TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

Florida Power Corporation d/b/a
Progress Energy Florida, Inc.
299 First Avenue, North
St. Petersburg, Florida 33701

Crystal River Energy Complex
Facility ID No. 0170004

PROJECT

Project No. 0170004-036-AC
Sulfur Dioxide Emission Standards/Controls for Boilers 1 and 2

COUNTY

Citrus County, Florida

PERMITTING AUTHORITY

Florida Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

July 31, 2012

1. GENERAL PROJECT INFORMATION

1.1. Air Pollution Regulations

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following applicable chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Chapters 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial categories. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations in Rule 62-204.800, F.A.C.

1.2. Facility Description and Location

The Progress Energy Crystal River Energy Complex is an existing power plant, which is categorized under Standard Industrial Classification Code No. 4911. Refer to Figures 1 and 2. The existing Crystal River Power Plant is located in Citrus County at 15760 West Power Line Street in Crystal River, Florida.

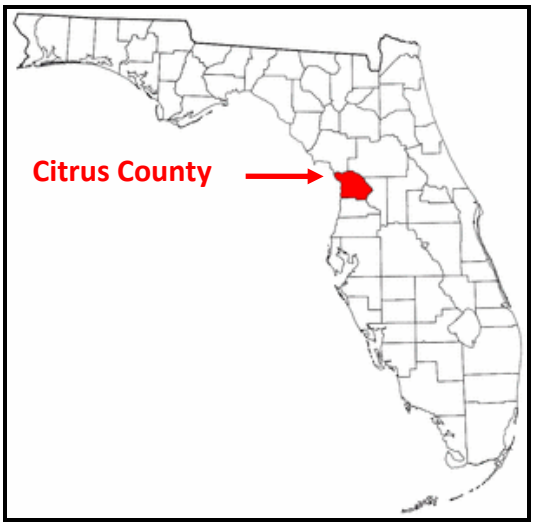


Figure 1. Citrus County, Florida

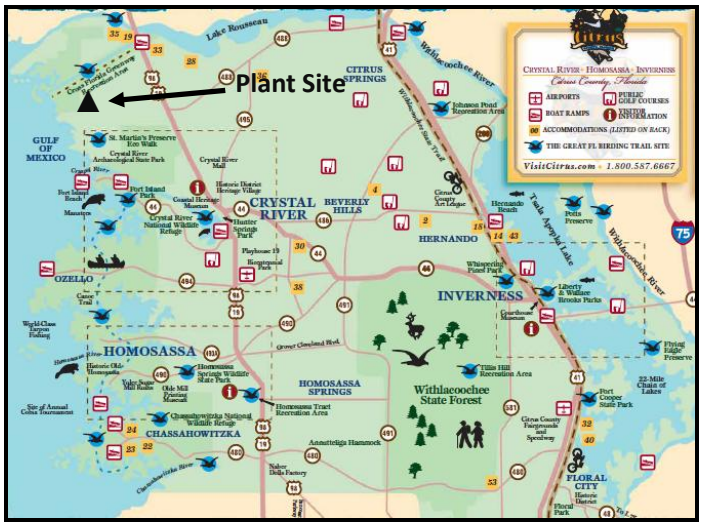


Figure 2. Location of Crystal River Energy Complex

The UTM coordinates of the existing facility are Zone 17, 334.3 km East and 3204.5 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to Ambient Air Quality Standards (AAQS).

Table 1 is a summary of Emissions Units (E.U.) from the Facility Title V Air Operation Permit 0170004-036-AV. Units 1 and 2 are the subject of the present permit application. Units 1 and 2 are tangentially-fired, dry bottom pulverized coal-fueled boilers with gross capacity ratings of 440.5 and 523.8 megawatts (MW), respectively. The units commenced commercial operation in 1966 and 1969, respectively.

