TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Orlando Utilities Commission
Curtis H. Stanton Energy Center

Unit 1 Scrubber Upgrades, Phase 2
Installation of a Selective Catalyst Reduction system (SCR) to Unit 1
Addition of Dry Sorbent Injection (DSI) system to Units 1 and 2

Orange County

DEP File No. 0950137-040-AC

Florida Department of Environmental Protection
Division of Air Resource Management
Office of Permitting and Compliance

August 2, 2012

1.0 GENERAL FACILITY DESCRIPTION

Facility Description and Location

The existing 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.

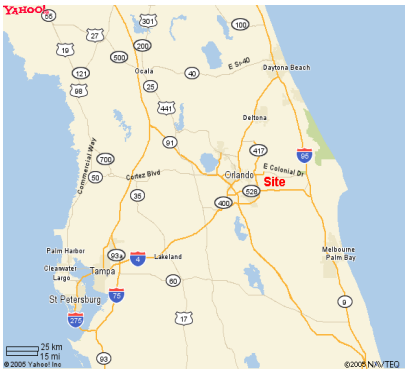

Figure 1. OUC Location **Stanton Units 1 and 2.** **Aerial View of Plant**

The OUC Stanton Energy Center presently consists of two fossil fuel-fired steam electrical generating units, two combined cycle units and ancillary equipment. 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 and Combined Cycle Unit B (300 MW) began operation in 2009.

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 Units 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 Clean Air Interstate Rule (CAIR) set forth in Rule 62-296.470, Florida Administrative Code (FAC).

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

Application Processing Schedule

06/11/12: Received application. Application determined complete.

08/02/12: Distributed draft permit and public notice package.

2.0 PROJECT DESCRIPTION

The proposed project consists of the following physical changes to the facility:

A. Installation of a Selective Catalytic Reduction (SCR) system on Unit 1.

B. Installation of Dry Sorbent Injection (DSI) systems on Units 1 and 2.

C. Upgrades to the Flue Gas Desulfurization system (FGD) system on Unit 1.

OUC is proposing to implement these air quality control systems upon Units 1 and 2 at its existing Curtis H. Stanton Energy Center (SEC) aimed at reducing emissions of key criteria pollutants in preparation for upcoming regulatory programs such as the Cross-State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards (MATS).

The following descriptions are based on information provided by Black and Veatch (BV) and previous determinations by the Department:

A. Description of Unit 1 NO_X Existing and Proposed Control Equipment

Unit No. 1 consists of a coal-fueled Babcock and Wilcox water-tube wall fired boiler/steam generator (Model RB 611) and steam turbine, which drives a generator with a nameplate rating of 468 Megawatts. No. 6 fuel oil 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}, low NOx burners (LNB) and overfire air (OFA) for NO_X control recently installed; and a wet flue gas desulfurization (WFGD) system, (i.e., a scrubber) for SO_2 control.

The initial NO_X requirements for Unit 1 were from the best available control technology (BACT) determination and permit No. PSD-FL-084 issued for Units 1 and 2 in May 1982. Unit 1 is also subject to the requirements of 40 CFR 60, Subpart Da.

The specific controls for NO_X and CO were described in the original technical evaluation and preliminary determination (TEPD) as follows:

> *"The applicant has proposed to reduce NO_X emissions by combustion control, not by post-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)."*

In November 2007, a permit was issued for Unit 1 approving the installation of low NO_X burners and over-fired air (LNB/OFA) systems to reduce emissions of NO_X. Some excerpts from that TEPD are:

> *"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."*

The Department recognizes that a further reduction below the 0.28 lb NO_X/MMBtu vendor guarantee for the LNB/OFA can be achieved by the installation of an SCR system. In recent years, as reported in the application, the average NO_X emissions rate from Unit 1 has been 0.2613 lb/MMBtu (baseline period). OUC expects that the SCR project will substantially decrease NO_X emissions from its baseline to a value of approximately 0.04 lb/MMBtu. OUC states that it will operate the system to a level necessary to comply with the CSAPR. The current permit limits are 0.6 lb/MMBtu (30-days rolling average) and 0.46 lb/MMBtu (annual average).

NO_X Formation and Primary Control.

