole representatives to discuss the request was held on December 19, 1996. A response to the information requested in the Department's November 25th letter and other issues raised during the December 19th meeting was provided to the Department by Seminole in correspondence dated January 7, 1997.

## 6. Potentially Applicable Major Rules

Major rules that could potentially apply to this permit amendment request include the following:

i. Florida Electrical Power Plant Siting, Chapter 62-217, F.A.C. and Sections 403.501-519, Florida Statutes (F.S.);

ii. 40 CFR 60 - Standards of Performance for New Stationary Sources, Subpart Da - "Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978" (NSPS Subpart Da) adopted by reference in Chapter 62-204, Florida Administrative Code (F.A.C.);

iii. Section 62-212.400, F.A.C. - "Prevention of Significant Deterioration of Air Quality", (PSD Rules); and

iv. Chapter 62-297, F.A.C., related to emission monitoring at stationary sources.

Seminole has requested amendments to its existing PSD permit and Site Certification. Matters related to Site Certification amendments will be handled separately by the Department's Office of

Siting Coordination in accordance with Florida Power Plant Siting Act (PPSA) specified modification procedures.

As noted in Section 4 above, Units 1 and 2 are presently subject to the requirements of NSPS Subpart Da. They will continue to be operated in a manner at least as stringent as the requirements of Subpart Da.

The primary regulatory issue pertinent to Seminole's permit amendment request is that of PSD permitting applicability. Modifications which result in a *significant net emission rate increase* are classified as major modifications and therefore subject to PSD review. The procedures for determining whether a significant net emission rate increase will occur were changed by EPA in July 1992 as a result of the Wisconsin Electric Power Company (WEPCO) litigation. Prior to the WEPCO decision, the calculation of a net emission increase was based on comparing actual annual emissions for the two year period prior to the change (before case) with potential emissions following the change (after case). Another two year period (within a five year period prior to the change) could be used if it was demonstrated to be more representative of normal source operation. Unless constrained by a Federally enforceable permit condition, potential emissions would be calculated assuming continuous operation at rated capacity. This procedure is referred to as the *actual-to-potential* method.

As a result of the WEPCO litigation, the net emission increase for electric utility generating units is now determined by comparing actual emissions preceding the change with estimated future actual emissions or an *actual-to-actual* procedure. Any consecutive two year period within the preceding five years is used as the "before case". The "after case" is developed based on the projected future actual emission rates. The time period for the "after case" is the two years following the change or any other consecutive two year period within ten years after the change if that period would be more representative of normal source operations. Sources must monitor emissions for five years (or longer if the first five years are not representative of normal source operations) to document future actual emissions and to confirm that a significant net emission increase has not occurred. Increases in utilization that are unrelated to the physical change, such as demand growth, are not considered in calculating emission increases. The rationale for this exclusion is that these emission increases would have occurred in the absence of the physical change (assuming the unit was capable of increasing its capacity factor without the physical change).

Based on the petcoke test burn results, fuel analyses, historical emissions data, EPA emission factors, and evaluation of the Seminole Units 1 and 2 pollution control system capabilities, the Department has determined that Seminole's permit amendment request is not subject to PSD review, subject to certain Federally enforceable permit conditions. A detailed evaluation of PSD applicability is provided in Section G below.

With respect to emissions monitoring, Units 1 and 2 are currently equipped with continuous emissions monitoring systems (CEMS) to monitor and record $SO_2$ and $NO_X$ emission rates and continuous opacity monitoring systems (COMS) to monitor and record visible emissions. The units are also presently equipped to continuously monitor exhaust flow rates and carbon dioxide ($CO_2$)

concentrations. On an annual basis, Units 1 and 2 are tested to determine PM emission rates. The current emissions monitoring program is conducted pursuant to NSPS Subpart Da and Acid Rain Program requirements.

## 7. Evaluation of PSD Applicability

The main issue regarding Seminole's permit amendment request is that of PSD review applicability. The Department's detailed assessment of this regulatory issue is provided in this section.

