Title V Air Operation Permit Revision
Florida Power Corporation dba Progress Energy Florida, Inc.
Crystal River Power Plant
Final Permit No. 0170004-025-AV

APPLICANT

The applicant for this project is Florida Power Corporation dba Progress Energy Florida, Inc. The applicant's responsible official and mailing address are: Mr. Larry Hatcher, Plant Manager, Florida Power Corporation dba Progress Energy Florida, Inc., 299 First Avenue, North, Mail Code CN77, St. Petersburg, Florida 33701.

FACILITY DESCRIPTION

The applicant operates the existing Crystal River Power Plant, which is located in Citrus County at 15760 West Power Line Street, Crystal River, Florida.

This facility consists of: four coal-fired fossil fuel steam generating (FFSG) units with electrostatic precipitators; two natural draft cooling towers for FFSG Units 4 and 5; helper mechanical cooling towers for FFSG Units 1, 2 and nuclear Unit 3; coal, fly ash, and bottom ash handling facilities; and, relocatable diesel fired generators. Nuclear Unit 3 is not considered part of this permit, although certain emissions units associated with Unit 3 are included in this permit.

This facility is subject to regulation under: Acid Rain, Phase II (40 CFR 75); Clean Air Interstate Rule (Rule 62-296.470, F.A.C.); and, 40 CFR 60 Subparts A, D, Y, IIII and JJJJ, General Provisions, Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971, Standards of Performance for Coal Preparation Plants, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, and Standards of Performance for Stationary Spark Ignition Internal Combustion Engines, respectively. The facility is also subject to the regulations of 40 CFR 63 Subparts A and ZZZZ, General Provisions and National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, respectively.

The facility operates two stationary reciprocating internal combustion engines associated with Unit 3 which are subject to regulation under 40 CFR 63, Subpart ZZZZ - National Emissions Standards For Hazardous Air Pollutants For Stationary Reciprocating Internal Combustion Engines. However, since the engines being operated meet the Subpart ZZZZ definition of "existing units", there are no unit specific applicable requirements that must be met pursuant to this rule at this time.

The facility has three additional reciprocating internal combustion engines that are also subject to regulation under 40 CFR 63, Subpart ZZZZ and 40 CFR 60 Subpart IIII or 40 CFR 60 Subpart JJJJ. New regulated emission units (EU028, EU029 and EU030) were created for these units.

The facility operates flue gas desulfurization (FGD) systems, which include: limestone storage and handling; limestone preparation; limestone slurry injection; and, gypsum dewatering (collectively regulated as EU023, Limestone and Gypsum Material Handling Activities). The limestone preparation activities are subject to the applicable requirements in NSPS Subpart OOO of 40 CFR 60, Standards of Performance for Nonmetallic Mineral Processing Plants.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

PROJECT DESCRIPTION

This Title V air operation permit revision incorporates the specific conditions of final air construction permit Nos. 0170004-016-AC (PSD-FL-383), 0170004-019-AC (PSD-FL-383A), 0170004-022-AC (PSD-FL-383B), and 0170004-023-AC (PSD-FL-383C) for the above referenced facility, which authorized the installation of air pollution control equipment and a blend of bituminous/sub-bituminous coal on Units 4 and 5. The combination of fuel blends and control equipment resulted in PSD-significant emissions increases of carbon monoxide (CO), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and volatile organic compounds (VOC). Therefore, the permittee was required to install and is now authorized to operate the following additional equipment as the Best

Available Control Technologies (BACT) for these pollutants: low-nitrogen oxide (NO_X) burners (CO, PM/PM_{10}, and VOC); modifications to the existing electrostatic precipitators (PM/PM_{10} and SAM); and alkali injection systems (SAM).

PROCESSING SCHEDULE AND RELATED DOCUMENTS

Application for a Title V air operation permit revision received November 9, 2010.
Draft/Proposed permit posted onto web site on February 4, 2011.
Public Notice published on February 21, 2011.
Notification to U.S. EPA Region 4 of Publication of Public Notice on February 21, 2011.
Applicant comments received on March 24, 2011.

PRIMARY REGULATORY REQUIREMENTS

Title III: The facility is identified as a major source of hazardous air pollutants (HAP).

Title IV: The facility operates units subject to the acid rain provisions of the Clean Air Act.

Title V: The facility is a Title V major source of air pollution in accordance with Chapter 62-213, Florida Administrative Code (F.A.C.).

