TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Orlando Utilities Commission
Curtis H. Stanton Energy Center Units 1 & 2

Low Nitrogen Oxides Burners and Overfire Air Project

Orange County

DEP File No. 0950137-015-AC, PSD-FL-395

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Permitting South

November 21, 2007

1. GENERAL FACILITY DESCRIPTION

Facility Description and Location

The OUC Curtis H. Stanton Energy Center is located in Orange County, Southeast of Orlando and North of Highway 528 at 5100 South Alafaya Trail. The site is located 144 km southeast from the Chassahowitzka National Wildlife Area; the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area. The UTM coordinates for this site are 483.6 km East and 3151.1 North. The location of the OUC Stanton Energy Center is shown in Figure 1.

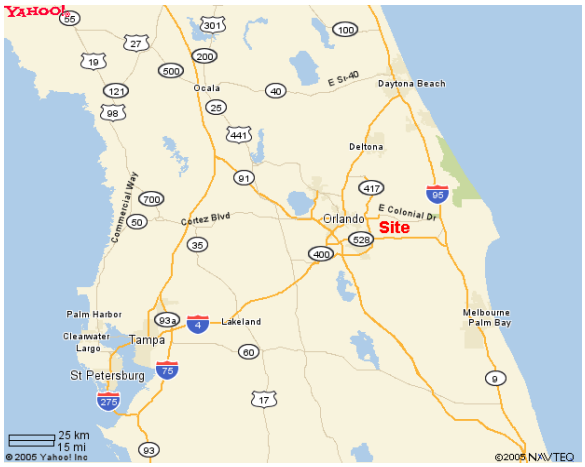

Figure 1. OUC Curtis H. Stanton Energy Center Location and Stanton Units 1 and 2.

The OUC Stanton Energy Center presently consists of two fossil fuel-fired steam electrical generating units and a combined cycle unit. Fossil fuel-fired steam electric generating Units 1 and 2 (468 megawatts-MW each) began operation in 1987 and 1996 while Combined Cycle Unit A (640 MW) began operation in 2003.

Table 1. OUC Curtis H. Stanton Energy Center SIC Codes

STANDARD INDUSTRIAL CLASSIFICATION CODES (SIC)		
Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

Key Regulatory Categories

The key regulatory provisions applicable to Stanton Unit s 1 and 2 are:

Title I, Part C, Clean Air Act (CAA): The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. It is classified as a "fossil fuel-fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 Prevention of Significant Deterioration (PSD) Major Facility Categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year, therefore the facility is classified as a "major stationary source" of air pollution with respect to Rule 62-212.400 F.A.C., Prevention of Significant Deterioration of Air Quality.

Title I, Section 111, CAA: Units 1 and 2 are subject to Subpart Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) of the New Source Performance Standards in 40 CFR 60.

Title I, Section 112, CAA: The facility is a "Major Source" of hazardous air pollutants (HAP).

Title IV, CAA: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V, CAA: The facility is a Title V or "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 per year (TPY). Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

CAIR: The facility is subject to the Federal Clean Air Interstate Rule (CAIR) in accordance with the Final Department Rules issued pursuant to CAIR as implemented by FDEP in Rule 62-296.470, Florida Administrative Code (FAC).

CAMR: The facility is subject to the Federal Clean Air Mercury Rule (CAMR) implemented by the Department in Rule 62-296.480, F.A.C.

Siting: The facility was originally certified pursuant to the power plant siting provisions of Chapter 62-17, F.A.C.

Application Processing Schedule

02/05/07: Received application to construct, install or improve low NO_X burners (LNB), overfire air (OFA), forced oxidation, ash loadout system and scrubber on Units 1 and 2.

03/07/07: Application determined incomplete. Sent request for additional information (RAI).

08/09/07: Received partial responses to RAI.

09/04/07: Received additional responses to RAI including Best Available Control Technology (BACT) proposal for carbon monoxide (CO), revised application pages for PSD application, air dispersion modeling, etc.

09/06/07: Separated out requests into different projects including the present one for the LNB and OFA systems.

09/20/07: Received PSD permit fee of $7,500 to process the application for the LNB and OFA systems. Determined it is complete.

11/21/07: Distributed public notice package including the draft PSD permit for the LNB and OFA project.