A brief description of the PSD review procedures resulting from the WEPCO litigation was provided above in Section F. Both EPA and the Department have revised their NSR permitting rules to implement the WEPCO PSD review procedures. The Department's revised definition of "actual emissions" [Chapter 62-204 (12), F.A.C.] follows:

(12) "Actual Emissions" The actual rate of emission of a pollutant from an emissions unit as determined in accordance with the following provisions:

(12)(a) In general, actual emissions as of a particular date shall equal the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during a two year period which precedes the particular date and which is representative of the normal operation of the emissions unit.

The Department may allow the use of a different time period upon a determination that it is more representative of the normal operation of the emissions unit. Actual emissions shall be calculated using the emissions unit's actual operating hours, production rates and types of materials processed, stored, or combusted during the selected time period.

(12)(b) The Department may presume that unit-specific allowable emissions for an emissions unit are equivalent to the actual emissions of the emissions unit provided that, for any regulated air pollutant, such unit-specific allowable emissions limits are federally enforceable.

(12)(c) For any emissions unit (other than an electric utility steam generating unit specified in subparagraph (d) of this definition) which has not begun normal operations on a particular date, actual emissions shall equal the potential emissions of the emissions unit on that date.

(12)(d) For an electric utility steam generating unit (other than a new unit or the replacement of an existing unit) actual emissions of the unit following a physical or operational change shall equal the representative actual annual emissions of the unit following the physical or operational change, provided the owner or operator maintains and submits to the Department on an annual basis, for a period of 5 years representative of normal post-change operations of the unit, within the period not longer than 10 years following the change, information demonstrating that the physical or operational change did not result in an emissions increase. The definition of "representative actual annual emissions" found in 40 CFR 52.21(b) (33) is adopted and incorporated by reference in Rule 62-204.800, F.A.C.

The Federal definition of "representative actual annual emissions", which the Department has incorporated by reference, follows:

(33) Representative actual annual emissions means the average rate, in tons per year, at which the source is projected to emit a pollutant for the two-year period after a physical change or change in the method of operation of a unit, (or a different consecutive two-year period within 10 years after that change, where the Administrator determines that such period is more representative of normal source operations), considering the effect any such change will have on increasing or decreasing the hourly emissions rate and on projected capacity utilization.

In projecting future emissions the Administrator shall:

(i) Consider all relevant information, including but not limited to, historical operational data, the company's own representations, filings with the State or Federal regulatory authorities, and compliance plans under title IV of the Clean Air Act; and

(ii) Exclude, in calculating any increase in emissions that results from the particular physical change or change in the method of operation at an electric utility steam generating unit, that portion of the unit's emissions following the change that could have been accommodated during the representative baseline period and is attributable to an increase in projected capacity utilization at the unit that is unrelated to the particular change, including any increased utilization due to the rate of electricity demand growth for the utility system as a whole.

Seminole has submitted information which demonstrates that the planned combustion of coal and petcoke fuel blends will not increase actual emissions in accordance with the applicable regulations. Seminole believes the use of No. 2 fuel oil for electrical generation will not result in emissions increases. This is correct on the basis of emissions per unit of heat input. However, the Department believes, oil use will marginally increase unit availability, resulting in emission increases which are not significant with respect to PSD. Seminole's analysis of PSD applicability is included in the submitted application as Appendix E and as Attachment 3 to this Preliminary Determination. Seminole's discussion of potential emission rate changes resulting from the use of No. 2 fuel oil to generate electric capacity is included in the submitted application as Appendix F.

Petcoke is a by-product of the petroleum refining process. Petcoke is a high carbon, relatively low ash content solid material that historically has been used in the manufacture of anodes and electrodes for aluminum reduction processes. Because of its favorable heating value and cost, petcoke is presently being considered by a number of electric utilities as a supplemental fuel source for coal-fired boilers.

