TECHNICAL EVALUATION

&

PRELIMINARY DETERMINATION

APPLICANT

Shady Hills Power Company, LLC
120 Long Ridge Road
Stamford, CT 06937

Shady Hills Generating Station
ARMS Facility ID No. 1010373

PROJECT

Site Expansion
Two Simple Cycle Combustion Turbine Electric Generators
Draft Permit No. PSD-FL-402A
Project No. 1010373-012-AC

Modification and Reissuance of Permit No. 1010373-007-AC

COUNTY

Pasco County, Florida

PERMITTING AUTHORITY

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

February 7, 2012

1. GENERAL PROJECT INFORMATION

1.1. Facility Description and Location

Shady Hills Power Company, LLC (Shady Hills) operates the Shady Hills Generating Station. The facility is an electrical power generating plant with a Standard Industrial Classification Code of SIC No. 4911. Refer to Figures 1 and 2 below. The facility is located at 14240 Merchant Energy Way, Spring Hill, Florida. The UTM coordinates are Zone 17, 347.0 kilometers (km) East, and 3139.0 km North.

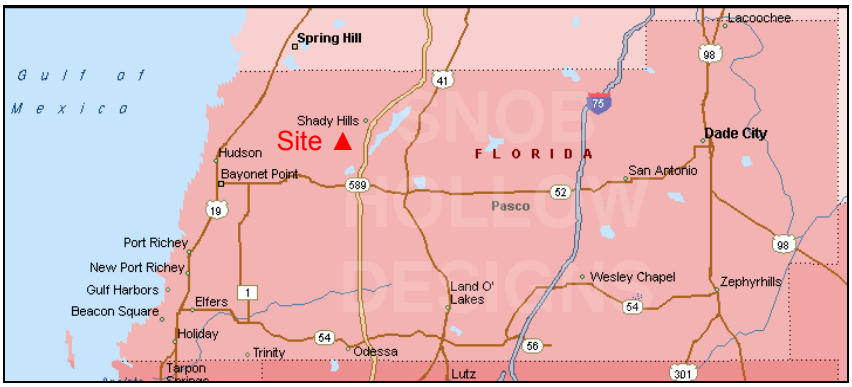


Figure 1 – Pasco County, FL **Figure 2 – Shady Hills Project Location**

The existing Shady Hills Generating Station includes:

- Three, dual-fuel, 170 megawatt (MW), General Electric (GE) Model 7FA.03, simple cycle combustion turbine-electrical generators (CTG);
- Three exhaust stacks that are 18 feet in diameter and 75 feet tall; and
- One 2.8-million gallon distillate fuel oil storage tank.

For reference, when initially permitted, the GE 7FA.03 was known as the GE PG7241FA.

1.2. Primary Regulatory Categories

- The existing 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 and Rule 62-210.200 (Definitions), F.A.C.
- The existing facility is not a major source of hazardous air pollutants (HAP).
- The existing facility has units regulated under Clean Air Act, Title IV, Acid Rain provisions, Phase II.
- The existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.

1.3. Project Description

On January 9, 2009, the Department issued permit No. 1010373-007-AC (PSD-FL-402) to Shady Hills to construct two additional 170 MW GE 7FA.03 simple cycle combustion turbines and ancillary equipment. On July 14, 2010 (prior to initiation of construction and expiration of the permit), Shady Hills submitted an application to modify the initial permit. The purpose is to construct larger combustion turbines than original planned and to add a second distillate fuel oil storage tank at the facility.

Briefly, the project (designated as 1010373-012-AC or PSD-FL-402A) will now consist of:

- Two dual-fuel, 223 MW GE 7FA.05 simple cycle combustion turbine-electrical generators;
- Two exhaust stacks that are 18 feet in diameter and 75 feet tall;
- One 2,500 kilowatts (kW) emergency generator;

- One 10-million British thermal units per hour (10 MMBtu/hour) natural gas heater; and
- One 2.8-million gallon distillate fuel oil storage tank.

The combustion turbines will fire natural gas as a primary fuel (3,390 hours/year/CTG) and ultra low sulfur distillate (ULSD) fuel oil as a secondary fuel (500 hours/year/CTG). To control nitrogen oxides (NO_X) emissions, the units will be equipped with lean-premix Dry Low NO_X (DLN) combustors and water injection (flame temperature reduction) capability.

The updated models will also incorporate certain features from a family of GE products known as OpFlex™. The specific OpFlex™ feature known as GE Start-up NO_X will reduce emissions during startup and low load operation.

In the July 2010 application, the applicant proposed low limits for carbon monoxide (CO) to avoid triggering PSD, consistent with the January 2009 permit. On December 27, 2011 the applicant resubmitted the application with greater CO emissions estimates and a best available control technology (BACT) proposal.

This project is subject to the state preconstruction review requirements of the PSD including:

- Revalidation of the final NO_X BACT determination issued by the Department in January, 2009;
- Revalidation of the final BACT for particulate matter (PM) and PM smaller than 10 micrometers (µm) – i.e. PM_{10};
- A CO BACT determination;
- Ambient air quality modeling for NO_2, PM_{10}/$PM_{2.5}$, and CO; and
- Analyses of air quality related values (AQRV), including visibility.

Table 1 indicates the emissions unit identification numbers (E.U. ID Nos.) that will be assigned for tracking within the Department's Air Resource Management System (ARMS). The changes compared with the previously issued permit are indicated by ~~strikethrough~~ and double-underline notation.

Table 1 – List of Emissions Units for the Proposed Shady Hill Expansion Project

ID No.	Description
005	~~170~~ 223 MW General Electric Model 7FA.05 simple cycle combustion turbine-electrical generator
006	~~170~~ 223 MW General Electric Model 7FA.05 simple cycle combustion turbine-electrical generator
007	2,500 kilowatts emergency generator
008	10 MMBtu/hour natural gas heater
009	2.8 million gallon distillate fuel oil storage tank

1.4. Processing Schedule

January 9, 2009	The Department issued permit 1010373-007-AC (PSD-FL-402) to construct two GE Model 7FA.03 CTG and related equipment. Link to Permit PSD-FL-402
July 14, 2010	Prior to expiration of the previous permit, the Department received the application for an air construction permit modification to construct two larger CTG and associated equipment. Link to Application and Documents
August 13, 2010	The Department issued a request for additional information (RAI) related primarily to EPA-issued guidance for a new 1-hour nitrogen dioxide (NO_2) standard and the AQRV visibility modeling requirements of the U.S. Fish and Wildlife Service (FWS). Link to RAI No. 1
February 7, 2011	Department received additional information. Link to Response to RAI No. 1
March 8, 2011	The U.S. FWS advised the Department on behalf of the federal land manager for

	the Chassahowitzka National Wilderness Area (NWA) that Shady Hills needs to perform individual sector analysis and then determine cumulative frequencies followed by performing analyses in accordance with visibility modeling guidance (VISCREEN Level II). Link to U.S. FWS Request
March 9, 2011	The Department forwarded the U.S. FWS request as a RAI. Link to RAI No. 2
April 27, 2011	The U.S. EPA advised Shady Hills to submit certain evaluations together with an expected application for a PSD greenhouse gas (GHG) permit application to be reviewed by EPA. Link to U.S. EPA Request
October 21, 2011	Department received response to RAI No. 2 including a refined visibility assessment. Link to Visibility Assessment
November 16, 2011	The Department deemed the application complete effective October 21, 2011.
December 27, 2011	Shady Hills revised its application to include a PSD BACT proposal for CO. Link to CO BACT Application
January 20, 2012	Shady Hills submitted PSD modeling analysis for CO. Application complete.

2. 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:

Table 2 - Applicable Rules from the F.A.C.

Chapter	Description
62-4	Permits
62-204	Air Pollution Control – General Provisions
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Stationary Sources – Preconstruction Review
62-213	Operation Permits for Major Sources (Title V) of Air Pollution
62-214	Requirements for Sources Subject to the Federal (Title IV) Acid Rain Program
62-296	Stationary Sources – Emission Standards
62-297	Stationary Sources – Emissions Monitoring

The U.S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40, Code of Federal Regulations, part 60 (40 CFR 60) that identifies New Source Performance Standards (NSPS) for a variety of industrial activities. 40 CFR 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP). 40 CFR 63 specifies NESHAP provisions based on the Maximum Achievable Control Technology (MACT) for given source categories.

Federal regulations adopted by reference are given in Rule 62-204.800, F.A.C. State regulations approved by EPA are given in 40 CFR 52, Subpart K – Florida, also known as the State Implementation Plan (SIP) for Florida.

3. PSD APPLICABILITY REVIEW

3.1. General PSD Applicability

The Department regulates major stationary sources in accordance with Florida's PSD program pursuant to Rule 62-212.400, 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, NO_X, PM, PM_{10}, sulfur dioxide (SO_2), volatile organic compounds (VOC), lead (Pb), fluorides (F), sulfuric acid mist (SAM), 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 MSW landfill emissions as non-methane organic compounds (NMOC).

As defined in Rule 62-210.200(189)(a)1, 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; or
- 100 tons/year or more of any PSD pollutant and the facility belongs to one of the 28 listed PSD major facility categories.

The list given in the citation does not include the category of "fossil fuel fired simple cycle combustion turbines". The nearest classification is a fossil fuel steam generator. However, the electric generators associated with this project are directly coupled to the combustion turbines and no steam is involved in electrical power produced by the proposed project. The Shady Hills Generating Station is a major stationary source based on actual emissions of and potential to emit 250 tons/year or more of several individual PSD pollutants.

For major stationary sources such as the Shady Hills Generating Station, PSD applicability for modification projects is based on thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200(274), F.A.C. Any "net emissions increase" as defined in Rule 62-210.200(204), 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 TPY as applicable) for only one PSD pollutant, a project must include BACT controls for any PSD pollutant that exceeds the corresponding significant emission rates given in Table 3.

Table 3 - List of Significant Emissions Rates (SER) by PSD-Pollutant [1, 4]

Pollutant	SER (tons/year)	Pollutant	SER (tons/year)
CO	100	NO_X	40
PM	25	PM_{10} [2]	15
Ozone (NO_X) [3]	40	Ozone (VOC) [3]	40
SO_2	40	SAM	7
Mercury	0.1	Fluoride	3

1. Excluding those defined exclusively for MWC and MSW landfills.
2. $PM_{2.5}$ is also a PSD pollutant, but a significant emission rate has not yet been defined in the Department's rules. It is regulated by its precursors and surrogates (e.g. PM, PM_{10}, NH_3, SO_2 and NO_X).
3. Ozone (O_3) is regulated by its precursors (VOC and NO_X).
4. A federal significant emission rate of 75,000 tons/year for greenhouse gases (GHG) as carbon dioxide equivalent (CO_2e) exists but has not been incorporated into Department rules. Shady Hills must submit a GHG PSD application to EPA.

PM smaller than 2.5 µm ($PM_{2.5}$) is a federal PSD pollutant and the Department is in the process of adopting a significant emission rate of 10 tons/year. Refer to Link to $PM_{2.5}$ Rulemaking Project . Until the rule is finalized, projects in Florida are not subject to a significant emission rate for $PM_{2.5}$.

3.2. PSD Applicability for the Project

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

Table 4 provides PSD applicability calculations based on the net emission increases expected to result from the Shady Hills Generating Station expansion project as originally permitted and then as revised by the present application. Greenhouse gas (GHG) emissions expressed as equivalent carbon dioxide (CO_2e) emissions are also included for comparison with federal greenhouse gas PSD applicability criteria.

Table 4 – Net PSD Pollutant Emission Increases due to the Shady Hills Site Expansion in tons/year

Pollutant	Net Emissions Increase (PSD-FL-402)[1]	Net Emissions Increase (PSD-FL-402A)[2]	SER	PSD Applies? (Yes, No)
NO_X	343	397	40	Yes
PM	35	69 [3]	25	Yes
PM_{10}	35	69 [3]	15	Yes
$PM_{2.5}$	Not applicable	69 [3]	10 [4]	No [3]
CO	93	135	100	Yes
SO_2	32	29.7	40	No
SAM	5	5	7	No
VOC	15	19	40	No
Lead	0.020	0.015	0.6	No
CO_2e	Not applicable	~822,000	75,000 [5]	Yes [5]

1. This column represents the potential emissions from the previously approved site expansion project.
2. This column represents the potential emissions from approved site expansion project as revised by the present application.
3. Much of the "increase" in $PM/PM_{10}/PM_{2.5}$ emissions compared with first project is due to inclusion of condensable species.
4. PSD is not triggered because the Department's rulemaking project to establish a $PM_{2.5}$ SER has not yet been finalized. However, the project consumes PSD $PM_{2.5}$ increment as described in the modeling discussion.
5. The federal EPA significant emission rate applies to this project and the applicant must submit a greenhouse gas PSD permit application to EPA.

The permitted site expansion project was subject PSD preconstruction review for emissions of NO_X, PM, and PM_{10}. The December 2011 version of the revised application triggers PSD preconstruction review for the same pollutants as well as CO under state rules. While the Department has not yet completed its adoption of the federal $PM_{2.5}$ significant emission rate, the applicant submitted a BACT proposal and conservatively modeled direct $PM_{2.5}$ as equal in magnitude to emissions of PM_{10} and including both filterable and condensable components. Because construction was not commenced in a timely manner, PSD for CO_2e is now applicable to the project under federal rules. A separate PSD CO_2e application will be submitted to and reviewed by EPA Region 4.

3.3. Requirements for Projects Subject to PSD

In accordance with Rule 62-212.400(4), F.A.C., for the construction of any new "major stationary source" or the major "modification" of any existing major stationary source, the applicant must provide the following information:

(a) A description of the nature, location, design capacity, and typical operating schedule of the source or modification, including specifications and drawings showing its design an plant layout;

(b) A detailed schedule for construction of the source or modification;

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available

control technology (BACT) including a proposed BACT;

(d) The air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact and an analysis of "good engineering practice" stack height; and

(e) The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.

4. BEST AVAILABLE CONTROL TECHNOLOGY (BACT) – DRAFT DETERMINATIONS

4.1. Definitions and Requirements Related to BACT

"Best Available Control Technology" or "BACT" is defined in Rule 62-210.200(40), F.A.C. as follows:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. Energy, environmental and economic impacts, and other costs,

2. All scientific, engineering, and technical material and other information available to the Department; and

3. The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

(b) If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for eh application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.