Description of Units 1 and 2 and Original NO_X and CO Control Equipment

Unit No. 1 consists of a coal-fueled Babcock and Wilcox boiler/steam generator (Model RB 611) and steam turbine, which drives a generator with a nameplate rating of 468 Megawatts. Fuel oil No. 6 is used for startup and flame stabilization. Biogas from a nearby landfill is also combusted. Air pollution control equipment consists of an electrostatic precipitator (ESP) for PM/PM_{10} and a wet flue gas desulfurization (WFGD) system, i.e., a scrubber for SO_2.

The initial requirements for Unit 1 were from the BACT determination and permit PSD-FL-084 issued for Units 1 and 2 in May 1982. Unit 1 is also subject to the requirements of Subpart Da.

The specific controls for NO_X and CO were described in the technical evaluation as follows:

> *"The applicant has proposed to reduce NO_X emissions by combustion control, not combustion control. The boiler manufacturer will guarantee that the NO_X emissions from the proposed boilers will meet the NSPS" i.e. the Subpart Da limit of 0.6 pounds per million Btu heat input (lb/mmBtu) on a 30-day basis).*
>
> *"Good operation practice and excess air control will reduce CO emissions to minimum levels. There will be no post-combustion CO control for the proposed boiler" (also no limits were specified)."*

Unit No. 2 consists of a coal-fueled Babcock and Wilcox boiler/steam generator (Model RB 621) and steam turbine, which drives a generator with a nameplate rating of 468 Megawatts. Fuel oil No. 6 is used for startup and flame stabilization. Biogas from a nearby landfill is also combusted. Air pollution control equipment includes an ESP for PM/PM_{10} and a scrubber for SO_2. In addition, Unit 2 includes low NO_X burners (LNB), overfire air (OFA) and a selective catalytic reduction (SCR) system for NO_X control. The more stringent requirements for Unit 2 are from a modification of PSD-FL-084 dated December 1991.

The Unit 2 NO_X limitation is Unit 2 is 0.17 lb/mmBtu on a 30-day basis by SCR per the BACT determination accompanying the modification of PSD-FL-084. There is a CO limitation applicable to Unit 2 of 0.15 lb/mmBtu based on "the use of combustion controls to minimize incomplete combustion". In its analysis, EPA noted some lower CO determinations between 0.02 and 0.11 lb/mmBtu. However in view of the use of LNB, EPA concluded:

> *"In regards to changing boiler conditions, the major impact would be environmental, i.e., decreasing CO and VOC could cause a resultant increase in NO_X emissions. The emissions levels proposed by the applicant, 0.15 lb/mmBtu for CO and 0.015 lb/mmBtu for VOC is based upon the utilization of low NO_X burners."*

Each unit has five elevations, each containing six dual register burners for a total of 30 burners per unit. The following figure shows the key additional equipment (LNB, OFA, SCR) on Unit 2.