The sulfur content of petcoke varies with the sulfur content of the refinery coker feedstock. Petcoke has a relatively low ash content; i.e., typically less than 1.0 weight percent. The lower heat content of petcoke, on a dry basis, is approximately 13,500 to 14,000 British thermal units (Btu) per pound. Moisture content of petcoke is in the range of 7 to 10 weight percent. The nitrogen content of

petcoke is comparable to that of coal; i.e., approximately 1.3 weight percent on a dry basis. As with coal, petcoke also contains a variety of trace metals. These general characteristics of petcoke indicate that the primary concern, from an emissions viewpoint, is potential increases in $SO_2$ emissions.

Seminole Units 1 and 2 presently meet an overall 90 percent reduction in potential $SO_2$ emissions from coal as required by NSPS Subpart Da using a combination of pre-combustion fuel treatment (e.g., coal washing) and post-combustion FGD sulfur removal technologies. The current average FGD $SO_2$ removal efficiency for Units No. 1 and 2 is approximately 84.5% which, together with a typical coal washing credit of 6.0 percent, is sufficient to meet the NSPS Subpart Da 90.0 percent $SO_2$ removal requirement. To ensure that no increases in actual $SO_2$ emissions above the historical two year averages occur due to the use of petcoke, Seminole proposes to increase the $SO_2$ removal efficiency of the current FGD systems. Seminole has submitted information demonstrating that under worst-case conditions (i.e., combustion of coal and petcoke fuel blends containing the maximum requested amount of petcoke and maximum requested coal and petcoke sulfur contents), a FGD $SO_2$ removal efficiency of 88 percent will be required. This removal efficiency represents an approximate four percent increase over that currently required of Units 1 and 2 FGD systems by NSPS Subpart Da. Seminole also submitted information demonstrating that the existing FGD systems have been able to successfully achieve a $SO_2$ removal efficiency in excess of 90 percent, excluding the coal washing credit. Units 1 and 2 are each equipped with five FGD scrubber modules and include provisions for the addition of adipic acid additive to increase $SO_2$ removal efficiencies. Presently, the 5th FGD scrubber module for each unit serves as a spare. The demonstration of FGD $SO_2$ removal efficiencies in excess of 90 percent was conducted with only four FGD scrubber modules in use. Due to the proven successful operation of the existing FGD system and the demonstrated ability of the current FGD system to achieve $SO_2$ removal efficiencies in excess of 90 percent (or two percent above the projected maximum FGD removal efficiency required during combustion of coal and petcoke blends), the Department concludes that there is reasonable assurance that the use of petcoke will not result in an actual increase in $SO_2$ emissions. In addition, Seminole's optional use of the 5th FGD scrubber module and/or increased use of adipic acid additive provides further assurance that an actual increase in $SO_2$ emissions will not occur.

The information submitted by Seminole with respect to the remaining PSD regulated pollutants indicates that there will also be no actual emission increases for any of these pollutants including $NO_X$, CO, PM, and sulfuric acid mist ($H_2SO_4$). Information provided by Seminole to support this conclusion include the petcoke test burn results, typical coal and petcoke compositions, and EPA emission factors. For $NO_X$, CO, PM, and $H_2SO_4$, the petcoke test burn results provide reasonable assurance that actual emission increases will not occur for these pollutants due to the use of petcoke. Regarding future actual $NO_X$ emissions, Seminole has elected to be subject to the Federal Acid Rain Program $NO_X$ emission limits contained in 40 CFR §76.5 under the Acid Rain $NO_X$ Early Election Program for Group 1, Phase II boilers. Under the $NO_X$ Early Election Program, Seminole is required to meet an annual average $NO_X$ emission limit of 0.50 lb/MMBtu effective January 1,1997. Seminole's participation in the Acid Rain $NO_X$ Early Election Program provides further reasonable assurance that a significant net increase in $NO_X$ emissions will not occur due to the use of petcoke. With respect to future actual PM emission rates, the lower ash content of petcoke compared to coal provides further assurance that an actual increase in emissions will not occur. The ash content of

petcoke (approximately 0.5 percent by weight) is only 5.5% of the ash content of coal (approximately 9 percent by weight). Accordingly, petcoke combustion will generate significantly less fly ash (i.e., PM emissions) than the combustion of coal.

