TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

Tampa Electric Company
Post Office Box 111
Tampa, Florida 33601-0111

Polk Power Station
Facility ID No. 1050233

PROJECT

Polk 2 Combined Cycle Project
4 on 1 Combined Cycle Operation

COUNTY

Polk County, Florida

PERMITTING AUTHORITY

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

December 31, 2012

1 GENERAL PROJECT INFORMATION

1.1 Facility Description and Location

The Tampa Electric Company (TEC) operates the existing Polk Power Station, which is an electric power plant consisting of five key electrical generating units (Units 1 to 5). The facility is categorized under Standard Industrial Classification Code No. 4911, for electrical services. The existing plant is located in Polk County at 9895 State Road 37 South in Mulberry, Florida. The UTM coordinates are Zone 17, 402.45 kilometers (km) East, and 3,067.35 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to state and federal Ambient Air Quality Standards (AAQS). Figure 1 shows the location of Polk County. Figure 2 is an aerial view of the facility. The current Title V Air Operation Permit under which the facility operates is No. 1050233-026-AV.

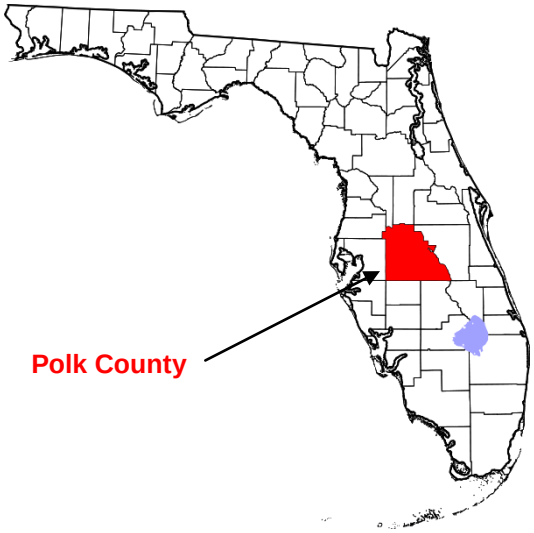


Figure 1 – Polk County in Florida.

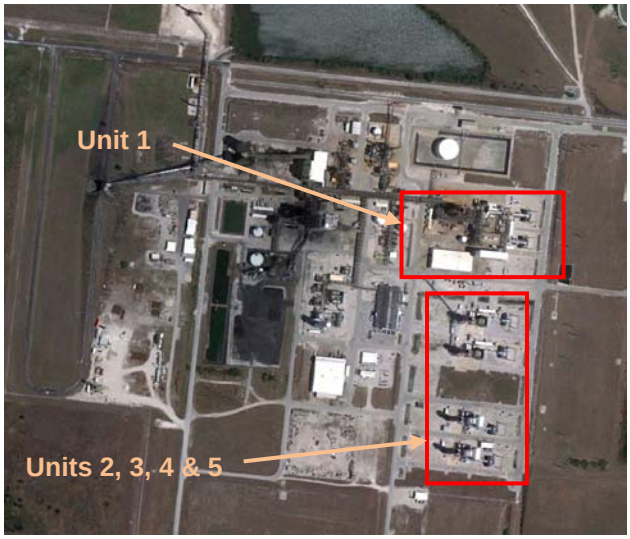


Figure 2 - Aerial View of the TEC PPS.

Unit 1 consists of a nominal 250 megawatt (MW, net) solid fuel-based integrated gasification and combined cycle (IGCC) plant. Units 2-5 are nominal 165 MW natural gas-fueled General Electric (GE) 7FA.03 simple cycle combustion turbine-electric generators (CTG). Units 2-5 (renamed Units 2A-2D) modified by this project and are visible in the aerial view of the Polk Power Station in Figure 2 above.

1.2 Project Description

1.2.1 How Simple Cycle Combustion Turbines Work

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA.03 combustion turbine where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

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)

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA.03 operate at lower flame temperatures, which minimize nitrogen oxides (NO_X) formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine -section at temperatures of approximately 2500 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent (%) is required to drive the compressor section.

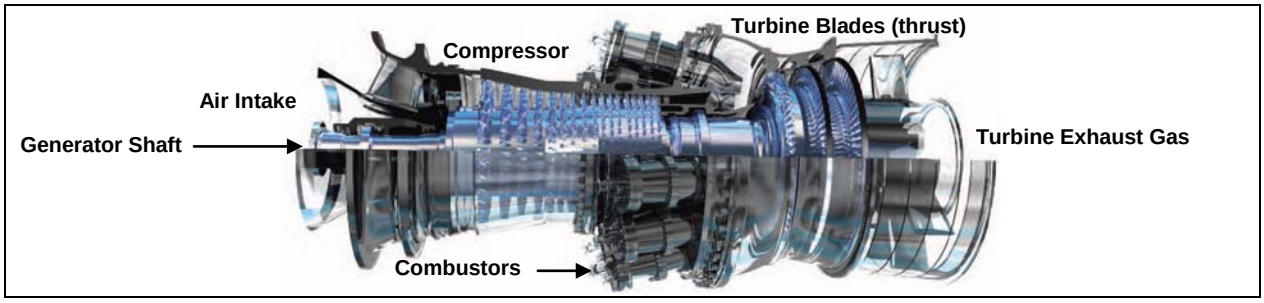


Figure 3 – Parts and Internal View of a GE 7FA.05 Combustion Turbine-Electrical Generator

The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Simple cycle turbine exhaust gas contains more than 12% oxygen (O_2) at a temperature on the order of 1100 °F and is available for steam production and as combustion air.

1.2.2 Combined Cycle Project Overview

TEC will add a nominal 500 MW steam cycle to Units 2A-2D and operate them as a single "4 on 1" combined cycle unit as shown in Figure 4. The additional components and features are highlighted in red.

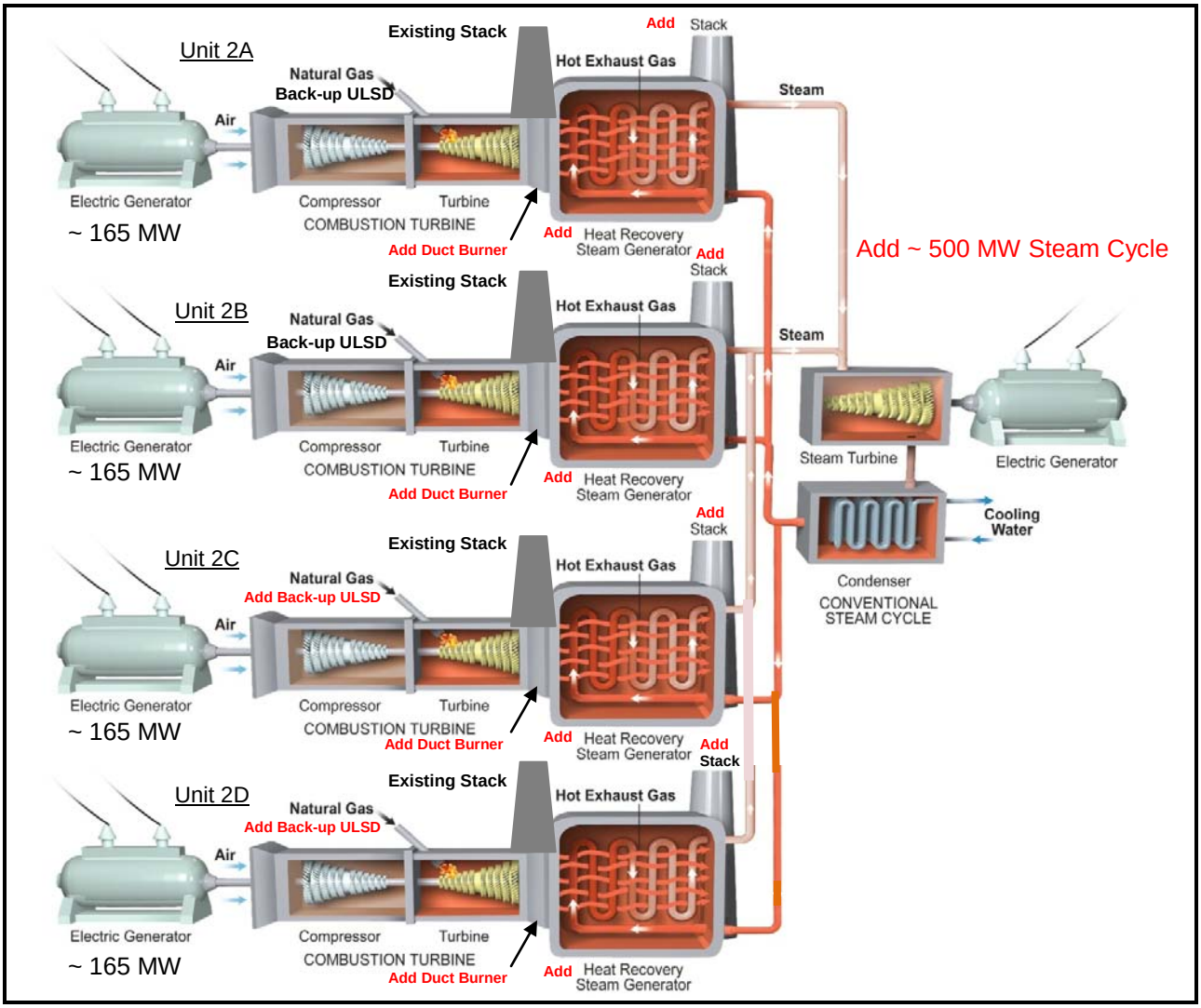


Figure 4 – Conversion of Simple Cycle Units 2A-2D to operation as a "4 on 1" Combined Cycle.

The conversion will be accomplished by: directing the hot turbine exhaust gas from the existing stack to a duct-fired heat recovery steam generator (HRSG); directing the lower temperature exhaust gas through a new stack; and directing the steam to a single steam turbine-electrical generator (STEG) to generate the additional electricity. The project will also include a new six-cell mechanical draft cooling tower, a new emergency generator diesel engine, a new transmission line and upgrades to existing transmission lines. The resulting "4 on 1" combine cycle unit will be known as the Polk 2 Combined Cycle.

The Polk 2 Combined Cycle will use pipeline-quality natural gas as its primary fuel with back-up ultralow sulfur distillate (ULSD) fuel oil serving as a backup fuel. Each of the four combustion turbines will operate up to 8,760 hours/year when firing natural gas in combined cycle mode. The natural gas-fired duct burners in the four HRSG's are rated at 264 million Btu per hour (MMBtu/hour) and will operate up to 4,000 hours/year/unit. Use of back-up ULSD fuel oil use will be limited to 12 hours/day/unit (averaged over the four units) and up to 750 hours/year/unit (averaged over the four units) when operating in combined cycle mode.

The combustion turbines will operate in simple cycle mode (as they presently operate) using the existing stacks as bypass stacks when the STEG is out of service or as dictated by power demands. The application is premised on continued allowed use of the existing simple cycle units as presently configured and permitted. Basically, TEC requests that only the additional (predominant) mode of operation be evaluated without reassessment of previously issued simple cycle mode and the applicable emission standards under that mode. Figure 5 shows the planned layout of the Polk 2 Combined Cycle. New components are shown in green. Figure 6 is a picture of a combined cycle unit at a different facility.

Figure 5 **– Layout of Polk 2 Combined Cycle.**

Figure 6 – A Combined Cycle Unit.

1.2.3 Emissions and Controls

The principal project emissions sources are the four combustion turbines and their associated duct burners. The project results in short or long-term emission increases of NO_X, carbon monoxide (CO), volatile organic compounds (VOC), sulfur dioxide (SO_2), particulate matter (PM), PM with a mean diameter of 10 microns or less (PM_{10}), PM with a mean diameter of 2.5 microns or less ($PM_{2.5}$), sulfuric acid mist (H_2SO_4 also called SAM) and carbon dioxide equivalents (CO_2e) for greenhouse gases (GHG). The following controls will be employed when operating in combined cycle mode:

- Lean pre-mix, Dry Low-NO_X (DLN) combustion (when firing natural gas), water injection (when firing ULSD fuel oil), and selective catalytic reduction (SCR) technology for NO_X control;
- Lean pre-mix, high temperature, good combustion practice to minimize formation of CO and VOC;
- Use of low-sulfur, pipeline-quality natural gas (primary fuel) and ULSD fuel oil (backup fuel) for control of particulate matter PM/PM_{10}/$PM_{2.5}$, SO_2 and H_2SO_4 emissions.

This project will add Emission Units (EU) Nos. 018 to 023 (highlighted in yellow) to the listing of EU's in Table 1. Units 2-5 (EU 009, 010, 013 and 014) will retain their previously issued EU Nos. until completion of the Polk 2 Combined Cycle that will retain simple cycle operation capability.

Table **1 – Listing of EU's.**

Facility ID No. 1050233	
EU No.	**Emission Unit Description**
001	260 MW Combined Cycle Gas Turbine No. 1
003	120 Million Btu per Hour Auxiliary Boiler
004	Sulfuric Acid Plant
005	Solid Fuel Handling System
006	Solid Fuel Gasification System
007	Emergency Generators
008	Heating Units and General Purpose Internal Combustion Engines
009	Nominal 165 MW Simple Cycle Turbine No. 2 (to be operated as Unit 2A, EU No. 020 in future)
010	Nominal 165 MW Simple Cycle Turbine No. 3 (to be operated as Unit 2B, EU No. 021 in future)
013	Nominal 165 MW Simple Cycle Turbine No. 4 (to be operated as Unit 2B, EU No. 022 in future)
014	Nominal 165 MW Simple Cycle Turbine No. 5 (to be operated as Unit 2D, EU No. 023 in future)
015	High-Temperature Syngas Cleanup System and Carbon Capture System (pre-commercial scale)
018	500 KW Emergency Generator Diesel Engine
019	Mechanical Draft Cooling Tower – consisting of six cells with six individual exhaust fans
020	Unit 2A Nominal 165 MW Combustion Turbine and Duct-fired Heat Recovery Steam Generator [1]
021	Unit 2B Nominal 165 MW Combustion Turbine and Duct-fired Heat Recovery Steam Generator [1]
022	Unit 2C Nominal 165 MW Combustion Turbine and Duct-fired Heat Recovery Steam Generator [1]
023	Unit 2D Nominal 165 MW Combustion Turbine and Duct-fired Heat Recovery Steam Generator [1]
1. Steam produced in the Duct-fired HRSG's will drive a separate 500 MW Steam Turbine-Electric Generator.	