Table 1. Summary of Emissions Units

E.U. No.	Brief Description
Regulated Emission Units	
001	Fossil Fuel Steam Generator, Unit 1
002	Fossil Fuel Steam Generator, Unit 2
004	Fossil Fuel Steam Generator, Unit 4
003	Fossil Fuel Steam Generator, Unit 5
006	Fly ash transfer (Source 1) from Unit 1
008	Fly ash storage silo (Source 3) for Units 1 and 2
009	Fly ash transfer (Source 4) from Unit 2
010	Fly ash transfer (Source 5) from Unit 2
014	Bottom ash storage silo for Units 1 and 2
012	Relocatable diesel generators
013	Cooling towers for Units 1, 2, and 3
015	Cooling towers for Units 4 and 5
016	Material handling activities for coal-fired steam units
020	Portable Cooling Towers for Units 1 and 2
028	3500 kW diesel generator associated with Unit 3
023	Limestone and Gypsum Material Handling Activities
029	Diesel fire pump, south yard
030	Emergency generator (meteorological weather station)
Unregulated Emissions Units and/or Activities	
017	Fuel and lube oil tanks and vents
018	Sewage treatment, water treatment, lime storage
019	Two 3500 kW diesel generators associated with Unit 3

Unit 1 is equipped with a 499 foot stack and Unit 2 has a 502 foot stack. Each has an electrostatic precipitator (ESP) to control particulate matter (PM) and Low NO_X burners to control nitrogen oxides (NO_X). Each is equipped with Continuous emissions monitoring systems (CEMS) to measure and record NO_X and sulfur dioxide (SO_2) emissions and a continuous opacity monitoring system (COMS) to measure and record the opacity of the exhaust gas.

1.3. Facility Regulatory Categories

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.

1.4. Application

On June 15, 2012, Progress Energy Florida submitted an air construction permit application for Crystal River Power Plant Units 1 and 2. Link to Application The application includes the three options listed below.

1. Commit to cease operation of Crystal River Units 1 and 2 as coal-fired units by December 31, 2020.
2. Install and operate a sulfur dioxide (SO_2) Flue Gas Desulfurization (FGD) system before January 1, 2018, or within 5 years of EPA's final approval of Florida's final Regional Haze SIP, whichever is later, and establish emissions standards of 95 percent sulfur dioxide SO_2 removal efficiency or 0.15 pounds per million Btu heat input (lb/MMBtu) from Crystal River Units 1 and 2 as presumptive Best Available Retrofit Technology (BART).
3. Agree to a permit limit for SO_2 by January 1, 2018 or within 5 years of EPA's final approval of Florida's final Regional Haze State Implementation Plan, whichever is later, at a level sufficient to exempt out of BART.

Details on the SO_2 project are available in a separate document submitted to the Department on May 30, 2012 as the Best Available Retrofit Technology (BART) proposal for Units 1 and 2.

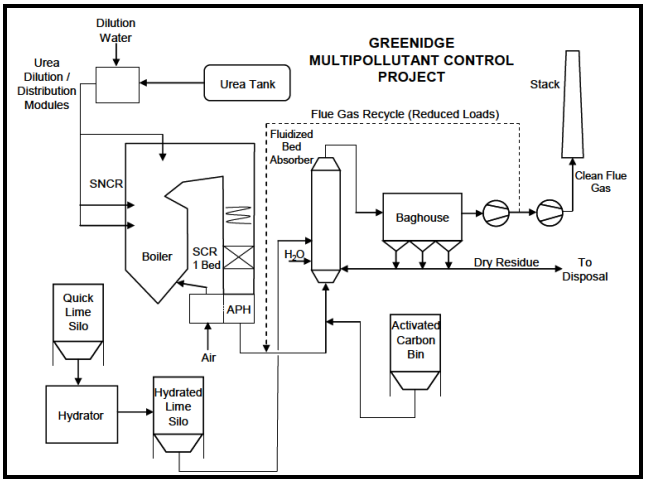
1.5. Project Description

If Crystal River Units 1 and 2 continue to operate as coal-fueled units beyond 2020, the company will install FGD technology. The supplementary information included analyses of wet FGD and dry FGD options. However, the document indicated a preference by the applicant towards the latter due to lower impacts related to water use, volume of coal combustion products (calcium sulfite sludge or gypsum product), and lower capital costs (e.g. less expensive carbon steel).