The Seminole Power Plant is a baseload facility currently operating at an approximate 80 percent capacity factor. This relatively high capacity factor (a typical industry average for baseload units is 70 percent) will not increase due to the use of petcoke. Accordingly, an increase in actual emissions because of increased utilization is not expected.

Based on the performance test results, fuel analyses, historical emissions data, EPA emission factors, and evaluation of pollution control system capabilities, the Department concludes that the use of petcoke as described in Seminole's permit application will not result in a significant net increase in any PSD regulated pollutant and therefore the permit amendment request regarding the use of petcoke in Units 1 and 2 is not subject to PSD review. As discussed below in Section I, the Department plans to include appropriate permit conditions to ensure that no significant increases in PSD regulated pollutants occur due to the use of petcoke at the Seminole Power Plant.

The use of No. 2 fuel oil to generate electric capacity will not result in significant emissions increase of PSD regulated pollutants. Seminole projects limited usage of No. 2 fuel oil because of economic considerations; i.e., No. 2 fuel oil is a considerably more expensive source of fuel to generate electricity in comparison to coal. In a worst-case scenario, Seminole projects that fuel oil would constitute only 6.3 percent of the instantaneous hourly heat and 0.14 percent of the annual heat input to Units 1 and 2. The Department concludes that the use of No. 2 fuel to generate electric capacity as described in Appendix F of Seminole's permit application will not result in a significant net actual increase in any PSD regulated pollutant and therefore the permit amendment request regarding the use of No. 2 fuel oil to generate electric capacity is not subject to PSD review.

## 8. Proposed Addition of New Conditions of Approval to Permit PSD-FL-018

Following review of the test burn report, permit amendment request application, and the additional information submitted by Seminole, the Department proposes adding the following new conditions of approval to permit PSD-FL-018:

Section D (new)

D. FOR THE ELECTRIC UTILITY STEAM GENERATING UNITS WHEN BURNING COAL AND PETROLEUM COKE FUEL BLENDS

Stack emissions from Units 1 and 2 shall comply with the following conditions when burning blends of coal and petroleum coke:

Item 1 - Sulfur Dioxide Emissions

(a) Unit 1:

$$E_{SO2} = [ ( \%C_{HI} / 100 ) * (P_S ) * ( 1 - ( \% R_o / 100 )) ] + [ ( 1 - ( \%C_{HI} / 100 )) * ( 0.74 \text{ lb } SO_2 / \text{MMBtu} )] \quad \text{(Eqn. 1)}$$

(b) Unit 2:

$$E_{SO2} = [ ( \%C_{HI} / 100 ) * ( P_S ) * ( 1 - ( \% R_o / 100 ))] + [ ( 1 - ( \%C_{HI} / 100 )) * ( 0.72 \text{ lb } SO_2 / \text{MMBtu} )] \quad \text{(Eqn. 2)}$$

where:

| | | |
|---|---|---|
| $E_{SO2}$ | = | allowable $SO_2$ emission rate; lb $SO_2$/MMBtu, 30-day rolling average |
| $\%C_{HI}$ | = | percent of coal used on a heat input basis |
| $P_S$ | = | potential $SO_2$ combustion concentration (unwashed coal without emission control systems) as defined by NSPS Subpart Da; lb $SO_2$/MMBtu, 30-day rolling average |
| $\% R_o$ | = | overall percent $SO_2$ reduction from Equation 19-21 of EPA Reference Method 19. Per NSPS Subpart Da, $\% R_o$ must not be less than 90%, 30-day rolling average |
| 0.74 | = | historical 2-year annual average $SO_2$ emission rate for Unit 1; lb/MMBtu |
| 0.72 | = | historical 2-year annual average $SO_2$ emission rate for Unit 2; lb/MMBtu |

Compliance with the lb per million Btu heat input emission limitations and percent reduction requirement shall be determined on a 30-day rolling average basis.