2 AIR POLLUTION REGULATIONS

2.1 Department 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 air quality regulations as part of the Florida Administrative Code (F.A.C.), which includes the applicable chapters contained in Table 2:

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

Chapter	Description
62-4	Permits
62-17	Electrical Power Plant Siting
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

2.2 Federal Rules

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.

2.3 Overview of Key Regulations Applicable to the TEC PPS Project

- According to the applicant, the facility is **not** a major source of hazardous air pollutants (HAP) before and after the project.
- The facility includes units subject to the acid rain provisions of the Clean Air Act (CAA). The combustion turbines involved in this project are subject to the acid rain provisions of the CAA.
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. because the potential emissions of at least one regulated pollutant exceed 100 tons/year. Key regulated pollutants include CO, NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, VOC and SAM.
- The facility is subject to the Clean Air Interstate Rule (CAIR) in accordance with the Final Department Rules issued pursuant to CAIR as implemented by the Department in Rule 62-296.470, F.A.C.
- The facility is a major stationary source in accordance with Department Rule 62-212.400, F.A.C. – Prevention of Significant Deterioration (PSD).
- This project (as discussed below) **does** trigger a PSD review and a requirement to conduct a Best Available Control Technology (BACT) pursuant to Department Rule 62-212.400, F.A.C.
- The proposed project includes units subject to the New Source Performance Standards (NSPS) of 40 Code of Federal Regulations Part 60 (40 CFR 60).
- The proposed project includes units subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) of 40 CFR 63.
- The project is subject to certification under the Florida Power Plant Siting Act, 403.501-518, F.S. and Chapter 62-17, F.A.C. TEC has submitted an application for the project to the Siting Office.

2.4 New Source Performance Standards (NSPS) Applicable to the Project

2.4.1 40 CFR 60, Subpart A – General Provisions

Link to NSPS Subpart A

Several sections from NSPS Subpart A apply to this project or to existing units that will be used in the project. The excerpts below relate to modifications of existing affected sources, (i.e. Units 2-5).

§ 60.2 Definitions

Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

§ 60.14 Modification

*(a) …. any physical or operational change to an existing facility which results in an increase in the **emission rate** to the of any pollutant to which a standard applies shall be considered a modification within the meaning of*

section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

(b) Emission rate shall be expressed as kilograms per hour (kg/hour) of any pollutant discharged into the atmosphere for which a standard is applicable.

(h) No physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification for the purposes of this section provided that such change does not increase the maximum hourly emissions of any pollutant regulated under this section above the maximum hourly emissions achievable at that unit during the 5 years prior to the change.

The kg/hour (short-term) emission rate basis for determining a modification under the NSPS regulations is in contrast to the tons/year (long-term) emission rate basis for determining a modification under the PSD regulations.

2.4.2 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

NSPS Subpart GG

§ 60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value (LHV) of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of § 60.332.

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in 40 CFR 60, Subpart A – General Provisions.

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled.

The existing combustion turbines (Units 2-5) as presently operated are regulated pursuant to NSPS Subpart GG. Based on the discussion below, NSPS Subpart GG will not apply to Units 2-5 after addition of duct burners to the four units and fuel oil capability to Units 4 and 5. [refer to § 60.4305(b)]

2.4.3 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Gas Turbines

NSPS Subpart KKKK

§ 60.4305 Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to your turbine. Any additional heat input to associated HRSG's or duct burners should not be included when determining your peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.

*(b) Stationary combustion turbines regulated under this subpart **are exempt from the requirements of subpart GG of this par**t. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of 40 CFR 60, Subparts Da, Db, and Dc.*

Based on applicability criteria from 40 CFR 60, Subparts A and KKKK, the conversion to combined cycle will make them subject to Subpart KKKK instead of Subpart GG because:

- The applicant estimates greater heat input rates in the future than allowed by present permits;

- Addition of the duct-fired HRSG's to the four combustion turbines and addition of fuel oil capability to Units 4 and 5 constitute physical and operational changes which result in an increase in the emission rate in kg/hour to the atmosphere of at least one pollutant to which a standard applies (SO_2 and/or NO_X) and is thus a modification within the meaning of section 111 of the Act;
- In particular the emission rate of NO_X from Units 4 and 5 will be substantially greater than the maximum hourly emissions achievable at those units during the 5 years prior to the change;
- The project constitutes an increase in the production rate of each turbine that can only be accomplished with a significant capital expenditure on that facility (actually greater than the installed cost of each combustion turbine); and
- Stationary combustion turbines regulated under Subpart KKKK are exempt from the requirements of NSPS Subpart GG.

The duct-fired HRSG's would normally be regulated pursuant to NSPS Subpart Da. However, duct burners regulated under NSPS Subpart KKKK are exempt from NSPS Subparts Da, Db, and Dc.

For reference, the EPA recently proposed to revise NSPS Subpart KKKK to make it possible for owners of existing combustion turbines to comply with Subpart KKKK in lieu of complying with Subpart GG and any associated steam generating unit NSPS (absent modification or reconstruction).

2.4.4 Emergency Generator – 40 CFR 60 NSPS Subpart IIII Applicability

NSPS Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the CI ICE are manufactured after April 1, 2006, and are not fire pump engines or after July 1, 2006, for certified National Fire Protection Association fire pump engines. NSPS Subpart IIII

NSPS Subpart IIII specifies emissions limitations, monitoring, reporting, and recordkeeping requirements for NO_X, CO, non-methane hydrocarbons (NMHC), and PM. NSPS Subpart IIII is applicable to the emergency generator diesel engine proposed for this project.

2.5 National Emission Standards for Hazardous Air Pollutants (NESHAP) Applicable to the Project

2.5.1 Emergency Generator – 40 CFR 63 NESHAP Subpart ZZZZ

EPA promulgated a final NESHAP for stationary RICE (40 CFR 63, Subpart ZZZZ) on June 15, 2004. Subpart ZZZZ was subsequently amended on March 3, 2010 to address CI RICE located at area sources of hazardous air pollutants (HAP). Since the facility is an area HAP source, the emergency generator diesel engine proposed for the project will be subject to the applicable requirements of Subpart ZZZZ.

Pursuant to Section 63.6590(b)(c)(1), new stationary RICE located at an area source subject to the requirements of NSPS Subpart IIII have no further requirements under Subpart ZZZZ. As note previously, the emergency generator diesel engine will be subject to the applicable requirements of NSPS Subpart IIII. The following is a link to Subpart ZZZZ: NESHAP Subpart ZZZZ

2.5.2 40 CFR 63 NESHAP Subpart YYYY – Stationary Combustion Turbines

The requirements of NESHAP Subpart YYYY only apply to certain stationary combustion turbines located at major HAP sources. According to the applicant, the facility is and will continue to be a minor or area source of HAP. Accordingly, NESHAP Subpart YYYY is not applicable to the project.

3 PSD APPLICABILITY

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}, $PM_{2.5}$, SO_2, VOC, SAM, lead (Pb), fluorides (F), and mercury (Hg).

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

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

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

The list given in the citation includes the category of "fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input". The given category applies to the facility before and after the proposed project. The Polk Power 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 Polk Power Station, PSD applicability for modification projects is based on thresholds known as the significant emission rates (SER) as defined in Rule 62-210.200(Definitions), F.A.C. Any "net emissions increase" as defined in Rule 62-210.200(Definitions), F.A.C. of a PSD pollutant from the project that equals or exceeds the respective SER is considered "significant". SER also means any emissions rate or any net emissions increase of a PSD pollutant associated with a major stationary source or major modification which would construct within 10 km of a Class I area and have an impact on such area equal to or greater than 1 gram per cubic meter, 24-hour average.

Although a facility may be "major" (i.e. emits or has the potential to emit 100 or 250 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.

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

Table 3 – List of SER by PSD-Pollutant. [1, 3]

Pollutant	SER (TPY)	Pollutant	SER (TPY)
CO	100	NO_X	40
$PM/PM_{10}/PM_{2.5}$	25/15/10	Ozone (VOC) [2]	40
$PM_{2.5}$ (NO_X)	40	$PM_{2.5}$ (SO_2)	40
Ozone (NO_X) [2]	40	SAM	7
SO_2	40	Pb	0.6
Hg	0.1	GHG (CO_2e)	75,000 [3]

1. Excluding fluoride and those pollutants defined for Pulp and Paper, MWC, MSW landfills.
2. Ozone (O_3) is regulated by its precursors (VOC and NO_X). PSD for $PM_{2.5}$ can be triggered by its precursors (NO_X and SO_2).
3. Federal SER of 75,000 TPY for GHG (as CO_2e) for PSD sources and has not been incorporated into Department rules.

The project is located in Polk County, which is in an area that is currently in attainment with the state and federal AAQS or otherwise designated as unclassifiable. The combined cycle project will emit the following PSD-pollutants SO_2, NO_X, CO, PM, PM_{10}, $PM_{2.5}$, SAM, VOC, CO_2e, and small amounts of mercury and lead.

3.2 Methodology for Calculations of Baseline Actual Emissions and Projected Actual Emissions

To determine whether the project causes net emissions increases equal to or greater than the respective SER (triggering PSD) requires a comparison of recent "baseline actual emissions" with future "projected actual emissions". According to Rule 62-210.200(Definitions), F.A.C., for an existing unit other than an electric steam generating unit (existing simple cycle units are not yet electrical steam generating units):

"Baseline Actual Emissions" means the rate of emissions, in tons/year of a PSD pollutant, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding the date a complete permit application is received by the Department.

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

(a) Shall consider all relevant information, including historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans or orders, including consent orders; and
(b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns; and
(c) Shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project including any increased utilization due to product demand growth; or
(d) In lieu of using the method set out in paragraphs (a) through (c) above, may be directed by the owner or operator to use the emissions unit's potential to emit, in tons per year.

3.3 Baseline Actual Emissions from Simple Cycle Units 2A through 2D

Existing Simple Cycle Units 2A and 2B were permitted in 1999 (PSD-FL-263) and began operation in 2000 and 2002, respectively. Simple Cycle Units 2C and 2D were permitted in 2006 and both began operation in 2007. Table 4 is a summary of the approximate potential-to-emit (PTE) for the two projects as publicly noticed in 1999 and 2006 and the baseline actual emissions estimated by the Department based on Annual Operating Reports (AOR's) submitted by TEC for the calendar years 2007 through 2011.

Table 4 – Potential and Baseline Actual Emissions from Simple Cycle Units 2A – 2D (tons/year).

Pollutant	PTE Units 2A, 2B [1]	PTE Units 2C, 2D [2]	Total PTE	Baseline Actual Emissions [3,4]
SO_2	126	42	168	2.0 (2009-2010)
NO_X	581	267	848	72 (2010-2011)
CO	303	100	403	82 (2010-2011)
PM/PM_{10} (f) [5]	54	79	133	12.2 (2010-2011)
VOC	18	12	30	19.5 (2010-2011)
GHG (CO_2e)	~980,000	~940,000	~1,920,000	213,305 (2010-2011)

1. Units 2A and 2B permitted to operate 4,380 hours/year/unit on natural gas and 750 hours/year/unit on fuel oil.
2. Units 2C and 2D permitted to operate 4,380 hours/year/unit on natural gas. Not fuel oil capable.
3. Average rate at which Units 2A-2D actually emitted during any consecutive 24-month period within the 5- year period immediately preceding the date a complete permit application was received by the Department. (Used highest 2-year period).
4. CO_2 emissions from EPA Air Markets Database. Other pollutant emissions from Annual Operating Reports (AOR).
5. Filterable (f) portion only.

3.4 Future Emissions from Polk 2 Combined Cycle Unit

Table 5 provides the applicant's PSD applicability calculations based on the Potential to Emit (PTE) from the Polk 2 Combined Cycle as described in Section 1.2.2 above. The applicant did not consider the baseline actual emissions from recent minimal operation of the four combustion turbines in simple cycle mode or the projected future actual emissions if the four units continue to operate as allowed by the existing permits (PSD-263 and PSD-FL-363).

Table 5 – Projected Emissions in tons/year and PSD Applicability for the Polk 2 Combined Cycle.

Pollutant	Polk 2 Combined Cycle Unit	Cooling Tower	Emergency Generator	Total	PSD SER	Trigger PSD?
SO_2	192.3	0	<<0.1	192.3	40	Yes
NO_X	743.5	0	1.4	744.9	40	Yes
CO	933.9	0	1.1	935.0	100	Yes
PM (f) [1]	187.8	0.35	<0.1	188.3	25	Yes
PM_{10} (f + c) [2]	308.6	0.31	<0.1	309.0	15	Yes
$PM_{2.5}$ (f + c) [2]	308.6	<0.1	<0.1	308.6	10	Yes
SAM	42.7	0	<<0.1	42.7	7	Yes
VOC	137.0	---	0.6	137.6	40	Yes
Lead	0.18	0	<<0.1	0.18	0.6	No
GHG (CO_2e)	4,307,655	---	207	4,307,862	75,000	Yes
HAP	18.2	<<0.1	<<0.1	18.2	N/A	N/A
Mercury	6.5 lb/yr	0	<<0.1	6.5 lb/yr	200 lb/yr	No

1. Filterable (f) portion only.
2. Filterable (f) and condensable (c) combined.

3.5 Conclusion Regarding PSD Applicability

Regardless of applicability methodology used, the project is subject to PSD and BACT determinations for SO_2, NO_X, CO, PM/PM_{10}/$PM_{2.5}$, SAM, VOC and GHG (CO_2e). EPA is processing the GHG application.

4 DEPARTMENT'S BACT REVIEW

4.1 Definition of BACT

Rule 62-210.200, F.A.C. defines "BACT" as:

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.

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 the 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.

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

In no event shall application of best available control technology 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 Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA. These determinations are provided in the following sections and are organized and presented by emission unit.

4.2 Combustion Turbines and Duct Burners (EU 020 to 023)

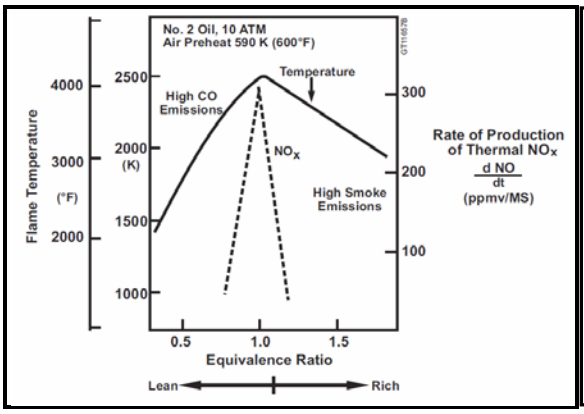
4.2.1 Nitrogen Oxides

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 nitrogen oxide (NO) and nitrogen dioxide (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 7. GE Report GER 3568G

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 8, which is from a General Electric discussion on these principles.