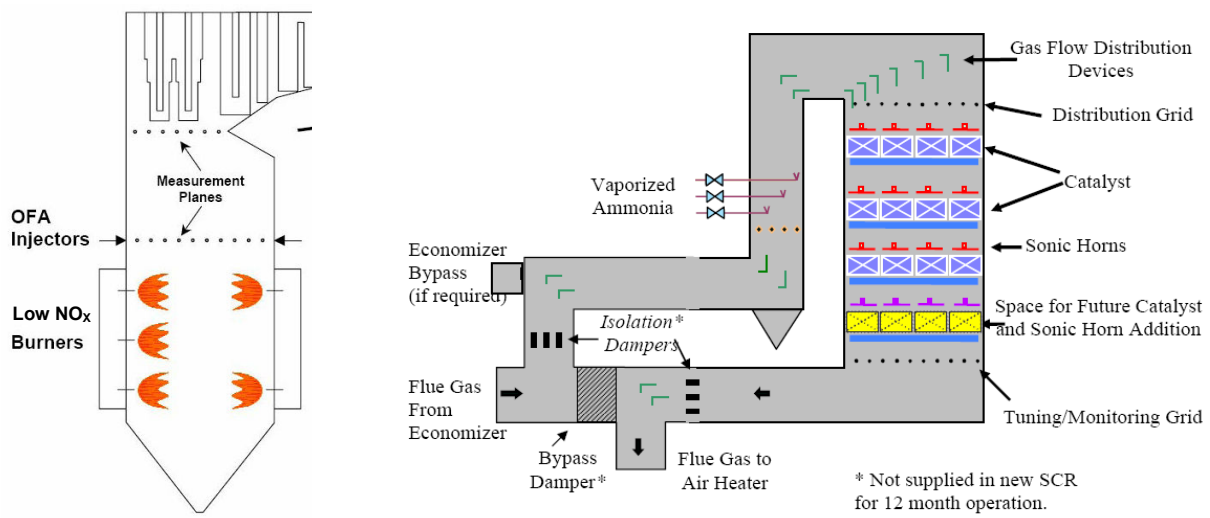

Figure 2. An opposed wall-fired furnace and an SCR system such as in OUC Unit 2

2. PRINCIPLES OF LOW NO_X BURNERS AND OVERFIRE AIR

The following discussion is largely based on information provided by the applicant's consultant, Black & Veatch (B&V) as well as a cooperative study by the Department of Energy (DOE) and Sunflower Electric Power Cooperative (SEPC) of Kansas and the Department's analysis.

LNB systems control the formation and emission of NO_X through a form of staged combustion. The basic NO_X reduction principles for LNB are to control and balance the fuel and airflow to each burner also to control the amount and position of secondary air in the burner zone so that fuel devolatization and high temperature zones are not oxygen rich. Mixing of the fuel and the air by the burner is controlled in such a way that ignition and initial combustion of the coal takes place under oxygen deficient conditions, while a portion of the combustion air is mixed in a delayed fashion along the length of the flame.

The objective of this process is to drive the fuel bound nitrogen (FBN) out of the coal as quickly as possible, under conditions where no oxygen is present, and where it will form molecular nitrogen (N_2), rather than oxidized to NO_X. Any N_2 escaping the initial fuel rich region has a greater opportunity to be converted to NO_X as the combustion process is completed.

The net result of staged combustion is usually longer and/or wider flames, due to this delayed mixing process. This is also one of the main reasons why low NO_X combustion is normally associated with the potential for *increased carbon in ash and higher CO emissions*, as the combustion process begins to encroach on cooled boiler surfaces. This is particularly true of wall fired boiler systems, where, compared to tangential firing, the combustion process must be confined to well defined flame zones, and is less able to make maximum use of the available burner zone volume.

Under conditions in which the target NO_X level is not achieved by LNB, it may be necessary to further stage the combustion. In this case, not all the air required for combustion is introduced through the LNB. The remaining air required for complete combustion is introduced at a higher elevation in the boiler where the temperature is lower, thus limiting the production of additional NO_X. This is the principle of OFA operation. The OFA is necessary to achieve the desired levels of carbon burnout and to limit CO emissions.

There are varying designs and degrees of aggressiveness with which LNB and percentage of OFA that can be practiced. It is even possible to add additional burners at higher elevation in the furnace to effect the process of *reburn* to further reduce NO_X and then to follow up with additional OFA.

3. PROPOSED LOW NO_X BURNER AND OVERFIRE AIR PROJECTS

To provide full flexibility in implementing the federal cap and trade program for NO_X under the Clean Air Interstate Rule (CAIR), the applicant proposes to install a LNB and OFA on Unit 1 and to perform modifications and improvements on the existing LNB and OFA systems in Unit 2. The work on Unit 1 will be conducted during an early 2008 outage while the work on Unit 2 will occur during an outage in late 2008.

The exact scope of work was not specified and the selected vendor, Siemens, has some latitude in achieving the technical specifications. The key vendor guarantee for each LNB/OFA is 0.28 lb NO_x/mmBtu for each unit after the LNB/OFA project at full load and exclusive of an SCR system.

In recent years, NO_X emissions from Unit 1 have been approximately 0.41 lb/mmBtu. The expectation is that the LNB/OFA project will substantially decrease NO_X emissions. Recent emissions of NO_X from Unit 2 have been approximately 0.16 lb/mmBtu with the existing LNB/OFA/SCR control strategy. The LNB/OFA improvements for Unit 2 will make it easier to achieve the emission limit of 0.17 lb/mmBtu and allow achievement of even lower emissions.