PSD: The facility is a Prevention of Significant Deterioration (PSD)-major source of air pollution in accordance with Rule 62-212.400, F.A.C.

NSPS: The facility operates units subject to the New Source Performance Standards (NSPS) of 40 Code of Federal Regulations (CFR) 60.

NESHAP: The facility operates units subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) of 40 CFR 63.

CAIR: The facility is subject to the Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, F.A.C.

SITING: Emissions units EU001, EU002, EU003 and EU004 were originally certified pursuant to the power plant siting provisions of Chapter 62-17, F.A.C.

CAM: Compliance Assurance Monitoring (CAM) applies to emissions units EU001, EU002, EU003 and EU004 at the facility. CAM applies because these units have control equipment used to meet federally enforceable limits or standards.

PROJECT REVIEW

To reflect the changes and conditions contained in the final air construction permit Nos. 0170004-016-AC (PSD-FL-383), 0170004-019-AC (PSD-FL-383A), 0170004-022-AC (PSD-FL-383B), and 0170004-023-AC (PSD-FL-383C), the following conditions of the Title V permit are revised as indicated below. ~~Strikethrough~~ is used to denote the deletion of text. Double-underlines are used to denote the addition of text. The permit has been re-numbered to reflect the additions and deletions.

1. The Facility description on page 2 of the permit is revised to reflect the addition of the new emissions unit and the new control devises.

Subsection A. Facility Description.

This facility consists of: four coal-fired fossil fuel steam generating (FFSG) units with electrostatic precipitators; two natural draft cooling towers for FFSG Units 4 and 5; helper mechanical cooling towers for FFSG Units 1, 2 and nuclear Unit 3; coal, fly ash, and bottom ash handling facilities; and, relocatable diesel fired generators. Nuclear Unit 3 is not considered part of this permit, although certain emissions units associated with Unit 3 are included in this permit. The facility continuously operates low-NO_X burners, selective catalytic reduction systems (SCR), flue gas desulfurization systems (FGD) which includes limestone and gypsum material handling activities and alkali injection systems for existing Units 4 and 5, as authorized by permit No. 0170004-023-AC (PSD-FL-383C). In conjunction with the new control equipment, units 4 and 5 are now also authorized to burn a blend of bituminous/sub-bituminous coal.

2. The emissions unit description in Section III., Subsection B., is revised to reflect the new control devices.

~~Emissions units 003 and 004 (EU003 and EU004) are pulverized coal, dry bottom, wall-fired boilers. Both are rated at 760 MW. Emissions are exhausted through their own stacks. Each stack is 600 feet stack with a 25.5 feet exit diameter, 253 °F exit temperature and 2,979 acfm actual volumetric flow rate. Emissions are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Combustion Engineering.~~

Emissions units 003 and 004 (Unit 5 and Unit 4, respectively) are fossil fuel-fired electric utility steam generators, each consisting of a pulverized coal, dry bottom, wall-fired boiler rated at 760 MW. These units began commercial operation in 1984. Air pollution control equipment includes: low-NO_X burners; selective catalytic reduction (SCR) systems; flue gas desulfurization (FGD) systems; alkali injection systems; and, an electrostatic precipitator (ESP) manufactured by Combustion Engineering. Units 4 and 5 share a common 550 foot tall chimney with separate internal stack liners with continuous emissions monitoring systems (CEMS) on each stack liner. The flue gases exhaust at 130° F with a volumetric flow rate of 2,205,195 acfm through the individual stack liners, which are 30.5 feet in diameter.

3. Specific Condition B.1. is revised to reflect the authorized increase in the allowable heat input.

B.1. Permitted Capacity. The maximum allowable heat input rate is as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
004	~~6,665~~ 7,200	Bituminous Coal and Bituminous Coal /Bituminous Coal Briquette Mixture
003	~~6,665~~ 7,200	Bituminous Coal and Bituminous Coal /Bituminous Coal Briquette Mixture

The maximum heat input rates to Units 4 and 5 are 7,200 MMBtu per hour per unit based on a 24-hour block average (midnight to midnight) and 6,800 MMBtu per hour per unit based on a 30-day rolling average. Compliance shall be demonstrated by collecting the fuel feed rate and fuel heating values as monitored by the existing operating data monitoring system. [Permit No. 0170004-023-AC (PSD-FL-383C), Specific Condition 3.A.5.a.]

