TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0100

Lansing Smith Electric Generating Plant
Facility ID No. 0050014

PROJECT

Project No. 0050014-020-AC
Sulfur Dioxide Emission Standard/Control for Boilers 1 and 2

COUNTY

Bay 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 30, 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 Gulf Power Company Lansing Smith Generating Plant is categorized under Standard Industrial Classification Code No. 4911. Refer to Figures 1 and 2. The Lansing Smith Generating Plant is located in Bay County at 4300 County Road 2300, Southport, Florida.

Figure 1. Bay County, Florida

Figure 2. Location of Lansing Smith Plant

The UTM coordinates are Zone 16; 623.74 Kilometer (km) East and 3349.11 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 0050014-018-AV. Boilers 1 and 2 are the subject of the present permit application. Boilers 1 and 2 are tangentially fired, dry bottom coal-fueled boilers that began commercial operation in 1965 and 1967, respectively.

E.U. No.	Brief Description
Regulated Emissions Units	
001	Boiler Number 1 - 1,944.8 MMBtu/hour
002	Boiler Number 2 - 2,246.2 MMBtu/hour
003	Combustion Turbine - 542 MMBtu/hour Peaking Unit
004	170 MW Gas Combustion Turbine with HRSG and Duct Burner
005	170 MW Gas Combustion Turbine with HRSG and Duct Burner
006	Cooling Tower
010	Portable Welding Machine
011	Diesel Emergency Sump Pump
012	Diesel Emergency Generator for units -001 and -002
Unregulated Emissions Units and Activities	
007	Material Handling of Coal and Ash
008	Fugitive PM Sources - On-site Vehicles
009	General Purpose Internal Combustion Engines

Boilers 1 and 2 have a common 199-foot stack and are equipped with the air pollution control and measurement equipment listed below:

- Hot and cold side electrostatic precipitators to control particulate matter (PM);
- Low NO_X burners and non-selective catalytic reduction (SNCR) systems to control nitrogen oxides (NO_X); and
- Continuous emissions monitoring systems (CEMS) to measure and record NO_X and 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. Project Description

The project establishes a sulfur dioxide (SO_2) emission standard of 0.74 pounds per million Btu of heat input (lb/MMBtu) on a 30-day rolling average basis for Boilers 1 and 2. The limit will be accomplished by a combination of dry sorbent injection (DSI) upstream of one or both electrostatic precipitators located on each unit, upgrades to the electrostatic precipitators to capture the reacted sorbent, and coal sourcing consistent with the DSI system capabilities and the SO_2 standard.

Refer to Figure 3. DSI systems remove SO_2 and other acid gases through two basic steps. A powdered sorbent is injected into the boiler furnace exhaust gas with the SO_2. The sorbents most commonly associated with DSI are sodium sesquicarbonate (trona), sodium bicarbonate, and hydrated lime. The resulting reaction products and excess unreacted sorbent are removed by a downstream particulate matter (PM) control device such as an electrostatic precipitator (ESP) or a fabric filter (baghouse).

Figure 3. Simplified Diagram of Dry Sorbent Injection System for Acid Gas Removal

As discussed below, during recent years, annual emission factors from Boilers 1 and 2 combined have ranged from 0.93 and 1.48 lb/MMBtu. Given that the future coal sulfur range will be similar to the range in coal used over the past few years, then SO_2 removal objective for the DSI systems is approximately 20 to 50 percent (%). Per the applicant, future coal sourcing is primarily Colombian coal. According to the U.S. Geological Service (USGS):

"Colombia is the top coal producing country in South America. The coals are largely Cretaceous to Tertiary in age and are low in sulfur, ash, and potential hazardous air pollutants." Refer to the following link: Link to USGS Colombian Coal

Boilers 1 and 2 are each equipped with hot-side and cold-side ESP. Refer to Figures 4 and 5. In a hot side ESP configuration, the exhaust gases from the respective furnace economizers pass through the first ESP (the hot side ESP) then through an air preheater that transfers some of the remaining exhaust gas heat to incoming combustion air. In a cold side configuration, the exhaust gases pass through an air preheater and then the cooler exhaust gas passes through the cold-side ESP.

Figure 4. Hot Side ESP Ahead of Air Preheater **Figure 5. Cold Side ESP After the Air Preheater**

Boilers 1 and 2 are equipped with hot *and* cold side ESPs. Therefore the air preheater in each unit is located between the two ESPs. Depending upon the reagent loading required to reduce SO_2 to target levels, it may become necessary to remove greater mass than just the fly ash emitted from the furnaces. The additional mass removal may require operational changes but could also be accomplished by physical changes.

Among the possible changes envisioned is conversion of hot-side ESPs to cold side ESPs by moving the preheaters from present locations between the ESPs to locations immediately after the economizers. Such changes reduce the actual volumetric flow rates treated by the first ESPs and increase the residence time of exhaust gases within the control equipment. Reagent can be injected before or after the air preheaters and before or between the ESPs. High temperature injection can promote a popcorn effect, which increases the reagent surface to volume ratio.