Fabric filters are often used in conjunction with dry FGD technologies, especially when high efficiency SO_2 removal is required. The reason is that the filter cake (e.g. lime) that builds up in the bags provides additional contact between exhaust gases and reagent compared with an ESP. The Department infers from the information reviewed to-date that a dry FGD technology, including fabric filters is the most likely scenario for the second option listed above.

Refer to Figures 3 and 4. There are various types of dry and semi-dry FGD designs. The discussion below features one of dozens of possible arrangements possible for dry FGD installations at coal-fueled power plants. It is shown here for convenience to explain principles of dry scrubbing. It is not a design proposed by the company or an arrangement specifically recommended by the Department.

The arrangement in Figure 3 was installed at the small AES Greenidge Unit 4 in New York. It features a hydrated lime [$Ca(OH)_2$] based scrubber and a fabric filter (baghouse) associated with the scrubber to optimize use of the hydrated lime sorbent. The circulating fluidized bed (CFB) scrubber (called TurboSorp®) shown in Figure 4 was used within AES Greenidge project.



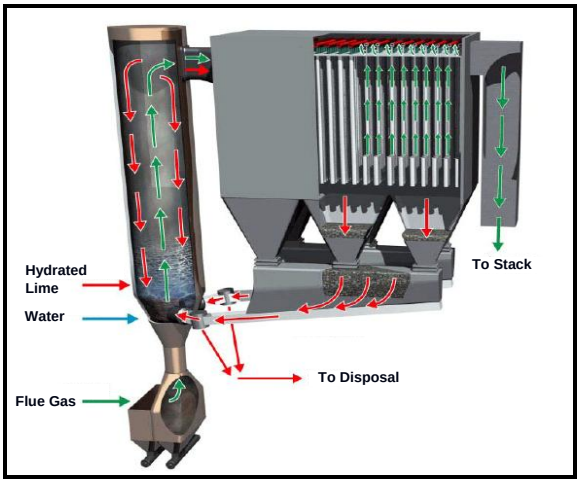


Figure 3. Control System at AES Greenidge **Figure 4. Circulating Fluidized Bed Dry Scrubber**

To achieve 95% efficiency with a dry scrubber will require a baghouse. To achieve 0.15 lb SO_2/MMBtu without a baghouse will likely require use of lower sulfur coal and require substantial upgrades to the existing ESPs.

1.6. Processing Schedule

May 30, 2012 Received control options document in advance of application.

June 15, 2012 Received application.

July 31, 2012 Issued Draft Permit Package.

2. PSD APPLICABILITY FOR DRY SCRUBBING OPTION

2.1. General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400(PSD), F.A.C. PSD preconstruction review is required in areas that are currently in attainment with the state and federal ambient air quality standards (AAQS) or areas designated as "unclassifiable" for these regulated pollutants.

Commonly addressed PSD pollutants in the power industry include: CO, SO_2, NO_X, PM, PM smaller than 10 micrometers (µm) (PM_{10}), PM smaller than 2.5 µm ($PM_{2.5}$), volatile organic compounds (VOC), sulfuric acid mist (SAM), lead (Pb), fluorides (F), and mercury (Hg).

Additional PSD pollutants that are more common to certain other industries include: hydrogen sulfide (H_2S), TRS including H_2S, reduced sulfur compounds (RSC) including H_2S, municipal waste combustor (MWC) organics measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans (dioxin/furan), MWC metals measured as PM; MWC acid gases measured as SO_2 and HCl, and municipal solid waste (MSW) landfill emissions as non-methane organic compounds (NMOC).