4. Paragraph d. has been added to Specific Condition B.2. to reflect the new allowable blend of fuels.

B.2. Methods of Operation - Fuels. The fuels that are allowed to be burned in these units are:

a. Bituminous coal,
b. Bituminous coal and bituminous coal briquette mixture with the exception that No. 2 Fuel oil may be used as an ignitor fuel and natural gas may be used as a startup and low load flame stabilization fuel.
c. Used oil in accordance with the specific conditions of this permit (See Subsection **J.**).
d. Blend of approximately 80% bituminous coal with 20% Powder River Basin coal (sub-bituminous coal). Coal fuel blends shall not exceed a maximum sulfur content of 3.13% by weight.

[Rule 62-213.410, F.A.C.; Permit Nos. 0170004-006-AC~~;~~ and 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.6.; PPSC PA-77-09 and modified conditions]

5. Because the FGD systems have been installed, Specific Condition B.3. is obsolete and has been deleted.

~~**B.3.** Flue Gas Desulfurization (FGD) Equipment. Prior to the installation of any FGD equipment, plans and specifications for such equipment shall be submitted to the Department for review and approval. [PPSC PA-77-09]~~

6. To reflect the new emissions control equipment requirements, a new Control Technology header and Specific Condition B.5. have been added.

Control Technology

B.5. Emissions Control Equipment and BACT Controls.

a. *Low-NO_X Burners*. The permittee is required to operate and maintain low-NO_X burners manufactured by Babcock & Wilcox (Model No. DRB-42) or equivalent. Based on the preliminary design, each unit contains 54 burners.

b. *Selective Catalytic Reduction (SCR) Systems*. The permittee is required to operate and maintain SCR systems to reduce NO_X emissions. Each system consists of the following basic components: an ammonia injection grid, a mixing grid, SCR reactor with catalyst modules, a urea-to-ammonia processing system, associated bulk storage systems, an automated control system, piping, electrical, and other ancillary equipment. As needed, urea shall be converted into ammonia, which shall be mixed to the proper concentration. Ammonia shall be injected ahead of the SCR reactor, which is installed upstream of the air heater for each unit. The ammonia combines with NO_X in the presence of the catalyst in a reduction reaction to form nitrogen and water. Based on the preliminary design, the SCR systems are capable of a 90% reduction in NO_X emissions with a maximum ammonia slip of 2 to 5 ppmv. The system also incorporates dampers and ductwork to provide the capability of bypassing the SCR system. The bypass is most commonly used to gradually heat or cool the catalyst structure to minimize thermal fatigue during startup and shutdown.

c. *Flue Gas Desulfurization (FGD) Equipment*. The permittee is required to operate wet flue gas desulfurization (FGD) systems after the existing ESPs and induced draft fans to reduce SO_2 and other acid gas emissions. A limestone slurry shall be injected into the FGD absorbers at the design feed rate of approximately 352 gallons per minutes (gpm). The slurry consists of approximately 25 to 30% solids and a specific gravity of 1.22. Based on the preliminary design, the FGD systems are capable of a 97% reduction in SO_2 emissions. In addition to the FGD absorbers, the systems consist of: limestone storage and handling; limestone preparation; limestone slurry injection; FGD blowdown; and, gypsum dewatering, transfer and storage.

d. *Alkali Injection Systems*. The permittee is required to operate and maintain alkali injection systems to reduce SAM emissions. The alkali injection system uses ammonia generated from the urea-to-ammonia processing system, which is part of the SCR system. Ammonia shall be injected into the flue gas through a uniform injection grid located after the boiler air heaters and SCR reactor and before the existing ESP. The additional ammonia reacts with sulfur trioxide (SO_3) to form salts (e.g., bisulfates), which shall be removed by the ESP. Based on the preliminary design, the alkali injection systems are capable of an 85% reduction in SAM emissions.

e. *Electrostatic Precipitator (ESP)*. The permittee is required to operate and maintain the existing ESPs to achieve the PM/PM_{10} emissions standards.

[Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.2 & 3.]

7. In Section III. Subsection B. Emission Limitations and Standards, Specific Conditions B.6. – B.14 are revised to reflect the new emissions limiting standards for Emission Units 004 and 005.

Unless otherwise specified, the averaging times for Specific Conditions **B.6. – B.1~~0~~4.** are based on the specified averaging time of the applicable test method.