The project will also facilitate achievement of lower emissions based on OUC's CAIR strategy and to comply with a separate NO_X cap on Units 1 and 2 required by the permit PSD-FL-373 by the startup of Stanton Unit B. The specific condition requires that:

> *"The combined NO_X emissions from existing coal fired boiler steam electric generating Stanton Unit 1 and Stanton Unit 2 shall not exceed 8,300 tons per year on a 12-month rolling total beginning the first month of first fire of Unit B and thereafter. Total NO_X emissions shall be based on data collected from the Unit 1 and Unit 2 NO_X CEMS and the rolling 12-month total from each unit shall be computed in accordance with Condition 46 of this subsection."*

4. EFFECTS OF THE LNB AND OFA PROJECT ON CO EMISSIONS

Operating the burners with lesser amounts of air in the lower furnace will tend to increase the formation of carbon monoxide (CO). The presence of CO is one of the key drivers in reducing NO_X formation in conventional power plants. The OFA compensates for the lesser air during initial combustion. However the total time of turbulent contact and the temperature will be reduced and less carbon burnout will be achieved compared with the present arrangement.

The following table provides the manufacturer guarantees for the project.

Table 1. Performance after the LNB and OFA Project excluding Unit 2 SCR system

Parameter	Guaranteed Emissions (lb/mmBtu)			
	Unit 1		Unit 2	
	40% Load	100% Load	40% Load	100% Load
NO_X	0.25	0.28	0.25	0.28
CO*	~0.09	~0.17	0.15	0.15
	100 ppm	200 ppm	175 ppm	175 ppm

* CO is guaranteed in lb/mmBtu and parts per million at 3.5 percent oxygen (ppm)

The LNB and OFA systems to reduce NO_X place constraints on CO guarantees if not on CO emissions. This was recognized by EPA when issuing the CO BACT determination for Unit 2 in 1991. While there are few data demonstrating the relation between NO_X and CO at units in Florida, the Department reviewed the previously-mentioned SEPC/DOE showing a relation for an opposed wall-fired unit equipped with LNB (but not OFA) and burning Powder River Basin

(PRB) coal. The relation shown in the following figure would not apply for OUC's bituminous coal-fueled units, but the trends would likely be similar.

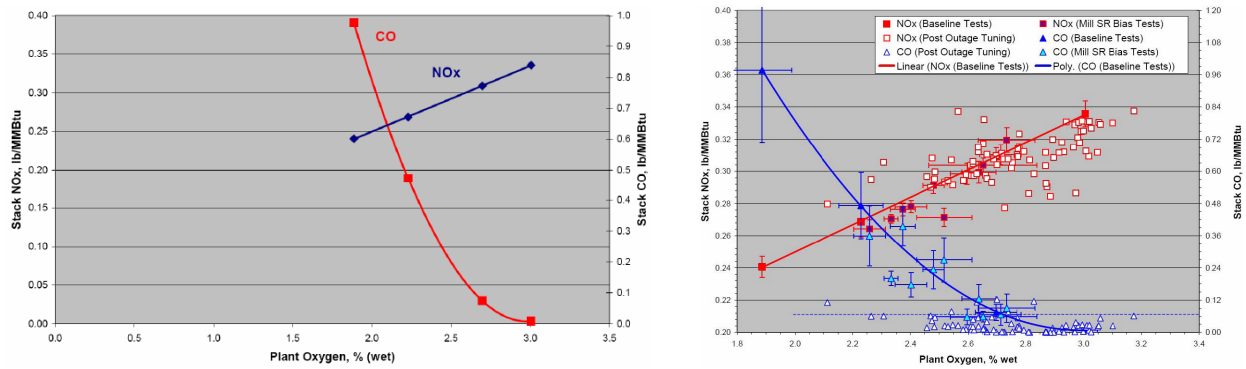

Figure 3. Baseline testing and optimization of first generation LNB system at SEPC

SEPC was subject to a CO emissions limit of 0.15 lb/mmBtu. Baseline tests using the early LNB system are summarized ion the left hand side of the figure. These showed that CO emissions rise rapidly for relatively small decreases in NO_X. An optimization program to improve the NO_X reduction characteristics of the LNB within the CO constraint was conducted. The results are shown on the right and it was possible to suppress CO emissions at excess O2 values less than approximately 2.5%.