Item 2 - Nitrogen Oxide Emissions

(a) 0.60 lb. per million Btu heat input, and 35 percent of the potential combustion concentration (65 percent reduction). Compliance with the lb. per million Btu heat input emission limitation and percent reduction requirement shall be determined on a 30-day rolling average basis. Compliance with the 0.60 lb. per million Btu heat input emission limitation shall also constitute compliance with the 65 percent reduction requirement; and

(b) 0.50 lb. per million Btu heat input determined on an annual average basis, when subject to the 40 CFR §76.8 Early Election Program for Group 1, Phase II Boilers or in any year when petcoke is burned.

Item 3 - Particulate Matter Emissions

0.03 lb. per million Btu heat input, and 1 percent of the potential combustion concentration (99 percent reduction). Compliance with the 0.03 lb. per million Btu heat input emission limitation shall also constitute compliance with the 99 percent reduction requirement.

Item 4 - Carbon Monoxide Emissions

The Permittee shall maintain and submit to the Department, on an annual basis for a period of five years from the date the units begin firing petroleum coke, test results demonstrating that the operational changes did not result in a significant emissions increase of the pollutant when compared to the past actual coal levels. The carbon monoxide emissions shall be based on test results using EPA Method 10.

Item 5 - Sulfuric Acid Mist Emissions

The Permittee shall maintain and submit to the Department on an annual basis for a period of five years from the date the units begin firing petroleum coke, test results demonstrating that the operational changes did not result in a significant emissions increase of the pollutant when compared to the past actual coal levels. The sulfuric acid mist emissions shall be based on test results using EPA Method 8.

Item 6 - Fuel Specifications

Fuels fired shall consist of coal and petroleum coke blends containing a maximum of 30 percent petroleum coke by weight. The maximum weight of the petroleum coke burned shall not exceed 125,000 pounds per hour (averaged over 24 hours). The petroleum coke sulfur content shall not exceed 7.0 percent by weight, dry basis.

Item 7 - Reporting and Recordkeeping

(a) Documentation verifying that the coal and petroleum coke fuel blends combusted in Units 1 and 2 have not exceeded the 30 percent maximum petroleum coke by weight limit specified by Condition of Approval, Section D., Item 6 shall be maintained and submitted to the Department's Northeast District Office with each annual report; and

(b) The Permittee shall maintain and submit to the Department, on an annual basis for a period of five years from the date the units begin firing petroleum coke, data demonstrating that the operational change associated with the use of petroleum coke did not result in a significant emission increase pursuant to Rule 62-210.200(12)(d), F.A.C.

Item 8 - Handling of Petroleum Coke

All prior conditions of approval that address coal handling shall also apply to the handling of petroleum coke.

Section E (new)

E. FOR THE ELECTRIC UTILITY STEAM GENERATING UNITS WHEN BURNING NO 2 FUEL OIL

Use of No. 2 fuel oil is authorized for startups, flame stabilization, to generate emergency electric reserve capacity requirements, and to meet normal continuous operating electric load ratings when coal quality, process conditions, and/or burner equipment prevents meeting demand with solid fuels only.

I. Discussion of Proposed New Conditions of Approval to Permit PSD-FL-018

The proposed new conditions contained in Section 8 above address allowable emissions of $SO_2$, $NO_X$, PM, CO and $H_2SO_4$ in addition to including provisions pertaining to fuel blend characteristics, reporting and recordkeeping, and petcoke handling.