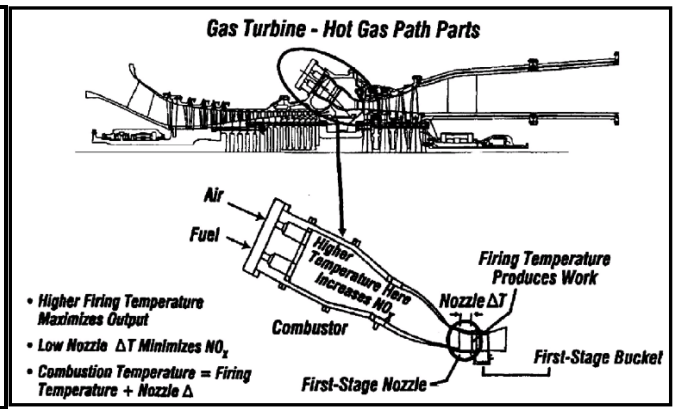


Figure 7 - NO_X vs. Temp., Equivalence Ratio. **Figure 8 - Hot Gas Path Parts, NO_X Control.**

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.

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.

CO and 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. Premixing of gaseous fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized high temperatures pockets within the combustion zones.

Refer to Figure 9. 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 10 . The combustor design is such that NO_X concentrations can be tuned to achieve less than 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.

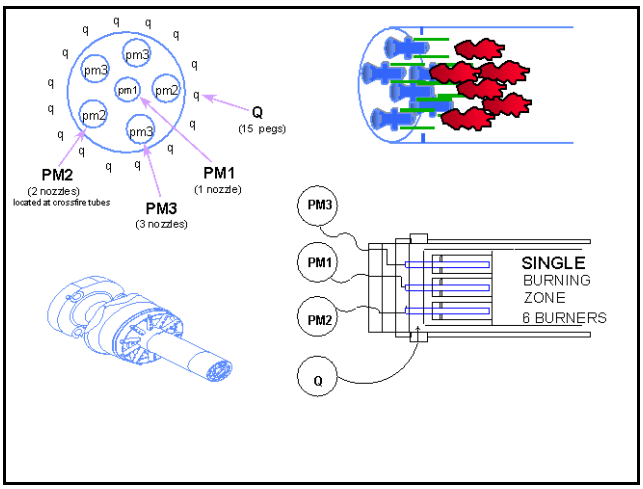


Figure 9 - DLN-2.6 Fuel Nozzle Arrangement.

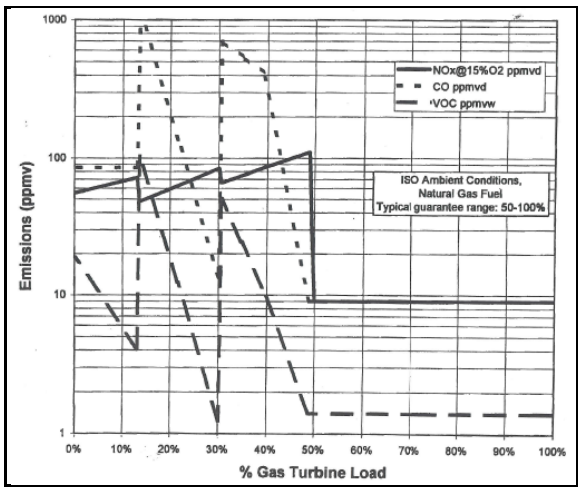


Figure 10 – Design Characteristics for DLN-2.6

GE7FA units guaranteed to achieve 9 ppmvd @15% O_2 of NO_X were typically also guaranteed to 9 ppmvd (uncorrected) of CO which equates to approximately 7.4 ppmvd CO @15% O_2.

Figure 11 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 11. Also actual emissions of CO at loads greater than 50% of full load have proven to be less than suggested by Figure 10 and more like the behavior shown in Figure 12

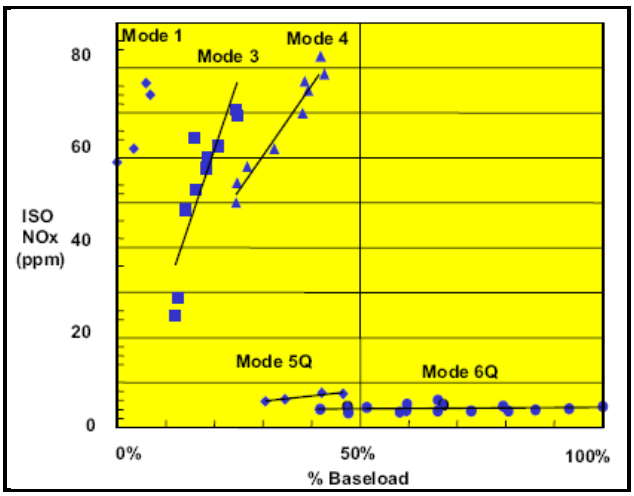


Figure 11 - NO_X Performance of DLN-2.6

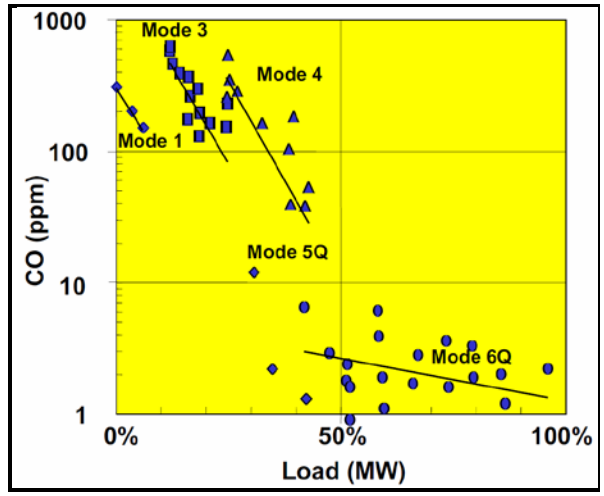


Figure 12 – CO Performance of DLN-2.6

Table 6 below is a summary of the new and clean tests for NO_X conducted in 2000 on TECO Polk Power Unit 2A, operating as a simple cycle unit.

Table 6 – NO_X Test Results for Natural Gas-fueled Simple Cycle GE 7FA.03 CTG (Unit 2A) [1]

Percent of Full Load	NO_X, ppmvd @15% O_2
50	5.3
70	6.3
85	6.2
100	7.6

The test results at the Polk Power Station (and at many similar units in Florida) confirm low NO_X emissions consistent with the emission characteristics contained in Figure 11. Numerous simple cycle (and combined 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 of approximately 95% compared with uncontrolled emissions (from 200 ppmvd @15% O_2) and a reduction greater that 40 percent compared with the NSPS Subpart KKKK limit of 15 ppmvd when firing natural gas.

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:

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

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

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 HRSG.

Figure 13 (Nooter-Eriksen) is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the ammonia injection grid.

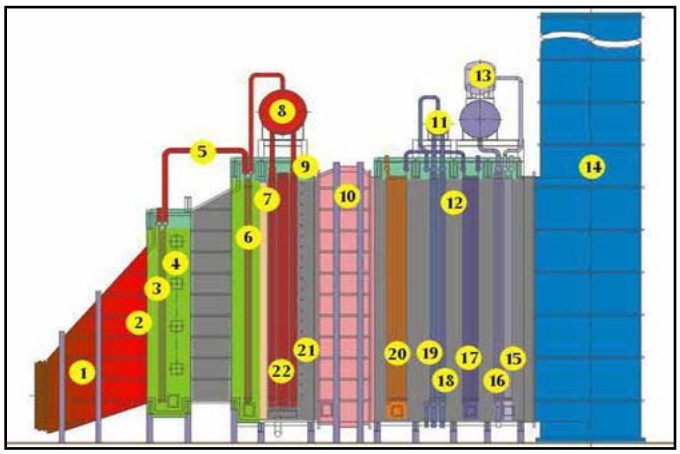


Figure 13 - Key HRSG Components (10 is SCR). **Figure 14 - FPL West County Energy Center.**

The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 14 is a photograph of the recently constructed FPL West County Energy Center (WCEC) Unit 1 Power Block. The external lines to the NH_3 injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

In such applications, NO_X emissions on the order of 2.0 ppmvd @15% O_2 are achieved. The SCR catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive NH_3 use can increase emissions of CO, NH_3 (slip) and $PM_{10}/PM_{2.5}$ when sulfur-bearing fuels are used.

For higher temperature simple cycle applications (i.e. no HRSG), 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 simple cycle applications (~1,100 ^oF), such as the GE7FA.03, even more expensive formulations (e.g. zeolite) or substantial tempering air would be required.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_X emissions (< 2.0/8.0 ppmvd @15% O_2 for gas/oil firing). SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or wet injection in a combined cycle unit or total control on the order of 95 to 99%.

Catalytic Combustion – XONON™. Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[2] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

Catalytica has developed a system known as XONON™, which works 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™.[3] 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.[4] By now, at least five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[5] 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. The technology is not feasible at this time for the existing GE7FA.03 combustion turbines located at the Polk Power Station.

EMx formerly $SCONO_X$. This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power was the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

EMx systems were installed at seven sites ranging in capacity from 5 to 43 MW.[6] None was installed at a large facility.

EMx technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. EMx has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. EMx systems also oxidize emissions of CO and VOC for additional emission reductions. EMx can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from a natural gas reforming unit.

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2 Compliance Manual. California EPA, CARB Compliance Division. Gas Turbines. June 1996.

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

4 News Release. Catalytica. Catalytica Energy Systems XONON Cool Combustion System Demonstrating NO_X Emissions Well Below its 3 ppm Guarantee in Commercial Gas Turbine Applications. February 17, 2004.

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

6 White Paper. Emerachem. NO_X Abatement Technology for Stationary Gas Turbine Power Plants – An Overview of Selective Catalytic Reduction (SCR) and Catalytic Absorption ($SCONO_X$™) Emission Control Systems. September 19, 2002.

Table 7 contains averaged cost values for SCR with oxidation catalyst (SCR/CO) and for $SCONO_X$™ (now EMx) developed by the California Air Resources Board for their Legislature.[7] The comparison is for a "2 on 1" 500 MW combined-cycle power unit meeting BACT requirements.

Table 7. Cost Comparison between SCR and $SCONO_X$ (now EMx) for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	$SCONO_X$™	SCR/CO	$SCONO_X$™
6,259,857	20,747,637	1,355,253	3,027,653

The SCR/oxidation catalyst package costs less than the EMx system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

While the Department does not accept or reject the values given in Table 7, it appears that EMx is not cost-effective for the present project and that the CO portion of $SCONO_X$ would have little if any benefit for the existing CTG's at Polk Power Station.

Requirements of NSPS Subpart KKKK

Applicable NO_X Emission Standards. The BACT determination cannot result in emissions of NO_X which would exceed the emissions allowed by NSPS Subpart KKKK that are listed in Table 8. The BACT emissions standards must be at least as stringent as those contained in the table.

Table 8 – 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 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.
3. For simple cycle units without heat recovery, assess excess emissions on a 4-hour rolling average basis. For combined cycle and combined heat and power units with heat recovery, assess excess emissions on a 30 unit operating day rolling average basis, as described in § 60.4380(b)(1).

Applicant's NO_X Emissions BACT Proposal

Combined Cycle Mode. While firing natural gas in combined cycle mode, TEC proposes a BACT NO_X limit of 2.0 @15% O_2 based on a 24-hour block average with and without the duct burners in operation. The proposed control system to achieve this emissions limit is DLN combustors and SCR.

While firing ULSD fuel oil, TEC proposed a BACT NO_X limit of 8.0 ppmvd at @15% O_2 based on a 24-hour block average with and without duct burners in operation. TEC also proposes to limit ULSD fuel oil firing to no more than 48 hours/day and 3,000 hours/year combined for the four combustion turbines.

The proposed control system to achieve this emissions limit is wet injection and SCR. Compliance for both the natural gas and fuel oil NO_X emission limits is by continuous emission monitoring systems (CEMS).

[7] Draft Report to the Legislature. California Air Resources Board. Gas -Fired Power Plant NO_X Emissions Controls and Related Environmental Impacts. March 2004.

Simple Cycle Mode. The applicant did not propose updated NO_X BACT values for operating in simple cycle. The present BACT NO_X limit already applicable to Units 2A and 2B is 10.5 ppmvd @15% O_2 when burning natural gas and 42 ppmvd @15% O_2 when burning fuel oil. However, the two units were required to meet the guaranteed value of 9.0 ppmvd @15% O_2 during the initial "new and clean" tests.

The BACT NO_X limit already applicable to Units 2C and 2D is 9 ppmvd @15% O_2. These units are not authorized to burn fuel oil by past permits but would use ULSD fuel oil as a backup fuel for a limited number of hours.

Although the applicant did not submit BACT proposals for the simple cycle case, the applicant agreed that a limit of 9 ppmvd @15% O_2 would be acceptable when firing natural gas in Units 2A - 2D. Simple cycle firing after conversion to combined cycle operation will be even less frequent compared with already permitted and actual simple cycle operation (see Table 4).

In summary, presumed proposed future simple cycle emission standards are:

- 9.0 ppmvd at @15% O_2 on a 24-hour block average when firing natural gas and based on lean premix DLN technology;
- Maximum operation in simple cycle mode of 4,380 hours/year/unit averaged over four units as presently permitted;
- 42 ppmvd at @15% O_2 on a 4-hour rolling average (per NSPS Subpart KKKK) when firing back-up ULSD fuel oil and based on wet injection technology;
- Maximum operation on ULSD fuel oil while in simple cycle mode of 750 hours/year/unit averaged over Units 2A and 2B;
- Maximum operation on ULSD fuel oil while in simple cycle mode of 375 hours/year/unit to be applicable to Units 2C and 2D;
- The proposed control system to achieve these emissions limit is lean premix, DLN combustors when firing natural gas and wet injection when firing fuel oil; and
- Compliance will be demonstrated by NO_X-CEMS.

Department's Draft NO_X BACT Determinations – Steady State

Table 9 includes some recent BACT determinations in Florida and other states including some Lowest Achievable Emission Rate determinations as required in ozone non-attainment areas (e.g. California). All used SCR. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average. The Department does not consider a 1-hour averaging time to be necessary to insure continuous low NO_X levels. Increasing the averaging time provides relief from some of the small risks of occasionally exceeding the very low BACT NO_X limits during an hour while not exceeding it when averaged over a day.

The Department reviewed compliance test data for the 1,100 MW FP&L Turkey Point Unit 5, which is practically identical to the proposed TEC project. Average NO_X emissions during the tests from the four CTGs that comprise Turkey Point Unit 5 ranged from 1.36 to 1.70 ppmvd @15% O_2 while firing natural gas (whether or not the duct burners were used).