The vendor guarantee for the OUC LNB/OFA project includes a specification for unburned carbon (UBC) in the fly ash. UBC in the Unit 1 fly ash is guaranteed to increase no more than 20% above the baseline prior to the LNB/OFA project, while UBC is guaranteed to be less than or equal to the baseline value for Unit 2.

The following table is the applicant's estimate of *baseline actual emissions* for CO and NO_X during a 2 year period (2004-2005) within the most recent five years of operation (2001-2006). CO emissions were calculated based on a low emissions factor from EPA's publication AP-42 wherein an emission factor in the range of 0.02 to 0.03 lb/mmBtu is given. Such emission factors were likely developed before the widespread implementation of LNB and OFA.

Table 2. Baseline actual emissions and projected actual emissions after LNB/OFA project

Pollutant	Baseline Emissions	Projected Emissions	Increase (decrease)
NO_X (TPY)	9,325	<8,300	(>1,024)
CO (TPY)	753	5,975	5,222

The NO_X values are the actual measurements from the continuous emissions monitoring systems (CEMS) on Units 1 and 2. The future projected actual emissions were calculated by the applicant on the basis of meeting the NO_X emission cap as required by the PSD permit for Stanton Unit B and the *requested* CO limits of 0.18 and 0.15 lb/mmBtu for Units 1 and 2 respectively.

5. REGULATIONS THAT APPLY TO THE PROJECT

State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the F.S. The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the F.A.C. This project is subject to the applicable rules and regulations defined in the following Chapters of the Florida Administrative Code. These include: 62-4 (Permitting Requirements); 62-204 (Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference); 62-210 (Permits Required, Public Notice, Reports, Stack Height Policy, Circumvention, Excess Emissions, and Forms); 62-212 (Preconstruction Review, PSD Review and BACT); 62-213 (Title V Air Operation Permits for Major Sources of Air Pollution); 62-296 (Emission Limiting Standards); and 62-297 (Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures).

General PSD Applicability

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program set forth in Rule 62-212.400, F.A.C. A PSD review is required in areas currently in attainment with the state and federal Ambient Air Quality Standards (AAQS) or areas designated as "unclassifiable" for a given pollutant. A new facility is considered "major" with respect to PSD if it emits or has the potential to emit: 250 tons per year or more of any regulated air pollutant; or 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 PSD Major Facility Categories defined in Rule 62-210.200, F.A.C.; or 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the "Significant Emission Rates" defined in Rule 62-210.200, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and applicants must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant, and evaluate the air quality impacts.

Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several regulated pollutants that exceed the Significant Emission Rates.

PSD Applicability for the Project

The OUC Stanton Plant is a major facility under Department Rules. The applicant estimated annual emissions increases of 5,222 TPY of CO. The CO emissions increase will be greater than 100 TPY and a review pursuant to the PSD rules and a BACT determination for CO are required for this project.

It is noted that since 1992 and until 2005 there was an exemption from PSD Review for increases in emissions of pollutants caused by installation of "Pollution Control Projects" (PCP). The purpose of the exemption as applied to power plants was primarily to exempt from the PSD rules increases caused by projects intended to reduce emissions of SO_2 and NO_X such as required for compliance with the Acid Rain regulations.

It was generally agreed that as long as PCP were on balance "environmentally beneficial" and no national ambient air quality standards were exceeded and substantial decreases in acid rain pollutants were realized, then significant emissions of collateral emissions such as CO were allowable. Therefore, during that period of time quite a number of PCP were conducted that caused significant collateral increases of CO and (in the case of some SCR projects) sulfuric acid mist that were not subjected to PSD or a BACT determination.

6. BACT DETERMINATION FOR CO

BACT Methodology.

A determination of the "Best Available Control Technology (BACT)" is required for each of these pollutants, which is defined in Rule 62-212.200, F.A.C. 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.*

CO BACT Evaluation Provided by the Applicant

OUC provided information on recent BACT determinations for coal-fueled units throughout the country for numerous new projects. The CO BACT determinations ranged from 0.1 to 0.25 lb CO/mmBtu and typically about 0.15 lb/mmBtu. Such new projects also provide for the inclusion of NO_X control methods such as LNB and OFA.