(c) Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

(d) In no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

4.2. Draft BACT Determinations for the Combustion Turbine-Electrical Generators

How a Combustion Turbine-Electric Generator (CTG) Works

Refer to Figure 3. A combustion turbine (also known as a gas turbine) compresses air and mixes it with fuel. The fuel is burned and the hot air-fuel mixture is expanded through turbine blades, making them spin. The spinning turbine drives a generator which converts the spinning energy into electricity. (GE)

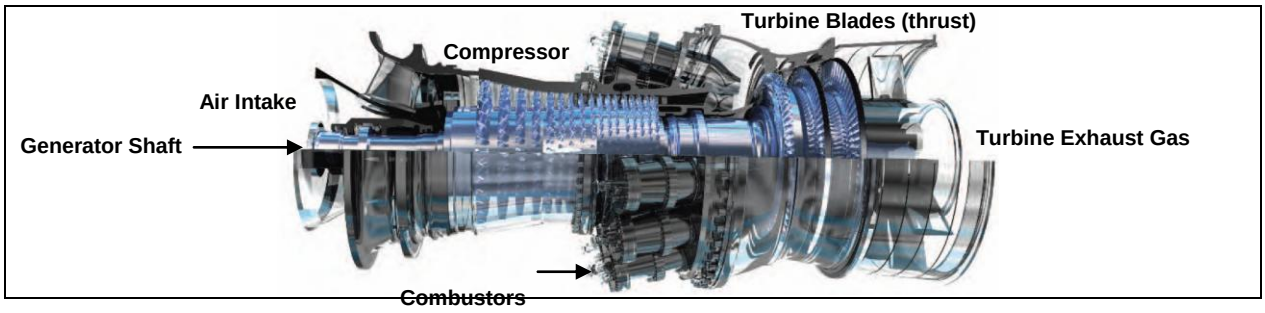


Figure 3 – Parts and Internal View of a GE 7FA.05 Combustion Turbine-Electrical Generator

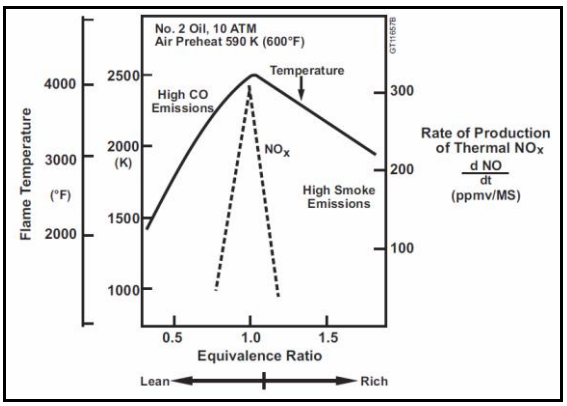
In the Shady Hills project, the units will operate in simple cycle mode, meaning that the hot turbine exhaust gases are directed through a stack without prior waste heat recovery and steam generation.

BACT for Nitrogen Oxides (NO_X)

NO_X Formation

NO_X is formed during combustion as a result of the dissociation of molecular nitrogen (N_2) and oxygen (O_2) to their atomic forms and subsequent recombination into seven different oxides of nitrogen (especially NO and NO_2).

Thermal NO_X forms in the high temperature area of the combustor. Thermal NO_X increases exponentially with flame temperature and linearly with residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen, also known as the equivalence ratio. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The relation of NO_X production with respect to flame and equivalence ratios (lean versus rich operation) is shown in Figure 4.



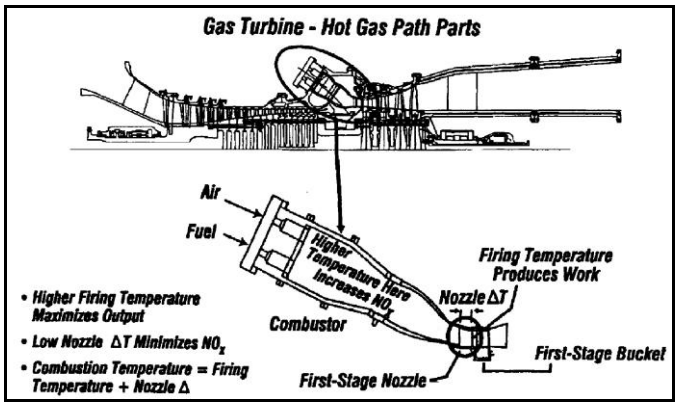


Figure 4 - NO_X vs. Temperature, Equivalence Ratio[1] Figure 5 - Hot Gas Path Parts, NO_X Control

In most combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. The relationship between flame temperature, firing temperature, work output and NO_X formation is depicted in Figure 5, which is from a General Electric discussion on these principles.

Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not of great concern when combusting natural gas.

Uncontrolled emissions from combustion turbines range from about 100 to 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd for large frame combustion turbines.[2]

NO_X Controls

Wet Injection. Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Carbon monoxide (CO) and volatile organic compounds (VOC) emissions are very low for large gas turbines when operated at higher loads. However steam or water injection may increase emissions of both of these pollutants.

Advanced dual-fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can achieve NO_X emissions in the range of 30 to 42 ppmvd @15% O_2 when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 90% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques as discussed below.

Dry Low NO_X (DLN) Combustion. The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of gaseous fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) within the combustion zones. This principle is incorporated into the General Electric DLN-2.6 can-annular combustor design depicted in Figure 6.

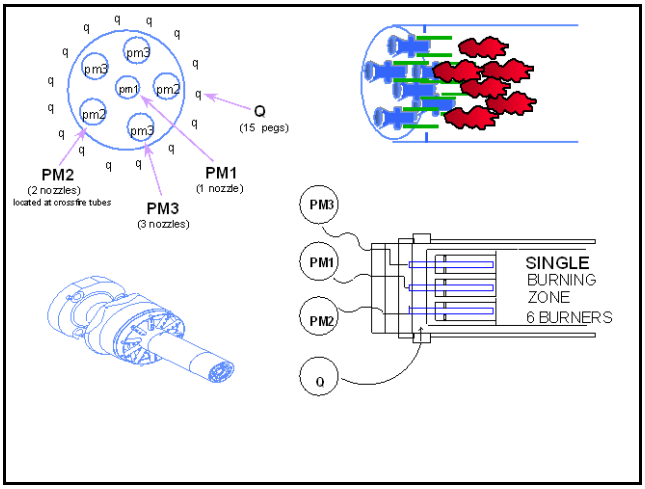


Figure 6. DLN-2.6 Fuel Nozzle Arrangement

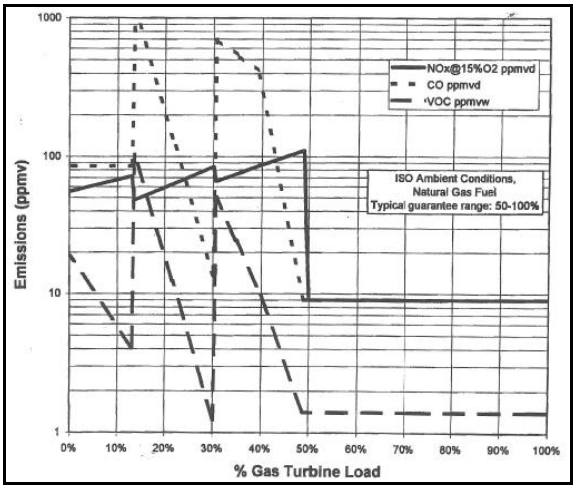
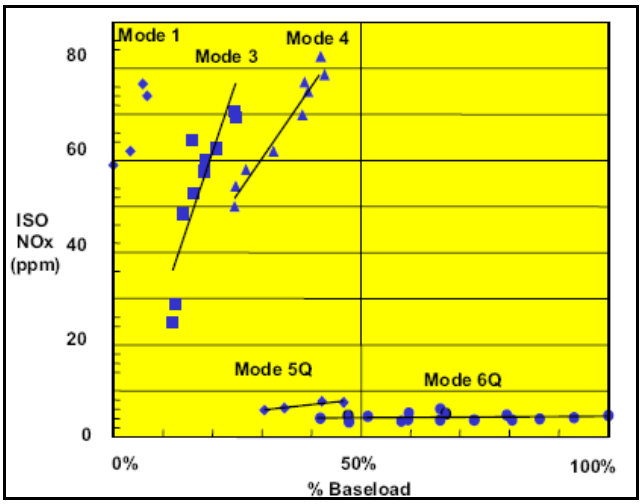


Figure 7 - Design Characteristics for DLN-2.6

Each combustor includes six nozzles within which gaseous fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability. Liquid fuel-based lean premix DLN combustion is generally not feasible for large combustion turbines.

Design NO_X, CO, and VOC emission characteristics (basis of guarantees) of the GE DLN-2.6 combustor for the GE 7FA.03 while firing natural gas are given in Figure 7. The combustor design is such that NO_X concentrations can be tuned to achieve 9 ppmvd @15% O_2 at loads between 50 and 100 percent of capacity. However, *concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity*. This suggests the need to *minimize operation at low load conditions and during startup*. Units guaranteed to achieve 9 ppmvd @15% O_2 of NO_X were typically guaranteed to 9 ppmvd (uncorrected) of CO which equates to approximately 7.4 ppmvd CO @15% O_2. In the further discussion below use of the term ppmvd implies that the value is not corrected to 15% O_2.

Figure 8 below is from a GE publication and is a plot of NO_X data from actual GE 7FA.03 combustion turbines (or earlier models) or possibly a test facility. Actual NO_X emissions are less than the design values. The Department has reviewed numerous reports and low load operation data from GE 7FA.03 units (or earlier 7FA models) in Florida and confirms the accuracy of Figure 8. Also actual emissions of CO at loads greater than 50% of full load have proven to be less than suggested by Figure 7 above and more like the behavior shown in Figure 9 below.



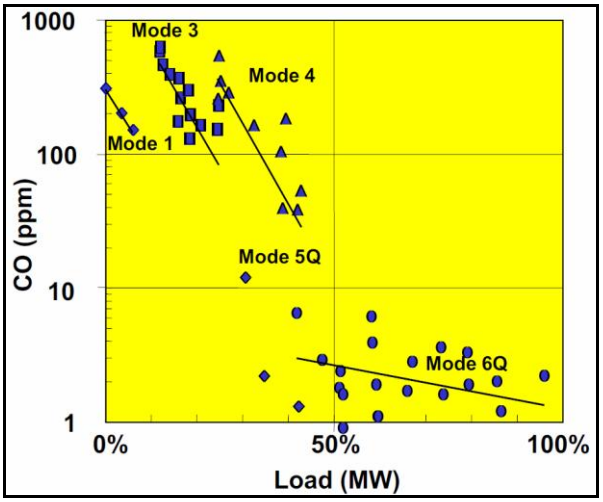


Figure 8 - NO_X Performance of DLN-2.6 (GE 7FA.03) **Figure 9 – CO Performance of DLN-2.6**

Table 5 summarizes the results of the new and clean tests conducted on a dual-fuel GE 7FA.03 CTG with DLN-2.6 combustors operating in simple cycle mode and burning natural gas at the existing Tampa Electric (TECO) Polk Power Station.[3] The test results over a range of loads confirm that NO_X, CO, and VOC emissions are, in practice, consistently less than the design (guarantee) values given in Figure 7.

Table 5 - Performance of DLN-2.6 Combustors on GE 7FA.03, TECO Polk Power Station (ppmvd)

Percent of Full Load	NO_X (@15% O_2)	CO	VOC
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1

Numerous simple cycle GE 7FA.03 units with DLN-2.6 technology for NO_X control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd @15% O_2. This represents a reduction greater than 95 percent, assuming uncontrolled emissions are 200 ppmvd.

The larger GE 7FA.05 combustion turbines that Shady Hills will install in lieu of those approved pursuant to the earlier 2008 permit will include certain features from a series of GE products known as Operational Flexibility Enhancements (OpFlex™) which involve advanced fuel scheduling. The Shady Hills project will incorporate at least one the products that will reduce NO_X and visible emissions (and presumably CO) at low loads while minimizing startup and excess emissions. Figure 10 from a GE brochure on OpFlex™ indicates the substantial NO_X reductions during low load operation and startup expected from these features. Figure 11 shows the improvement in low load visible emissions following the installation of GE Start-up NO_X on an existing GE 7FA.03.

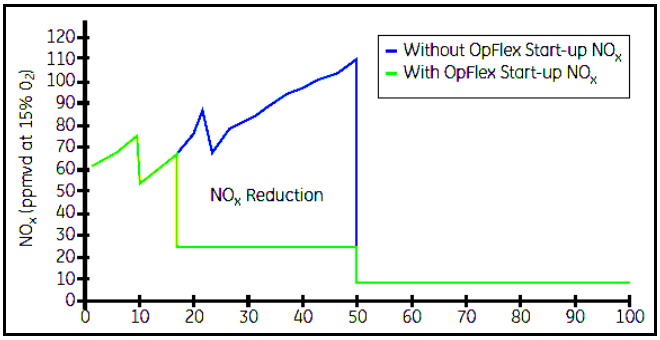


Figure 10 – DLN-2.6 with GE Start-up NO_X **Figure 11 – Low Load Opacity Improvement**

The GE Start-up NO_X profiles are similar to those shown in Figures 7 and 8 for higher loads but are far superior for low load operation. Given simple cycle peaking operation, it is easy to conclude that startup and low load emissions will be less for the larger GE 7FA.05 units with GE Start-up NO_X than the smaller GE 7FA.03 and GE 7FA.04 units without the feature.

Selective Catalytic Reduction (SCR). Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia (NH_3) into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water (H_2O) according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts are available for applications at temperatures between roughly 300 and 1,100 ^oF and typically are comprised of titanium oxide (as TiO_2), vanadium (as V_2O_5) and tungsten (as WO_3). The formulations contain progressively less vanadium and become more costly for the higher temperature applications. There are numerous examples of SCR installations at continuous duty combined cycle units throughout Florida. In combined cycle units, the catalyst can be placed at an optimal temperature (roughly 400 to 600 ^oF) for the purposes of high efficiency and lowest cost within the heat recovery steam generator. In such applications, NO_X emissions on the order of 2.0 ppmvd @15% O_2 are achieved.

At higher temperatures, vanadium can actually contribute to ammonia oxidation forming more NO_X or forming nitrogen without reducing NO_X according to:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \text{ and } 4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

Therefore, less V_2O_5 is used in formulations for higher temperature applications. The lowest cost for a given application may involve cost optimization between the selection of a catalyst formulation and the equipment to cool gas to the operating temperature of the formulation. SCR was installed on two small GE LM6000 simple cycle units at the City of Tallahassee's Hopkins facility. These are characterized by exhaust gas less than 900 ^oF and exhaust gas cooling was not required.