NO_X emissions are formed from the oxidation of nitrogen present in the combustion air and fuels. NO_X formation in the boiler may occur by three different mechanisms: fuel NO_X is formed from nitrogen compounds contained in fuel (fuel nitrogen); thermal NO_X is formed from molecular or atomic nitrogen (N_2) and oxygen (O_2) present in combustion air; and prompt NO_X is formed in the proximity of the flame front as intermediate combustion products.

Much of the following description is from the application submitted to the Department on June 11, 2012.

<u>Selective Catalytic Reduction (SCR)</u>. Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the boiler. SCR reduces NO_X emissions by injecting ammonia (NH_3) into the flue gas in the presence of a catalyst. In SCR systems, vaporized ammonia injected into the flue gas stream acts as a reducing agent, achieving NO_X emission reductions when passed over an appropriate amount of catalyst. Flue gas containing ammonia and NO_X undergoes an exothermic reaction as it passes through the catalyst, forming nitrogen and water vapor. The following are the predominant reactions.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O + \text{heat} \quad (1)$$

$$6\,NO_2 + 8\,NH_3 \xrightarrow{catalyst} 7\,N_2 + 12\,H_2O + heat \quad (2)$$

The reaction mechanisms are very efficient, with a reagent stoichiometry very close to 1.0.

A number of other reactions can also take place.

$$2SO_2 + O \longrightarrow SO_3\ (SO_2\ \text{Oxidation}) \quad (3)$$

$$NH_3 + SO_3 + H_2O \longrightarrow NH_4HSO_4\ (\text{ammonium bisulfate formation}) \quad (4)$$

$$2NH_3 + SO_3 + H_2O \longrightarrow (NH_4)_2SO4\ (\text{ammonium sulfate formation}) \quad (5)$$

These reactions are mitigated through selection of the catalyst, operation of the SCR to minimize ammonia slip and use of DSI to react with additional SO_3 (discussed below).

OUC proposes to duplicate the Unit 2 SCR system for Unit 1, incorporating improvements in SCR technology over the years. As show in Figure 2, below, the proposed SCR system will include a single reactor. The SCR reactor will consist of a steel reactor box designed to support the SCR catalyst modules and to properly distribute flue gas through the catalyst layers.

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

Flue gas ductwork will be provided from the existing economizer outlet to the existing air heater inlet. Flue gas will flow vertically downward through the catalyst. The SCR inlet duct will include provisions for static flue gas mixer (if required), and an ammonia injection grid. A large particle ash (LPA) screen will be added in the economizer hopper area. The reactor will include sonic horns to keep the catalyst free of fly ash buildup. Provisions for catalyst loading into the reactor will be included. The reactor will be designed for 3 initial layers of catalyst and a spare level for a future additional layer of catalyst.

Anhydrous ammonia will be delivered to the site by tank truck and unloaded into one of two new 330,000 gallon (nominal water capacity) bulk storage tanks located near the existing ammonia unloading and storage facility. Vaporized ammonia will be transferred from the storage tanks to the SCR enclosure. The ammonia will be mixed

with ambient air and distributed into the flue gas through ammonia injection grids located upstream of the reactors.