B.6. PM Emissions. No owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which:

a. Contain PM in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel.

b. Exhibit greater than 20 percent opacity, six minute average, except for one six-minute period per hour of not more than 27 percent opacity.

c. As determined by EPA Method 5 or 5b, PM emissions shall not exceed 0.030 lb/MMBtu and 216.0 lb/hour based on a 3-run test average conducted at permitted capacity.

[40 CFR 60.42(a)(1) & (2)[a&b]; Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.8.b.[c]]

B.7. SO_2 Emissions. No owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain SO_2 in excess of:

a. 340 nanograms per joule heat input (0.80 lb per million Btu), 24-hour average, derived from liquid fossil fuel.

b. 520 nanograms per joule heat input (1.2 lb per million Btu), 24-hour average, derived from solid fossil fuel.

c. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO2} = [y(340) + z(520)]/(y+z)$$

where:

PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,
y is the percentage of total heat input derived from liquid fossil fuel, and
z is the percentage of total heat input derived from solid fossil fuel.

d. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

e. As determined by CEMS data, SO_2 emissions shall not exceed 0.27 lb/MMBtu of heat input based on a 30-day rolling average for all periods of operation including startup, shutdown and malfunction. As determined by CEMS data, SO_2 emissions shall not exceed 1,944.0 lb/hour per unit based on a 24-hour block average excluding startup, shutdown and malfunction of the FGD system.

[(40 CFR 60.43(a), (b) and (c); and, PPSC PA 77-09)[a-d]; Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.9.b.[e]]

B.8. SO_2 – Sulfur Content.

a. The maximum percent sulfur content of the coal/briquette mixture shall not exceed 0.68%, by weight, averaged on an annual basis. [Rule 62-213.440, F.A.C.; and, Permit No. 0170004-006-AC]

b. Fuel oil shall not contain more than 0.73% sulfur by weight. (See Specific Condition **B.2**.) [Rule 62-213.410, F.A.C.; PPSC PA-77-09 and modified conditions]

c. Coal fuel blends shall not exceed a maximum sulfur content of 3.13% by weight. (See Specific Condition **B.2**.d.) [Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.6.a.]

B.9. Nitrogen Oxides (NO_X) Emissions. No owner or operator shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2, in excess of:

a. 86 nanograms per joule heat input (0.20 lb per million Btu), 30-day rolling average, derived from gaseous fossil fuel.

b. 129 nanograms per joule heat input (0.30 lb per million Btu), 30-day rolling average, derived from liquid fossil fuel.

c. 300 nanograms per joule heat input (0.70 lb per million Btu), 30-day rolling average, derived from solid fossil fuel.

d. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{x(86)+y(130)+z(300)}{x+y+z}$$

where:

PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels fired;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel.

e. As determined by CEMS data, NO_X emissions shall not exceed 2,085 tons per year per unit based on a 12-month rolling average for all periods of operation including startup, shutdown and malfunction.

[(40 CFR 60.44(a)(2) and (3), and (b); and, PPSC PA 77-09)[a-d]; Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.9.a.[e]]

B.10 ~~Unit Specific State Only Limit For NO_X. A unit specific, state-only average annual NO_X emission limit of 0.50 lb/MMBtu applies. Compliance shall be demonstrated within the Annual Operating Report (AOR). [Rule 62-4.070(3), F.A.C.]~~

Ammonia Slip Emissions. As determined by EPA Method CTM-027 (or equivalent), the ammonia slip shall not exceed 5 ppmv based on a 3-run test average conducted at permitted capacity. [Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.8.a.]

B.11. Sulfuric Acid Mist (SAM) emissions. As determined by EPA Method 8 or 8A, SAM emissions shall not exceed 0.009 lb/MMBtu and 64.8 lb/hour based on a 3-run test average conducted at permitted capacity. This standard applies at all times except during periods of maintenance and repair as authorized by this permit. Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.8.c.]

B.12. Volatile Organic Compound (VOC) Emissions. As determined by EPA Method 25A, VOC emissions shall not exceed 0.004 lb/MMBtu and 28.8 lb/hour based on a 3-run test average conducted at permitted capacity. Optionally, EPA Method 18 may be conducted concurrently in order to deduct non-regulated VOC emissions such as methane and ethane. Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.8.d.]

B.13. Opacity. As determined by EPA Method 9, the stack opacity shall not exceed 10% based on a 6-minute block average, except for one 6-minute period per hour of not more than 20%. Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.8.e.]