For the highest temperature applications (>1100 ^oF), such as large frame simple cycle turbines like the GE7FA.05, more expensive formulations or substantial tempering air would be required. The applicant estimated the installed capital cost of an SCR system at more than $10,000,000/CTG and a cost effectiveness of $10,794 per ton of NO_X removed when operating 3,390 hours/year including 500 hours/year using ultralow sulfur distillate fuel oil. The target values would be 14 and 2 ppmvd @15% O_2 while firing fuel oil and natural gas, respectively. The Department does not necessarily accept the cost estimates. However, the Department concurs that hot SCR is not cost-effective for the proposed primarily natural gas-fueled, limited operation, simple cycle units with a very high exhaust gas temperature.

Catalytic Combustion - XONON™. XONON™ operates by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X production) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[4] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[5] At least five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd @15% O_2.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[6] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. In 2008, the technology was available for gas turbines in the 10 to 15 MW bracket with an expectation of NO_X emissions less than 5 ppmvd @15% O_2. This technology is not feasible at this time for the Shady Hills project.

EMx (Formerly SCONO$_X$™) EMx is a NO_X and CO control system. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. One benefit is that it does not require ammonia injection. The required operating temperature range is between 300°F and 700°F, which exists within a heat recovery steam generator of a combined cycle unit but not in a simple cycle unit. Therefore substantial gas cooling would be required. EMx costs much more than SCR, is mechanically very complicated and requires on-site hydrogen production from natural gas. Even if it is technically feasible, it is not cost-effective for this project.

Requirements of 40 CFR Parts 60 and 63 on the Combustion Turbines with respect to NO_X

As stated in the definition of BACT given above, *"in no event shall application of BACT result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63"*. The two new combustion turbines are subject to the requirements in 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005. The citation is abbreviated as NSPS KKKK for the purposes of subsequent discussion. Link to NSPS KKKK . The minimum key emission limits for all combustion turbines subject to NSPS Subpart KKKK are given at the following link: Link to NSPS KKKK Table . Table 6 below includes the emission standards applicable to the Shady Hills project.

Table 6 – NSPS Subpart KKKK Standards for New Large Stationary Combustion Turbines

Combustion Turbine Type	Peak Load Heat Input, Power Output [1]	NO_X Standard [2]
New, modified, or reconstructed turbine firing natural gas	> 850 MMBtu/hour	15 ppm @15% O_2 or 54 ng/J, useful output (0.43 lb/MW-hour)
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 MMBtu/hour	42 ppm @15% O_2 or 160 ng/J, useful output (1.3 lb/MW-hour)
Turbines located north of the Arctic Circle, **turbines operating at less than 75% of peak load**, ..	> 30 MW output	96 ppm @15% O_2 or 590 ng/J, useful output (4.7 lb/MW-hour)

1. Heat input based on the higher heating value (HHV) or MW of useful output
2. ng/J means nanograms per joule

A NO_X standard of 96 ppmvd @15% O_2 is provided for combustion turbines operating at less than 75% of peak load. Per Figure 10 above, the GE NO_X Start-up product makes it possible to operate the GE 7FA.05 units at all loads while complying with the respective NSPS Subpart KKKK limits.

There are no NO_X standards in 40 CFR part 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The citation is abbreviated as NESHAP Subpart YYYY for the purposes of subsequent discussion. Link to NESHAP Subpart YYYY . For reference, as an area source of hazardous air pollutants (HAP), NESHAP Subpart YYYY does not apply to the proposed Shady Hills combustion turbines.

Applicant's NO_X BACT Proposal

The applicant proposes the following BACT determination for the control of NO_X emissions from the two proposed GE 7FA.05 CTG:

- NO_X emissions while firing natural gas shall be limited to 9.0 ppmvd @15% O_2 as BACT on a 24-hour basis achievable by lean premix Dry Low NO_X technology;

- NO_X emissions for limited ultralow sulfur fuel oil use shall be limited to 42.0 ppmvd @15% O_2 as BACT on a 4-hour basis achievable by water injection for flame cooling;
- Startup and low load emissions shall be further controlled by the GE Start-up NO_X work practices;
- The two combustion turbines may operate an average of no more than 3,390 hours/year/CTG with no single unit operating more than 5,000 hours/year;
- The two combustion turbines combined may operate up to 1,000 hours/year using ultralow sulfur distillate fuel oil; and
- If only one combustion turbine is installed, then it may operate up to 500 hours/year on ultralow sulfur distillate fuel oil. The single combustion turbine may fire an additional 250 hours/year of fuel oil, provided that for every hour of fuel oil fired beyond 500 hours, the combustion turbine must reduce its capability to fire natural gas by five hours (i.e. 5:1 natural gas to ULSD fuel oil ratio).

Under the single combustion turbine option, if the CTG operates on ULSD fuel oil for 750 hours in a calendar year, then it may only operate for only 1,640 hours on natural gas during the same calendar year [(3,390-500) – 5x(750-500)]. The restriction insures that the new combustion turbines will not be operated in the higher emissions mode to the extent that hot SCR appears to be economically feasible.

Further Fuel Oil Considerations

Per Table 7, historical fuel oil usage at the Shady Hills site has actually been very low.

Table 7 - Historical Fuel Use at the Existing Shady Hills Units 1, 2 and 3

Year	CTG No.	Gas Use (hours)	Oil Use (hours)
2006	1	749	1
	2	727	1
	3	737	1
	All Units	2,213	3
2007	1	2,394	54
	2	2,165	58
	3	2,428	74
	All Units	6,987	186
2008	1	2,668	2
	2	2,719	2
	3	2,680	1
	All Units	8,067	5
2009	1	2,253	0
	2	2,310	0
	3	2,357	0
	All Units	6,920	0
2010	1	1,865	205
	2	1,926	147
	3	2,112	88
	All Units	5,903	440
2006 - 2010	All Units	30,090 (2006/year/CTG)	634 (43/year/CTG)

It is recognized that some allowance can and should be made for limited back-up fuel oil firing to account for interruptions in the natural gas supply or sudden and unexpected price spikes. In that case a limit of 42 ppmvd @15% O_2 (equal to the NSPS Subpart KKKK requirement) achieved by wet injection during

500 hours of incidental fuel oil firing is appropriate but is not necessarily BACT when more significant amounts of fuel oil are fired.

The existing units permitted 12 years ago are allowed to operate 3,390 hours/year/CTG and to burn fuel oil 1,000 hours/year/CTG. According to the actual fuel use records, during the past five years the units have operated approximately 2,050 hours/year/CTG and only 43 hours/year/CTG while firing fuel oil.

Typically ULSD fuel oil prices are significantly greater than natural gas prices and the fuels do not deirectly compete within the power industry in Florida. ULSD fuel oil is only used during short-term supply interruptions and temporary natural gas price dislocations.

Changing market conditions in the United States over the past five years have led to dramatic decreases in natural gas prices from the higher levels when the facility was built. With the recent expansion of natural gas supplies from shale, it is reasonable to conclude that natural gas will continue to be more attractive for use in combustion turbines than ULSD fuel oil on the basis of price. Natural gas is also more favorable on the basis of equipment maintenance.

Department's Draft NO_X BACT Determination

The Department concurs with the applicant's NO_X BACT proposal as described above. The NO_X-CEMS already required for the purposes of the federal Acid Rain program will be used to demonstrate continuous compliance with the BACT emission limits and logging of excludable emissions. It will also be used to demonstrate compliance with the NSPS Subpart KKKK emission limits and logging of excess emissions.

BACT for Carbon Monoxide (CO)

CO Formation and Control Option Descriptions

CO is a product of incomplete combustion of carbon-containing fuels such as natural gas and fuel oil. Factors adversely affecting the combustion process are low temperatures, insufficient turbulence and residence times, and inadequate amounts of excess air. Most combustion turbines incorporate good combustion practices based on high temperature, sufficient time, turbulence, and excess air to minimize emissions of CO. Additional control can be obtained by installation of oxidation catalyst, particularly on certain combustion turbines that do not perform well at low load conditions.

Although relatively high BACT CO limits are sometimes proposed when using combustion controls, much lower emissions are actually reported for very large combustion turbines (at least at full load operation) without use of oxidation catalyst. Based on testing discussed in the NO_X technology section above, the earlier generation GE 7FA.03 units achieved CO emissions in the range of 0.3 to 1.6 ppmvd when firing gas at the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent.

Some of the more recent turbine projects within the state have been permitted with continuous emissions monitoring system (CEMS) requirements for CO. Continuous data from these units verify the ability of the GE 7FA.03 (and presumably the GE 7 FA.05) to operate continuously with CO emission rates well below the manufacturer's guarantee. A summary of CO-CEMS data recorded at the TECO Bayside Station and reflecting very low CO emissions for four GE 7FA.03 units is shown in Table 8 below.

CO and VOC emissions *should be and are* low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE 7FA. Performance guarantees are only now "catching up" with the field experience. GE recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units.[7] The following statement was taken from the report:

"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN (now the GE 7FA.03) on a case-by-case basis following a detailed evaluation of the situation – thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA (GE 7FA.03) DLN units while firing natural gas." (Parenthetical notes added by Department)

Table 8 - CO CEMS Data in ppmvd from GE 7FA.03 CTG at TECO Bayside Unit 1

Turbine	Quarter	CO Max 24-hr Block	CO Min 24-hr Block	CO Quarterly Average
1A	3rd Quarter 2003	4.3	0.3	0.83
1B		1.7	~0	1
1C		2.1	~0	0.8
1A	4th Quarter 2003	2.2	~0	0.76
1B		1.9	~0	1.14
1C		1.2	~0	0.74

A summary of stack test CO data in ppmvd from the three existing Shady Hills units along with their reported annual emissions in tons/year are given in Table 9. The annual emissions are probably under reported because they are based on near full load (low emissions) stack tests and do not consider the higher emitting startup and low load modes.

Table 9 – CO Test Results (ppmvd) and Annual Emissions (tons/year) - Shady Hills

Year	Unit 1 (ppmvd)	Unit 2 (ppmvd)	Unit 3 (ppmvd)	Facility (tons/year)
2003	0.29	0.23	0.2	3.3
2004	0.14	0.2	0.3	1.1
2005	0.17	No Data	0.07	1.2
2006	0.25	0.21	0.36	0.9
2007	0.26	0.31	0.17	2.8
2008	0.42	0.67	0.32	6.1
2009	0.44	0.36	0.44	4.4
2010	0.24	0.35	0.66	4.4
2011	0.1	0.45	0.12	Not yet received
Average	0.26	0.35	0.29	4.0

A summary of stack test data from facilities that fire ULSD fuel oil on a limited basis is shown in Table 10. The results suggest that emissions when firing fuel oil are minimal and slightly greater than when firing natural gas.

Table 10 - CO, Stack Test Results from GE 7FA.03 Simple Cycle Gas Turbines when firing Fuel Oil

Facility/Unit and percent (%) of Baseload	CO (ppmvd)
Martin Units 8A and 8B @100%	0.6 and 0.8
Purdom Unit 8 @50 and 100%	1.2 and 1.3
TECO Polk Unit 3 @100%	0.6
JEA Kennedy KCT-7 @100%	2.1
Stanton A – Units 25 and 26 @100%	1.0
Reliant Osceola Unit 1, 2, 3 @100%	0.04, 0.02 and 0.54
Oleander Power Units 1, 2, 3 and 4 @100%	1.8, 1.1, 3.8 and 2.7

Figure 12 is from the GE article mentioned above and likely relates to CO emissions while firing natural gas. The data are consistent with those collected by the Department for both natural gas and fuel oil.

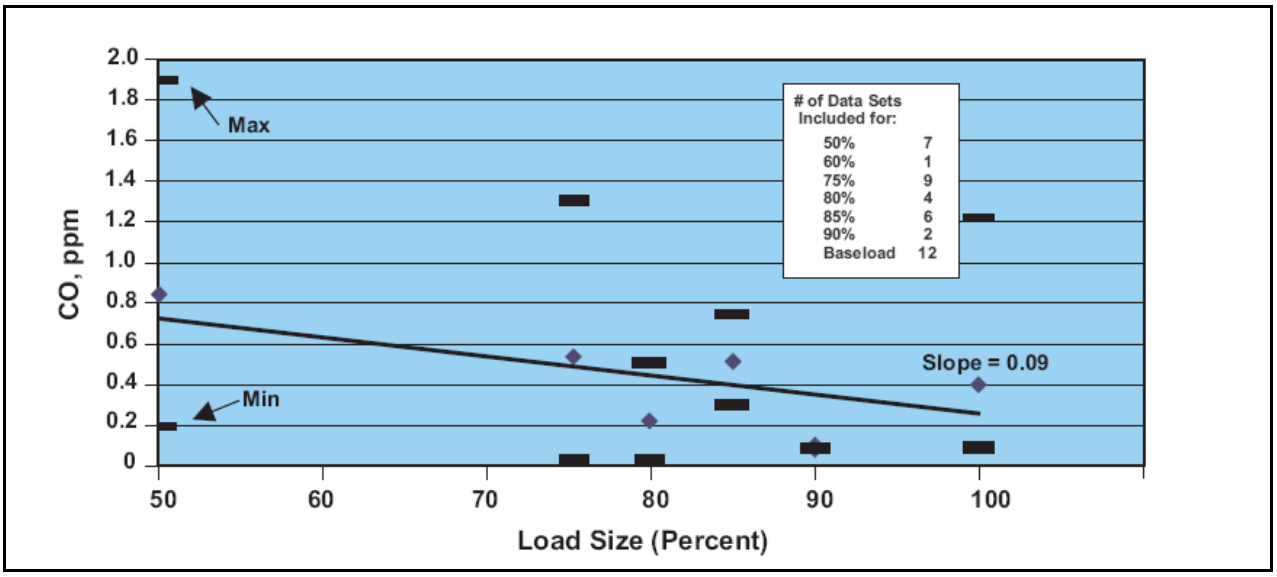


Figure 12 - Average CO Emissions versus Percent Load for GE 7FA.03 Combustion Turbines

Requirements of 40 CFR Parts 60 and 63 on the Combustion Turbines with respect to NO_X

Neither the NSPS Subpart KKKK nor the NESHAP Subpart YYYY applicable to combustion turbines includes a CO emission standard and therefore are not considered when conducting a BACT determination for this pollutant.