As defined in Rule 62-210.200(Definitions), F.A.C., a stationary source is a "major stationary source" (major PSD source) if it emits or has the potential to emit (PTE):

- 250 tons per year (tons/year) or more of any PSD pollutant; <u>or</u>
- 100 tons/year or more of any PSD pollutant <u>and</u> the facility belongs to one of the 28 listed PSD major facility categories.

The list given in the citation includes the category of "fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input". The given category applies to the Crystal River Energy Complex. The Crystal River Energy Complex is a major stationary source based on actual emissions of and potential to emit 100 tons/year or more of several individual PSD pollutants.

For major stationary sources such as the Crystal River Energy Complex, PSD applicability for modification projects is based on thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200 (Definitions), F.A.C. Any "net emissions increase" as defined in Rule 62-210.200 (Definitions), F.A.C. of a PSD pollutant from the project that equals or exceeds the respective SER is considered "significant".

SER also means any emissions rate or any net emissions increase of a PSD pollutant associated with a major stationary source or major modification which would construct within 10 km of a Class I area and have an impact on such area equal to or greater than 1 gram per cubic meter, 24-hour average. Although a facility may be "major" (i.e. emits or has the potential to emit 100 or 250 tons/year as applicable) for only one PSD pollutant, a project must include Best Available Control Technology (BACT) for any PSD pollutant increase in that equals or exceeds the corresponding significant emission rate given in Table1.

Table 1. List of Significant Emission Rates by PSD-Pollutant Relevant to the Facility [2]

Pollutant	SER (tons/year)	Pollutant	SER (tons/year)
PM	25	PM_{10}	15
$PM_{2.5}$	10	$PM_{2.5}$ (NO_X) [1]	40
$PM_{2.5}$ (SO_2) [1]	40	CO	100
SO_2		NO_X	40
Ozone (NO_X) [1]	40	Ozone (VOC) [1]	40
Sulfuric acid mist (SAM)	7	fluoride	3
mercury	0.1	lead	0.6

1. $PM_{2.5}$ is also regulated through precursors (NO_X and SO_2); Ozone (O_3) is regulated through precursors (VOC and NO_X).
2. There is federal SER of 75,000 tons/year for Greenhouse Gases (GHG) as carbon dioxide equivalent (CO_2e) that has not been incorporated into Department rules.

According to 40 CFR 52.21, six greenhouse gases (GHG), are also subject to regulation at new stationary sources According to 40 CFR 52.21, six greenhouse gases (GHG), are also subject to regulation at new stationary sources that will emit or have the potential to emit 100,000 tons/year (SER equal to 75,000 tons/year) expressed as the carbon dioxide equivalent emissions (CO_2e). This requirement has not been incorporated into Department rules but is a separate requirement of the EPA.

2.2. PSD Applicability for Project

The project is located in Citrus County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable.

Methodology for Calculations of Baseline Actual Emissions and Projected Actual Emissions

To determine whether the project causes net emissions increases equal to or greater than the respective SER (triggering PSD) requires a comparison of recent "baseline actual emissions" with future "projected actual emissions". According to Rule 62-210.200(Definitions), F.A.C., for any existing electric utility steam generating unit:

"Baseline actual emissions" means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date a complete permit application is received by the Department. The Department shall allow the use of a different time period upon a determination that it is more representative of normal source operation".

1. The average rate shall include fugitive emissions to the extent quantifiable, and emissions associated with startups and shutdowns.
2. The average rate shall be adjusted downward to exclude any non-compliant emissions that occurred while the source was operating above any emission limitation that was legally enforceable during the consecutive 24-month period.
3. For a PSD pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each PSD pollutant.
4. The average rate shall not be based on any consecutive 24-month period for which there is inadequate information for determining annual emissions, in tons per year, and for adjusting this amount if required by subparagraph 2., above.