OUC also reviewed and rejected the possibility of installing thermal or catalytic oxidation systems on the basis of technical infeasibility, impacts on other pollutants (e.g. conversion of SO_2 to SO_3) and the claim that such equipment has not been installed elsewhere. OUC proposes combustion controls as the method to achieve their BACT proposals of 0.18 and 0.15 lb/mmBtu for Unit 1 and 2 respectively.

Department Evaluation

The Department does not necessarily agree with the evaluation of the applicant. Some of the same arguments regarding oxidation catalyst erosion and conversion of SO_2 to SO_3 are typically made for SCR systems. The Department does not necessarily agree with those arguments and solutions are often found to mitigate the claimed effects. However, the Department agrees that oxidation catalyst is not appropriate for this project.

Thermal oxidation systems have been installed at other facilities although the Department did not find examples for coal-fueled power plants. For example TXI installed a regenerative thermal oxidation (RTO) system at a coal-fueled cement plant in Midlothian, Texas. However, a reheat system is required and the system was very expensive (~$15,000,000) for a much smaller gas stream than Units 1 and 2. Also, the CO emissions from that facility are inherently very high due to carbonaceous matter in the raw materials that evolves CO prior to pyroprocessing.

Structural changes can also be made to increase the residence time following the OFA system and before some of the convective passes. Those changes are not indicated for this project. The Department does not rule out consideration of greater burn out residence times or oxidation catalyst on modifications in general or on new units.

In recent years, a number of BACT determinations have been made for new units by other state agencies. However they often, although not always, are based on supplier statements and there is usually little or no supporting data. There has not been consistency in the associated averaging time. Some of those proposals or determinations are summarized in the Table 3.

Operating the furnace with very high CO emissions can cause the fly ash to contain excessive carbon as indicated by greater “loss on ignition” (LOI) properties. This can have ramifications on the salability of the fly ash and the fate of any additional mercury (Hg) collected on the higher LOI fly ash.

The Department will set BACT limits of 0.18 and 0.15 lb CO/mmBtu for Units 1 and 2 on a 30-day basis. These values can be achieved by good combustion practices within the constraints of the multi-pollutant controls on the unit. The value for Unit 1 will be a little greater than the value for Unit 2. This will provide more flexibility to reduce NO_X emissions from Unit 1 which does not have an SCR system. The BACT limit for Unit 2 is the same as originally set by EPA in the 1991 PSD permit modification.

The Department will require installation of a continuous emission monitoring system (CEMS). CEMS have been used throughout the industry as a cost-effective means for documenting compliance with BACT limits. There will be a requirement for the CEMS to be installed and certified by June 30, 2008, for Unit 1, and December 31, 2008, for Unit 2, respectively.

Table 3. Recent BACT Emission Limits for Carbon Monoxide. Averaging periods vary.

Facility	Capacity MW	Unit Type	Permit or Application	Date	State	Primary Fuel	Limit lb/mmBtu
Montana-Dakota Utilities	175	CFB	Permit	Jun-05	ND	Lignite	0.15
Omaha Public Power District	660	PC	Permit	Mar-05	NE	PRB	0.15
Xcel Energy – Comanche	750	PC	Permit	Mar-05	CO	Subbit	0.13
Longleaf Energy Associates, LLC	1200	PC	Application	Jan-05	GA	PRB or Bitum.	0.15
NEVCO Energy (Sevier Power)	270	CFB	Permit	Oct-04	UT	Subbit	0.12
City Pub Serv. of San Antonio	750	PC	Permit	Oct-04	TX	PRB	0.15
Intermountain Power	950	PC	Permit	Oct-04	UT	Subbit	0.15
Intermountain Power	950	PC	Permit	Oct-04	UT	Bitum.	0.15
WPSC Weston Unit 4	500	PC	Permit	Jul-04	WI	Subbit	0.15
Sandy Creek (LS Power)	800	PC	Permit	Jun-04	TX	PRB	0.15
Longview Power, LLC	600	PC	Permit	Mar-04	WV	Bitum 2.5% S	0.11
Hastings Utilities	220	PC	Permit	Mar-04	NE	PRB	0.15
Steag Desert Energy	1500	SCPC	Application	Feb-04	NM	Subbit	0.10
Elm Road Gen. Station	615	SCPC	Permit	Jan-04	WI	Pitt.#8	0.12