The Department accepts TEC's BACT proposal of 2.0 ppmvd NO_X @15% O_2 and a 24-hour block averaging period when operating in combined cycle mode while firing natural gas. The Department also accepts TEC's BACT proposal of 8 ppmvd NO_X @15% O_2 and a 24-hour block averaging period when firing fuel oil as BACT for this project. These limits apply whether or not the duct burners are in operation. The Department will limit fuel oil usage to 750 hours/year/unit as proposed by TEC.

The limits of 2.0 and 8.0 ppmvd NO_X @15% O_2 represent reductions of 87 and 81% for natural gas and fuel oil firing, respectively, compared with NO_X emissions standards contained in NSPS, Subpart KKKK.

Table 9 - Recent NO_X Standards for F-Class Combined Cycle Gas Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2, Fuel	Comments
FPL Bellingham, MA	~ 545	1.5 (1-hr – 90% of time) 1.5 – 2.0 (10% of time)	2 GE 7FA (cancelled)
Towantic Energy, CT	540	2.0 NG (1-hr) 5.9 – FO	2 GE 7FA
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3 GE 7FA & DB
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4 GE 7FA & DB
Kalama Energy Center, WA	~ 350	2.0 – NG (1-hr)	1 Siemens SGT6-5000F & DB
Russell City Energy Center, CA	600	2.0 – NG (1-hr)	2 Siemens 501F & DBs
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2 ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 - NG(3-hr)	4 GE 7FA & DBs
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2 ABB GT-24
OUC Stanton B, FL	300	2.0 – NG (24-hr) 8 – FO	1 GE 7FA & DB
FMPA Treasure Coast, FL	300	2.0 – NG (24-hr) 8 – FO	4 GE 7FA & DB
FPL Turkey Pt, FL	1,150	2.0 – NG (24-hr) 8 – FO	4 GE 7FA & DB
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2 WH 501F
Summit Vineyard, UT	560	2.0 – NG (3-hr)	2 WH501F & DB
Pacificorp Currant, UT	525	2.25 – NG (3-hr)	2 GE 7FA & DB
Notes: NG = Natural Gas; DB = Duct Burner; PA = Power Augmentation; FO = Fuel Oil; GE = General Electric WH = Westinghouse; and ABB = Asea Brown Bovari			

For simple cycle operation, the Department will update the BACT determination for Units 2A and 2B to 9.0 ppmvd at @15% O_2 based on a 24-hour block average when firing natural gas and to 42 ppmvd at @15% O_2 based on a 3-hour average when firing ULSD fuel oil. The Department will maintain the previous BACT determination for Units 2C and 2D of 9.0 ppmvd at @15% O_2 based on a 24-hour block average when firing natural gas.

As part of this determination, fuel oil use is limited to 750 hours/year/unit (Units 2A - 2D) of which 375 hours/year/unit may be used in Units 2A and 2B. No fuel oil firing is permitted in Units 2C and 2D.

The CTGs and HRSGs must meet the applicable NSPS Subpart KKKK emission limits for NO_X. Compliance for all BACT NO_X emission limits is by CEMS.

Department's Draft NO_X BACT Determinations – Startups, Shutdowns, Malfunctions

In general, Rule 62-210.700, F.A.C. provides for excess emissions.

1. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) <u>best operational practices to minimize emissions</u> are adhered to and (2) the <u>duration of excess emissions shall be minimized</u> but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
2. (Applicable to existing, conventional fossil fuel generators)
3. (Not applicable to CTGs)

4. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
5. Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest.

In accordance with § 60.11 of NSPS Subpart A and § 60.4333 of NSPS Subpart KKKK, the owner or operator must operate and maintain stationary combustion turbines, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

Pursuant to Rules 62-210.700(Excess Emissions), F.A.C., the Department specifically authorizes the following durations of excess NO_X emissions of NO_X applicable to the CTG/HRSG systems. For each CTG/HRSG system, excess emissions of NO_X resulting from startup, shutdown, or malfunction shall be excluded from CEMS data in any 24-hour period ("any 24-hour period" means a calendar day, midnight to midnight) for the following conditions (these conditions are considered separate events and each event may occur independently within any 24-hour period):

- *Steam Turbine-Electric Generator (STEG) Cold Startup*: For cold startup of the STEG, excluded emissions from any CTG/HRSG system shall not exceed eight (8) hours in any 24-hour period. A cold startup of the STEG is defined as startup of the 4-on-1 combined cycle system following a shutdown of the STEG lasting at least 48 hours.

  {During a cold startup of the STEG, each CTG/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue. Shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}
- *CTG/HRSG Cold Startup*: For cold startup of a CTG/HRSG system, excluded emissions shall not exceed four (4) hours in any 24-hour period. "Cold startup of a CTG/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 pounds per square inch, gauge (psig) for at least a one-hour period.
- *CTG/HRSG System Warm Startup*: For warm startup of a CTG/HRSG system, excluded emissions shall not exceed two (2) hours in any 24-hour period. "Warm startup of a CTG/HRSG system" is defined as a startup when the pressure in the HP steam drum is equal to or greater than 450 psig.
- *CTG/HRSG System Shutdown*: For shutdown of the CTG/HRSG operation, excluded emissions from any CTG/HRSG system shall not exceed two hours in any 24-hour period.
- *Fuel Switching*: For fuel switching, excluded emissions shall not exceed two (2) hours in any 24-hour period for each fuel switch and no more than four hours in any 24-hour period for any gas turbine/HRSG system.
- *Documented Malfunction*: For the gas turbine/HRSG system, excess emissions of NO_X resulting from documented malfunctions shall not exceed two hours in any 24-hour period. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

NO_X emissions during warm and cold startups are greater than during full load steady-state operation. STEG and HRSG/CTG cold startups are infrequent but of longer duration for combined cycle units. Startups are more frequent, but of less duration for simple cycle CTG's.

Department Rule 62-210.700, F.A.C. and NSPS Subparts A and KKKK require "best operational practices" and "good air pollution control practices" to minimize emissions during startup, shutdown and malfunction.

Pursuant to Rules 62-210.700 and 62-212.400(PSD/BACT), F.A.C., the Department will require inclusion of Best Operational Practices for Startup, Shutdown and Malfunction within the "4 on 1" Polk 2 Combined Cycle operating manual. The measures can include but are not limited to use of stack dampers to minimize heat loss during short-term shutdowns, additional piping, valves, practices, training or software to minimize the excess emissions implied by the graphs and plots contained in Figure 10 and Figure 11.

DLN Tuning

DLN combustion systems require initial and periodic "tuning" to account for changing ambient conditions, changes in fuels and normal wear and tear on the unit. Tuning involves optimizing NO_X and CO emissions, and extends the life of the unit components. A major tuning session would typically occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar event. Excess emissions of NO_X, CO, and opacity will be allowed during DLN tuning sessions. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least one working (business) day that details the activity and proposed tuning schedule.

4.2.2 Carbon Monoxide and Volatile Organic Compounds

CO and VOC Formation and Control Options

CO and VOC are emitted from CTG due to incomplete fuel combustion. Most CTG incorporate good combustion practices to minimize emissions of CO and VOC. The obvious control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst, particularly on combustion turbines that do not perform well at low load conditions.

CO and VOC Emissions from Natural Gas and Fuel Oil-fired GE 7FA.03 CTG's

Table 10 below is a summary of the new and clean tests for CO and VOC conducted on Polk Power Station simple cycle Unit 2A when burning natural gas.

Table 10 – CO/VOC Test Results for Natural Gas-fueled Simple Cycle GE 7FA.03 CTG (Unit 2A) [8]

Percent of Full Load	CO, ppmvd @15% O_2	VOC, ppmvd @15% O_2
50	1.6	0.5
70	0.5	0.4
85	0.4	0.2
100	0.3	0.1

The test results at the Polk Power Station (and at many similar units in Florida) confirm CO and VOC emissions less than the emission characteristics published by GE in Figure 10 and Figure 12 above. Many GE 7FA.03 units with DLN-2.6 technology for NO_X/CO control have been installed throughout the U.S. with guarantees of 9 ppmvd @15% O_2 (or less) and without a requirement for oxidation catalyst. For reference, NSPS Subpart KKKK does not contain a CO or VOC emission standard. VOC emissions less than 1 ppm have been consistently measured at new GE 7FA.03 units throughout the state.

Table 11 is a summary of annual CO (full load) stack test results for simple cycle Units 2A - 2D for the years 2000 through 2012. CO emissions are an order of magnitude less than the CO emission limits for all units. Units 2 C and 2 D are equipped with CEMS and annual tests are not required. However, the CO-CEMS record supports the conclusion that CO emissions are very low. Some of the results for tests

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

conducted during the annual Relative Accuracy and Test Audits (RATA) of the CEMS are included in the table. Clearly emissions are equally low from a GE 7FA.03 CTG whether natural gas or fuel oil is used.

Table 11 – CO Stack Test Results from PPS, Units 2A to 2D (2000 to 2012).

Year	CO (ppmvd @15% O_2) [1]					
	Unit 2A [2]		Unit 2B [2]		Unit 2C	Unit 2D
	Gas	Oil	Gas	Oil	Gas Only	Gas Only
2000	0.24	1.05	Not yet constructed		Not yet constructed	
2001	0.06	0.06				
2002	0.75	0.62	0.23	0.58		
2003	0.8	0.5	0.3	0.3		
2004	0.5		0.3			
2005	~0	~0	~0	~0		
2006	~0					
2007	0.57		1.0			
2008	0.22		0.21		0.2 [3]	0.19 [3]
2009	~0		~0			
2010	~0	0.04	0.04	0.04	0.7 [4]	1.2 [4]
2011	0.03		0.04		1.0 [4]	0.8 [4]
2012	0.4		0.6			
Average	0.3	0.5	0.3	0.2	0.6	0.7

1. Parts per million by volume @ 15% O_2.
2. Permit limit is 12 ppmvd @ 15% O_2 for gas firing and 20 ppmvd @ 15% O_2 for oil firing.
3. Initial stack test to validate emission rate of 9 ppmvd @15% O_2 or less. Subsequent compliance by CEMS to shown annual emission less than 100 TPY to avoid BACT.
4. Results from CO-CEMS data taken when demonstrating compliance at (near) full load.

TEC operates seven natural gas-fueled GE 7FA.03 CTG's at the Bayside Station. The units operate only in combined cycle and are equipped with CO-CEMS. The ranges of measurements during the early operation of three of the CTG's are summarized in Table 12 .

Table 12 - CO CEMS Data Results from TEC Bayside Station, Combined Cycle Unit 1.

Turbine	Period	Range of 24-hr Blocks (ppmvd @15% O_2)	Average (ppmvd @15% O_2)
1A	3rd Quarter 2003	0.3 - 4.3	0.83
1B		0 - 1.7	1.0
1C		0 - 2.1	0.8
1A	4th Quarter 2003	0 - 2.2	0.76
1B		0 - 1.9	1.14
1C		0 - 1.2	0.74

Duct Burner Considerations

TEC will equip each HRSG with supplemental natural gas-fueled duct burners. In typical GE 7FA.03 configurations with duct burners, the turbine exhaust gas exits the rotor section at a temperature of approximately 1,100 °F at high excess air (> 12% O_2). In the design shown in Figure 13, some of the heat is used by a high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the turbine exhaust gas prior to entering a second superheater (Component 6).

Figure 15 is a small section of a duct burner. Figure 16 is a picture of a HRSG under construction. The horizontal elements and flow baffles of the duct burner arrangement are clearly visible. The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 ºF. VOC such as

ethane and propane ignite at temperatures less than 900 ºF. All of the necessary conditions are present to minimize further CO production by the duct burner and to incinerate CO and VOC present in the turbine exhaust gas.

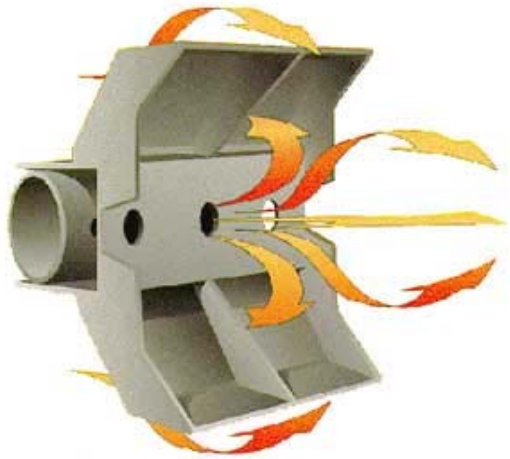

Figure 15 - Individual Duct Burner.

Figure 16 - Duct Burner and HRSG (Coen).

Table 13 contains results of CO and VOC testing completed on the two GE 7FA.03 combined cycle CTG's that comprise the existing Orlando Utilities Commission (OUC) Stanton Unit A. Tests were conducted on each CTG/HRSG stack with the duct burners off and with the duct burners in operation. CO concentrations increase slightly when firing duct burners, but remain very low.

Table 13 - CO and VOC Emissions while using Duct Burners – GE 7FA.03 CTG (ppmvd @15% O_2).

Unit (Modes)	CO	VOC
OUC Stanton A25 (duct burners off)	0.5	0.04
OUC Stanton A26 (duct burners off)	0.5	0.49
OUC Stanton A25 (duct burners on)	1.6	0.2
OUC Stanton A26 (duct burners on)	1.6	0.26

Low Load Considerations

Generally speaking, the full premix features of the DLN 2.6 operate at loads greater than 50%. The data in Figure 12 suggest that there is some turndown capability while achieving low CO emissions. To maintain very low CO, the unit would need to operate in Modes 5Q or 6Q which means that five or all six fuel nozzles and quaternary pegs are in operation. The manner by which the unit is ramped up through Modes 1, 2, 4, 5Q and 6Q and then backed down to low load cannot be inferred by this diagram. Flame stability of DLN conditions at low load is complex, and will not be addressed here.

The Department obtained data from operations at JEA Brandy Branch.[9] These are summarized in Table 14. For reference, a 65 MW load represents roughly 38% of full simple cycle CTG load. According to the utility, GE offers the software to tune and operate under the described conditions. A utility representative said that the unit operated in Mode 6Q during the tests.[10]

[9] Letter. Chansler, J.M., JEA to Koerner, J.F., FDEP. Brandy Branch Generating Station Units 2 and 3. Unit 1 Test Results. August 24, 2005.