According to Rule 62-210.200(Definitions), F.A.C., for an existing unit (other than an electric steam generating unit):

"Projected Actual Emissions" means the maximum annual rate, in tons/year, at which an existing emissions unit is projected to emit a PSD pollutant in any one of the 5 years following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that PSD pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source. One year is one 12-month period. In determining the projected actual emissions, the Department:

(a) Shall consider all relevant information, including historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans or orders, including consent orders; and

(b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns; and

(c) Shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project including any increased utilization due to product demand growth; or

(d) In lieu of using the method set out in paragraphs (a) through (c) above, may be directed by the owner or operator to use the emissions unit's potential to emit, in tons per year.

Department's Assessment of PSD Applicability

Figure 5 is a summary of information derived from the EPA Air Markets Website pertinent to operation of Crystal River Units 1 and 2. During 2007-2008 the combined gross generation capacity of the two units was approximately 61.5% based on the annual gross electric generation reported for these units per EPA and the gross capacity descriptions in the recent permits. In 2011, the combined gross capacity factor was only 33%.

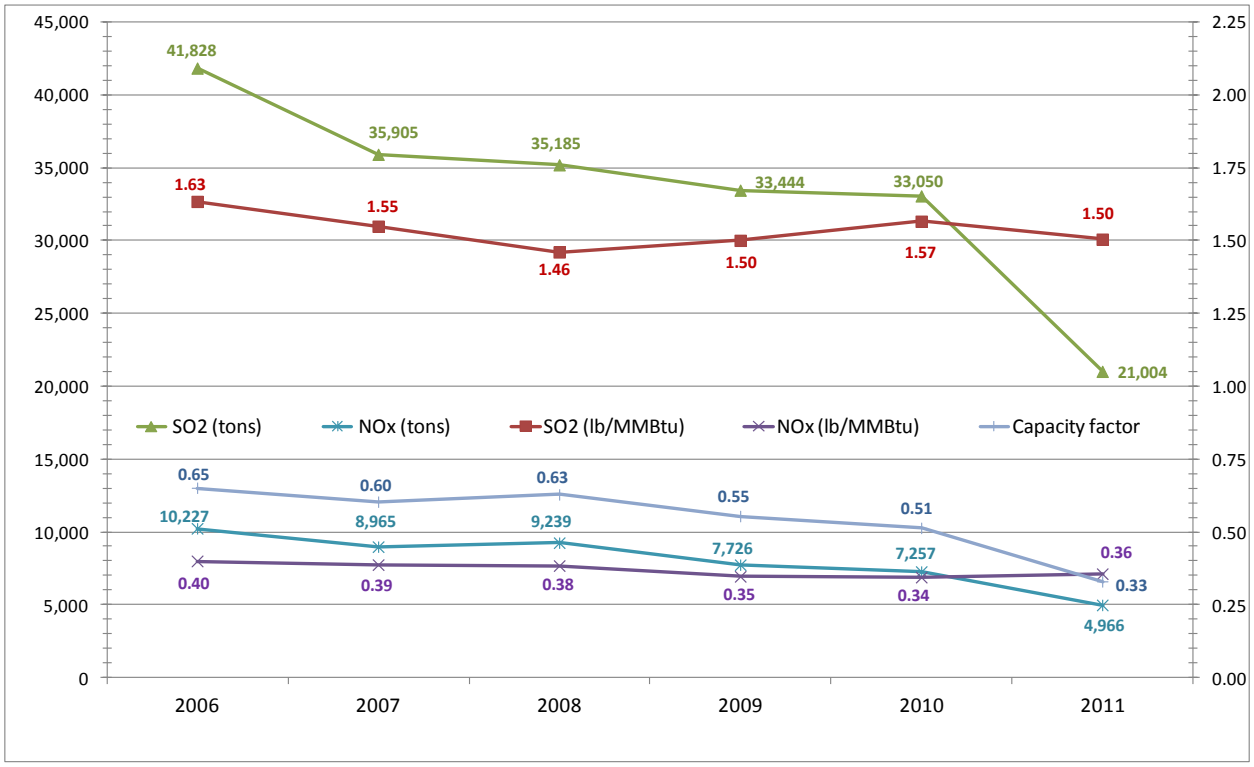


Figure 5. Combined Units 1 and 2 NO_X, SO_2 Emissions and Gross Generation Capacity Factors