The emission limits for $SO_2$ (Item 1) contain two algorithms (one for each unit) to ensure that actual increases in $SO_2$ emissions will not occur due to the use of petcoke. These algorithms contain two basic components which are enclosed in brackets. The first term in brackets addresses the coal portion of the coal and petcoke fuel blend and implements the current requirements of NSPS Subpart Da. The second term in brackets addresses the petcoke portion of the coal and petcoke fuel blend and represents the historical two year average $SO_2$ emission rate for each unit. Accordingly, NSPS Subpart Da $SO_2$ emission requirements will continue to apply to the coal portion of the fuel blends while petcoke $SO_2$ emissions will be held to each unit's historical two year annual average $SO_2$ emission rate.

The emission limits for $NO_X$ (Item 2) implement current NSPS Subpart Da requirements as well as the new annual average limit that Seminole has elected to meet under the Acid Rain $NO_X$ Early Election Program for Group 1, Phase II boilers. The emission limit for PM (Item 3) implements current NSPS Subpart Da requirements.

Item 6 of the proposed permit conditions contain constraints on the maximum amount of petcoke which may be blended and maximum petcoke sulfur content. These constraints are consistent with Seminole's permit amendment request and are included to provide assurance that an actual increase in $SO_2$ emissions will not occur.

Item 7 of the proposed permit conditions requires Seminole to demonstrate annually, for a period of five years, that an actual emission increase has not occurred due to the burning of petcoke. Seminole has indicated that it intends to make this demonstration using data obtained from the existing CEMS, fuel composition and usage rates, and results of periodic stack sampling.

## 9. Conclusions

The changes in operation authorized by these permit amendments are not expected to cause a net significant increase in actual emissions of any PSD regulated air pollutant. The changes will not result in any increases in ambient concentrations of any regulated air pollutants or cause or contribute to a violation of any ambient air quality standard or PSD increment.

1210003

# Compliance Assurance Monitoring Plan

For

$NO_x$ Emissions from Suwannee River Plant Combustion Turbines

Progress Energy Florida

Live Oak, Suwannee County, FL

## I. Background

A. Emissions Unit

EU ID(s): Combustion Turbines P1, P2 and P3 (Internal ID)
004, 005, and 006, respectively (Title V Permit Unit ID)

Descriptions: 739 MMBtu/hr (63 MW) nominally rated Natural Gas/No.2 Fuel Oil Fired Combustion Turbines

B. Applicable Emissions Limits and Current Monitoring Practices

*Emissions Limits:*

$NO_x$: 68 ppmvd @ 15% $O_2$ (natural gas)
75 ppmvd @ 15% $O_2$ (No.2 fuel oil)
Basis: BACT and Title V permit limitation

*Current Compliance Demonstration Requirements:*

| | |
|---|---|
| $NO_x$: | RM 20 (or 7E) testing |
| Nitrogen content Of Fuel Oil: | Fuel Supplier Certifications (Basis: Title V Permit Conditions B.19 and B.20) |
| Water/Fuel Ratio: | Continuous Monitoring (Basis: Title V Permit Condition B.18) |

*Current Periodic Monitoring Requirements:*

| | |
|---|---|
| $NO_x$: | Annual testing, if natural gas fired or liquid fuel fired more than 400 hours in a FY |
| Nitrogen content of Fuel Oil | Fuel Supplier Certifications<br>Each shipment of oil is accompanied by a bill of lading with the manufacturer's certification of the maximum nitrogen content of the oil being delivered. |
| Water Fuel Ratio: | Continuous Monitoring of the water to fuel ratio is performed while each unit is running. |

C. Control Technology

Water Injection for $NO_x$ control (WINJ)

D. Potential Emission Rates (Oil Firing)

| | |
|---|---|
| Pre-Control $NO_x$ | 788.5 tons per year per CT (assume 80% control) |
| Post-Control $NO_x$ | 157.7 tons per year per CT (210 lb/hr per CT) |