[10] Telecom. Mulkey, C., FDEP and Gianazza, N. B., JEA. Low Load Operation at JEA Brandy Branch Station. October 18, 2005

Table **14 - CO Emissions during Low Load Operation at JEA Brandy Branch Unit 1.**

Test/Run	Load (MW)	Load (% full load)	CO (ppm)	CO (ppm @15%O_2)
1/1	65	38	9.6	8.5
1/1	65	38	9.0	8.0
1/3	65	38	9.2	8.1
2/1	65	38	12.2	10.7
2/2	65	38	12.2	10.7
2/3	65	38	11.9	10.5
3/1	65	38	12.3	10.9
3/2	65	38	11.9	10.5
3/3	65	38	12.1	10.6

GE CO Guarantee on 7FA.03 CTG's

Original installations of the GE 7FA.03 CTG were guaranteed to achieve 9 ppmvd (uncorrected). This value equates to approximately 7.4 ppmvd @15% O_2. Following a determination by EPA Region 2 that required installation of oxidation catalyst on a large GE 7H CTG, GE published a report supporting the elimination of oxidation catalyst requirements for CO control on its units based on achievement of low CO emissions without oxidation catalyst.[11] Figure 17 from GE's article is consistent with the data collected by the Department.

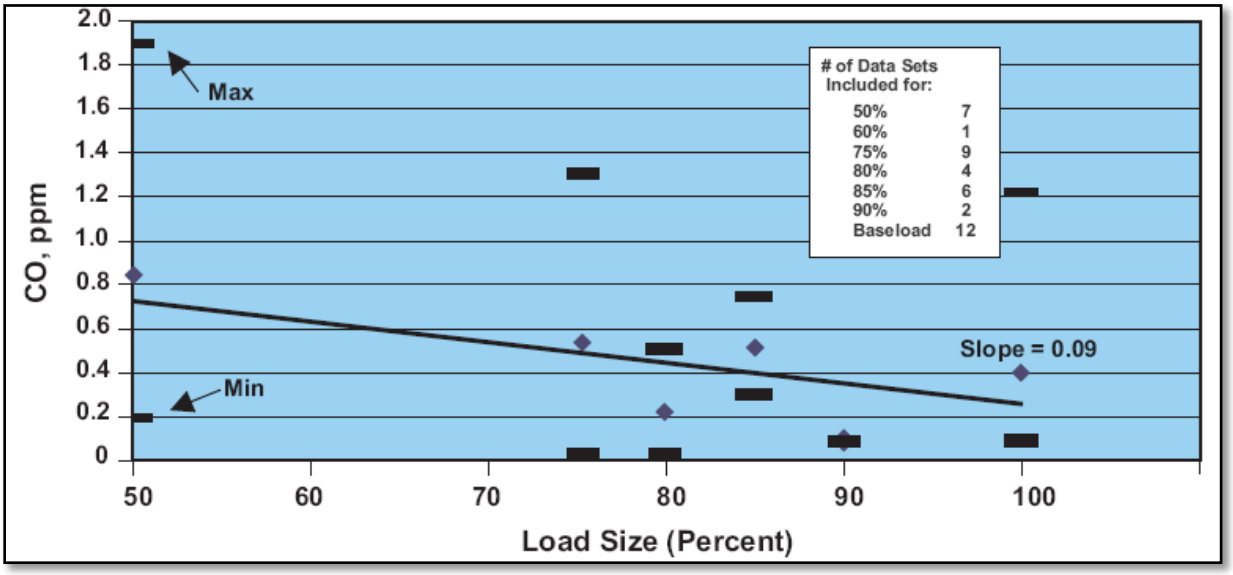

Figure 17 - Average CO Emissions (uncorrected) versus Percent Load for GE 7FA.03 CTG's.

[11] 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.

According to the referenced GE report:

> *"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN 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 DLN units while firing natural gas."*

For reference, 5 ppmvd of CO (uncorrected) from the turbine exhaust is approximately equal to 4.1 ppmvd @15% O_2 for this class of combustion turbine.

Applicant's CO and VOC Emissions BACT Proposal

CO proposal. TEC proposed a limit of 8 ppmvd @15% O_2 on a 24-hour basis as BACT for CO under all modes of operation (simple cycle, combined cycle, natural gas, ULSD fuel oil, duct burner on or off). BACT will be achieved through the use of good combustion practices and demonstrated by CO-CEMS.

VOC proposal. TEC proposed the following limits as BACT for VOC:

- 1.4 ppmvd @15% O_2 while firing natural gas with the duct burners off;
- 3.5 ppmvd@15% O_2 while firing natural gas with the duct burners on; and
- 3.0 ppmvd @15% O_2 while firing ULSD fuel oil.

Compliance with VOC BACT emissions limits will be achieved by good combustion practices and demonstrated annual stack testing.

According to TEC, the capital cost of oxidation catalyst to control CO (and VOC) is approximately $1,449,000 per CTG/HRSG set. On an annualized basis, the cost to reduce CO by 75% (from 8 to 2 ppmvd @15% O_2) using oxidation catalyst is estimated by the applicant at $4,633/ton of CO removed. TEC acknowledged that oxidation catalyst is technically feasible, but concluded that it is not cost-effective.

Department's Draft CO and VOC BACT Determinations – Steady State

CO determination. Table 15 includes some recent CO BACT determinations in Florida and other states known for especially strict limits. Some of the projects cited required oxidation catalyst. The "Top" BACT emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average. The limit is achievable by use of oxidation catalyst.

It is clear from Table 10 through Table 14 above that CO emissions from the GE 7FA are inherently low for the normal CTG natural gas simple or combined cycle modes, the duct firing mode and the fuel oil mode without oxidation catalyst. CO emissions were consistently less than 5 ppmvd @15% O_2. Emissions were also very low at loads equal to 50%.

The Department concurs with the applicant that installation of oxidation catalyst to reduce CO emissions from 8 to 2 ppmvd @15% O_2 is not cost effective, especially given that the CTG's achieve less than 2 ppmvd @15% O_2 without oxidation catalyst.

After conversion of simple cycle Units 2A – 2D to a single 4 on 1 combined cycle, emissions of CO will not change from the historical emissions already achieved at these CTG's. The Department will set a single limit of 4.1 ppmvd @15% O2 and require an initial demonstration while burning natural gas for each CTG after conversion to combined cycle. As shown in the foregoing discussion, there is no discernible difference in CO concentrations when burning natural gas or ULSD fuel whether the duct burners are used or not used.

VOC determination. The applicant's VOC BACT proposal of 1.4 ppmvd @15% O_2 is slightly greater than the "guaranteed" value given in Figure 10 (which is not corrected and is reported on a wet basis). Based on actual tests conducted on TEC Polk Power Station Units 2A – 2D, VOC concentrations are nearly an order of magnitude less than the values guaranteed by GE or proposed by TEC as BACT.

Table 15 - CO and PM Standards for "F-Class" Combined Cycle Units.

Project Location	CO – ppmvd (@15% O_2)	PM - lb/mmBtu (or gr/dscf or lb/hr)
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	0.008
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	0.01
Duke Morro, CA	2.0 (Ox-Cat)	0.0059 (DB off) 0.0064 (DB on)
Russell City Energy Center, CA	2.0 (1-hr Ox-Cat)	0.0036 $PM_{10}/PM_{2.5}$ or 7.5 lb/hr (Including Condensable $PM_{10}/PM_{2.5}$) (NH_3 = 5.0 ppmvd)
ANP Blackstone, MA	3.0 (Ox-Cat)	0.002 (NH_3 = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	0.0048 (NH_3 = 5 ppmvd) 0.0005 Cool Tower Drift
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip
OUC Stanton B, FL	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 14 – NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	11 lb/hr – NG (Front ½) 14.4 lb/hr – NG (DB on) 17.6 lb/hr – FO (Front ½) 10% Opacity – All Modes
FPL Turkey Pt., FL	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 14 – NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	11 lb/hr – NG (Front ½) 14.4 lb/hr – NG (DB on) 17.6 lb/hr – FO (Front ½) 10% Opacity – All Modes
FMPA TCEC, FL	8.0 NG (24-hr block) 12.0 FO (24-hr block)	38.0 lb/hr – NG (front + back ½) 52 lb/hr – FO (front + back ½)
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	0.011
Calpine OEC, PA	10 (1-hr)	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	10% Opacity NH_3 = 5
Metcalf Energy, CA	6 - NG (100% load)	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip
Notes: NG = Natural Gas; DB = Duct Burner; PA = Power Augmentation; FO = Fuel Oil; Ox-Cat = Oxidation catalyst		

According to TEC, total VOC emissions will be only 137.0 tons/year from the four combustion turbines. The test data reviewed by the Department indicates that actual emissions will be much less than this value and may even be less than the PSD significant emission rate of 40 tons/year.

Department's Draft CO and VOC BACT Determinations – Startups, Shutdowns, Malfunctions

The same considerations, rules and procedures previously discussed for excess NO_X emissions apply to excess emissions of CO and VOC.

4.2.3 Draft BACT Determinations for SO_2 and Sulfuric Acid Mist (SAM)

A review of the determinations for SO_2 and SAM from CTG's contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2 and SAM. The

use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at a refinery or gas conditioning plant prior to distribution of the fuel to the end customer.

For this project, the TEC proposed and the Department accepts as BACT the use of ULSD fuel oil (0.0015% sulfur by weight) and clean natural gas with a sulfur fuel specification less than 2 grains of sulfur per 100 standard cubic feet of natural gas ($\leq$ 2 gr/100 SCF).

For reference, the fuel sulfur limits given in NSPS Subpart KKKK are 0.05% by weight for fuel oil and 20 gr/100 SCF for natural gas.

The applicant estimated total emissions for the project at 192.3 tons per year of SO_2 and 42.7 tons per year of SAM. The Department accepts TEC's BACT proposal for SO_2 and SAM.

4.2.4 Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Draft BACT Determinations

$PM/PM_{10}/PM_{2.5}$ Formation and Control Options

$PM/PM_{10}/PM_{2.5}$ is emitted from CTG due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion. Natural gas and ULSD fuel oil will be the only fuels used in the CTG's and the duct burners. The fuels will be efficiently combusted in the CTG's. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure.

Natural gas is an inherently clean fuel and contains no ash. The ULSD fuel oil that will be combusted contains a minimal amount of ash making any conceivable add-on control technique for $PM/PM_{10}/PM_{2.5}$ either unnecessary or impractical. Table 16 contains a summary of PM_{10} emissions provided by GE to FP&L from GE 7FA units operating on natural gas or fuel oil.[12,13]

Table 16 - PM_{10} Emissions from GE 7FA Units (pounds per hour).

Fuel	Range	Average	Std. Deviation
Natural Gas - Front-half (filterable)	0 – 17	4.8	
Natural Gas - Back-half (condensable)	0 - 15	14	
Natural Gas Total	1 - 29	7.5	
Fuel Oil - Front-half (filterable)	1 - 20	10	4
Fuel Oil - Back-half (condensable)	3 - 21	14	6
Fuel Oil Total	4 - 37	24	9

Recent PM/PM_{10} emission limits are included in Table 15 above. Comparison is not simple because some of the limits represent filterable particulate matter while some of the limits represent the sum of filterable and condensable matter.

As previously discussed, there will be emissions of NO_X, SO_2 and SAM. These pollutants are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate which constitute $PM_{2.5}$ emissions. The NO_X control technology of SCR can increase $PM_{2.5}$ emissions due to formation of ammonium sulfates prior to exiting the stack.

Formation of ammonium species emitted from the stacks can be minimized by limiting the emissions of ammonia (known as slip). Elevated levels of ammonia slip may indicate a degrading catalyst. Almost all jurisdictions include a slip limit in conjunction with NO_X control technologies that rely on ammonia injection. A few permit limits are given in Table 15.

[12] Letter. Richani, B., General Electric to Gnecco, J., FP&L. Particulate Matter Emissions: GE 7241FA DLN Combustion Turbines. June 17, 2003.

[13] Letter. Richani, B., General Electric to Gnecco, J., FP&L. Expected Particulate Matter Emissions: GE 7FA DLN Combustion Turbines. September 19, 2003.

Table 17 is a summary of the initial compliance tests (2007) conducted on the previously mentioned FP&L Turkey Point 1,100 MW Combined Cycle Unit 5.[14] It has the same model (GE7FA.03) of CTG's and emission controls that will be included in the Polk 2 Combined Cycle. The ammonia emissions are higher when combusting firing fuel oil than when firing natural gas, because NO_X concentrations in the exhaust leaving the from the CTG's are greater. Much more ammonia is required to abate the additional NO_X and additional slip is a typical effect.

Table 17 - Emissions from FP&L Turkey Point Combined Cycle Unit 5 (ppmvd @15% O_2).

Unit	Mode	NO_X	CO	VOC (THC) [1]	NH_3	Opacity (%)
Unit 5A	Natural Gas	1.4	0.56	1.23	0.46	0
	Duct burner on	1.5	0.90	0.46	0.43	0
	Fuel oil	6.7	0.67	0.66	1.4	0
Unit 5B	Natural Gas	1.6	0.37	0.29	0.13	0
	Duct burner on	1.5	0.74	0.29	0.45	0
	Fuel oil	6.8	0.55	0.23	1.2	0
Unit 5C	Natural Gas	1.6	0.26	0.17	0.15	0
	Duct burner on	1.7	0.67	0.20	0.33	0
	Fuel oil	7.7	0.45	0.11	1.1	0
Unit 5D	Natural Gas	1.4	0.31	0.35	0.64	0
	Duct burner on	1.7	0.94	0.51	0.47	0
	Fuel oil	7.2	0.48	0.73	2.5	0

1. THC is a conservatively high estimate of VOC because it included methane and ethane not defined as VOC.

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

TEC proposes use of clean, low sulfur fuels and an opacity limit of 10% as BACT for $PM/PM_{10}/PM_{2.5}$ for all operating scenarios.

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

The Department proposes an ammonia slip limit of 5 ppmvd @15% O_2. This ammonia slip limit when combined with the use of clean fuels to minimize the formation of SO_2 and SAM and the SCR systems to minimize emissions of NO_X will minimize $PM_{2.5}$ emissions from the Polk 2 Combined Cycle.

The following conditions are established as the draft BACT standards for emissions of $PM/PM_{10}/PM_{2.5}$.

- The CTG's shall fire natural gas as the primary fuel, which shall contain no more than 2 gr/100 SCF of sulfur;
- The CTG's gas turbines may fire ULSD fuel oil as a restricted alternate fuel and the fuel oil shall contain no more than 0.0015% sulfur by weight and for no more than 48 hours/day and 3,000 hour/year for all four CTG's combined;
- The duct burners shall fire only natural gas, which shall contain no more than 2 gr/100 SCF of sulfur;
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.
- Ammonia emissions (slip) shall not exceed 5 ppmvd @15% O_2.