Average combined emissions of SO_2 and NO_X during 2007-2008 were 35,545 tons per year (tons/year) of SO_2 and 9,102 tons/year of NO_X. During 2011, SO_2 and NO_X emissions for 2011 were 21,004 and 4,966 tons/year, respectively.

During 2007-2008, the SO_2 and NO_X emissions factors were 1.5 and 0.385 pounds per million Btu per hour of heat input (lb/MMBtu/hr), respectively. During 2011, the values were 1.5 and 0.33 lb/MMBtu. The permitted SO_2 emission factor for Units 1 and 2 is 2.1 lb SO_2/MMBtu. The annual NO_X emission factor limit is 0.40 lb/MMBtu based on the Acid Rain Program (there is also an alternative limit based on company-wide averaging). Since 2006 emissions of SO_2 and NO_X from Units 1 and 2 have been reduced by approximately 50%.

Although not the subject of the present application, the emission trends at the adjacent Units 4 and 5 are relevant. Refer to Figure 6. Annual emissions and emission factors of both SO_2 and NO_X have been reduced by more than 90%. These reductions equate to 70,000 tons/year of SO_2 and NO_X combined. The reductions were achieved by installation of SCR and wet FGD scrubbers.

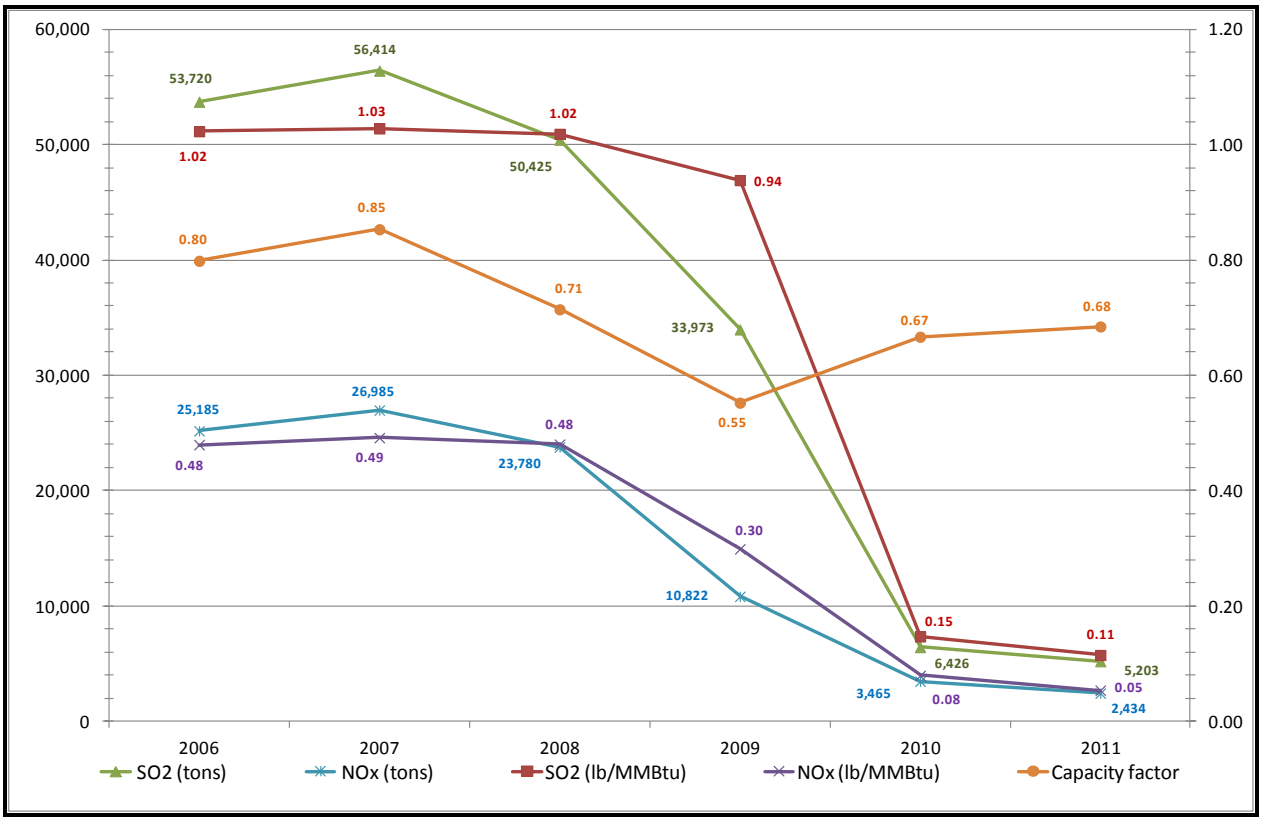


Figure 6. Combined Units 4 and 5 NO_X, SO_2 Emissions and Gross Generation Capacity Factors

Considering the four fossil fuel-fired units at the Crystal River Energy Complex, emissions of SO_2 and NO_X have been reduced by 72.5 and 79.2% since 2006. The reductions in total annual SO_2 and NO_X emissions are approximately 100,000 tons/year.

Because Progress Energy can take credit for the emission reductions to-date (by the PSD netting process) when considering future actual emissions, there is no reasonable scenario under which a future SO_2 control project ***including dry scrubbers and baghouses (or ESP improvements)*** on Units 1 and 2 can possibly trigger PSD.

On February 26, 2009 the Department issued a permit (0170004-017-AC) incorporating Best Available Retrofit Technology (BART) for Units 1 and 2. Link to BART Permit The permit includes PM limits for normal and soot blowing operations as follows:

3. Particulate Matter Emissions Standard – Steady State Operations. As determined by EPA Method 5 or 17, particulate matter emissions from Units 1 and 2 combined shall not exceed 0.04 lb/MMBtu, on a weighted average basis of the total heat input. Compliance shall be demonstrated on the average of the 3 required 1-hour test runs. [Rule 62-296.340 (BART), F.A.C.]
4. Particulate Matter Emissions Standard – Soot Blowing and Load Change Operations. As determined by EPA Method 5 or 17, particulate matter emissions from Units 1 and 2 combined shall not exceed 0.12 lb/MMBtu, on a weighted average basis of the total heat input. Compliance shall be demonstrated on the average of the 3 required 1-hour test runs. [Rule 62-296.340 (BART), F.A.C.]
5. Opacity Standard – Steady State Operations. As determined by data collected from the existing COMS or EPA 9, visible emissions during steady-state operations from: Unit 1 shall not exceed 30% opacity based on a 6-minute average except for one 6-minute average per hour not to exceed 35% opacity; Unit 2 shall not exceed 15% opacity based on a 6-minute average except for one 6-minute average per hour not to exceed 20% opacity. [Rule 62-296.340 (BART), F.A.C.]
6. Opacity Standard – Soot Blowing and Load Change Operations. As determined by data collected from the existing COMS or EPA 9, visible emissions resulting from soot-blowing and load change operations shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized. In no case shall the duration of such emissions exceed 3 hours in any 24-hour period and visible emissions from: Unit 1 shall not exceed 40% opacity based on a 6-minute average; Unit 2 shall not exceed 25% opacity based on a 6-minute average. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
   [Rule 62-296.340 (BART), F.A.C.]

The foregoing conditions and described limitations would not be compatible with the purpose and actual function of new dry scrubbers, if actually installed, on Units 1 and 2. With these conditions, there is not reasonable assurance that increases in PM will not occur once the substantial additional reagent and reaction product loadings are added to the existing fly ash loading.