Applicant's CO BACT Proposal

In its earlier submittal of July 2010, the applicant proposed CO limits of 6 ppmvd while burning natural gas and 13 ppmvd while burning ultralow sulfur distillate fuel oil for the purpose of avoiding PSD and the requirement to conduct a BACT determination. At these levels, the project CO emissions were estimated to be less than 100 tons/year.

In its December 2011 application, Shady Hills proposed BACT emission standards of 9 and 20 ppmvd for natural gas and ultralow sulfur distillate fuel oil, respectively. The applicant stated:

"Because there are no operational data for CO emissions from the new GE 7FA.05 model, the turbine vendor, GE Energy, is not offering emission guarantees for CO concentrations at the levels originally proposed, 6.0 ppmvd @15% O_2 for natural gas and 13 ppmvd @15% O_2 for fuel oil firing. Although operational data exist for CO emissions from GE 7FA.03 and GE 7FA.04 models that demonstrate these concentrations of CO are achievable, and are the basis for prior BACT determinations, the project will utilize GE 7FA.05 turbines for which no operational data exist.

"The design of the new GE 7FA.05 differs from the 7FA.03 and 7FA, and the MW output of the 7FA.05 is approximately 20% greater than the earlier models. The change in the 7FA.05 design yields uncertainty that the CO concentrations will be similar to the previous 7FA models, and the vendor guarantees at those concentrations are not available. As such, Shady Hills Power Company, LLC is requesting CO concentration limits equivalent to the vendor emission guarantee rates of 9 ppmvd for natural gas firing and 20 ppmvd for fuel oil firing."

(Note: the applicant appears to read the GE CO guarantees as requiring correction to 15% O_2. However, unlike the NO_X guarantees, the GE CO guarantees are normally stated as uncorrected values).

According to the applicant, the total capital costs of reducing CO emissions [from 9 to 2 ppmvd for natural gas and from 20 to approximately 4 ppmvd] are nearly $4,000,000 and the cost-effectiveness is between $10,766 and $13,177/ton CO removed.

Department's Assessment of Applicant's CO BACT Proposal

The Department does not necessarily agree with the costs presented by the applicant. However, the Department concurs that oxidation catalyst is not cost-effective to reduce CO emissions from the guaranteed values (12 and 20 ppmvd) to 2 and 4 ppmvd for natural gas and fuel oil, respectively. In fact, based on data from the GE 7FA.03 units, oxidation catalyst is not even necessary to meet the target values of 2 and 4 ppmvd.

The Department accessed product development information for the GE7FA.05 combustion turbine. Link to GE 7FA.05 Details . According to Table 11 below reproduced from their product information, it appears that they do not (yet) offer the 5 ppmvd guarantee for the GE 7FA.05 product. If they do offer such a guarantee on a case-by-case basis, they do not yet publicize it.

Table 11 – Performance of GE 7FA.05 Combustion Turbine-Generator (source GE)

Parameter	Simple Cycle	Combined Cycle*
Output (MW)	211	627
Efficiency (%, Lower heating Value - LHV)	38.5	57.5
Heat Rate (Btu/kW-hour, LHV)	8,872	5,934
NO_X (ppmvd@15% O_2)	9	2
CO (ppmvd)	9	9
* Combined cycle values assume gas fuel, ISO base load condition, 1.5 inches mercury steam turbine back pressure, two-on-one combined cycle utilizing GE 207D-11 steam turbine, SCR, no duct firing and no CO catalyst		

However, the arguments presented by the applicant do not make sense from a technical point-of-view. The GE 7FA.05 incorporates the same DLN-2.6 technology used by the 7FA.03 and 7FA.04. Clearly, GE had enough confidence to provide the same low NO_X guarantee of 9 ppmvd @15% O_2 for the newer and larger unit that was provided for the earlier ones. Generally, the entire GE 7FA line of turbines performs close to the guaranteed value for NO_X (refer to table 5) but emits much less CO than the guaranteed values.

The following statements are from one of GE's technical documents for the GE 7FA.05 available at its web site:

"The 7FA.05 gas turbine will employ the proven DLN-2.6 combustor. The combustor has more than 15 million hours and 400,000 starts of operational experience. Minor modifications to the DLN2.6 combustion system will be required for the improved output and efficiency" ……."The higher temperature-capable materials still operating in FA firing temperatures will further improve the successful experience of the 7FA wear modes for low cycle fatigue, oxidation and creep, thus supporting longer life and reduced repair costs." Link to GE 7FA.05 Test and Validation .

The inference from the statements is that the GE 7FA.05 will operate at the same firing temperature (and could at least theoretically operate at greater temperatures) than the rest of the 7FA line. It is difficult to attain greater output (such as characteristic of the GE 7FA.05) without increases in firing temperature. Increased firing temperatures simultaneously tend to lower CO emissions (other factors being equal). With only minimal modifications in the DLN-2.6 as stated, it is reasonable to conclude that the 7FA.05 will emit about the same and possibly a little less CO than the other units in the 7FA line.

FPL obtained the 5 ppmvd CO guarantee for GE 7FA.03 units installed at the Turkey Point Power Plant in Florida. FPL subsequently selected larger Mitsubishi 501G and Siemens SGT6-8000H for the West County and Riviera Power Plants, respectively. Both Mitsubishi and Siemens agreed to match the 5 ppmvd requirement based on the Department's BACT determination for the Turkey Point project. The technical differences between the GE 7FA.03 and the Mitsubishi and Siemens products are at least as great as the differences between the GE 7FA.03 and the GE 7FA.05.

The Department does not adopt the arguments presented by the applicant. However, it is understandable that commercial terms may require that the owner actually obtain a guarantee consistent with the issued construction permit.

Department's CO BACT Determination

The following approach will accommodate both the present unavailability of the 5.0 ppmvd CO guarantee and the requirement of a correct BACT determination. Following is the Department's initial BACT determination.

- CO emissions while firing natural gas shall be initially limited to 9.0 ppmvd as BACT and demonstrated by initial and annual stack tests.
- CO when firing natural gas shall also be controlled by DLN technology (that limits CO as well as NO_X) and a high firing temperature;
- Startup and low load CO emissions shall also be further controlled by the GE Start-up NO_X work practices that also control NO_X;
- CO for limited ultralow sulfur distillate fuel oil shall be initially limited to 20.0 ppmvd as BACT and demonstrated by initial and annual stack tests; and
- CO for limited ultralow sulfur distillate fuel oil shall also be controlled by a high firing temperature.

The Department will require the applicant to install, calibrate, maintain and operate a CO-CEMS on the first installed combustion turbine to gather operating data during a two year period following first fire. The applicant will be required to submit an updated BACT proposal based on the collected data. If the updated BACT emission standard would result in annual CO emissions (assuming maximum hours of operation) from two units that are much less than 100 tons/year, then the Department will specify a non-BACT limit that will insure annual emissions are less than 100 tons/year.

There are two very good reasons to expect annual CO emissions less than 100 tons/year. Firstly, Shady Hills has reported 6.1 tons CO/year or less from the existing three units based on eight years of stack test based annual operating report (AOR) submittals. Secondly, CO-CEMS based annual emissions from TECO Polk Power Units 4 and 5 were 39, 45, 44 and 36 tons/year for 2007, 2008, 2009 and 2010, respectively. The incorporation of the GE Start-up NO_X feature into the Shady Hills project (not present at the existing Shady Hills or TECO units) will also reduce the low load, startup and shutdown contributions to annual CO emissions.

BACT for Particulate Matter (PM, PM_{10} and $PM_{2.5}$)

Particulate matter ($PM/PM_{10}/PM_{2.5}$) is directly emitted from combustion turbines due to incomplete combustion, ash and sulfur present in the fuels. Such emissions are minimized by use of clean fuels, with low ash and sulfur content, and good combustion practices. Clean fuels are a necessity in combustion turbines in order to avoid excessive maintenance due to damaged turbine blades and other components already exposed to very high temperatures and pressures.

Applicant's $PM/PM_{10}/PM_{2.5}$ BACT Proposal

The applicant will use natural gas and ULSD fuel oil that are characterized by very low particulate formation potential. Furthermore the 7FA.05 will have a firing temperature greater than 2,400^{o}F and the fuels will be burned with a great deal of excess air (greater than 10% O_2 in the exhaust gas). Finally the low sulfur specifications, low NO_X and CO emissions and no usage of ammonia will minimize the potential to directly emit or subsequently form $PM_{2.5}$ and condensable PM.

The fuel specifications of 1.5 grains/100 standard cubic feet of natural gas and 0.0015% sulfur in the ULSD fuel together with a 10% opacity limits for visible emissions are proposed as BACT.

Department's $PM/PM_{10}/PM_{2.5}$ BACT Determination

The Department concurs with the applicant's proposal.

Draft BACT Determinations for the 2,500 kW Emergency Generator

One emergency generator is included for this project. Following are the specifications of the proposed emergency generator:

- Model is Caterpillar 3516BTA or equivalent;
- Usage of 500 hours per year;
- Engine rated at 3,200 Brake Horse Power (BHP); and
- Generator rated at 2,500 kilowatts (kW).
- Heat Input is 21.1 MMBtu/hour (higher heating value)

The requirements of 40 CFR part 60, subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (NSPS Subpart IIII) are given at: Link to NSPS Subpart IIII .

The area source requirements of 40 CFR part 63, subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (NESHAP Subpart ZZZZ) are given at: Link to NESHAP ZZZZ . A stationary reciprocating internal combustion engine subject to regulation under 40 CFR part 60 (i.e. NSPS) and that meets any of the criteria in paragraphs 63.6590(c) (1) through (7) of the NESHAP Subpart ZZZZ, must meet the requirements of this regulation by meeting the requirements of 40 CFR part 60, subpart IIII. No further requirements apply for such engines under 40 CFR part 63.

For the type of engine proposed by the applicant, the requirements of these two regulations are summarized in a third regulation which is 40 CFR part 60, subpart 89 – Control of Emissions from New and In-use Nonroad Compression-Ignition Engines. Link to 40 CFR 60, subpart 89 . The applicable requirements are summarized at the following link: Link to Nonroad Engine Emission Standards . Those specifically applicable to the engine specified by the applicant are extracted there from and summarized in Table 12.

Table 12 – NSPS Subpart IIII, NESHAP ZZZZ Standards for Large Nonroad Engines (Tier 2)

Emergency Generator (kW> 560)	**CO** (g/kW-hr)[1]	**PM** (g/kW-hr)	**NMHC[2]+NO_X** (g/kW-hr)	**Diesel Fuel[3]** (sulfur)
2011 and later	3.5	0.20	6.4	15 ppm

1. g/kW-hr means grams per kilowatt-hour.
2. NMHC means Non-Methane Hydrocarbons.
3. Nonroad diesel specification from 40 CFR part 80, subpart I – Motor Vehicle Diesel Fuel; Nonroad, Locomotive, and Marine Diesel Fuel; and ECA Marine Fuel. Link to Nonroad Diesel Spec

The Department will replace the less stringent limits established in the previous permit 1010373-007-AC with the requirements listed in Table 12 as satisfying the requirements of BACT for CO, NO_X and PM. Use of low sulfur nonroad diesel will result in substantially less PM than indicated above and will also further minimize PM_{10}, and $PM_{2.5}$ emissions and precursors.

4.3. Draft BACT Determinations for the Natural Gas Process Gas Heater

One natural gas heater is required for the project. The purpose of this unit is to heat natural gas above dew point temperature and prevent condensation.

Shady Hills described the specifications for the gas heater as follows:

- Hannover Compression Company or equivalent;
- Usage of 3,390 hours per year; and
- Maximum heat input rate of 10 MMBtu/hour.

The requirements of 40 CFR part 60, subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (NSPS Subpart Dc) are given at:

Link to NSPS Subpart Dc . Note that NSPS Subpart Dc would not even apply if the gas heater is marginally smaller than 10 MMBtu/hour. NSPS Subpart Dc does not address NO_X or CO. Also it does not set emission standards for PM or SO_2 from units exclusively fueled by natural gas.

No major source NESHAP apply to this project because the facility is an area source of HAP. The requirements of 40 CFR part 63, subpart JJJJJJ - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources (NESHAP Subpart JJJJJJ) are given at: Link to NESHAP Subpart JJJJJJ . Unlike the NSPS Subpart Dc, the NESHAP JJJJJJ excludes natural gas –fueled units. Unlike the major source NESHAP Subpart DDDDD, the area source NESHAP excludes process heaters.

The applicant proposed as BACT, the use of natural gas to limit PM/PM_{10} to 0.007 lb/MMBtu (0.12 TPY) and good combustion practices to minimize NO_X emission to less than 0.095 lb/MMBtu (1.61 TPY).

The Department determines that natural gas with a specification of 1.5 grains sulfur/100 SCF as sufficient for BACT on the small 10 MMBtu/hour gas heater at this project. This determination does not necessarily apply to future projects with several or larger gas heaters.

4.4. Requirements for the Distillate Fuel Oil Storage Tank (Not Subject to BACT)

The applicant did not evaluate BACT for the proposed 2.8 million gallons ULSD fuel oil storage tank because estimated VOC emissions from the project will be less than the significant PSD SER of 40 tons/year.

The applicant believes that this unit is subject to 40 CFR part 60, subpart Kb-Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (NSPS Subpart Kb).

The Department agrees that this unit is not subject to BACT. However, large tanks storing a liquid with a maximum true vapor pressure less than 3.5 kPa are not subject to NSPS Subpart Kb in accordance with section 40 CFR.110b(b). Link to NSPS Subpart Kb .

5. AMBIENT AIR QUALITY

5.1. Introduction

The proposed project will increase emissions of the following PSD-pollutants at levels in excess of the respective PSD SER: PM/PM_{10}, $PM_{2.5}$ (federal SER only), CO and NO_X. For these pollutants the applicant must provide a demonstration using approved air quality models that project emissions will not cause or contribute to a violation of an ambient air quality standard (AAQS) or PSD increment for the pollutants where they apply. Of these pollutants, PM_{10}, $PM_{2.5}$, SO_2, CO, and NO_X (the NO_2 portion, including NO that converts to NO_2) have defined national and state AAQS, and the pollutants PM_{10}, $PM_{2.5}$, and NO_2 have defined PSD increments. In addition, significant impact levels (SIL) and de minimis monitoring levels are defined for these pollutants and are used to determine the scope of the modeling analysis and the need for additional ambient air monitoring data.