The additional mass loading increases the volume of ash to be handled. There is at least the possibility of some minor changes in the coal and ash handling systems to facilitate the overall SO_2 reduction objective.

1.5. Processing Schedule

5/22/2012 Received the application for a minor source air pollution construction permit.

6/15/2012 Received additional information

7/16/2012 Received additional information regarding PM emissions

7/30/2012 Distributed Intent to Issue Air Permit package.

2. PSD APPLICABILITY

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 Lansing Smith Generating Plant. Lansing Smith Generating Plant 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 Lansing Smith Plant, 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 Putnam 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 6 is a summary of information derived from the EPA Air Markets Website pertinent to operation of Lansing Smith Boilers 1 and 2. During 2007-2008 the combined heat input factor of the two units was approximately 79% based on the annual fuel heat input reported for these units per EPA and the emissions unit descriptions contained in the permit application. In 2011, the combined heat input factor was only 36%.

The permitted SO_2 emission factors for Boilers 1 and 2 are 2.1 and 2.7 lb SO_2/MMBtu, respectively. When the two units operate simultaneously, the emission factor is equal to 4.50 lb SO_2/MMBtu. The theoretical potential to emit (PTE) based on the permit (without consideration of the latest ambient air quality standard) is 82,600 tons per year (tons/year).

Average combined emissions of SO_2 and NO_X during 2007-2008 were 16,087 and 5,760 tons per year (tons/year), respectively. During 2011, SO_2 and NO_X emissions for 2011 were 6,184 and 2,112, respectively. During 2007-2008, the SO_2 and NO_X emissions factors were 1.2 and 0.43 pounds per million Btu per hour of heat input (lb//MMBtu/hr), respectively. During 2011, the values were 0.93 and 0.32 lb/MMBtu.

The project will decrease the SO_2 emissions factor to 0.74 lb/MMBtu from the recent range of 0.93 to 1.48 lb/MMBtu and the permitted combined emission factor 4.5 lb/MMBtu. The combined Boiler 1 and 2 potential to emit (PTE) SO_2 will be reduce limited to 13,584 tons/year which is less than emissions during the baseline years. The reduction in PTE is approximately 83.5%

The project should not affect the NO_X emission factor. Urea-based SNCR systems were installed on Boilers 1 and 2 after the 2008-2009 baseline period. There is no reasonable scenario under which the emission factor in the future would be greater than 0.43 lb/MMBtu. Any future measured emissions increases would be due to increased utilization related to overall system demand and excludable.

Figure 6. Combined Boiler Nos. 1 and 2 NO_X, SO_2 Emissions and Relative Heat Input Factors

There is no reason to expect CO and VOC emissions increase due to the project.

According to the applicant, project is expected to increase PM emissions (and thus PM_{10} and filterable $PM_{2.5}$) by less than 9 tons/year assuming continuous full load operation (i.e. heat input factor of 100%). The basis of the calculation is that dry sorbent will be injected into the ducting from Boiler 1 and 2 at the rates of 5,000 and 6,000 lb/hour and that removal efficiencies of two ESPs in series will be 99.1% from the first and further reduction of 98% from the second.

The key global reaction that reduces SO_2 when using trona as the DSI reagent is:

Trona + sulfur dioxide react in the exhaust gas stream to yield sodium sulfite + carbon dioxide + Water

$$2(Na_2CO_3 \bullet NaHCO_3 \bullet 2\ H_2O) + 3\ SO_2 \rightarrow 3\ Na_2SO_3 + 4\ CO_2 + 5\ H_2O$$

The Department does not necessarily concur with the exact estimate, but agrees that the $PM/PM_{10}/PM_{2.5}$ increases should be minimal because of the dual ESP configuration. The sorbent would also reduce condensable $PM/PM_{10}/PM_{2.5}$ by reacting with sulfuric acid mist and ammoniated sulfate and chloride compounds.

Any estimates of "baseline actual emissions" to "projected actual emissions" suggest no significant emissions increase or significant net emissions. Therefore, a PSD review is not required based on the information submitted to date. The Department will require submittal of a baseline actual emissions to future actual emissions comparison once a final design is available for the project. At this time the applicant has proposed early 2015 as the likely date to order and install the system by March 31, 2016.

3. PRELIMINARY DETERMINATION

Although the permit will authorize the applicant to proceed with the project, the applicant has requested that the SO_2 emission standard of 0.74 lb/MMBtu not become effective until the effective date of EPA's approval of these specific requirements in the Florida Regional Haze State Implementation Plan to the extent that it applies to these units. Thereafter, the compliance date for the requested emission standard shall be no later than March 31, 2016.

No air quality modeling analysis was required because the project does not result in a significant increase in emissions.

The Department makes a preliminary determination that the proposed project to reduce SO_2 emissions will comply with presently applicable state and federal air pollution regulations as conditioned by the draft permit. This determination is based on a technical review of the application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. Leigh-Ann Pell is the project engineer responsible for reviewing the application and drafting the permit. 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, Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.