As an example, it would be reasonable to assume Crystal River Units 1 and 2 (after installing significant air pollution control equipment) will during some years operate at an annual gross capacity factor on the order of 61.5% (like baseline years 2007-2008). To remove on the order of 30,000 tons/year and achieve 0.15 lb SO_2/MMBtu requires formation of roughly 60,000 tons/year of coal combustion products of calcium sulfate or calcium sulfite excluding hydration water present in each species.

If the existing ESPs removed 99% of the additional solids, then the remaining 1% would equal 600 tons/year of PM. At 99.9% removal, the additional PM would equal 60 tons/year.

To provide reasonable assurance that PSD is not triggered for PM/PM_{10} under the dry FGD option, the Department will limit PM in this permit 0.015 lb PM/MMBtu at both units and limit visible emissions to 15% opacity at both units and 20% under soot blowing and load change operations.

If NO_X reductions such as by further combustion controls are implemented in the future, it is possible that PSD could be triggered for carbon monoxide (CO). Most likely the same combustion controls used for NO_X can be optimized to achieve low CO consistent with a Best Available Control Technology (BACT) determination.

3. RETIREMENT OPTION FOR UNITS 1 AND 2

In late 2008 Progress Energy announced that it planned to shut down Units 1 and 2 in conjunction with the construction of a 1,100 MW nuclear power plant in nearby Levy County. The previously mentioned permit includes the following relevant condition:

16. Shutdown of Units 1 and 2. Units 1 and 2 shall cease to operate as coal-fired units by December 31, 2020. This date assumes timely licensing, construction and commencement of commercial operation of PEF's proposed new nuclear units (Levy County Units 1 and 2). The shutdown of Units 1 and 2 coal-fired units is contingent upon completion of the first fuel cycle for Levy County Unit 2. PEF shall timely advise the Department of any developments that would delay the shutdown (or repowering) of Units 1 and 2 beyond the completion of the first fuel cycle for Levy County Unit 2. [Rule 62-296.340 (BART), F.A.C. and Applicant Request].

The Department will in this permitting action supersede the contingent language under the shutdown option contemplated within the present application. The description of the option creates a possible new contingency put forward by the applicant based upon a "remaining useful life" cost-effectiveness evaluation. The procedures for the evaluation are not clear and the caveat will not be included in this condition as it is implicit in the other options.

4. ALTERNATIVE REQUEST

The applicant's third option is to agree a permit limit for SO_2 by January 1, 2018 or within 5 years of EPA's final approval of Florida's final Regional Haze State Implementation Plan, whichever is later, at a level sufficient to exempt out of BART.

This option will be included as a new condition with some minor rewording to clarify that the new permit limit will be effective on January 1, 2018 and that the agreement will occur well before that date. The Department would require additional information in the future to insure that PSD is not triggered or would require submittal of a PSD application for increases in foreseen or as-yet unforeseen collateral emission increases in PSD pollutants such as PM, PM_{10} and CO.

5. PRELIMINARY DETERMINATION

The permit will authorize the applicant to proceed with a DFGD project and will require improvements to the existing ESPs and/or installation of baghouses in conjunction with the DFGD systems. The Department will include the requested SO_2 emission standard of 95% SO_2 removal or 0.15 lb/MMBtu, whichever is less stringent. The emissions standard shall become effective upon the effective date of EPA's approval of these specific requirements in the Florida Regional Haze State Implementation Plan. Thereafter, the compliance date for the requested emission standards shall be no later than January 1, 2018, or within 5 years of the effective date of EPA's approval of this specific requirement in the Florida Regional Haze State Implementation Plan, whichever is later.

Additional details of this analysis may be obtained by contacting the project engineer at leigh.pell@dep.state.fl.us, 850/717-9033, or the Department's Office of Permitting and Compliance, 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400.