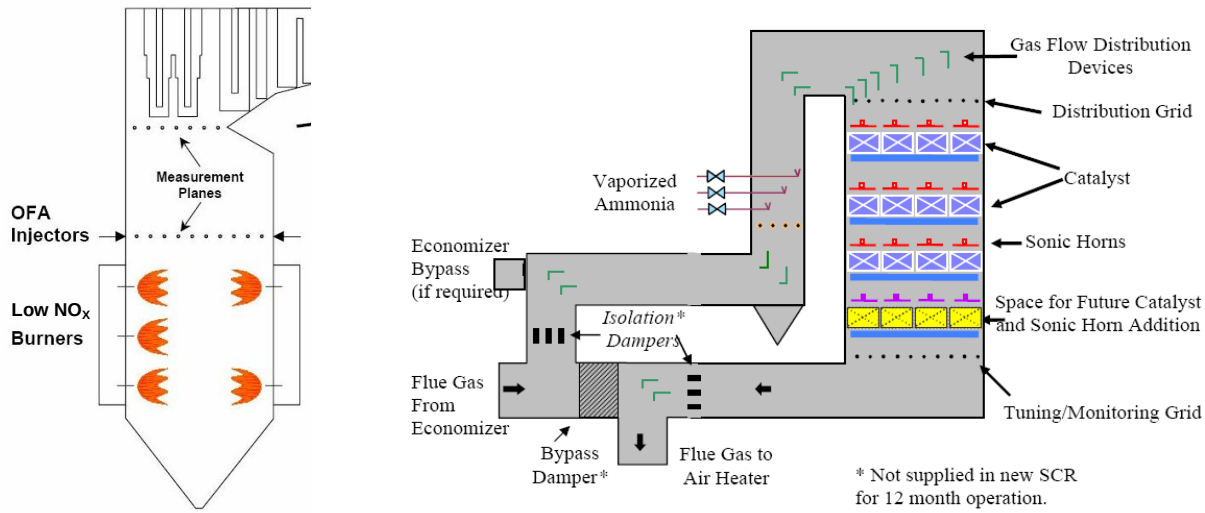

Figure 2. An opposed wall-fired furnace and an SCR system such as in OUC Unit 2

Figure 3 is a general diagram of the proposed SCR installation. This configuration is typically known as dusty or hot side SCR meaning it is placed before the electrostatic precipitator.

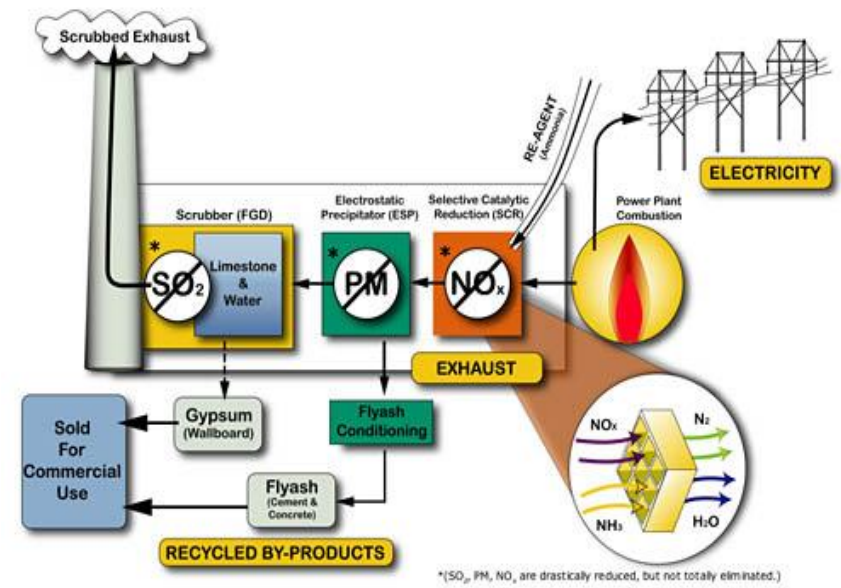

Figure 3. Diagram of SCR Installation and Existing Pollution Control Equipment

With the addition of the SCR itself, several other modifications to the unit are required to support the SCR including:

- Upgrading the ID fans to operate with new variable frequency drives.
- Modifying the existing air heater to reverse the rotational direction and develop an ammonium bisulfate (ABS) tolerant design.
- Expanding the existing fire protection system and other miscellaneous utilities for the new SCR enclosure.

Installation of the SCR system will not impact stack temperature, gas flow rates, ash generation, or heat input.

Generally, 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.

The cost to install SCR on a similar unit was estimated to be approximately $70,000,000. The annual operating and maintenance costs were estimated to be approximately $2,500,000.

The applicant proposed that the Department will consider the new anhydrous ammonia storage tank as an insignificant unit since the existing tanks are classified as such.

B. Description of the Dry Sorbent Injection (DSI) System for Units 1 and 2

OUC proposes to install and utilize a DSI system to inject hydrated lime into the exhaust gas ductwork upstream of the ESPs to minimize SO_3 formation and ultimately to control H_2SO_4 emissions from the stacks to a concentration of approximately 3 ppm in both units. The DSI system will also mitigate potential "blue-plume" episodes by controlling H_2SO_4 that could occur as a result of oxidation of SO_2 by the SCRs and will allow both units to maintain H_2SO_4 emissions at current levels. Based on the test results from the full scale temporary DSI system which operated during December 2011, the total particulate emissions are expected to be controlled to current levels, or below, as DSI was found to be effective at controlling the condensable portion of particulate matter, which is not currently removed by the ESP alone.