PC = pulverized coal SC = supercritical CFB = circulating fluidized bed PRB – Powder River Basin coal
Bitum = bituminous coal Subbit = sub bituminous coal Pitt = Pittsburgh coal

AIR QUALITY IMPACT ANALYSIS

Introduction

The proposed project will increase emissions of carbon monoxide (CO) at levels in excess of PSD significant amounts. CO is a criteria pollutant and has Ambient Air Quality Standards (AAQS), significant impact levels and de minimis monitoring levels defined for it.

Major Stationary Sources in Orange County

The current largest stationary sources of CO in Orange County are listed below. The information is from annual operating reports submitted to the Department.

Table 4. Largest Sources of CO in Orange County (2006)

Owner	Site Name	Tons per year
Orlando Utilities Commission	***Stanton (Unit 4 Proposed Project)***	***5,128***
Orlando Utilities Commission	Stanton Energy Center (Existing)	716
FL Gas Transmission Co.	FGTC Station 18, Orange Co.	71
Kinder Morgan Energy Partners	Central Florida Pipeline	49
Middlesex Asphalt	Orange Co. Plant #1	29
Walt Disney World	Walt Disney World Complex	26

Air Quality and Monitoring in Orange County

Orange County currently operates twelve monitors at five sites measuring PM_{10}, $PM_{2.5}$, ozone, CO, lead, SO_2 and NO_2. The 2006 monitoring network is shown in the figure below. There are two PM fine monitors at the Winter Park site.

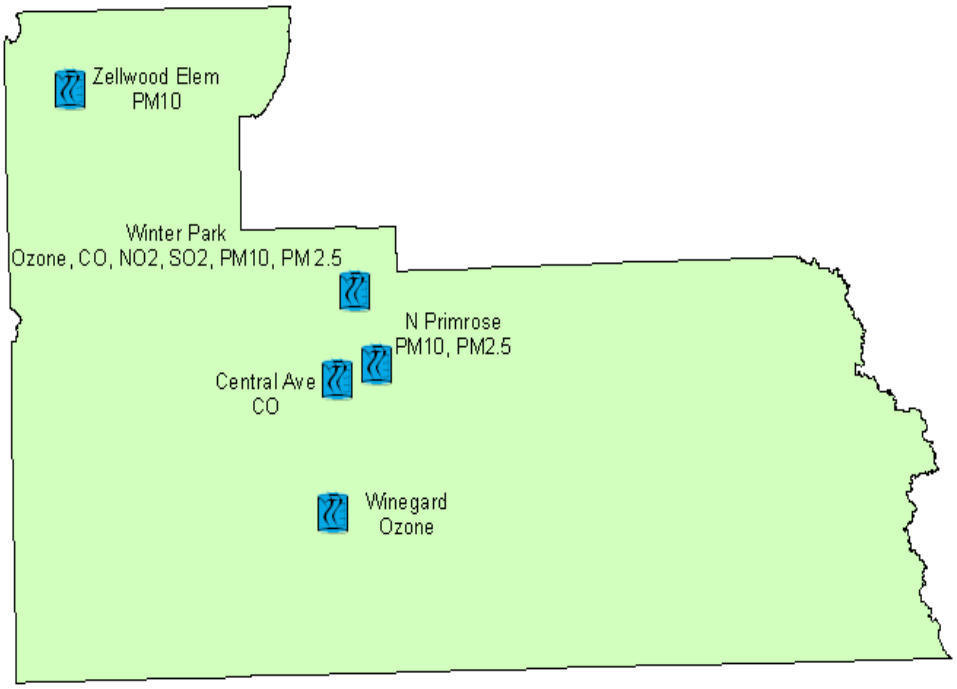

Figure 4. Orange County Ambient Air Monitoring Network

Measured ambient air quality information is summarized in the following table.