At this time, $PM_{2.5}$ increments, SIL, and de minimus monitoring levels have not yet been adopted into Florida rules. NO_2 SIL and de minimis monitoring levels for the 1-hour standard have not been formally proposed. The U.S. EPA has provided guidance on 1-hour NO_2 SIL until a formal rule is proposed.

5.2. Major Stationary Sources Nearest to the Project

Tables 13 to 16 list the largest sources of the pollutants across West-Central Florida (near the project site) per annual operating reports (AOR) filed with the Department in 2010. The values include the contributions of the existing Shady Hills Generating Station Units 1, 2 and 3 as well as the future Shady Hills Generating Station Units 4 and 5 are included due to their magnitudes or for comparison purposes. Facilities have been arranged from greatest to least 2010 emissions. Figure 13 indicates the major emission sources nearest to this proposed project.

Table 13 - Largest Sources of SO_2 Nearest to the Project in tons/year

Owner	Site Name	County	Year 2010
Progress Energy	Crystal River Power Plant	Citrus	39,441
Tampa Electric (TECO)	Big Bend Generating Station	Hillsborough	9,617
Mosaic Fertilizer	New Wales Facility	Polk	7,890
Progress Energy	Anclote Power Plant	Pasco	7,065
Lakeland Electric	C.D. McIntosh Power Plant	Polk	4,240
Mosaic Fertilizer	Bartow Facility	Polk	4,088
Mosaic Fertilizer	Riverview Facility	Hillsborough	3,144
CF Industries	Plant City Phosphate Complex	Hillsborough	2,525
Cemex and Arroyo Energy	Brooksville South Facility [1]	Hernando	2,219
TECO	Polk Power Station	Polk	1,386
Mosaic Fertilizer	South Pierce Facility	Polk	547
EnviroFocus	EnviroFocus Lead Battery Recycling	Hillsborough	306
Pinellas County	Pinellas Resource Recovery Facility (RRF)	Pinellas	187
Wheelabrator Ridge Energy	Ridge Generating Station	Polk	170
Shady Hills Power Co.	**Shady Hills Gen. Station Future Units**	**Pasco**	**30**
Shady Hills Power Co.	**Shady Hills Gen. Station Units 1,2,3**	**Pasco**	**17**

Table 14 - Largest Sources of NO_X in Pasco and Nearby Counties in tons/year

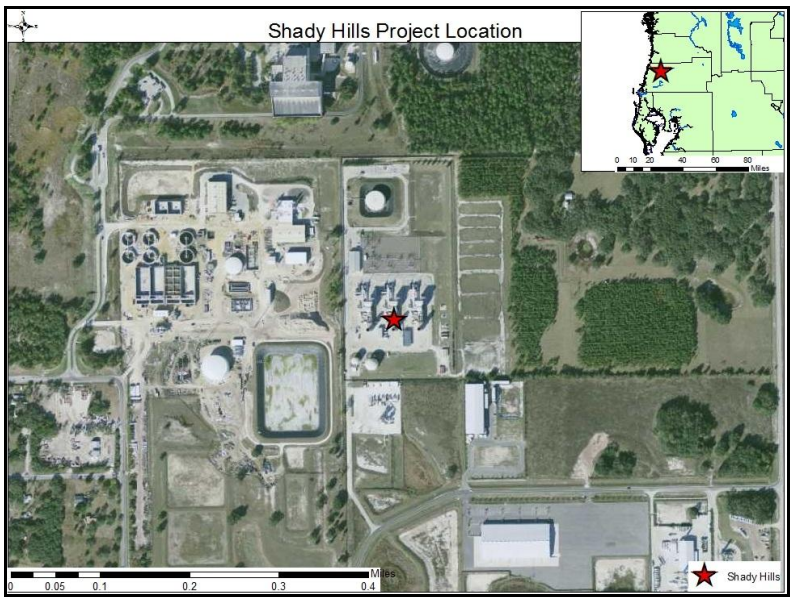
Owner	Site Name	County	Year 2010
Progress Energy	Crystal River Power Plant	Citrus	10,715
TECO	Big Bend Generating Station	Hillsborough	4,835
Progress Energy	Anclote Power Plant	Pasco	1,962
Cemex and Arroyo Energy	Brooksville South Facility	Hernando	1,911
Lakeland Electric	C.D. McIntosh Power Plant	Polk	1,544
Pinellas County	Pinellas County RRF	Pinellas	1,344
Hillsborough RRF	Hillsborough County RRF	Hillsborough	865
Pasco County	Pasco County RRF	Pasco	826
TECO	Bayside Generating Station	Hillsborough	604
Florida Gas Transmission (FGT)	FGT Station No. 17	Marion	566
Progress Energy	Bartow Plant	Pinellas	503
TECO	Polk Power Station	Polk	472
American Cement Co	Sumterville Plant	Sumter	418
Shady Hills Power Co.	**Shady Hills Gen. Station Future Units**	**Pasco**	**397**
City of Tampa	Tampa McKay Bay RRF	Hillsborough	330
Wheelabrator Ridge Energy	Ridge Generating Station	Polk	247
Mosaic Fertilizer	New Wales Facility	Polk	211
Shady Hills Power Co.	**Shady Hills Gen. Station Units 1,2,3**	**Pasco**	**199**
Mosaic Fertilizer	Riverview Facility	Hillsborough	146
Mosaic Fertilizer	Bartow Facility	Polk	130
Cutrale Citrus Juices	Cutrale Citrus Juices	Polk	118
Pasco Cogen	Pasco Cogen	Pasco	115

Table 15 - Largest Sources of PM_{10} Nearest to the Project in tons/year

Owner	Site Name	County	Year 2010
Progress Energy	Crystal River Power Plant	Citrus	1,303
TECO	Big Bend Generating Station	Hillsborough	857
TECO	Bayside Generating Station	Hillsborough	206
Lakeland Electric	C.D. McIntosh Power Plant	Polk	195
Progress Energy	Anclote Power Plant	Pasco	173
Mosaic Fertilizer	New Wales Facility	Polk	113
Cemex and Arroyo Energy	Brooksville South Facility	Hernando	111
Shady Hills Power Company	**Shady Hills Gen. Station Future Units**	**Pasco**	**69**
Shady Hills Power Company	**Shady Hills Gen. Station Units 1,2,3**	**Pasco**	**10**

Table 16 - Largest Sources of CO Nearest to the Project in tons/year

Owner	Site Name	County	Year 2010
TECO	Big Bend Generating Station	Hillsborough	9,169
Florida Power Corp	Crystal River Power Plant	Citrus	1,370
Cemex and Arroyo Energy	Brooksville South Facility	Hernando	1,216
Cutrale Citrus Juices	Cutrale Citrus Juices	Polk	984
Lakeland Electric	C.D. McIntosh Power Plant	Polk	642
Wheelabrator Ridge Energy	Ridge Generating Station	Polk	501
Progress Energy	Hines Energy Complex	Polk	446
Calpine Construction	Osprey Energy Center	Polk	442
Citrosuco North America	Citrosuco North America	Polk	398
American Cement Company	Sumterville Cement Plant	Sumter	335
EnviroFocus	EnviroFocus Lead Battery Recycling	Hillsborough	350
Progress Energy	Anclote Power Plant	Pasco	318
TECO	Bayside Power Station	Hillsborough	317
Citrus World Inc.	Citrus World Inc.	Polk	248
Bartow Citrus	Bartow Citrus	Polk	197
Pinellas County	Pinellas County RRF	Pinellas	194
Calpine/Auburndale	Auburndale Peaking Energy Center	Polk	174
Progress Energy	Bartow Power Plant	Pinellas	152
Marion County	Marion County Baseline Landfill	Marion	142
TECO	Polk Power Station	Polk	139
Shady Hills Power Company	**Shady Hills Gen. Station Future Units**	**Pasco**	**135**
Shady Hills Power Company	**Shady Hills Gen. Station Units 1,2,3**	**Pasco**	**4**



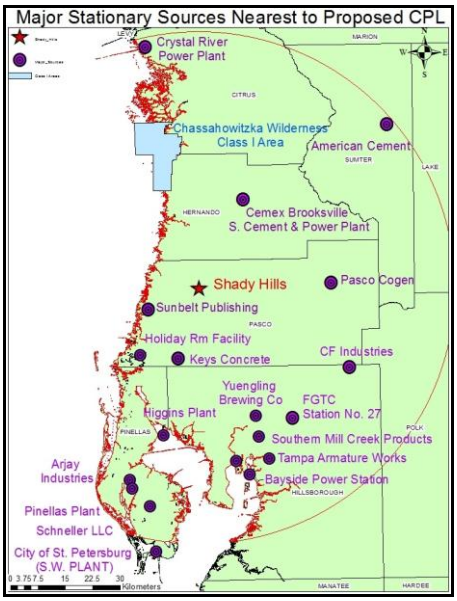


Figure 13 – Shady Hills Generating Station Location **Figure 14 – Large Sources near Project Site**

5.3. SO_2 and NO_X Emission Trends from Power Plants in the Southeastern U.S.

There are regional efforts underway through the Federal (Title IV) Acid Rain Program, the Clean Air Interstate Rule (CAIR) and the Cross-State Air Pollution Rule (CSAPR) to reduce emissions of NO_X and SO_2. Regional SO_2 emissions from existing power plants in the Southeast U.S. in 1995, 2007 and 2010 are listed in Table 17.

Table 17 - SO_2 Emission from Power Plants in the Southeast in 1995, 2007 and 2010 in tons/year

State	1995	2007	2010	Δ Since 1995 (%)	Δ Since 2007 (%)
Alabama	532,485	447,189	204,197	328,288 (62%)	242,992 (54%)
Florida	**598,262**	**317,582**	**144,552**	**453,710 (76%)**	**173,030 (54%)**
Georgia	478,904	635,484	218,911	259,993 (54%)	416,573 (66%)
Kentucky	676,263	379,837	271,514	404,749 (60%)	108,323 (29%)
Mississippi	83,869	69,796	54,696	29,173 (35%)	15,100 (22%)
North Carolina	385,737	370,826	120,387	265,350 (69%)	250,439 (68%)
South Carolina	177,855	172,726	94,656	83,199 (47%)	78,070 (45%)
Tennessee	493,472	237,231	118,723	374,749 (76%)	118,508 (50%)
Total	**3,426,847**	**2,630,671**	**1,227,636**	**2,199,211 (64%)**	**1,403,035 (53%)**

SO_2 emissions from power plants in the Southeast U.S. were reduced by nearly 2,200,000 TPY and 64% referenced to emissions in 1995. Over 1,200,000 TPY of those reductions occurred during the 2008-2010. The state and regional SO_2 reduction trends will continue as coal fueled power plants continue to install scrubbers to control SO_2 emissions and in anticipation of additional regulations to control HAP and cross state pollution transport.

Between 1995 and 2010, SO_2 emissions from power plants in Florida declined by 453,710 tons/year and 76%. These reductions are the largest in the Southeast U.S. and are four orders of magnitude greater than the future emissions from the Shady Hills project.

Regional NO_X emissions from existing power plants in the Southeast U.S. in 1995, 2007 and 2010 are listed in Table 18. NO_X emissions from power plants in the Southeast U.S. were reduced by nearly

1,300,000 tons/year and 74% referenced to emissions in 1995. Almost 400,000 tons/year of those reductions occurred during 2008-2010.

Table 18 - NO_X Emission from Power Plants in the Southeast in 1995, 2007 and 2010 (TPY)

State	1995	2007	2010	Δ Since 1995 (%)	Δ Since 2007 (%)
Alabama	202,776	122,374	66,049	136,727 (67%)	56,325 (46%)
Florida	**297,056**	**184,171**	**79,493**	**217,263 (73%)**	**104,678 (57%)**
Georgia	169,999	107,471	60,588	109,411 (64%)	46,883 (44%)
Kentucky	365,532	174,840	91,979	273,553 (75%)	82,861 (47%)
Mississippi	47,243	48,546	29,774	17,469 (37%)	18,772 (39%)
North Carolina	258,469	59,417	57,305	201,164 (78%)	2,112 (4%)
South Carolina	93,480	46,062	28,833	64,647 (69%)	17,229 (37%)
Tennessee	309,237	102,886	35,056	274,181 (89%)	67,830 (66%)
Total	**1,743,792**	**845,767**	**449,077**	**1,294,415 (74%)**	**396,690 (47%)**

NO_X emissions from power plants in Florida were reduced by more than 217,000 tons/year (73%) with half of the reduction occurring in the period 2008-2010. This reduction is 600 times greater than the future emissions from the Shady Hills project. The Department graphed the SO_2 and NO_X emission trends during the period 1998-2010 from power plants in Florida that report their emissions to the EPA Clean Air Markets database. The results are summarized in Figure 15.