B.14. Carbon Monoxide (CO) Emissions.

a. *CO Emissions (Interim).* As determined by CEMS data, CO emissions shall not exceed 0.17 lb/MMBtu of heat input based on a 30-day rolling average excluding periods of startup, shutdown and malfunction. As determined by CEMS data, CO emissions shall not exceed 1,156.0 lb/hour based on a 30-day rolling average for all periods of operation including startup, shutdown and malfunction.

b. *CO Emissions (Final).* Within 24 months of commencing commercial operation of each unit with the new low-NO_X burners, the permittee shall submit an application proposing a revised (lower) final BACT standard. The final standard shall be based on actual CO emissions data collected for initial operation after completing installation of the new low-NO_X burners. There may be separate standards proposed for different fuels.

[Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.9.c.&d.]

8. Specific Conditions B.11. and B.12. are revised to reflect the new Excess Emissions limitations.

B.1~~1~~5. Excess Emissions Allowed.

a. Excess emissions resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

b. In accordance with Rule 62-210.700(6), F.A.C., excess emissions due to startup, shutdown or malfunction have been considered in establishing the sets of CEMS-based emissions standards of this permit. With regard to SAM emissions, the alkali injection system is currently shared by Units 4 and 5 and the system must be shutdown to conduct some maintenance and repairs. The following additional conditions apply to the shared alkali injection system:

(1) *Additional SAM Testing.* No later than March 18, 2012, the permittee shall conduct additional SAM emissions tests (at least three, 1-hour test runs) on at least one unit without the alkali injection system in operation while firing lower sulfur "substitute coal". The SAM emissions standard shall not apply during these information-gathering tests. The purpose of the tests are to determine the SAM emissions rate (lb/MMBtu) while firing "substitute coal" with the alkali injection system offline. The permittee shall submit a test report in accordance with the requirements of this permit and specifically identify whether the units are capable of complying with the SAM emissions limit while firing the tested "substitute coal". Each test report shall also include the results from all previous tests conducted for such purposes. If the sulfur content of the "substitute coal" increases, subsequent SAM tests may be conducted as necessary in accordance with this condition.

{Permitting Note: Currently, "substitute coal" is available at the plant and used for Units 1 and 2. Although the permitted maximum sulfur content of this coal is approximately 1.3% by weight (2.1 lb

SO_2/MMBtu), the actual sulfur content is less than 1% by weight. When firing "substitute coal", reductions in SAM emissions by the wet FGD system may be sufficient to demonstrate compliance with the SAM emissions standard.}

(2) *Preventive Maintenance*. To minimize malfunctions of the alkali injection system and resulting excess SAM emissions, the permittee shall conduct annual preventive maintenance.

(a) The preventive maintenance shall be scheduled for a period when at least one unit (Unit 4 or Unit 5) is down for a scheduled outage, which occurs approximately every 18 months per unit. Whenever possible, the scheduled outages shall be staggered such that only one unit will be in an outage each year to accommodate the required annual preventive maintenance.

(b) When conducting the required preventative maintenance of the alkali injection system, the permittee may operate no more than one unit while firing "substitute coal" without the alkali injection system in operation for no more than 240 hours per calendar year. If stack testing demonstrates compliance with the SAM emissions standard while firing "substitute coal" for a given sulfur content without the alkali injection system in operation, the hours of operation while firing that coal shall not count towards this operational restriction.

(3) *Repair*. The following conditions apply to malfunctions of the alkali injection system. A malfunction is defined as, "Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner."

(a) The permittee shall maintain a list and inventory of spare parts associated with the shared alkali injection equipment to facilitate quick repairs.

(b) When a malfunction occurs, the permittee shall immediately investigate to determine the corrective action required. For malfunctions that will require an extended period of time to repair, the permittee shall begin preparations to fire "substitute coal". When initially evaluating a given malfunction and performing the repair, Units 4 and/or 5 may be operated without the alkali injection system for no more than 72 hours; thereafter, Units 4 and/or 5 shall begin firing "substitute coal" to continue operating while the plant makes the repair.

(c) The alkali injection system shall not be offline (including the malfunctions) for more than a total of 480 hours per calendar year to evaluate malfunctions and conduct repairs. This operational restriction shall include: authorized hours of firing normal coal for initial evaluation and repair (up to 72 hours per event); and authorized hours of operation firing "substitute coal" that has not yet demonstrated compliance with the SAM emissions standard. If stack testing demonstrates compliance with the SAM emissions standard while firing "substitute coal" for a given sulfur content without the alkali injection system in operation, the hours of operation while firing that coal shall not count towards this operational restriction.