The proposed permanent DSI system will require additional material handling systems for the hydrated lime additive. Hydrated lime will be delivered by trucks and unloaded to a single or double storage vessel/silo (5-7 days storage capacity) with a bin vent/dust collector or other comparable device. From the silo, hydrated lime is fed into one of two weigh hoppers. From the respective weigh hopper hydrated lime is gravity fed to a variable speed rotary feeder and then gravity fed through the flex hose and hard piping to the conveying line where hydrated lime is conveyed to the injection locations. Once the hydrated lime reacts with SO_3, it will be converted to other materials such as $CaSO_4$ (majority), which will be collected with the fly ash and hauled to the onsite landfill for disposal.

The general pieces of new equipment required as part of the DSI installation are;

- Pneumatic truck unloading station.
- DSI Storage Silos (one each per unit) with bin vent dust collectors.
- Weigh hoppers and rotary feeders (two each per unit) and associated piping.

The increases from the existing material handling will all be in the form of additional truck traffic into and around the site and are shown in the Table below.

Table 1. Material Handling Sources Emissions Increase (TPY)

Source	Potential To Emit (PTE)		
	TSP	PM_{10}	$PM_{2.5}$
Hydrated Lime Silo # 1 Bin Vent	0.28	0.28	0.28
Hydrated Lime Silo # 2 Bin Vent	0.28	0.28	0.28
Hydrated Lime Deliveries	0.068	0.014	0.003
Anhydrous Ammonia Deliveries	0.013	0.003	0.001
Scrubber Reagent Deliveries	0.018	0.004	0.001
Waste Hauling (from DSI use)	5.92	2.08	0.21
Gypsum Hauling	0.97	0.34	0.03
Total Material Handling Emissions Increase	7.56	3.0	0.81
PSD Significant Emission Rates	25	15	10

This project will not result in any changes to the existing material handling sources, but will increase the amounts of limestone/limestone slurry delivered, as well as the fly ash (as DSI waste) and gypsum hauled to the onsite land fill.

C. Description Scrubber Upgrades on Unit 1

Stanton Unit 1 (as well as Unit 2) utilizes WFGD limestone-based scrubbers to control SO_2 emissions. Figure 4 is a simplified flow diagram of a design from the early 1990's that reasonably represents the scrubbing principles used at OUC Stanton Units 1 and 2. Each unit's scrubber system includes three (3) 50 percent (%) capacity absorber modules, with two normally in operation and the other designated as a spare.

Limestone is ground and mixed with water in a reagent preparation area. The resultant slurry is pumped to the absorber and sprayed into the flue-gas stream. The slurry droplets absorb SO_2 from the flue gas and fall to the base of the absorber, where they are collected in a reaction tank.