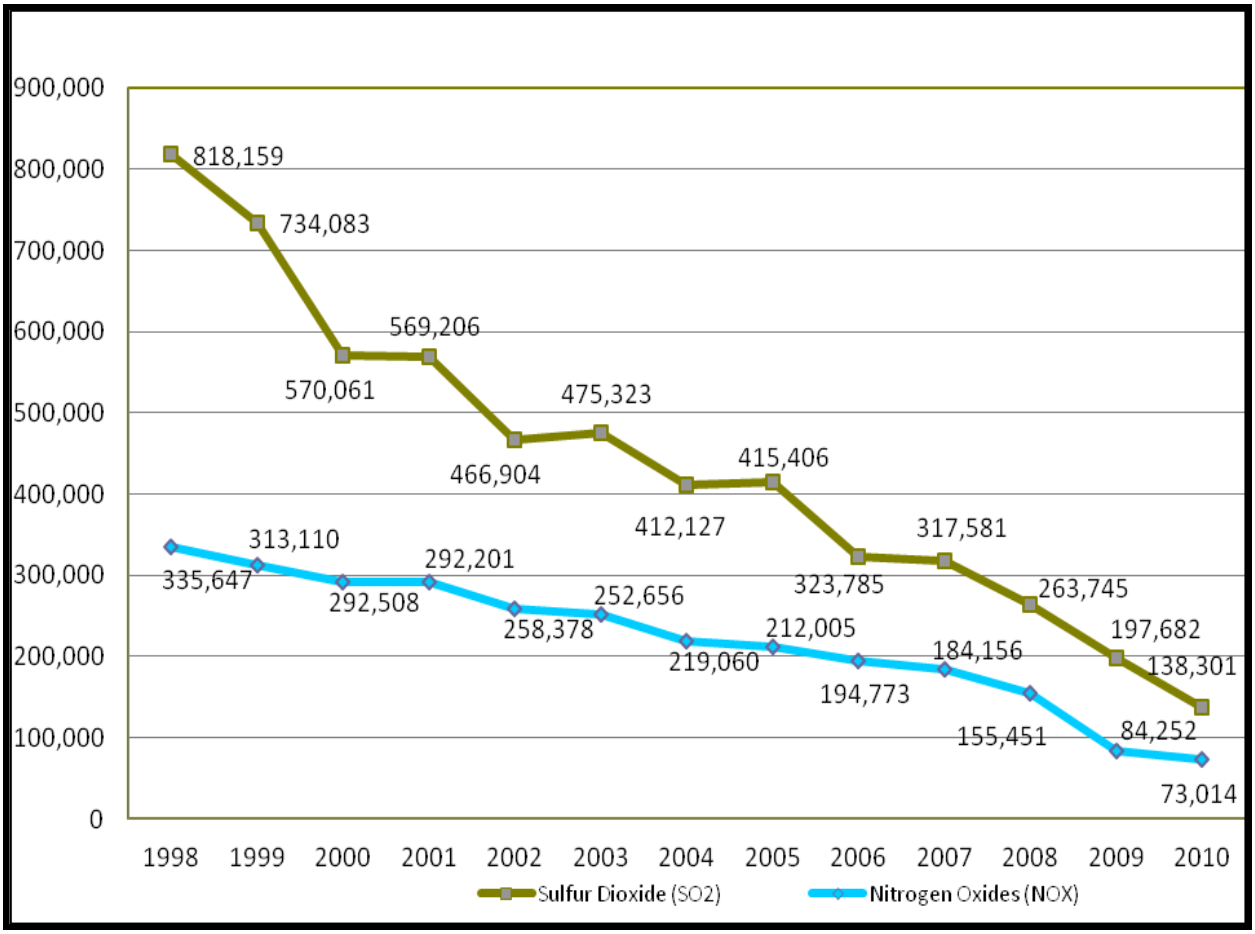


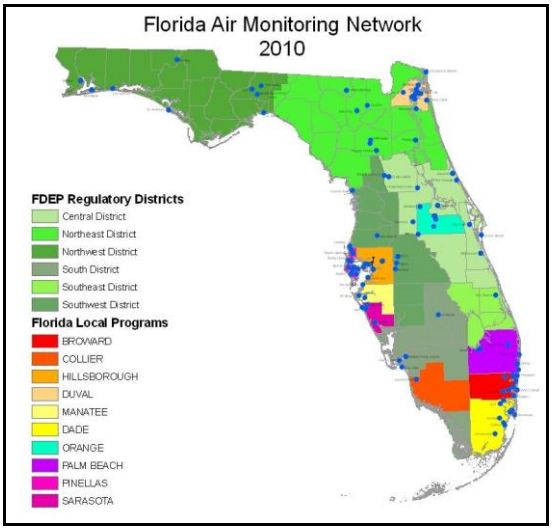
Figure 15 – SO_2 and NO_X reductions in tons/year at Florida Power Plants (1998-2010)

The state and regional NO_X reduction trends will continue as coal-fueled power plants operators throughout the southeastern states continue to install selective catalytic reduction systems to control NO_X due to regulations to control hazardous air pollutants and to reduce cross state pollution transport.

By comparison with the overwhelming downtrend of regional and local emissions of SO_2 and NO_X (that are also $PM_{2.5}$ precursors), the future emissions of 30 tons/year of SO_2 and 379 tons/year of NO_X from Shady Hills project are very low. Statewide and area $PM_{2.5}$ precursor reductions will overwhelm the small increases in direct and indirect $PM_{2.5}$ emissions from the Shady Hills project.

5.4. Ambient Air Quality Monitoring

The state ambient air monitoring network operated by the Department and its partners includes more than 23 monitors at 11 sites. These monitors measure NO_2, SO_2, PM_{10}, $PM_{2.5}$ and ozone (O_3). The 2010 monitoring network is shown below in Figure 16. A close up of just the most representative monitors in Pasco County or adjacent Pinellas County and Hillsborough County is shown in Figure 17. These monitors are used to estimate the existing air quality in the area of the proposed facility.



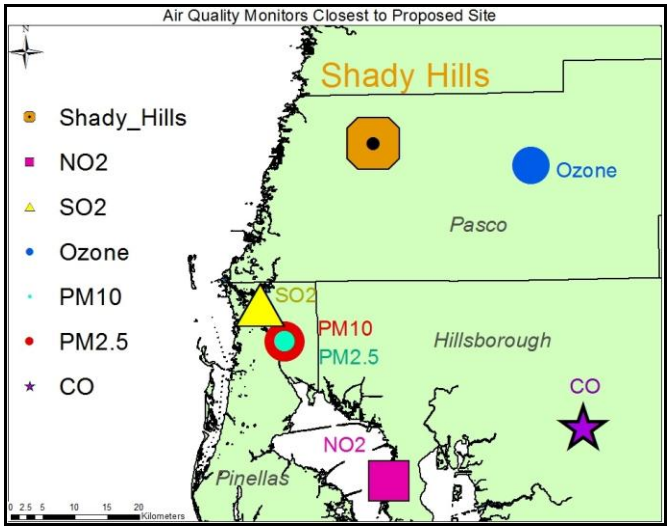


Figure 16 - 2010 Air Monitoring Network **Figure 17 –Representative Monitors of Shady Hills Site**

Air quality measurements from these monitors are summarized below in Table 19 and compared with the National and State Ambient Air Quality Standards (AAQS). Currently, all monitors in Florida indicate in attainment with the relevant AAQS.

The existing monitoring data show no violations of any ambient air quality standards. The Department determines that the data collected from these monitors is representative of the air quality in the vicinity of the project and may be used to satisfy the preconstruction monitoring requirements for $PM_{2.5}$. As necessary, the above ambient concentrations will be used as the ambient background concentrations for any required AAQS analysis, which as will be shown later will also include PM_{10} emissions.

5.5. Existing Ambient Air Quality – $PM_{2.5}$ and Ozone

Ozone is a key indicator of the overall state of regional air quality. It is not emitted directly from combustion processes. Rather it is formed from VOC and NO_X emitted primarily from regional industrial and transportation sources. VOC is also emitted from fires and vegetation (e.g. isoprene). These two precursors participate in photochemical reactions that occur on an area-wide basis and are highly dependent on meteorological factors.

Table 19 - Ambient Air Quality Based on Most Representative Monitors near the Project Site

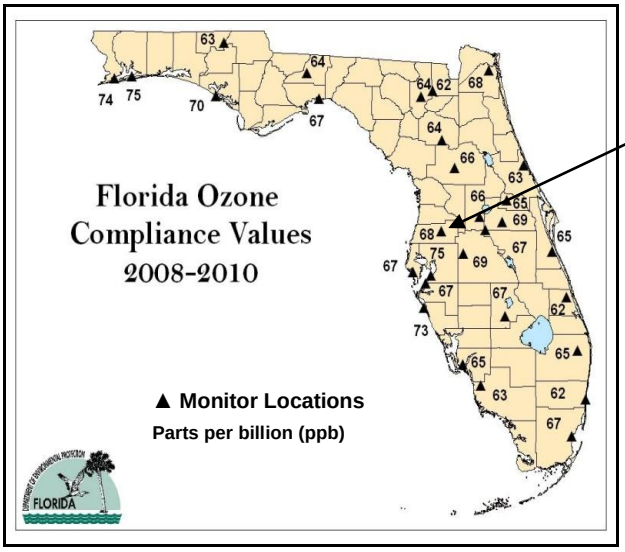
Pollutant	County (Site No.)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [a]
PM_{10}	Pinellas (L103-5002)	24-hour [b]	2010	35	150	$\mu g/m^3$
		Annual [c]		16	50	$\mu g/m^3$
$PM_{2.5}$	Pinellas (L103-5002)	24-hour [d]	2008-2010	17	35	$\mu g/m^3$
		Annual [e]		9.5	15	$\mu g/m^3$
SO_2	Pinellas (L103-5003)	1-hour [i]	2008-2010	34	75	ppb
		3-hour [f]	2010	76	1300	$\mu g/m^3$
		24-hour [f]		13.1	260	$\mu g/m^3$
		Annual [c]		2.9	60	$\mu g/m^3$
NO_2	Hillsborough (057-1065)	Annual [c]	2010	6.1	53	ppb
		1-hour [h]	2008-2010	38	100	ppb
CO	Hillsborough (L0573002)	1-hour [f]	2010	1	35	ppm
		8-hour [f]		0.9	9	ppm
Ozone	Pasco (L1010005)	8-hour [g]	2008-2010	0.068	0.075	ppm

a. Units are in: micrograms per cubic meter ($\mu g/m^3$); parts per billion (ppb); or parts per million (ppm).
b. Not to be exceeded on more than an average of one day per year over a three-year period.
c. Arithmetic mean.
d. Three year average of the 98th percentile of maximum daily 24-hour concentrations with exceptional events excluded (as approved by EPA).
e. Three year average of the arithmetic annual means with exceptional events excluded (per EPA).
f. Not to be exceeded more than once per year.
g. Three year average of the annual 4th highest daily 8-hour maximum.
h. Three-year average of the annual 98th percentile maximum daily 1-hour value (design value).
i. Three-year average of the annual 99th percentile maximum daily 1-hour value.

Ozone limits and measurements are summarized on three year blocks, rolled annually. The reported ozone value was calculated by taking the maximum 8-hour readings recorded each day during the three years. The fourth highest of the recorded maxima were identified for each year and then the average of those three values was reported as the compliance value, and is compared to the standard of 75 parts per billion (ppb).

The ozone monitor located in Pasco and the $PM_{2.5}$ monitor in Pinellas County are most representative of the ambient air quality near the Shady Hills project site. The Pasco County ozone compliance value is 68 ppb. It is shown in Figure 18, which shows the highest compliance values measured in each county where at least one ozone station is located.

$PM_{2.5}$ (also known as PM_{fine}) is another key indicator of the overall state of regional air quality. Some $PM_{2.5}$ is directly emitted as a product of combustion from transportation and industrial sources as well as fires. Much of it consists of particulate nitrates and sulfates formed through chemical reactions between gaseous precursors such as SO_2 and NO_X from combustion sources and ammonia (NH_3) naturally present in the air or added by other industrial sources.



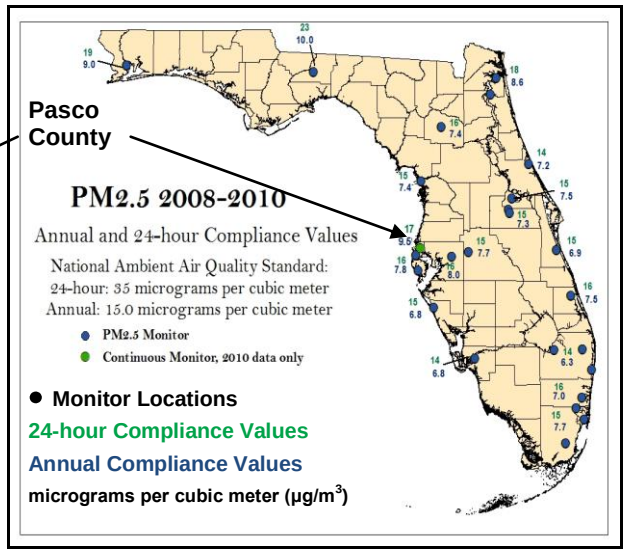


Figure 18 – Florida Ozone Compliance Values **Figure 19 – Florida $PM_{2.5}$ Compliance Values**

$PM_{2.5}$ limits and measurements are summarized on three year blocks, rolled annually. The reported 24-hour compliance value for $PM_{2.5}$ is 16 µg/m^3, shown in Figure 19 above for the Pinellas County site, and was calculated by taking the average 24-hour readings recorded each day during the three years (2008-2010). The value for each year that exceeds 98% of all daily measurements within each given year was identified and then the average of those three numbers was reported as the 24-hour compliance value and compared with the standard of 35 µg/m^3.

The simple average of all $PM_{2.5}$ measurements within each three years (2008-2010) was also calculated and then the mean of the three averages (7.8 µg/m^3) was reported as the annual compliance value and compared with the standard of 15 µg/m^3.

The results indicate that Pasco County is in attainment with the applicable ozone and $PM_{2.5}$ AAQS.

5.6. Ambient Air Quality Impact Analysis

This section provides a general overview of the modeling analyses required for PSD preconstruction review followed by the specific analyses required for this project.

Overview of the Required Modeling Procedures

Pursuant to Rule 62-212.400, F.A.C., the applicant is required to conduct the following analyses for each PSD significant pollutant:

- A preconstruction ambient air quality analysis,
- A source impact analysis based on EPA-approved models, and
- An additional impact analyses.

Preconstruction Ambient Monitoring Procedure

Generally, the first step is to determine whether the Department will require preconstruction ambient air quality monitoring. Using an EPA-approved air quality model, the applicant must determine the predicted maximum ambient concentrations and compare the results with regulatory thresholds for preconstruction ambient monitoring, known as de minimis air quality levels. The regulations establish de minimis air quality levels for PSD pollutants as shown in Table 20. Only the CO, NO_2 and PM_{10} de minimis levels and the ozone analysis are relevant for the Shady Hills project.

If the predicted maximum ambient concentration is less than the corresponding de minimis air quality level, Rule 62-212.400(3)(e), F.A.C. exempts that pollutant from the preconstruction ambient monitoring analysis.

Table 20 – De Minimis Concentrations to Determine Preconstruction Monitoring Requirements [1]

PSD Pollutant	De Minimis Air Quality Levels	PSD Pollutant	De Minimis Air Quality Levels
CO	575 μg/m^3 8-hour average	Fluoride	0.25 μg/m^3, 24-hour average
NO_2	14 μg/m^3 annual average;	Total Reduced Sulfur	10 μg/m^3 1-hour average
PM_{10}	10 μg/m^3 24-hour average	Hydrogen sulfide	0.2 μg/m^3 1-hour average
SO_2	13 μg/m^3 24-hour average	Reduced sulfur compounds	10 μg/m^3 1-hour average
Lead	0.1 μg/m^3 3-month average	Mercury	0.25 μg/m^3 24-hour average

1. There is no de minimis air quality level for ozone. However, any net increase of 100 tons/year or more of VOC or NO_X subject to PSD would be required to perform an ambient impact analysis including the gathering of ambient air quality data.