(4) *Purpose*. The purpose of this condition is to provide operational flexibility to conduct timely maintenance and repair on the alkali injection system shared by Units 4 and 5 while minimizing excess SAM emissions. Once compliance is demonstrated for firing "substitute coal" with a given sulfur content, periodic testing is not required except as allowed by Rule 62-297.310(7)(b), F.A.C. (Special Compliance Tests). In addition, the compliant sulfur content for "substitute coal" shall be established based on the following equation:

$$\% S_{Comp.} = (\%S_{Tested})\ (SAM_{Limit}) / (SAM_{Tested})$$

Where:

$\%S_{Comp.}$ = Maximum percent sulfur content by weight that would demonstrate compliance
$\%S_{Tested}$ = Actual percent sulfur content by weight fired during stack test
SAM_{Limit} = Permitted SAM emissions limit, 0.009 lb/MMBtu
SAM_{Tested} = Actual SAM emissions rate in lb/MMBtu based on stack test

Example: Stack testing shows an actual SAM emissions rate of 0.0085 lb/MMBtu when firing substitute coal with a sulfur content of 0.98% by weight and the alkali injection system offline. Therefore, the maximum sulfur content of "substitute coal" considered demonstrated would be:

$$\% S_{Comp.}(SC) = (0.98\%\ S)\ (0.009\ lb/MMBtu) / (0.0085\ lb/MMBtu) = 1.04\%\ sulfur\ by\ weight$$

Therefore, if "substitute coal" is fired with an actual sulfur content equal to or less than the maximum sulfur content as calculated above ($\%S_{Comp.}$), then the hours while firing that coal do not count towards the operational restrictions specified for maintenance and repair. If "substitute coal" is fired with an actual sulfur content higher than the calculated value ($\%S_{Comp.}$), then the hours while firing that coal do count towards the operational restrictions specified for maintenance and repair.

[Rules 62-210.700(1) & (6), F.A.C. and Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.12.]

B.1~~2~~6. Excess Emissions Prohibited. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C. and Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.11.]

9. To reflect new continuous monitoring requirements, the Continuous Monitoring Requirements portion of Subsection B. has been revised.

Continuous Monitoring Requirements

B.~~16~~20. Required Continuous Monitoring Systems (CMS). Continuous monitoring systems are required for SO_2, NO_X, CO_2 and opacity. ~~CMS shall be in accordance with the requirements of 40 CFR 60.45.~~ Each COMS and CEMS shall be located such that representative measurements of emissions or process parameters from the facility are obtained. The monitors shall be operated and maintained in accordance with the existing requirements of 40 CFR 60.45, as well as the provisions of the federal acid rain program. [40 CFR 60.45; ~~and~~ PPSC PA 77-09; and Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.13.]

B.~~17~~21. Continuous Opacity Monitoring Systems (COMS) for Periodic Monitoring. Periodic monitoring for opacity shall be COMS, which are maintained and operated in conformance with 40 CFR Part 75. [Rule 62-213.440, F.A.C.]

B.22. CO CEMS. For Units 4 and 5, the permittee shall properly calibrate, operate and maintain CEMS to measure and record CO emissions in the terms of the applicable standard. Each CEMS shall be located such that representative measurements of emissions or process parameters from the facility are obtained in accordance with the procedures contained in the applicable performance specification of 40 CFR Part 60, Appendix B. [Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.14.]

10. Specific Condition B.18. has been revised to reflect additional allowable test methods.

B.~~18~~23. Test Methods. Required tests shall be performed in accordance with the following reference methods:

EPA Method	**Description of Method and Comments**
1 - 4	Methods for Determining Traverse Points, Velocity, Flow Rate, Gas Analysis, and Moisture Content. These methods shall be performed as necessary to support other methods.
~~3A~~	~~Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources.~~
~~3B~~	~~Gas Analysis for The Determination of Emission Rate Correction Factor or Excess Air.~~
5	Determination of Particulate Emissions from Stationary Sources.
5B	~~Determination of Sulfur Dioxide Emissions from Stationary Sources~~ Determination of Nonsulfuric Acid Particulate Matter from Stationary Sources.
6	~~Determination of Sulfur Dioxide Daily Average Emissions from Fossil Fuel Combustion Sources~~ Determination of Sulfur Dioxide Emissions from Stationary