## II. Monitoring Approach

A. Background

All three combustion turbines are identical in configuration. They are Combustion Turbine Model Turbo Power and Marine Systems FT4C-3 LF water injected twin packs. Nitrogen oxides emissions are controlled by using water injection for both natural gas and fuel oil firing. Natural gas and new No. 2 distillate fuel oil are allowed to be fired in these emissions units and the maximum allowable fuel oil sulfur content is 0.5%, by weight. Each emissions unit has a maximum generating output of 63 MW and a maximum heat input of approximately 739 MMBtu/hr (LHV: lower heating value) at 59 degrees F while firing new No. 2 distillate fuel oil or natural gas. The maximum No. 2 distillate fuel oil that can be fired is 37,910 lbs/hr (127 barrels at 59 degrees F). The emissions units may operate 1,500 hours per year per CT.

Units Nos. 1 and 2 (P-1 and P-2, respectively) commenced commercial operation in October, 1980. Unit No. 3 (P-3) commenced commercial operation in November, 1980. The emissions units are regulated under NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines; adopted and incorporated by reference in Rule 62-204.800(7)(b)38., F.A.C; PSD-FL-014 and PSD-FL-014(A), Prevention of Significant Deterioration (PSD), in Rule 62-212.400, F.A.C.; Best Available Control Technology (BACT), in Rule 62-212.410, F.A.C.

The CTs are subject to emission limitations of 68 ppmvd @ 15% $O_2$ while firing natural gas and 75 ppmvd @ 15% $O_2$ while firing fuel oil. These CTs use water injection to meet the limitations on gas and oil, and they have a potential precontrol $NO_x$ emission rate greater than the 100 ton per year major source threshold. The CTs, therefore, are subject to the requirements of 40 CFR 64, Compliance Assurance Monitoring (CAM), pursuant to Section 64.2(a).

B. Use of Presumptively Acceptable Monitoring

40 CFR 64.4(b) states: To justify the appropriateness of the monitoring elements proposed, the owner or operator may rely in part on existing applicable requirements that establish the monitoring for the applicable pollutant-specific emissions unit or a similar unit. If an owner or operator relies on presumptively acceptable monitoring, no further justification for the appropriateness of that monitoring should be necessary other than an explanation of the applicability of such monitoring to the unit in question, unless data or information is brought forward to rebut the assumption.

C. Summary of Proposed CAM for $NO_x$

Since the existing monitoring system is required under current regulations, its use as CAM for $NO_x$ monitoring is therefore proposed. Continuous monitoring of water to fuel ratio is required by 40 CFR Part 60 Subpart GG. If the water-to-fuel ratio does not fall below the level used to demonstrate compliance during $NO_x$ testing, compliance is reasonably assured. The minimum water to fuel ratio does not apply during periods of startup, shutdown, or malfunction.