[14] Report. Air Hygiene International Inc. Emission Compliance Test for Turkey Point Unit 5. April 4-7, 2007.

4.2.5 Summary of Draft BACT Determinations for Polk 2 Combined Cycle

The draft BACT emission standards applicable to the Polk 2 Combined Cycle are summarized in Table 18 below. The requirements from Subpart KKKK are included where relevant. The limits are readily achievable based on the foregoing discussion and validated by the testing conducted at the nearly identical FP&L Unit 5 Combined Cycle and numerous similar installations in Florida.

Table 18 **- Draft BACT Determinations CTG/HRSG, TEC CC Conversion Project.**

Pollutant	Methods of Operation [a]	Emission Standard			BASIS [d]
		ppmvd [b]	lb/hour [c]	Compliance Method	
NO_X	Simple Cycle/Gas	15	N.A.	4-hour rolling, CEMS	KKKK
		9	68.4	24-hour block, CEMS	BACT
	Simple Cycle/Fuel Oil	42	370.7	4-hour rolling, CEMS	KKKK, BACT
	Combined Cycle/Gas	2.0 [f]	17.1	24-hour block, CEMS	BACT [c]
	Combined Cycle/Fuel Oil	8.0 [f]	70.5		
	Simple Cycle	96	N.A.	4-hour rolling, CEMS	KKKK
	Combined Cycle			30-day rolling, CEMS	
CO	Gas	4.1	17.6	Initial, Annual Stack Test	BACT
	Fuel Oil	8.0	39.0		
VOC	All	1.4	3.9	Initial Stack Test	BACT
SO_2, SAM	All	2 gr S/100 SCF of gas, 0.0015% S fuel oil [f]			BACT
$PM/PM_{10}/PM_{2.5}$	All	2 gr S/100 SCF of gas, 0.0015% S fuel oil [g]			BACT [g]
		Visible emissions shall not exceed 10% opacity for each 6-minute block average, as measured by EPA Method 9 [g]			
		Ammonia emissions shall not exceed 5 ppmvd @15% O_2 as measured by initial and annual stack tests [g]			

a. Simple = simple cycle and emissions measured in the bypass exhaust stack; Combined = combined cycle with or without use of duct burner and emissions measured in the HRSG exhaust stack.
b. ppmvd means parts per million by volume, dry and corrected to 15% oxygen.
c. The mass emission rate standards in pounds per hour (lb/hour) are based on 110% of the design heat input achievable at 20°F and represent the maximum allowable emission rate. No corrections of the stated lb/hour emission rate standards to account for site-specific conditions (temperature, pressure, humidity) are allowed.
d. Basis for the emission standard is either NSPS Subpart KKKK or Department's BACT determination.
e. The BACT emission standards for NO_X while operating in combined cycle are more stringent than the corresponding Subpart KKKK emissions standards of 15 and 42 ppmvd @15% O_2 on a 30-day rolling average for natural gas and fuel oil, respectively.
f. The applicant requested the stated sulfur fuel limits. These BACT values are more stringent and insure compliance with the corresponding Subpart KKKK SO_2 emission standard.
g. The listed work practices and limits on surrogates and precursors limit potential $PM/PM_{10}/PM_{2.5}$ (filterable and condensable).

4.3 Draft BACT Review, Cooling Tower (EU 019)

TEC proposes to include in the CC conversion project a 6-cell mechanical draft cooling tower with the following specifications: circulating water flow rate of 62,450 gallons per minute; Total Dissolved Solids (TDS) of 514 parts per million by weight; and drift eliminators with a drift rate of no more than 0.0005%.

Mechanical draft cooling towers emit a small amount of $PM/PM_{10}/PM_{2.5}$ emissions. A small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets because of direct contact between the cooling water and ambient air. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large size water droplets (e.g., greater than 200 microns) constitute the majority of the drift released. These large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential $PM/PM_{10}/PM_{2.5}$ emissions because of the fine particles formed by crystallization of the dissolved solids contained in the droplets.

The only feasible technology for controlling $PM/PM_{10}/PM_{2.5}$ from wet mechanical draft cooling towers is the use of drift eliminators. Drift eliminators rely on inertial separation caused by airflow direction changes to remove water droplets from the air stream leaving the tower. Drift eliminator configurations include herringbone (blade-type), wave form, and cellular (honeycomb) designs. Drift eliminator materials of construction include ceramics, fiber-reinforced cement, metal, plastic, and wood fabricated into closely spaced slats, sheets, honeycomb assemblies, or tiles.

The Department accepts the BACT proposed by TEC of a design drift rate of no more than 0.0005% of the circulating water flow rate. At this drift rate and with the expected TDS and flow rate of the circulating water, TEC estimates of 0.35 and 0.31 tons/year of PM and PM_{10} emissions, respectively, due to drift losses. $PM_{2.5}$ emissions were estimated at 0.0021 tons/year.

4.4 Draft BACT Review, Emergency Generator (EU 018)

One 568 kilowatt (kW) emergency generator is included for this project. As previously described, the emergency generator is subject to the provision of NSPS Subpart IIII and NESHAP Subpart ZZZZ, respectively. 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. NSPS 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 TEC are summarized in Table 19 below.

Table 19 - 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 applicant proposed and the Department accepts the emission standards in Table 19 as 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.

5 AIR QUALITY IMPACT ANALYSIS

5.1 Introduction

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 (as NO_2) have defined national and state AAQS, and the pollutants PM_{10}, SO_2, and NO_X 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.

5.2 Major Stationary Sources Near the Proposed Project

To provide some perspective on the relative scale of the proposed project, Table 20 to Table 24 list the largest stationary sources, by pollutant, in and around Polk County. The maximum expected future emissions in TPY from the proposed project are also shown for comparison.

The proposed project will increase emissions of the following PSD-pollutants at levels in excess of the respective PSD significant emission rates: $PM/PM_{10}/PM_{2.5}$, SO_2, CO, VOC, and NO_X. The fence line of the project site is shown in Figure 18 below.

Figure 18 - Fence Line of TEC Polk Power Station.

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 (as NO_2) have defined national and state AAQS, and the pollutants PM_{10}, SO_2, and NO_X 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.

Table 20 - Largest Sources of SO_2 (2011) Nearest to the Proposed Project Site (TPY).

Owner/Company Name	Site Name	County	Emissions
TEC	Big Bend Station	Hillsborough	9,106
Mosaic Fertilizer	New Wales Facility	Polk	7,901
Mosaic Fertilizer	Bartow Facility	Polk	4,426
C.D. McIntosh	Lakeland Electric	Polk	4,257
Mosaic Fertilizer	Riverview Facility	Hillsborough	3,034
FP&L	Manatee Power Plant	Manatee	1,653
CF Industries	Plant City Complex	Hillsborough	1,609
TEC	**Polk Power Station (existing facility)**	**Polk**	**1,263**
Mosaic Fertilizer	South Pierce Facility	Polk	1,124
Vulcan Materials Co	Florida Cement	Polk	665*
EnviroFocus	EnviroFocus	Hillsborough	307
Wheelabrator Ridge Energy	Ridge Generating Station	Polk	237
TEC	**Polk 2 Combined Cycle (future)**	**Polk**	**192**

Table 21 - Largest Sources of NO_X (2011) Nearest to the Proposed Project Site (TPY).

Owner/Company Name	Site Name	County	Emission
TECO	Big Bend Station	Hillsborough	4,630
C.D. McIntosh, Jr	Lakeland Electric	Polk	1,635
FP&L	Manatee Power Plant	Manatee	1,130
Hillsborough County	Hillsborough County Resource Recovery Facility	Hillsborough	875
TEC	**Polk 2 Combined Cycle (future)**	**Polk**	**745**
Progress Energy	Hines Energy Complex	Polk	628
TECO	Bayside Power Station	Hillsborough	460
TEC	**Polk Power Station (existing facility)**	**Polk**	**446**
Seminole Electric	Midulla Generating Station	Hardee	368
City of Tampa	McKay Bay Refuse-to-Energy	Hillsborough	330
Wheelabrator Ridge Energy	Ridge Generating Station	Polk	322
Mosaic Fertilizer	New Whales Facility	Polk	310

Table 22 - Largest Sources of CO (2011) Nearest to the Proposed Project Site (TPY).

Owner/Company Name	Site Name	County	Emission
TEC	Big Bend Station	Hillsborough	9,811
FP&L	Manatee Power Plant	Manatee	2,003
Cutrale Citrus Juices USA	Cutrale Citrus Juices USA	Polk	1,004
TEC	**Polk 2 Combined Cycle (future)**	**Polk**	**935**
Wheelabrator Ridge Energy	Ridge Generating Station	Polk	638
Citrosuco North America	Citrosuco North America	Polk	484
C.D. McIntosh, Jr	Lakeland Electric	Polk	453
Progress Energy	Hines Energy Complex	Polk	410
Peace River Citrus Products	Peace River Citrus Products	Desoto	371
Calpine Construction	Osprey Energy Center	Polk	355
Bartow Citrus Products	Bartow Citrus Products	Polk	299

Table 23 - Largest Sources of PM_{10} (2011) Nearest to the Proposed Project Site (TPY).

Owner/Company Name	Site Name	County	Emission
TEC	Big Bend Station	Hillsborough	786
TEC	**Polk 2 Combined Cycle (future)**	**Polk**	**309**
FP&L	Manatee Power Plant	Manatee	215
C.D. McIntosh, Jr	Lakeland Electric	Polk	186
TEC	Bayside Power Station	Hillsborough	170
Mosaic Fertilizer	New Whales Facility	Polk	142
Congra Foods	Congra	Hillsborough	81

Table 24 - Largest Sources of VOC (2011) Nearest to the Proposed Project Site (TPY).

Owner/Company Name	Site Name	County	Emissions
Cutrale Citrus Juices USA	Cutrale Citrus Juices USA	Polk	602
Citrus World Inc	Citrus World Inc	Polk	556
Citrosuco North America	Citrosuco North America	Polk	533
Peace River Citrus Products	Peace River Citrus Products	Desoto	277
Bartow Citrus Products	Bartow Citrus Products	Polk	247
TECO	Bayside Power Station	Hillsborough	162
Manatee County Utilities	Lena Road Landfill	Manatee	149
TEC	**Polk 2 Combined Cycle (future)**	**Polk**	**138**
Insulfoam Carlisle Construction	Insulfoam	Polk	127

The largest emission sources nearest to this proposed project are graphically depicted in Figure 19. The emissions from these facilities were used in the cumulative modeling discussed below.

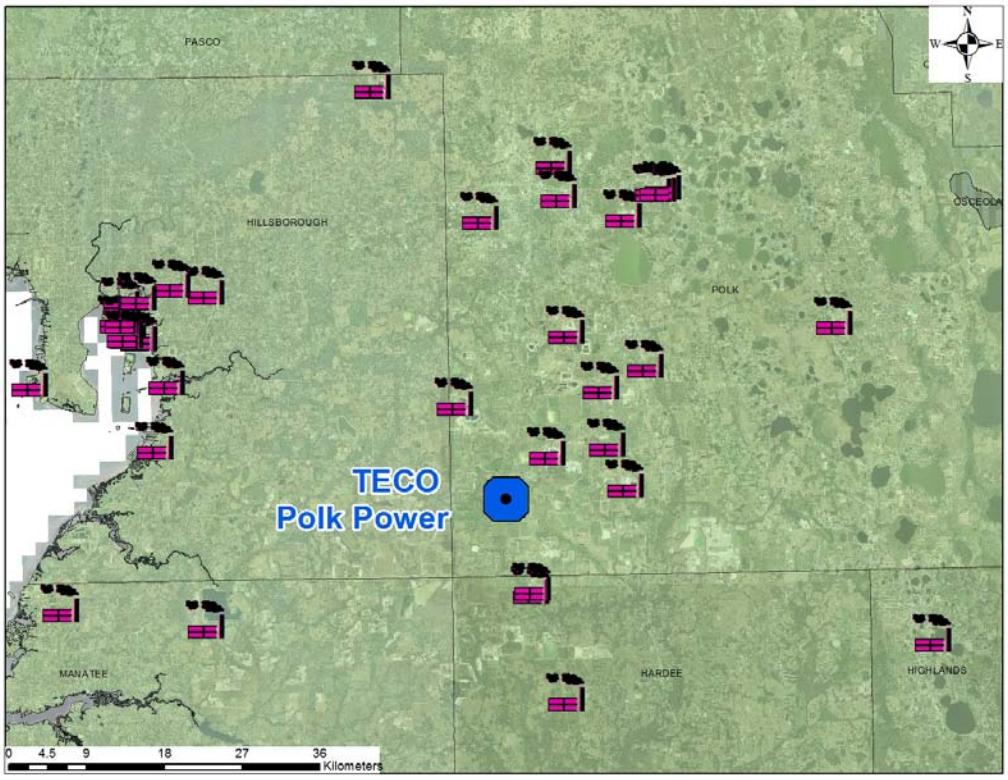

Figure 19 - Major Pollution Sources Nearest to the Proposed TECO Big Bend Project.

5.3 SO_2 and NO_X Emission Trends in the Southeast U.S. and Florida

There are regional efforts underway through the Federal Acid Rain Program and the Clean Air Interstate Rule (CAIR) to reduce emissions of NO_X and SO_2. Regional SO_2 emissions from existing power plants in the Southeast U.S. in 2007 and 2011 are listed in Table 25.

Table 25 - SO_2 Emission from Power Plants in the Southeast in 2007 and 2011 in tons/year.

State	2007	2011	Δ Since 2007 (%)
Alabama	447,189	179,250	267,939 (60%)
Florida	**317,582**	**91,380**	**226,202 (71%)**
Georgia	635,484	186,860	448,624 (71%)
Kentucky	379,837	246,396	133,441 (35%)
Mississippi	69,796	43,211	26,585 (38%)
North Carolina	370,826	73,507	297,319 (80%)
South Carolina	172,726	66,167	106,559 (62%)
Tennessee	237,231	120,325	116,906 (49%)
Total	**2,630,671**	**1,007,096**	**1,623,575 (62%)**

SO_2 emissions from power plants in the Southeast U.S. during 2011 were reduced by more than 1,600,000 tons/year and 62% referenced to emissions in 2007. SO_2 emissions from power plants in Florida during 2011 declined by more than 226,000 tons/year and 71%.

Regional NO_X emissions from existing power plants in the Southeast U.S. in 2007 and 2011 are listed in Table 26.

Table 26 - NO_X Emission from Power Plants in the Southeast in 2007 and 2011 (TPY).