EPA Method	Description of Method and Comments
	Sources.
6A	~~Determination of Sulfur Dioxide and Carbon Dioxide Daily Average Emissions From Fossil Fuel Combustion Sources~~ Determination of Sulfur Dioxide, Moisture, and Carbon Dioxide Emissions From Fossil Fuel Combustion Sources.
6B	~~Determination of Sulfur Dioxide Emissions from Stationary Sources~~ Determination of Sulfur Dioxide and Carbon Dioxide Daily Average Emissions From Fossil Fuel Combustion Sources.
6C	~~Determination of Nitrogen Oxide Emissions from Stationary Sources~~ Determination of Sulfur Dioxide Emissions from Stationary Sources (Instrumental Analyzer Procedure).
7	~~Determination of Nitrogen Oxide Emissions from Stationary Sources – Ion Chromatographic Method~~ Determination of Nitrogen Oxide Emissions from Stationary Sources.
7A	Determination of Nitrogen Oxide Emissions from Stationary Sources – ~~Alkaline-Permanganate/Colorimetric Method~~ Ion Chromatographic Method.
7C	Determination of Nitrogen Oxide Emissions from Stationary Sources ~~(Instrument Analyzer Procedure)~~ Alkaline-Permanganate/ Colorimetric Method.
7D	~~Gas Analysis for The Determination of Emission Rate Correction Factor or Excess Air~~Determination of Nitrogen Oxide Emissions from Stationary Sources – Alkaline-Permanganate/Ion Chromatographic Method.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrument Analyzer Procedure).
8 or 8A	Determination of Sulfuric Acid Mist and Sulfur Dioxide Emission from Stationary Sources.
9	Visual Determination of the Opacity of Emissions from Stationary Sources.
10	Method for Determining Carbon Monoxide Emissions (Instrumental). The method shall be based on a continuous sampling train.
18	Method for Determining Gaseous Organic Compound Emissions (Gas Chromatography). Concurrently with EPA Method 25A, EPA Method 18 may be used as an optional method to deduct emissions of methane and ethane from the total hydrocarbon (THC) emissions measured by Method 25A.
25A	Method for Determining Gaseous Organic Concentrations (Flame Ionization).
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source. This is an EPA conditional test method with a minimum detection limit of 1 ppm. Other equivalent methods may be used.
19	Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates (Optional F-factor method may be used to determine flow rate and gas analysis to calculate mass emissions in lieu of Methods 1-4.).
ASTM Method	Standard Methods by the American Society of Testing and Materials for fuel

EPA Method	Description of Method and Comments
D2015-77, D240-76, D1826-77, ASTM D2013-72, ASTM D3177-75, and ASTM D4239-85, or latest ASTM edition	analysis.

The above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rule 62-297.401, F.A.C.; 40 CFR 60 Subpart D; and Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.18.]

11. To reflect the testing requirements related to the new emissions limits and compliance by CEMS for NO_X and SO_2 instead of annual stack tests, the Compliance Test Requirements portion of Subsection B. has been revised.

B.2~~0~~5. Annual Compliance Tests Required. Except as provided in Specific Condition **B.~~27~~32.**, during each federal fiscal year (October 1st to September 30th), each EU003 and EU004 shall be tested to demonstrate compliance with the emissions standards for ~~PM, VE, SO_2 and NO_X~~ ammonia slip, opacity, PM, and SAM. [Rule 62-297.310(7), F.A.C.; and Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.19.b.]

B.2~~1~~6. Compliance Tests Prior To Renewal. Except as provided in Specific Condition **B.~~27~~32.**, in addition to the annual compliance tests specified above, during the year prior to submitting an application for permit renewal, compliance tests shall also be performed for ~~PM, VE, SO_2 and NO_X once every 5 years. The tests shall occur prior to obtaining a renewed operating permit~~ VOC to demonstrate compliance with the emission limits in Specific Conditions **B.6. – B.1~~0~~4.** [Rules 62-210.300(2)(a) and 62-297.310(7)(a), F.A.C.; and Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.19.b.]