If the predicted maximum ambient concentration is more than the corresponding de minimis air quality level, then the applicant must provide an analysis of representative ambient air concentrations (pre-construction monitoring data) in the area of the project based on continuous air quality monitoring data for each such pollutant with an Ambient Air Quality Standard (AAQS). If no AAQS exists, the analysis shall contain such air quality monitoring data as the Department determines is necessary to assess ambient air quality for that pollutant.

If preconstruction monitoring data are necessary, the Department may require the applicant to collect representative ambient monitoring data in specified locations prior to commencing construction on the project. Alternatively, the Department may allow the requirement for preconstruction monitoring data to be satisfied with data collected from the Department's extensive ambient monitoring network. Preconstruction monitoring data must meet the requirements of Appendix B to 40 CFR 58 during the operation of the monitoring stations. The preconstruction monitoring data will be used to determine the appropriate ambient background concentrations to support any required AAQS analysis.

Finally, after completing the project, the Department may require the applicant to conduct post-construction ambient monitoring to evaluate actual impacts from the project on air quality.

Source Impact Procedure

For each PSD-significant pollutant identified above, the applicant is required to conduct a source impact analysis for affected PSD Class I and Class II areas. This analysis is to determine if emissions from this project will significantly impact levels established for Class I and II areas. Class I areas include protected federal parks and national wilderness areas (NWA) that are under the protection of federal land managers. Table 21 identifies the Class I areas located in Florida or that are within 200 kilometers in nearby states. Class II areas represent all other areas in the vicinity of the facility open to public access that are not Class I areas.

Table 21 – List of Class I Areas and Responsible Land Managers in or near Florida

Class I Area	State	Land Manager	Class I Area	State	Land Manager
Chassahowitzka NWA	FL	U.S. FWS [1]	St. Marks NWA	FL	U.S. FWS
Bradwell Bay NWA	FL	Forest Service	Okefenokee NWA	GA	U.S. FWS
Everglades NP [1]	FL	NPS [1]	Wolf Island NWA	GA	U.S. FWS

1. NP means National Park; NPS means National Park Service; FWS means Fish and Wildlife Service

The Department is in the process of adopting Significant Emission Rates (SER), Significant Impact Levels (SIL) and ambient air quality standards for $PM_{2.5}$. The applicant modeled $PM_{2.5}$ according to federal guidance. In conducting this analysis, the applicant conservatively assumed that all PM_{10} is actually $PM_{2.5}$.

An initial significant impact analysis is conducted using the worst-case emissions scenario for each pollutant and corresponding averaging time. The regulations define separate significant impact levels (SIL) for Class I and Class II areas for CO, NO_2, lead, PM_{10} and SO_2. Only CO, NO_2 and PM_{10} are relevant for this project. Based on the initial significant impact analysis, no additional modeling is required for any pollutant with a predicted ambient concentration less than the corresponding SIL. However, for any pollutant with a predicted ambient concentration exceeding the corresponding SIL, the applicant must conduct a full impact analysis. In addition to evaluating impacts caused by the project, a full impact modeling analysis also includes impacts from other nearby major sources (and any potentially-impacting minor sources within the radius of significant impact) as well to determine compliance with:

- The PSD increments and the federal air quality related values (AQRV) including visibility for Class I areas.
- The PSD increments and the AAQS for Class II areas.

PSD Class I Model

PSD Class I Area**:** The California Puff (CALPUFF) dispersion model was used to evaluate the total nitrogen deposition impacts from NO_2 emissions from the proposed project in the Chassahowitzka Class I area. Meteorological MM4 and MM5 data used in this model was from 2001, 2002 and 2003. CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations.

PSD Class II Area Model, Class I Model for sources where all of the Class I area is < 50 km from source

The EPA-approved American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model is used to evaluate short range impacts from the proposed project and other existing major sources. In November of 2005, the EPA promulgated AERMOD as the preferred regulatory model for predicting pollutant concentrations within 50 kilometers of a source. The AERMOD is a replacement for the Industrial Source Complex Short-Term model (ISCST3). The AERMOD calculates hourly concentrations based on hourly meteorological data. The model can predict pollutant concentrations for annual, 24-hour, 8-hour, 3-hour and 1-hour averaging periods. In addition to the PSD Class II modeling, it is also used to model the predicted impacts for comparison with the de minimis ambient air quality levels when determining preconstruction monitoring requirements.

For evaluating plume behavior within the building wake of structures, the AERMOD incorporates the Plume Rise Enhancement (PRIME) downwash algorithm developed by the Electric Power Research Institute (EPRI). A series of specific model features recommended by the EPA are referred to as the regulatory options. The applicant used the EPA-recommended regulatory options in each modeling scenario and building downwash effects were evaluated for stacks below the good engineering practice (GEP) stack heights.

Meteorological data used in the AERMOD model consisted of a concurrent five-year period of hourly surface weather observations from the National Weather Service office located at Tampa International Airport and twice-daily upper air soundings from Ruskin. The five-year period of meteorological data was from 2001 through 2005. These stations were selected for use in the evaluation because they are the closest primary weather stations to the project area and are most representative of the project site.

Stack Height Considerations

GEP stack height means the greater of 65 meters (213 feet) or the maximum nearby building height plus 1.5 times the building height or width, whichever is less. Where the affected stacks did not meet the requirements for GEP stack height, building downwash was considered in the modeling analyses. Based on a review of this application, the Department determines that the project complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators.

PSD Significant Pollutants for the Project

As discussed previously, the proposed project will increase emissions of the following pollutants in excess of the PSD significant emissions rates: CO, NO_X, PM_{10} and $PM_{2.5}$.

Source Impact Analysis for PSD Class I Areas

The PSD Class I Chassahowitzka NWA is located only 28 kilometers from the facility. A total of 113 receptors were used in the modeling analysis. For the preliminary significant impact analysis, the highest short-term predicted concentrations will be compared to the significant impact levels. Using the AERMOD, the applicant predicted the following maximum ambient impacts from the project.

Table 22 - Significant Impact Analysis for the PSD Class I Chassahowitzka NWA

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	0.006	0.2	No
	24-hour	0.06	0.3	No
NO_2	Annual	0.005	0.1	No

As shown, the maximum predicted impacts are less than the corresponding significant impact levels for each pollutant. Therefore, a full impact analysis for the PSD Class I areas is not required.

Source Impact Analysis for PSD Class II Areas

For the preliminary significant impact analysis, the highest short-term predicted concentrations will be compared to the respective significant impact levels. Since five years of data are available, the highest-second-high (HSH) short-term predicted concentrations will be used for any required AAQS and PSD Class II increment analysis with regard to short-term averages. However, for annual averages, the highest predicted annual average will be compared with the corresponding annual level. The following table shows the results of the preliminary PSD Class II significant impact analysis.

Table 23 - Significant Impact Analysis for PSD Class II Areas (Vicinity of Facility)

Pollutant	Averaging Time	Maximum Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Significant Impact (SI)?	SI Radius (km)
NO_2	Annual	0.5	1	NO	NONE
	1-hr	78	7.6	YES	13.5
PM_{10}	Annual	0.05	1	NO	NONE
	24-hr	2	5	NO	NONE
$PM_{2.5}$	Annual	0.04	0.3	NO	NONE
	24-hr	1.0	1.2	NO	NONE
CO	8-hour	21	500	NO	NONE
	1-hour	22	2000	NO	NONE

As shown above, the predicted impacts of annual NO_2 and annual and 24-hour $PM_{10}/PM_{2.5}$ are well below the corresponding PSD Class II significant impact levels, and no further analysis is required. The 1-hour NO_2 predicted impacts are greater than the corresponding PSD Class II significant impact level; therefore, a full impact analysis for this pollutant and averaging time is required within the applicable significant impact area as defined by the predicted radius of significant impact identified above. For 1-hour NO_2 only an AAQS analysis is required for this project.

Preconstruction Ambient Monitoring Analysis

The modeled results provided in Tables 22 and 23 for CO, NO_2 and $PM_{10}/PM_{2.5}$ are much less than their respective values given in Table 20. These pollutants are exempt from preconstruction monitoring because the predicted impacts are less than the de minimis levels listed in Table 20. Nevertheless, the Department collects substantial data near the project site as summarized in Table 19 above through 2010. The monitoring sites and monitoring history are sufficiently representative for the purposes of providing background data if preconstruction monitoring were required.

Ozone Ambient Impact Analysis Including the Gathering of Ambient Air Quality Data.

The project results in emissions of 19 tons/year of VOC and 397 tons/year of NO_X. Because the NO_X emissions are greater than 100 tons/year an ozone ambient impact analysis and gathering of ambient air quality data are required.

The regional nature of ozone formation from precursors, the extensive ozone network and the historical collected data are sufficient to satisfy preconstruction monitoring and to provide a background upon which to project impacts.

Ozone site-specific modeling is not typically completed for single source permitting because of its complexity. Ozone is a secondarily formed pollutant that is known to be caused by the regional emissions of VOC and NO_X in combination with meteorological parameters (temperature, rainfall, solar insolation, etc.).

To conclusively prove whether or not the 379 tons/year will not cause or contribute to a violation, a very sophisticated and expensive model would need to be run for the entire region. The key inputs to the model would be traffic, power plants emissions throughout the region, other industrial sources, and very detailed meteorology.

Refer to Table 18 and Figure 15 above. Power plant NO_X emissions in Florida declined by more than 100,000 tons/year between 2007 and 2010. Most of the reduction occurred within the West Central Florida Intrastate Air Quality Control Region as described in 40 CFR part 81 – Designation of areas for Air Quality Planning Purposes (the WCFIAQCR). The region includes the coastal counties of Citrus, Hernando, Pasco, Pinellas, Hillsborough and Manatee County and adjacent inland counties. The power plants within the WCFIAQCR that accounted for most of the reductions during 2007-2010 include the Progress Energy Crystal River Power Plant in Citrus County, the Progress Energy Bartow Plant in Pinellas County and the TECO Big Bend Power Station in Hillsborough County.

The massive historic reduction in NO_X emissions has been largely responsible for the reduction in ground-level ozone concentrations observed over the same period. The effects of the future Shady Hills project upon ground level ozone concentrations would not be measurable considering the effects of the past, present and future regional power plant NO_X reductions and climatological variability. The uncertainty in the concentrations and ozone increases projected by any regional ozone model would be greater than the contribution from this project.

Receptor Grids for Performing PSD Increments and AAQS Analyses

For each pollutant subject to an AAQS analysis, the total impact on ambient air quality is obtained by adding an ambient background concentration to the maximum predicted concentration from modeled sources. The ambient background concentration accounts for all sources that are not explicitly modeled. Table 24 summarizes the results of the AAQS analysis for the affected pollutants.

Table 24 - AAQS Analysis

Pollutant	Averaging Time	Modeled Sources (μg/m^3)	Ambient Background Concentration (μg/m^3)	Total Impact (μg/m^3)	AAQS (μg/m^3)	Greater than AAQS?
NO_2	1-hour	89	80	169	188	No

The modeled value in this table is based on Tier 2 NO_2 results and default NO_2 to NO_X ratio of 0.8. As shown in this table, impacts from the proposed project modification are not expected to cause or significantly contribute to a violation of any AAQS.

5.7. Additional Impact Analysis

The applicant has modeled to show that the proposed modification will not violate AAQS. However, PSD regulations require additional analyses of air quality impacts to sensitive types of vegetation and soil, air quality impacts related to growth, and visibility in the affected Class I areas.

Impacts on Soils, Vegetation and Wildlife

The maximum predicted ground-level concentrations of CO, NO_2 and $PM_{10}/PM_{2.5}$ from the proposed project and all other nearby sources are below the corresponding AAQS. The effects of any possible ozone formation would be negligible. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils, vegetation or wildlife in the vicinity of the project.

Air Quality Impacts Related to Growth

The proposed modification will not change employment, population, housing, commercial development, or industrial development in the area to the extent that significant air quality impact will result.

Visibility Analysis

Written notification is required to all affected Federal Land Managers of any proposed new major stationary source or major modification that may affect visibility in any Federal Class I area. A visibility analysis involves an assessment of how a proposed new or modified source's emissions would affect visibility. The assessment is performed using the visibility in a Class I area under natural conditions (i.e. not under present conditions affected by existing stationary sources).

Level-I and Level-II Screening Analyses. The project is located less than 50 km away from the Class 1 area and plume visibility analyses using the VISCREEN model was preformed to analyze visibility impacts at the CNWA. The VISCREEN is an EPA recommended screening model that simulates the view of an observer on the boundary of a Class I area. The model assesses the perceptibility of a plume based on two key parameters including:

- A parameter indicating the contrast in brightness between an object (plume) and the background (sky or terrain) and;
- A color difference parameter, Delta-E (or ΔE).

ΔE equal to 1.0 and "Contrast" equal to 0.02 are assumed to be the thresholds of perceptibility. VISCREEN is designed to calculate these parameters for emission sources of particulate, NO, NO_2, and soot, and results are compared to screening criteria of 2.0 for ΔE and 0.05 for green contrast (wavelength equal to 0.55 micrometers (μ). Level-I screening is designed to provide an initial conservative estimate of plume visual impacts.

Worst case particle size and density are assumed for this level of analysis, together with worst-case meteorological conditions of "F" stability (very stable atmosphere) and 1 meter/second (near calm) wind speed. This worst-case meteorological condition is assumed to persist for 12 hours, with a wind direction that would transport the plume directly adjacent to the observer, as shown in Figure 20. The applicant initially provided a Level-I Screening Analysis, and modeled impacts within and outside of the Chassahowitzka National Wildlife Area (CNWA) due to firing both gas and oil. The modeled VISCREEN Level-I projections within the CNWA are provided in Table 24.