State	2007	2011	Δ Since 2007 (%)
Alabama	122,374	61,398	60,976 (50%)
Florida	**184,171**	**54,748**	**129,423 (70%)**
Georgia	107,471	54,823	52,648 (49%)
Kentucky	174,840	92,051	82,789 (47%)
Mississippi	48,546	25,078	23,468 (48%)
North Carolina	59,417	41,348	18,069 (4%)
South Carolina	46,062	23,262	17,229 (30%)
Tennessee	102,886	26,838	76,048 (74%)
Total	**845,767**	**379,546**	**396,690 (45%)**

NO_X emissions from power plants in the Southeast U.S. during 2011 were reduced by nearly 400,000 tons/year and 45% referenced to emissions in 2007.

The Department graphed gross electrical generation and the SO_2 and NO_X emission trends during the period 1998-2011 from power plants in Florida that report their emissions to the EPA Clean Air Markets database. The results are summarized in Figure 20. By comparison with the overwhelming downtrend of regional and local emissions of SO_2 and NO_X, the emission increases from the Polk 2 Combined Cycle Station are very low.

During the period 1998-2011 there was a *decrease* from 818,159 to 24,700 tons/year (89%) in SO_2 emissions from the FP&L fossil fleet in peninsular Florida. Similarly there was a *decrease* from 335,647 to 54,748 tons/year (84%) in NO_X emissions. For comparison purposes, the future project will emit 192 tons/year of SO_2 and 745 tons/year of NO_X. These additional emissions from the proposed project will not affect the general, overwhelming and continuing downward trend in $PM_{2.5}$ precursors. Similarly, it will not have an appreciable effect on local or regional $PM_{2.5}$ concentrations.

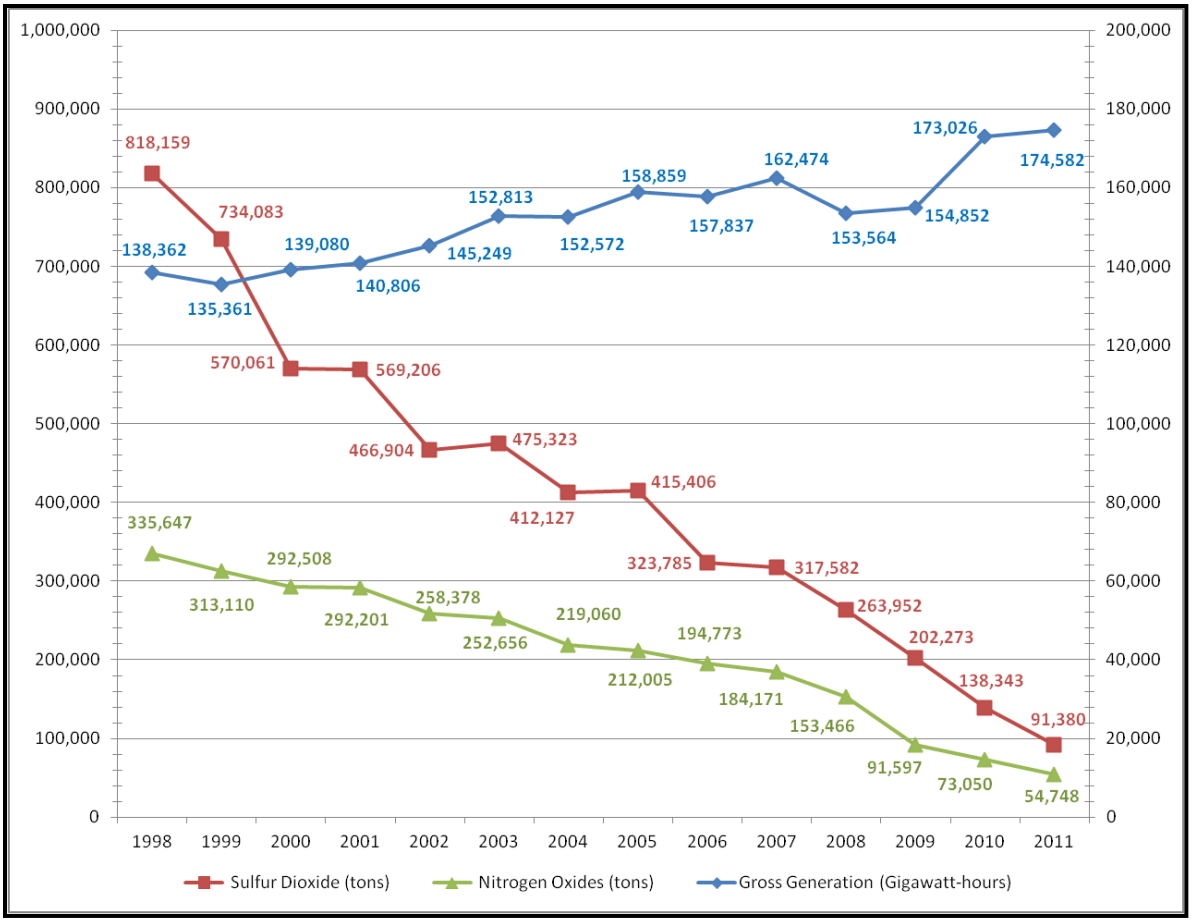

Figure 20 – Gross Electric Generation, SO_2, NO_X Emissions from Florida Acid Rain Units, 1998-2011.

5.4 Ambient Air Monitoring Surrounding Proposed Facility

The State ambient air monitoring network operated by the Department and its partners (local air pollution control programs) includes monitors in counties containing over 90% of the population. Refer to Figure 21 and Figure 22 indicate, the ambient air monitoring sites are concentrated in areas of high population density, along the coasts and near major highways in the interior portion of the state.

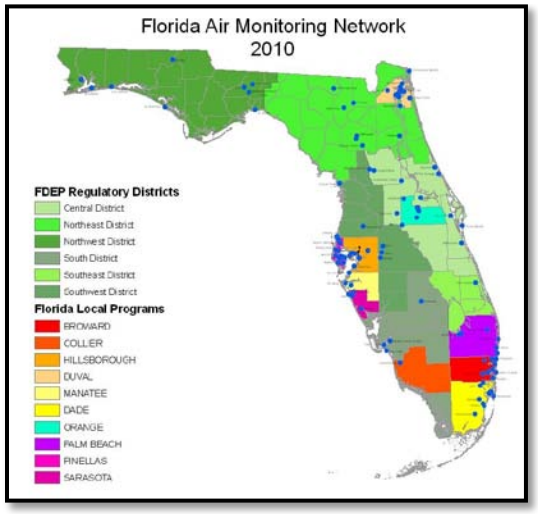

Figure 21 – Air Monitoring Network.

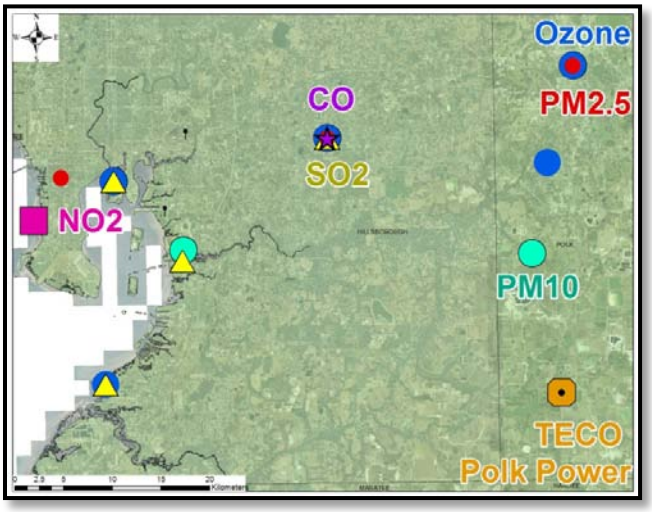

Figure 22 - Monitors Closest to Proposed Project Site.

The monitors listed in Table 27 are used to estimate the existing air quality in the area of the proposed facility. The monitors chosen are most representative of the proposed site for due to their close proximity.

Table 27 - Ambient Air Quality Measurements Nearest to the Project Site (2008-2011).

Pollutant	Location (Site Number)	Averaging Period	Ambient Concentration			
			Compliance Period	Value	Standard	Units [a]
PM_{10}	Polk Co (D1050010)	24-hour [b]	2010	33	150	$\mu g/m^3$
		Annual [c]	2010	16.3	50	$\mu g/m^3$
$PM_{2.5}$	Polk Co (D1056006)	24-hour [d]	2009-2011	15	35	$\mu g/m^3$
		Annual [e]	2009-2011	7.5	15	$\mu g/m^3$
SO_2	Hillsborough Co (L0573002)	1-hour [i]	2009-2010	15	75	ppb
		3-hour [f]	2010	36.7	1300	$\mu g/m^3$
		24-hour [f]	2010	7.9	260	$\mu g/m^3$
		Annual [c]	2008-2010	3.4	60	$\mu g/m^3$
NO_2	Hillsborough Co (L0571065)	Annual [c]	2011	5.1	53	ppb
		1-hour [h]	2009-2011	37	100	ppb
CO	Hillsborough Co (L0573002)	1-hour [f]	2011	0.9	35	ppm
		8-hour [g]	2011	0.5	9	ppm
Ozone	Polk Co (D1056006)	8-hour [g]	2011	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.
e. Three year average of the arithmetic annual means.
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
i. Three-year average of the annual 99th percentile maximum daily 1-hour value

The ambient air measurements listed in Table 27 above are values that do not contain 'exceptional events'. An 'exceptional event' is defined by EPA in accordance with 40 CFR 50.14 as an event that affects air quality, is not reasonably controlled or preventable, is an event caused by human activity that is unlikely to recur at a particular location or natural event. Such events include complex wildfires, driven by prolonged drought conditions and other large-scale meteorological patterns. The Department has evaluated several $PM_{2.5}$ episodes and found that they occur in conjunction with certain meteorological conditions, combined with very high SO_2 emissions and sulfate deposition.

5.5 Existing Ambient Air Quality Near Project Site – $PM_{2.5}$ 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 authorized agricultural fires, natural drought-related fires and natural emissions from vegetation. These two precursors participate in photochemical reactions that occur on an area-wide basis and are highly dependent on meteorological factors.

Ozone limits and measurements in Table 27 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 given in Table 27 and Figure 23.

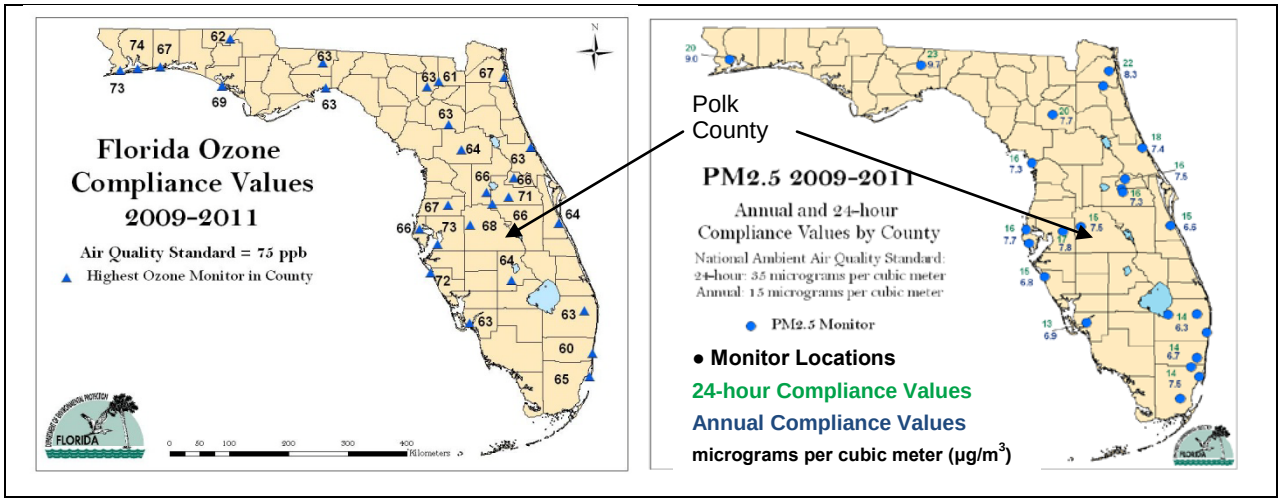

Figure 23 – Florida Ozone Compliance Values. **Figure 24 – Florida $PM_{2.5}$ Compliance Values.**

$PM_{2.5}$ (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.

$PM_{2.5}$ limits and measurements are summarized on three-year blocks, rolled annually. The reported 24-hour compliance value for $PM_{2.5}$ is 15 µg/m^3 as indicated in Table 27 for the Polk County site, and was calculated by taking the average 24-hour readings recorded each day during the three years (2009-2011). 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 (2009-2011) was also calculated and then the mean of the three averages (7.5 µg/m^3) was reported as the annual compliance value and compared with the standard of 15 µg/m^3. Comparisons of the 24-hour and annual $PM_{2.5}$ compliance values for the Polk County station are shown in Figure 24 along with compliance values for the rest of the state. The results indicate that Polk County is in attainment with the applicable ozone and $PM_{2.5}$ AAQS.

5.6 Air Quality Impact Analysis

5.6.1 Significant Impact Analysis

Significant Impact Levels (SIL) are defined for PM_{10}/$PM_{2.5}$, SO_2, CO, and NO_X. A significant impact analysis is performed on each of these pollutants to determine if a project can cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a significant impact analysis, the applicant has used the proposed project's maximum short-term emissions as inputs to the models. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SIL for the PSD Class I and II Areas.

If this modeling for a particular pollutant shows ground-level increases less than its SIL, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SIL, then additional modeling including emissions from all major facilities or projects in the region (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS and PSD increments for those pollutants.

For the Class II analysis, a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 25-meter intervals around the facility fence line. The remaining receptor grids consisted of densely spaced Cartesian receptors at 100 meters apart extending out to 3 km meters, 250-meters apart extending out to 6 km, 500 meter spacing was placed out to 15 km, 1000 meters out to 30 kilometers.

The EPA-approved version of CALPUFF was used by the applicant to address the significant impact on two PSD Class I areas: the Chassahowitzka National Wildlife Area (CNWA) and the Everglades National Park (ENP). The CWNA is located 117 km northwest of the project, and contains 113 discrete receptors used in the modeling. The ENP is located 211 km southeast of the project, and contains 901 discrete receptors used in the modeling. The receptor locations were provided by the National Park Service.

The results of the applicant's significant impact analysis are shown below in Table 28 and Table 29.

Table 28 - Maximum Predicted Air Quality Impacts from the Proposed Project for Comparison to the PSD Class II SIL.