~~**B.23.** Annual RATA Tests May Substitute for Annual NO_X and SO_2 Tests. Annual RATA tests performed for NO_X and SO_2 may be substituted for the annual compliance tests for these pollutants. To substitute for the annual compliance tests, the owner or operator must notify the Department of the RATA tests at least 15 days prior to the date on which each formal compliance test is to begin and the results must be submitted as the compliance tests no later than 45 days after the last sampling run of each test is completed. The test runs shall be consecutively completed in a manner that fulfills the test length requirements of the EPA test methods. [40 CFR 75; Request of applicant, February 11, 1998]~~

B.28. Compliance by CEMS. Compliance with the standards for opacity and emissions of CO, NO_X, and SO_2 shall be demonstrated with data collected from the required continuous monitoring systems. The permittee shall comply with the conditions of Appendix F - Standard Continuous Monitoring Requirements of this permit as the compliance method for the corresponding emissions standards. [Permit No. 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.15.]

B.33. Additional Compliance Test requirements.

a. *Test Fuel*. Initial compliance tests were to have been conducted with the highest sulfur content representative of the actual coal blends being fired. Within 60 days of determining that the fuel sulfur content of the actual coal blends fired have increased by 0.5% by weight or more from the highest tested sulfur content that demonstrated compliance, the permittee shall conduct new tests to determine emissions of opacity, PM and SAM. For purposes of this condition, the fuel sulfur content shall be based on an average of the as-fired fuel samples for 30 successive operating days. Once compliance has been demonstrated at the higher fuel sulfur levels (2.63% to 3.13% sulfur by weight), subsequent tests shall be conducted using a fuel with a sulfur content that is representative of the actual coal blends being fired.

b. *Operational Data for Tests*. When compliance tests are conducted, for each test run, the permittee shall monitor and record the following information: fuel feed rate; heat input rate; sulfur content of fuel; the ammonia injection rate of the SCR control system; the limestone slurry injection rate of the FGD control

system; alkali injection rate of the alkali injection system; flue gas oxygen content (%); CO, NO_X, and SO_2 CEMS emissions data; and opacity data.
[Permit No 0170004-023-AC (PSD-FL-383C) Specific Conditions 3.A.19.c. & d. and 3.A.20.]

12. To reflect new record keeping and reporting requirements, the following conditions have been added.

B.37. Fuel Monitoring – Units 4 and 5. Using the existing operating data system, the permittee shall continuously monitor each fuel to determine the heat input rates to Units 4 and 5. The heat input rates shall be calculated from the amounts of fuel fired and the higher heating value (HHV) of each fuel as determined by vendor certifications or the regular sampling and analysis required by the current Title V permit. Data shall be reduced to 1-hour blocks, 24-hour blocks (midnight-to-midnight), and 30-day rolling averages (average of all the 1-hour blocks for 30 operating days). [Permit No 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.23.]

B.38. Control Device – Record Keeping for Parametric Monitoring.

a. *SCR System*. The permittee shall continuously monitor and record the ammonia injection rate of the SCR control system. Data shall be reduced to 1-hour block averages.
b. *FGD System*. The permittee shall continuously monitor and record the limestone slurry injection rate of the FGD control system. Data shall be reduced to 1-hour block averages.
c. *Alkali Injection System*. The permittee shall continuously monitor and record the alkali injection rate of the alkali injection system. Data shall be reduced to 1-hour block averages. Operation of the alkali injection system shall be determined by the automated control system, which shall be set in accordance with the preliminary performance and compliance tests for SAM emissions.
d. *ESP*. The permittee shall continuously monitor and record the opacity in the ductwork just after the ESP for use as part of the Compliance Assurance Monitoring Plan under Title V. Operation of the ESP shall be based upon COMS data collected during satisfactory PM emissions compliance tests.

[Permit No 0170004-023-AC (PSD-FL-383C) Specific Condition 3.A.25.a, b., c. & d.]

13. Specific Condition and cross reference numbers have been revised as appropriate due to the additions and deletions of conditions within Section 3, Subsection B.

14. To reflect the requirements and limitations governing the new Emission Unit No. 023 - Limestone and Gypsum Material Handling Activities, a new Subsection K. has been added to Section III. (Please refer to draft/proposed permit No. 0170004-025-AV for the added conditions.)

15. In addition, Appendix NSPS, Subpart OOO - Standards of Performance for Nonmetallic Mineral Processing Plants has been added to the appendices section to reflect the requirements applicable to the Limestone and Gypsum Material Handling Activities (EU023).

16. Also, Table H, Permit History, was updated to reflect the latest projects.

CONCLUSION

This project revises Title V air operation permit No. 0170004-024-AV, which was effective on January 1, 2010. This Title V air operation permit revision is issued under the provisions of Chapter 403, Florida Statues (F.S.), and Chapters 62-4, 62-210, 62-213 and 62-214, F.A.C.