## III. Monitoring Approach Justification

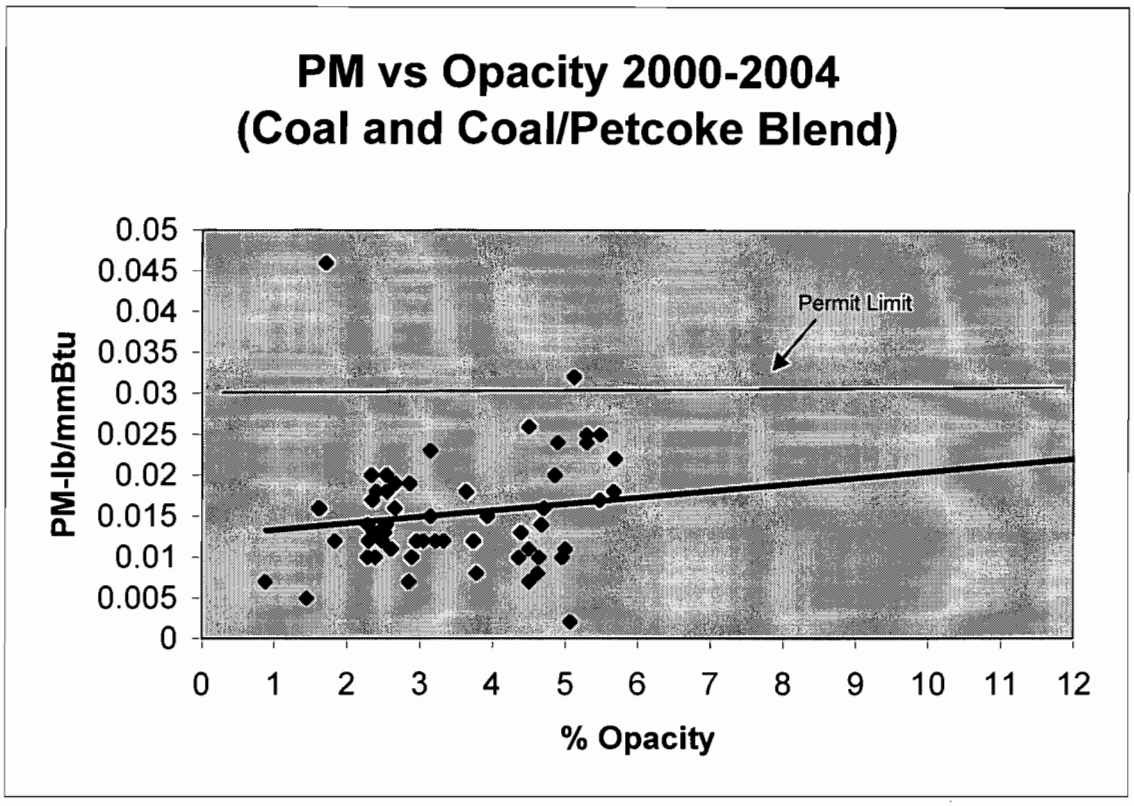
### A. Explanation of Applicability of Monitoring

These emission units are subject to 40 CFR 60, Subpart GG regulations requiring the monitoring of the water-to-fuel ratio. In addition, Specific Condition B.52 of the current TV permit specifies minimum water-to-fuel ratios necessary for operation. As agreed upon, the Department will delete this language from Condition B.52 of the renewed TV permit, as the appropriate water-to-fuel ratios expected for normal operation are now indicated in this CAM Plan. Since this is considered presumptively acceptable monitoring, no further justification is necessary.

**Table 1. $NO_x$ CAM Plan Summary- Suwannee River Plant Units P1, P2 and P3**

| | |
|---|---|
| **A. Indicator**<br>Measurement Approach | Water-to-fuel ratio |
| **B. Indicator Range** | An excursion is defined as any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the Target ratio values ( excluding startup, shutdown and malfunction) for each of the CTs as follows:<br><br>Fuel Oil<br>• 0.570<br><br>Natural Gas<br>• 0.380<br><br>(CT2A and CT2B do not currently fire natural gas)<br><br>These water-to-fuel ratios have been determined to provide a reasonable assurance of compliance with the limits contained in NSPS, Subpart GG and the Title V permit. Excursions trigger an inspection of the water injection system to determine the cause and any necessary corrective action.<br><br>In addition, if water flow to any unit is unavailable for more than 90 minutes, the affected CT will automatically shut down. |
| **C. Performance Criteria** | |
| 1. Data Representativeness | The system meets the specifications of 40 CFR Part 60, Subpart GG. |
| 2. Verification of Operational Status | Not applicable, use of existing monitoring equipment is proposed. |
| 3. QA/QC Practices and Criteria | All data QA/QC is in accordance with the requirements of 40 CFR Part 60. |
| 4. Monitoring Frequency | Continuous |
| 5. Data Averaging Period | 1 hour average (data collection frequency is continuous) |
| 6. Data Collection | Automated data acquisition system (DAHS) |

Suwannee River




A.41. PM 120 min sample time
Total test = 6 hrs Test avg.

6½% for 1hr
12% avg 1-6min