Pollutant	Averaging Time	Max Predicted Impact [a] ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Ambient Air Standards ($\mu g/m^3$)	Significant Impact?
PM_{10}	Annual	0.179	1	50	No
	24-Hour	2.8	5	150	No
$PM_{2.5}$	Annual	0.018	0.3	15	No
	24-Hour	2.8	1.2	35	Yes
SO_2	Annual	0.118	1	60	No
	24-Hour	1.43	5	260	No
	3-hour	5.7	25	1300	No
	1-hour	8.6	7.9 [b]	196	Yes
NO_2 [a]	Annual	0.122	1	100	No
	1-Hour	47.3	7.6	189	Yes
CO	1-hour	26.2	2,000	40,000	No
	8-hour	97.3	500	10,000	No

a. Assumes 80 and 75% conversion of NO_X to NO_2 for the 1-hour and annual averaging periods, i.e., the tier 2 modeling approach.

Maximum predicted impacts are greater than the applicable SIL for the Class II area for $PM_{2.5}$ 24-hour, and SO_2 & NO_2 1-hour averaging periods. Consequently, a full AAQS analysis (in which the PSD Increment analysis considering all sources of these pollutants in the area) is required.

Table 29 - Maximum Air Quality Impacts of TECO Polk Power for Class I SIL.

Pollutant	Averaging Time	Max. Predicted Impact ($\mu g/m^3$)		Class I SIL □($\mu g/m^3$)	Significant Impact?
		CNWA	ENP		
$PM_{2.5}$	Annual	0.0034	0.00122	0.04 [a]	No
	24-hour	0.067	0.037	0.07 [a]	No
NO_2 [a]	Annual	0.0031	0.00067	0.1	No
SO_2	Annual	0.0018	0.00058	0.1	No
	24-Hour	0.039	0.017	0.2	No
	3-Hour	0.17	0.057	1.0	No

a. Assumes 75% conversion of NO_X to NO_2, i.e., the Tier 2 modeling approach.

For the Class I analysis shown in Table 29, the maximum predicted impacts of due to the proposed project are all predicted to be less than the proposed PSD Class I significant impact levels for both Class I areas in all pollutants averaging periods. Thus, no cumulative impact analyses were performed since the project's impacts are expected to be well below the Class I SIL.

5.6.2 Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is performed for those pollutants with listed significant monitoring concentrations (de minimus levels). These are levels, which, if exceeded, would potentially require pre-construction ambient monitoring. As shown in Table 30 below, the maximum predicted impacts due to the proposed project are predicted to be below the PSD de minimis concentration levels for all pollutants.

Table 30 – Maximum Air Quality Impacts for Comparison to the De Minimis Concentration Levels.

Pollutant	Averaging Time	Max Predicted Impact (μg/m^3)	De Minimis Level (μg/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	2.8	10	No
$PM_{2.5}$	24-hour	2.8	4	No
NO_2	Annual	0.122 [a]	14	No
SO_2	24-hour	1.43	13	No
CO	8-hour	97.3	575	No

a. Assumes 75% conversion of annual NO_X to NO_2, i.e., the tier 2 modeling approach.

Because the predicted maximum $PM_{2.5}$, $PM_{10,}$ and SO_2 concentrations are less than the de minimis levels, a pre-construction ambient monitoring analysis is not required.

5.6.3 Models, Emissions Data, and Meteorological Data Used in the AAQS, PSD Increments Analysis

The EPA-approved AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Areas. The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

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. Direction specific downwash parameters were used for all sources for which downwash was considered.

Emissions data used in the modeling analysis were obtained from the DEP ARMS database, DEP permit files, and recent PSD permit reviews. Emissions data for the new proposed facility derive from the proposed maximum permit limits imposed on the facility for each pollutant.

The AERMET meteorological data used for this analysis consisted of a concurrent 5-year period of hourly surface weather observations from the Orlando International Airport (MCO) and twice-daily upper air soundings from the Tampa International Airport (TPA), respectively. The 5-year period of meteorological data is from 2006 through 2010. The location of the proposed facility is 64 miles to the north-northeast of MCO and 38 miles to the west-northwest of TPA. The meteorological dataset was prepared by the department using the current versions of AERMET and AERMINUTE.

Multi-source PSD Class II Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration. No increment standards currently exist for 1-hour NO_X or SO_2. However, a PSD increment analysis was required for $PM_{2.5}$ for the 24-hour averaging period. The maximum predicted, second high short-term average PSD Class II area impacts

from this project and other increment-consuming sources in the vicinity of the proposed facility are shown in Table 31 below.

Table 31 - PSD Class II Increment Analysis.

Pollutant	Averaging Time	Max Predicted Impact (μg/m^3)	Allowable Increment (μg/m^3)	Impact Greater Than Allowable Increment?	% Increment Consumed
$PM_{2.5}$	24-hour	7.29	9	No	81%

AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum modeled concentration. This "background" concentration is based on existing monitoring data for each pollutant and representative of the area of the proposed source. This background is intended to account for sources of a particular pollutant that are not explicitly modeled. Since no attempt is typically made to subtract out the impacts due to the explicitly modeled sources on these monitored values, there is some amount of double-counting reflected in the total concentration (modeled + background) used to compare with the appropriate AAQS.

An evaluation of the emission inventories for background sources considered in the PSD application for the TECO Polk Power modification was performed to determine whether the method used to eliminate background sources from NAAQS compliance modeling demonstration was reasonable. All background sources within the significant impact area of the project were included in the modeling demonstration.

Only major sources (of 100 TPY or greater) and increment consuming sources were included in the modeling of each pollutant. The applicant modeled sources that were within the Significant Impact Area (SIA) + 10 km for each pollutant and averaging period. Sources from a 35 km radius from TECO Polk Power were included in the NO_2 modeling, sources out to 15 km were included for SO_2, and sources out to 45 km were included for $PM_{2.5}$.

The sources that are explicitly modeled include the subject facility and nearby sources that are judged to potentially have a significant interaction with the proposed facility. The appropriate calculations for the modeled and background values are different for each pollutant, but generally follow the form for compliance with the AAQS. Table 32 shows the results of this analysis. As shown in the below table, emissions from the proposed facility are not expected to cause or contribute to a violation of an AAQS.

Table 32 - Ambient Air Quality Impacts.

Pollutant	Averaging Time	Major Sources Impact (μg/m^3)	Background Conc. (μg/m^3)	Total Impact (μg/m^3)	Total Impact > AAQS?	AAQS (μg/m^3)
$PM_{2.5}$	24-hour	27.1	15	42.1	Yes	35
SO_2	1-hour	205	39.3	244.3	Yes	195
NO_2	1-hour	227	69.6	296.6	Yes	188

The above table shows potential exceedances of NAAQS for each pollutant. However, upon closer inspection, the proposed facility modification does not have a significant contribution to any of the modeled exceedances. A significant contribution is defined by the SIL of each pollutant. Therefore, all modeled exceedances showed that TECO Polk Power's proposed facility modification contribution showed results less than the SIL for all modeled exceedances.

Based on the results of the air quality modeling analysis, the operation of the proposed facility will not cause or contribute to a violation of an ambient air quality standard or maximum allowable concentration increase (PSD increment).

Ozone Modeling

Projects with VOC and NO_X emissions greater than 100 TPY are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC and NO_X emissions from the project to be 138 and 735 TPY respectively.

The ozone monitoring data in Polk County is from a site only 33 km south of the proposed project and is sufficient for the purposes of background values at the TEC Polk Power site.

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.). Ambient ozone levels in Polk County are primarily due to ozone transport from upwind areas. Despite significant increases in population and motor vehicle activity, ambient ozone air quality in Florida has improved over the last 5 years due to improvements in motor vehicle emissions rates. Continued reductions in average motor fleet emissions would be expected to further improve ozone air quality. In addition, implementation of CAIR has resulted in significant actual reductions in existing power plant NO_X emissions throughout Florida. As previously discussed, the NO_X emission rates across Florida have declined by more than 200,000 tons/year over the last decade.

To conclusively prove whether or not 735 TPY of NO_X and 138 TPY of VOC will not cause or contribute to a violation, a very sophisticated and expensive model (such as the EPA CMAQ) would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. The effects of the proposed project on ozone would not be measurable considering the overwhelming effects of the statewide reductions and the climatological variability. The uncertainty in any regional ozone model would be greater than the contribution from this project. Polk County is projected to remain in compliance with the ozone ambient quality standard due to the continued significant reductions in regional motor vehicle and power plant emissions.

5.7 Additional Impacts Analysis

5.7.1 General Description with Regard to Growth and Air Quality Impacts Since 1977

U.S. Census data shows that the population of the Polk County has increased by approximately 24.4 percent between 2000 and 2010. The 2010 estimated population of Polk County is 602,095. In 2004, Polk County was ranked as the eighth most populous county with a population density of 334.9 persons per square mile, which is within 5 percent of the average population density of Florida. Population growth in Polk County had been increasing at a rate of approximately 7 percent higher than the rate for the rest of Florida from 2000 to 2010. Major Polk County population areas are Lakeland and Bartow.

Although there has been significant population growth in Polk County and Florida over the past 25 years, improvements in motor vehicle emissions controls, use of clean transportation fuels, reductions in electric utility emissions due to the ARP, and well controlled stationary sources have resulted in air quality in Polk County that is currently below the national and Florida AAQS for all pollutants. As evidenced by the Polk County air quality index data, air quality in Polk County has been steadily improving over the past 10 years. The number of days per year with good air quality in Polk County increased from 281 in 2001 to 317 in 2011.

Accordingly, it is concluded that air quality in Polk County has not deteriorated since 1977. As discussed previously, the emissions associated with the Project will result in air quality impacts that are well below the national and Florida AAQS.

5.7.2 Growth-Related Impacts Due to the Proposed Project

According to the applicant, impacts associated with construction with the project will be minor. During the 32-month construction period, Tampa Electric will employ an average of 250 workers. The

temporary increase in vehicle traffic and emissions in the area would be insignificant, as would any temporary increase in vehicular emissions.

The project is being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the Project are anticipated. When operational, the project will not require any additional fulltime workers. The increase in natural gas and ULSD fuel oil due to the operation of the project will have no major impacts on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

5.7.3 Impact on Soils, Vegetation, and Wildlife

Potential impacts to soils, vegetation, and wildlife resources resulting from the Project operation include the effects of air emissions. Table 33 summarizes the modeled air quality impacts due to the Project for all relevant Class I and II areas. In addition, Table 33 provides predicted maximum annual nitrogen and sulfur deposition values at the Class I areas of concern. As previously discussed, the Project will employ state-of-the-art technology and emissions controls. Maximum air quality impacts in the vicinity of the Project will be well below the applicable national and Florida AAQS. Given the resulting low emissions rates and low air quality impacts, potential detrimental effects on soils, vegetation, and wildlife will be insignificant.

Table 33 – Soils and Vegetation Screening Modeling.

Parameter	Averaging Period	AERMOD Predicted Concentration (µg/m^3)	USEPA Screening Level (µg/m^3)
SO_2	1-hour	56	917
	3-hour	106	786
	Annual	3	18
NO_2	4-hour	50	3760
	8-hour	45	3760
	1-month	8	564
	Annual	3	94

The predicted concentrations for SO_2 and NO_2 are less than the screening levels, thereby demonstrating that impacts to soils and vegetation will be negligible.

5.7.4 Impact on Wildlife

The applicant thoroughly discussed possible project impacts on wildlife at length in the application. Refer to Chapter 9 at the following link: Polk 2 Combined Cycle Application The Department concludes that any impact will be minimal because the ground level concentrations of pollutants emitted from the project will be orders of magnitude less than the values associated with respiratory stress or decreases in abundance. Further, emissions of persistent pollutants or pollutants that are magnified within the ecosystem (such as mercury) are minimal. Any possible impact is overwhelmed by the beneficial effects of the ongoing reductions in regional and state-wide emissions of pollutants from existing power plants as discussed in Section 5.3 above.

5.7.5 Class I Area Impacts- Air Quality Related Values (AQRV)

An AQRV analysis was conducted to assess the potential risk to AQRV at the Chassahowitzka National Wildlife Area (CNWA) Everglades National Park (ENP), due to the proposed emissions from the proposed facilities. The CWNA is located 117 km northwest and the ENP is located 211 km southeast of the project. The applicant's discussion is available at the link given above.

In October 2010, the Federal Land Managers (FLMs), consisting of the National Park Service, U.S. Forest Service, and U.S. Fish and Wildlife Service, issued the Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report- Revised (2010). Based on the report, the FLM's

recommended initial screening criteria that would exempt a source from AQRV impact review based on a source's annual emissions and distance from a Class I areas.

The FLM's will consider a source located greater than 50 km from a Class I area to have negligible impacts with respect to Class I AQRVs if its total SO_2, NO_X, PM_{10}, andH_2SO_2 annual emissions in tons/year based on 24-hour maximum allowable emissions), divided by the distance (km) from the Class I area (Q/D) is 10 or less. The FLMs would not request any further Class I AQRV impact analyses from such sources.

As shown in Table 34, the Q/D value of 10 is exceeded at the CNWA Chassahowitzka National Wildlife Area (CNWA), but at the Everglades National Park (ENP). Therefore, an AQVR analysis is required only for the CNWA.

Table 34 – FLAG Guidance Screening Analysis.

	NO_X	SO_2	H_2SO_4	PM_{10}	Total
Potential Emissions (Q) (tons/year)	618.5	215.5	61.3	332.9	**1,228.2**
Determination of AQRV Analysis		**CNWA**		**ENP**	
Distance from Project (D) (km)		116.9		211.8	
FLAG screening ratio (Q/D) (tons/year/km)		10.5		5.8	
Greater than FLAG guidance?		**Yes**		**No**	

An assessment of the project regional haze impacts was conducted using the current EPA-approved CALPOST program, background light extinction Method 8, with sub-mode 5 monthly relative humidity data for the CNWA in accordance with current FLM guidance. The assessment evaluated the 98th percentile of the 24-hour average impacts. The results are summarized in Table 35.

Table 35– AQVR Analysis.

Maximum 24-Hour Average 98th Percentile Impacts	Background	% of Light Extinction	FLM's Visibility Threshold
0.297	22.9	1.3%	5%

According to the analysis, 98% of the time, the light extinction potentially caused by the TEC Polk 2 Combined Cycle will be less than 1.3%. This value is less than the FLM's visibility threshold of 5% at the 98th percentile.

6 PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed 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 complete application, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. Leigh Ann Pell is the project engineer responsible for preparing the draft permit conditions. She may be contacted at leigh.pell@dep.state.fl.us and 850-717-9033. Melody Lovin is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at melody.lovin@dep.state.fl.us and 850-717-9084, or by mail at the Department's Office of Permitting and Compliance at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.