Table 5. Ambient Air Quality Concentrations Nearest to Project Site (2006)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Orlando	24-hour	42	38		150[c]	ug/m^3
		Annual			20	50[f]	ug/m^3
$PM_{2.5}$	Orlando	24-hour	34	25		35[d]	ug/m^3
		Annual			11*	15[e]	ug/m^3
SO_2	Winter Park	3-hour	10	9		500 [a]	ppb
		24-hour	3	3		100[a]	ppb
		Annual			1	20 [b]	ppb
NO_2	WinterPark	Annual			8	53 [b]	ppb
CO	Orlando	1-hour	3	2		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Orlando	1-hour	.102	.089		0.12[a]	ppm
		8-hour	.083	.082		0.08[g]	ppm

*Annual data from Winter Park monitor. Orlando annual data did not satisfy summary criteria.
a - Not to be exceeded more than once per year
b - Arithmetic mean
c - Not to be exceeded more than an once per year on average over three years
d- Three year average of the 98th percentile of 24-hour concentrations
e- Three year average of the weighted annual mean
f- EPA has revoked Annual Standard
g- Three year average of the fourth-highest daily maximum of 8-hour concentrations

The highest measured values of all pollutants are all less than the respective National Ambient Air Quality Standards (NAAQS), including ozone. Although the 8-hour ozone concentrations in the table above suggest a violation of the standard, the three year average of the fourth-highest daily maximum of 8-hour concentrations for 2006 was 0.079 ppm, which is in compliance with the standard.

Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for CO. A significant impact analysis is performed on CO to determine if the proposed project can cause an increase in ground level concentrations greater than the SILs.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-

term concentrations predicted by this modeling are compared to the appropriate SILs for the PSD Class II Areas (vicinity of the proposed project).

For the Class II analysis, receptors extending out to 15 kilometers (km) from the center of the facility were chosen for predicting maximum concentrations in the vicinity of the project. Receptors along the property boundary were spaced 50 meters (m) apart. Receptors extending out to 3 km had 100m spacing. Receptors from 3 to 6 km had 250m spacing and beyond 6km, a spacing of 500m was used for this analysis.

If this modeling at worst-load conditions shows ground-level increases less than the SILs, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SILs, 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 or PSD increments.

The applicant's initial CO air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area. These values are tabulated in the table below and are compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 6. Maximum Projected Air Quality Impacts from the OUC Stanton modification for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
CO	8-Hour	33	500	3,450	10,000	NO
	1-Hour	68	2000	2,300	40,000	NO

Maximum predicted impacts from the project for CO are much less than the respective AAQS and the baseline concentrations in the area. CO concentrations are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for CO with a listed de minimis impact level was less than this level. Therefore, no pre-construction monitoring is required for CO.

Table 7. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels.

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
CO	8-hour	33	575	3,450	NO

Based on the preceding discussions, the only additional detailed air quality analyses required by the PSD regulations for this project is the following:

- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. 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. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

AERMET meteorological data prepared by the Department used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations from the Orlando International Airport and twice-daily upper air soundings from the National Weather Service at Ruskin (Tampa). The 5-year period of meteorological data was from 1999 through 2003. These stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators.

Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

The proposed project is in response to the addition of control technologies on Units 1 and 2. These controls will provide emissions reductions for NO_X, which will improve the current impact on soils, vegetation and wildlife from the Stanton facility. These reductions of NO_X will also reduce a source of ozone formation in the vicinity of the project. With regards to the increase in CO emissions, the maximum ground-level concentrations predicted to occur for CO as a result of the proposed project will be considerably less than the Significant Impact Levels and the respective AAQS. The Significant Impact Levels are more stringent that the AAQS, which are health-based standards that are also in place to protect sensitive populations.

Growth-Related Impacts Due to the Proposed Project:

The size of the project is relatively small. There will relatively no increase in the labor force due to the proposed project.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, the U.S. Census Bureau reported a population of approximately 1 million for Orange County. The population has grown by approximately 50% between 1980 and 2000. Despite the population and obvious mobile source growth, the County is in attainment with all ambient air quality standards.

Specifically for CO, there has not been an exceedance of the standards since 1988 for the entire State of Florida. Since 1993, the highest reported 1-hour concentration for CO in Orlando was 26,450 compared to a 40,000 AAQS and the highest reported 8-hour concentration was 8,050 compared to a 10,000 AAQS. These highest concentrations of CO occurred in 1996.

7. 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.