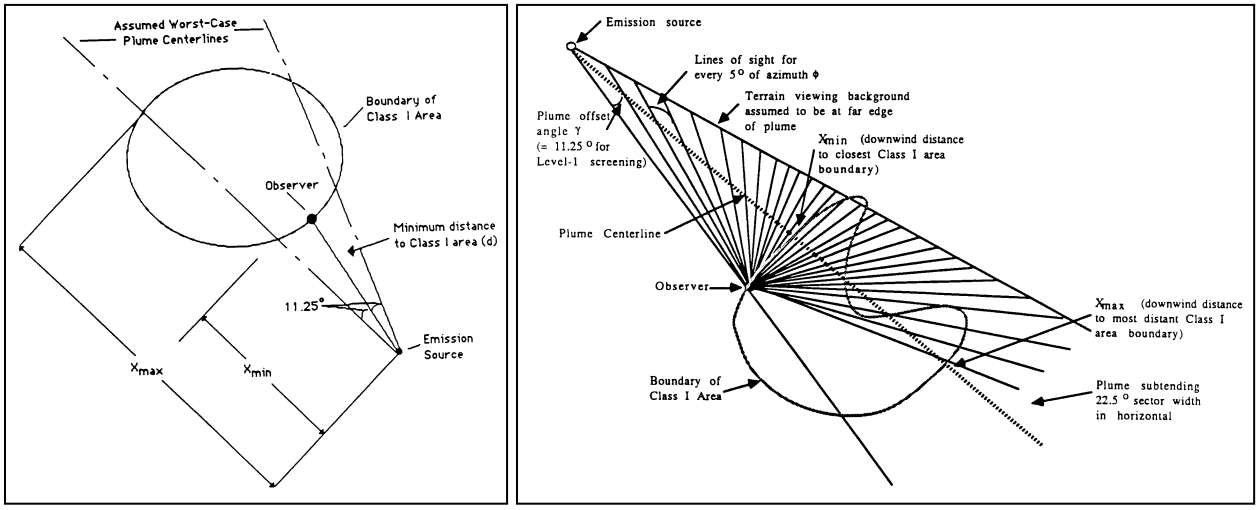


Figure 20 – Generalized Plume Geometry, Observer Lines of Sight for Plume Visual Impact Screening

Table 24 - VISCREEN Level-I - Maximum Projected Visual Impacts Inside the CNWA

Background, Fuel	Theta (degrees)	Azimuth (degrees)	Distance (km)	Alpha (degrees)	ΔE		Contrast	
					Criterion	Plume	Criterion	Plume
Sky, Natural Gas	10	152	46	16	2.00	6.69*	0.05	0.09*
Sky, Natural Gas	140	152	46	16	2.00	3.352*	0.05	-0.08*
Sky, Fuel Oil	10	150	43.6	19	2.00	19.58*	0.05	0.06*
Sky, Fuel Oil	140	150	43.6	19	2.00	11.10*	0.05	-0.19*
* Exceeds the absolute value of the respective screening criterion of ΔE = 2.0 and Contrast = 0.05.								

As shown in the results above, the impacts were greater than the screening criteria in the Class I area for all VISCREEN Level-I Analyses. The applicant then conducted and provided a Level-II screening analysis. VISCREEN Level-II analyses are based on actual meteorological data that are representative of areas around the source and Class I area. Overly conservative meteorological conditions that do not occur in the region are taken out of the analysis.

Also, more realistic occurrences of conditions that would transport plumes towards the Class I area are used. The modeled VISCREEN Level-II projections <u>within</u> the CNWA are provided in Table 25.

Table 25 - VISCREEN Level-II - Maximum Projected Visual Impacts Inside the CNWA

Background, Fuel	Theta (degrees)	Azimuth (degrees)	Distance (km)	Alpha (degrees)	ΔE		Contrast	
					Criterion	Plume	Criterion	Plume
Sky, Natural Gas	10	152	46	16	2.00	0.97	0.05	0.01
Sky, Natural Gas	140	152	46	16	2.00	0.51	0.05	-0.01
Sky, Fuel Oil	10	152	46	16	2.00	12.01*	0.05	0.03
Sky, Fuel Oil	140	152	46	16	2.00	6.95*	0.05	-0.11*
* Exceeds the absolute value of the respective screening criteria of ΔE = 2.0 and Contrast = 0.05.								

The Level-II analysis did not reveal impacts in excess of the respective VISCREEN screening criteria for the cases during which natural gas is fired. However, impacts are indicated when firing fuel oil. As discussed in the BACT section, historically Shady Hills has used fuel oil just 43 hours/year/combustion turbine even though those three units are each permitted to fire fuel oil for 1,000 hours/year. Thus the probability of coincident occurrence of fuel oil firing and the conditions that give rise to plume perceptibility would be minimal if not miniscule.

Level III PLUVUE Analysis. The Federal Land Manager (through the U.S. Fish and Wildlife Service) required the applicant to conduct a more rigorous Level III analysis using a model called PLUVUE II. PLUVUE II is a more detailed model used for estimating visual range reduction and atmospheric discoloration resulting from the emissions of particles, NO_X and SO_X from a single emission source. The model predicts the transport, dispersion, chemical reactions, optical effects, and surface deposition of point or area source emissions.

PLUVUE II predicts ΔE for four different background types: sky, white, gray, and black. Because the CWNA is flat with no terrain features, only predictions for the sky background type were considered by the applicant. However, results from the remaining three background types were still compiled and were provided to the Department and the U.S. Fish and Wildlife Sevice. In conducting this analysis, the applicant assessed the impacts from the vantages of four observers positioned as shown in Figure 21 and compared the results with even more sensitive criteria of ΔE = 1 and Contrast = 0.02.

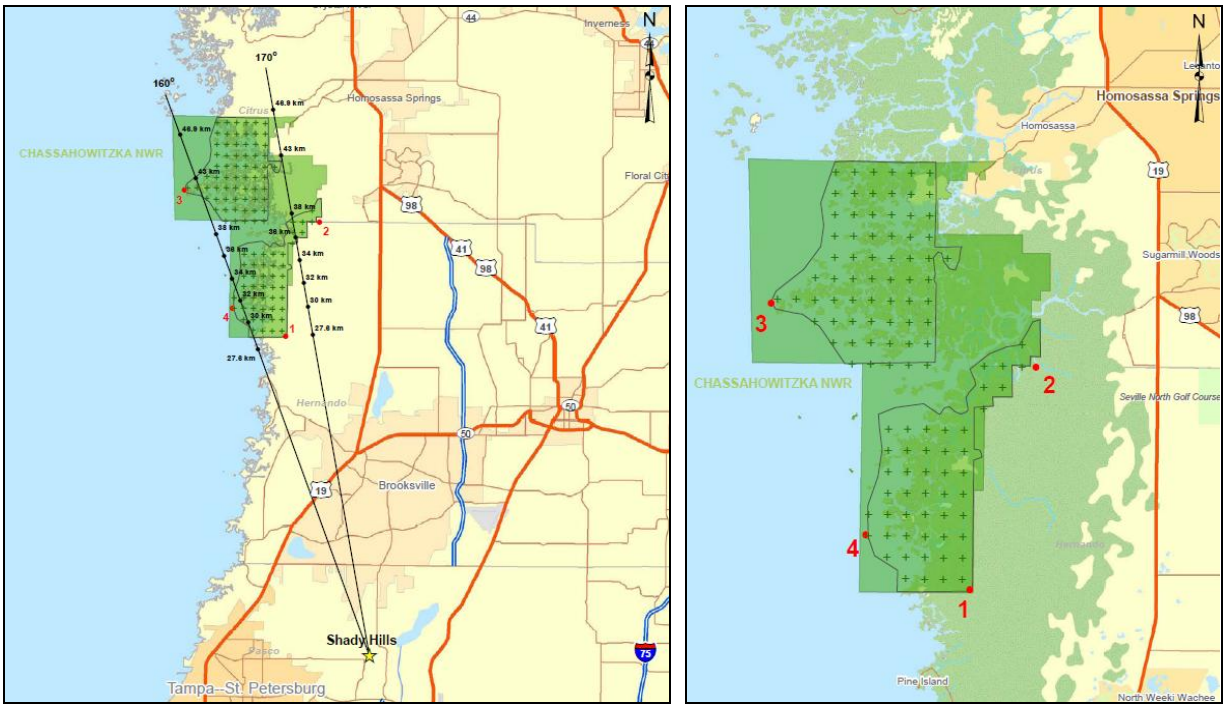


Figure 21 – Observer Locations and Viewing Angles for 160 and 170 degrees Wind Directions

Event Frequencies

Table 26 summarizes the number of occurrences when the project impacts are predicted to exceed the stricter visibility criteria during a five-year period inside of the CNWA.

Table 26 – PLUVUE Level III – Projected Exceedances of Visibility Criteria in a 5-year Period [a]

Observer Location	Stability Class C (Slightly Unstable)	Class D (Neutral)	Class E (Slightly Stable)	Class F (Stable)	Exceedances [b] (5 Year Total)	Exceedances (Per/Year)
1	3	27	54	12	96	19.2
2	3	21	48	12	77	14.8
3	1	24	40	12	74	15.4
4	2	20	40	12	77	14.8

a. Compared with stricter visibility criteria of ΔE = 1.0 and absolute value of plume contrast = 0.02.
b. Based on 43,824 observations in 5 years considered in the analysis.

As shown above, the highest predicted exceedance based on four observer locations is 96 hours during an entire 5-year period (43,824 hours). This represents 0.22% of the time. Again, the probability of coincident occurrence of fuel oil firing and the conditions that give rise to plume perceptibility would be miniscule.

Event Magnitudes

The below table indicates the number of predicted events occurring with ΔE or Contrast magnitudes greater than the respective modeled criteria of 1.0 or 0.02, respectively. The coincident occurrences when both parameters exceeded the respective criteria are provided in Table 27.

Table 27 – PLUVUE Level III – Number of Events Occurring within Ranges of Plume Perceptibility

Observer Location	1 < ΔE <2		2 ≤ ΔE ≤4		Other Events	All
	C < 0.02	0.02 ≤C ≤0.04	0.02 ≤C ≤0.04	0.04 ≤ C ≤ 0.06		
1	54	21	8	6	7	96
2	49	3	17	1	4	74
3	27	9	25	4	12	77
4	40	12	14	2	6	74

a. Compared with stricter visibility criteria of ΔE = 1.0 and absolute value of plume contrast = 0.02.
b. Based on 43,824 observations in 5 years considered in the analysis.

As shown in the first column, the majority of these events met the visibility criteria. The magnitude of events during which the visibility criteria is not met occurs 0.2% of the time.

Predicted Plume Elevation

Table 28 summarizes the project's plume elevation predicted at the location of Observer No. 1 (the observer on the Class 1 area boundary nearest to the proposed project, which had the maximum amount of exceedances). The results are listed by stability class.

Table 28 – PLUVUE Level III – Plume Elevations during Events Exceeding the Ranges of Plume Perceptibility

Stability Class	Conditions	Count	Minimum Plume Elevation (ft)	Average Plume Elevation (ft)
C	Slightly Unstable	3	4,025	6,022
D	Neutral	27	2,365	4,208
E	Slightly Stable	54	974	1,148
F	Stable	12	777	872

The minimum predicted plume heights occur during very stable (class F) stability class hours, which generally occur before sunrise and after sunset when daylight is minimal.

The results of PLUVUE modeling show that the visibility criteria were exceeded when the applicant fires fuel oil instead of natural gas. When an exceedance occurs, the project is evaluated by examining the frequency, magnitude, and duration during the predicted exceedances. The results yielded the following conclusions:

- Over 5 years of meteorological data, the wind only blows from the direction of Shady Hills towards the CNWA 2.8% of the time.

- The frequency of occurrence that Level-III visibility criteria are exceeded (assuming the applicant is firing fuel oil at the time winds are blowing towards the CNWA) is 0.2%.
- The magnitude of predicted impacts, even when the visibility criteria are exceeded, is very low.
- 85% of the time, the duration of predicted impacts lasts for one hour.
- Because predicted plume height is, on average, >2,000ft and never < 777 ft during worse-case conditions, an observer at ground level would not likely perceive a plume when looking into the park.

As stated previously, the Level-III criteria would be exceeded only during times when the applicant fires oil instead of natural gas. However, Shady Hills historically uses oil very infrequently. The probability of simultaneously firing oil during the 2.8% of time that conditions occur that would transport a plume to the CNWA is very small. Furthermore, in the unlikely event of an exceedance, frequency, magnitude, and duration impacts are expected to be very minimal.

Nitrogen Deposition

Total Nitrogen deposition rates on the Class I area was predicted using CALPUFF. The results are listed in Table 29.

Table 29 – Total Nitrogen (N) Deposition Rates on the Class I Chassahowitzka NWA

Species	Year	Total Wet and Dry Deposition (kg/ha/yr)	Deposition Analysis Threshold (kg/ha/yr)
Nitrogen	2001 - 2003	0.002	0.01

The maximum predicted nitrogen deposition rates are below the threshold levels recommended by the Federal Land Manager.

5.8. Conclusion on Air Quality Impacts

The Department has reasonable assurance that the proposed project will not cause, or significantly contribute to, a violation of any AAQS or PSD increment. Furthermore, the Department concludes that there will minimal effects on the air quality related values (AQRV), including visibility at the nearest Class I area.

6. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the application, the reasonable assurances provided by the applicant, and the conditions specified in the Draft permit.

This changes to the previously issued permit No. 1010373-007-AC (PSD-FL-402), including addition of a carbon monoxide BACT determination, are shown in the enclosed updated draft permit for the larger combustion turbines and ancillary equipment. Changes are indicated as follows: additions are shown as double underlined text (underlined) with deletions in strikethrough text (~~strikethrough~~). Double underlined and strikethrough text indicators will be removed upon issuance of the final permit.

Melody Lovin is the meteorologist responsible for reviewing and preparing the ambient air quality analyses. Alvaro Linero, P.E. is the project engineer responsible for reviewing the revised application, preparing the draft permit and writing the technical document. Details of the analyses may be obtained by contacting Ms. Lovin at melody.lovin@dep.state.fl.us or Mr. Linero at alvaro.linero@dep.state.fl.us .

[1] Technical Report GE Power Systems GER 3568G. Davis, L. B., and S.H. Black, General Electric. "Dry Low NO_X Combustion Systems for GE Heavy-Duty Gas Turbines." 2000.

[2] Technical Report GE 3695E. Badeer, G. H., General Electric. "GE Aeroderivative Gas Turbines – Design and Operating Features." 2000.

[3] Report. Cubix Corporation. "Exhaust Emissions from a GE PG7241FA Simple Cycle Power Turbine at TEC Polk Power Station." September 2000.

[4] News Release. Catalytica. First Gas Turbine with Catalytica's XONON installed to Produce Electricity at a Utility. October 8, 1998.

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[6] Statement. EPA and Research Triangle Institute. ETV Joint Verification Statement. XONON™ Cool Combustion. December, 2000.

[7] Technical Report GE 4213. Davis, L.B. and Black, S.H. GE Power Systems. "Support for Elimination of Oxidation Catalyst Requirements for GE PG7242FA DLN Combustion Turbines." August 2001.