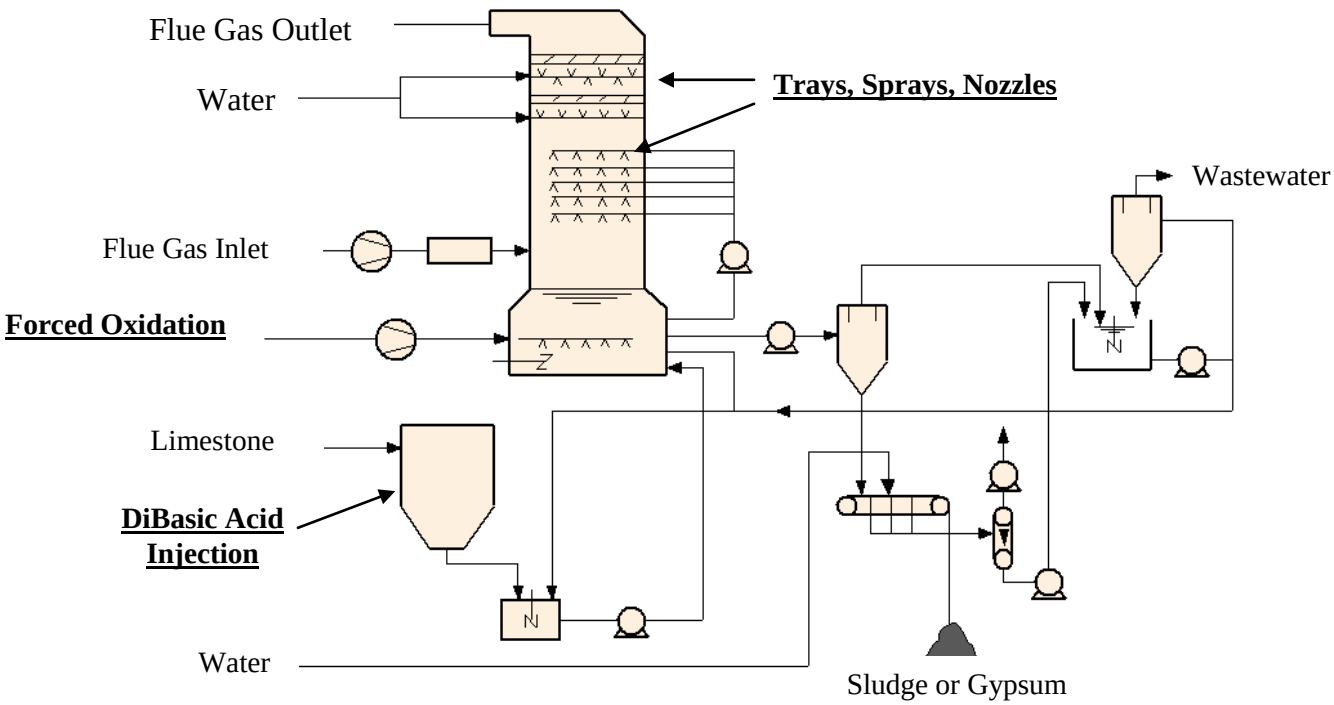

Figure 4. Diagram of a WFGD Limestone Scrubber System (Soud and Takeshita, 1994).

The reactions in the absorber and tank can be represented by the following simplified description:

Equation 1. Sulfur dioxide and water react to form sulfurous acid.

$$SO_2 + H_2O \rightarrow H_2SO_3$$

Equation 2. Sulfurous acid reacts with limestone to form calcium sulfite ($CaSO_3 \cdot ½H_2O$), carbon dioxide (CO_2) and water (H_2O).

$$2H_2SO_3 + 2CaCO_3 \rightarrow 2CaSO_3 \cdot ½H_2O + 2CO_2 + H_2O$$

Equation 3. Most $CaSO_3 \cdot 0.5H_2O$ is further oxidized to form gypsum ($CaSO_4 \cdot 2H_2O$).

$$2CaSO_3 \cdot ½H_2O + O_2 + H_2O \rightarrow 2CaSO_4 \cdot H_2O$$

It is estimated that in the existing natural oxidation WFGD systems, approximately 75% of the SO_2 reaction product is $CaSO_4 \cdot 2H_2O$, while in a forced oxidation system (such as recently approved for Units 1 and 2),

approximately 98% of the SO_2 reaction product is expected to be $CaSO_4 \cdot 2H_2O$, with the remainder in both cases being $CaSO_3 \cdot ½H_2O$.

At the present time, fly ash removed by the electrostatic precipitators (ESPs) prior to scrubbing is blended with scrubber sulfite/sulfate sludge and hydrated lime to solidify the material. It is then deposited in special retention areas on site, and covered with soil and vegetation.

Phase 1 Upgrades.

Authority to inject dibasic acid (DBA) was given under permit No. 0950137-011-AC, issued January 10, 2007. Authority to install a forced oxidation system was given under permit No. 0950137-014-AC issued September 2007. Additionally, minor upgrades to the mist eliminator vanes and fixed grid wash system on Unit 1 were authorized and installed under air permit No. 0950137-034-AC, issued June 2010. These scrubber upgrades were done to improve scrubber efficiency and performance.

Phase 2 Upgrades.

This phase involves installation of spray header modifications along with possible gas/liquid contact devices, such as dual flow tray and/or wall rings, on the inside of the absorber, to improve the contact of the slurry and the flue gas absorber modules. It may also require OUC to modify and increase the speed of the Unit 1 Induced Draft (ID) fans to account for additional pressure drop caused by the upgrades and to resolve vibration issues.

These modifications were previously authorized under permit No. 0950137-012-AC, issued in 2007. However, OUC did not complete Phase 2 modifications prior to the expiration date of that permit on December 31, 2008. As was previously the case, these modifications are expected to reduce emissions and improve control system reliability. As such, this application includes the same modifications as were contained in the previous scrubber upgrade permit and described below with minor updates.

The existing FGD System consists of three 50% capacity absorber modules, with normal operation consisting of two operating absorber modules and one module designated as a spare. The absorber chemistry is limestone based, operating in natural oxidation mode. Four recycle pumps per module are provided, with three used for normal operation and the fourth acting as an installed spare. All of the absorber modifications being evaluated are essentially internal to the absorber and may be used alone or in combination with others, depending on the optimized improvement approach developed by the selected vendor.

To further increase reliability and flexibility of the Unit 1 WFGD system, OUC commissioned a study to evaluate improvements in SO_2 removal capability of the FGD system. This study was performed by Black and Veatch (BV) with assistance from Wheelabrator Air Pollution Control Company (WAPC). The study provided guidance on the most cost effective means to improve SO_2 removal performance, mitigate process problems, and improve reliability.

OUC is in the bidding process for determining which FGD vendor can provide the most cost effective upgrades for meeting the new SO_2 emission target and the exact nature of the FGD improvements necessary. The final upgrades will work in conjunction with the previous upgrades to reduce SO_2 emissions for up to the maximum design coal sulfur content of 3.5%, by weight, that OUC sees in its fuel deliveries.

Based on the study conducted, OUC plans the following possible modifications, although the final selection of the FGD upgrades is still underway.

Installation of Distribution Tray

Based on the existing absorber modules, the study indicated that the Unit 1 WFGD system performance can be significantly improved with the addition of a perforated distribution tray. The use of distribution trays have commonly been used by the industry in the design of new scrubber systems and have been used as a retrofit option to improve performance of existing FGD. The distribution trays provide intimate contact between the gas and liquid phases and the resulting increased mass transfer surface area improves the amount of SO_2 absorbed in the scrubbers.

Wall Rings

Much as the distribution trays above, industry experience has shown FGD system performance can be significantly improved with the addition of wall rings between the spray headers. Wall rings have commonly been used by the industry in the design of new scrubber systems and have been used as a retrofit option to improve performance of existing FGD system. The wall rings are attached to the inner circumference of the absorber between the spray headers. The rings direct both the flue gas and the slurry away from the wall where contact between the two phases is limited towards areas where gas-liquid contact is enhanced.

Improved Spray Header and Nozzle Design

New spray headers with a modified nozzle arrangement with more modern nozzles can be used to maximize spray coverage. Improvements in recycle spray nozzles and their arrangements provide a more uniform and denser spray coverage pattern, which provides better interaction between the spray and better gas/liquid contact. Changes in the direction of the sprays (use of both counter and co-current spray), dual nozzles to allow the spray to interact better, and flatter spray patterns are all options that are currently presented by the various vendors and are being evaluated. This modification of the nozzles may provide a lower pressure drop that may allow the existing pumps to produce higher flow rates (thus increasing the L/G) without changing the current pump operating speeds.

Induced Draft (ID) Fan Modifications

ID fan modifications may be necessary to support the specific FGD improvements selected. The addition of additional trays and distribution devices to each absorber module will cause the absorber pressure drop to increase, which will require additional fan static pressure. When additional air quality control systems (AQCS) components are to be installed, ID fan modifications are often needed to increase the pressure capacity to offset the increased component pressure drops. The switch to high speed operation would provide significant additional ID fan pressure capacity or else upgrade modifications or new fans may be necessary. The modifications needed would be determined during detailed design.

OUC plans to leave the final details of the design modifications open until further site investigations are performed and detailed data can be obtained from equipment manufacturers.

Ultimately, the purpose and primary result of the Unit 1 scrubber upgrade is to improve the removal efficiency of the scrubber and the Unit 1 scrubber upgrade will not include the addition of any new emission units at the facility. The only expected effect of the Unit 1 scrubber upgrade on facility air emissions would involve a decrease in Unit 1 SO_2 emissions and possibly slight increases in limestone material handling emissions resulting from slightly higher limestone usage associated with improved SO_2 removal.

In recent years, as reported in the application, the average SO_2 emissions rate from Unit 1 has been 0.1910 lb/MMBtu (baseline period) with an anticipated post-project emission factor of 0.1655 lb/MMBtu. The expected new SO_2 emission target is 0.2 lb/MMBtu (30-day average). OUC states that it will operate the system to a level necessary to comply with the MATS regulations. The current permit limit is 1.14 lb/MMBtu.

3.0 MODIFICATION AND PERMITTING APPLICABILITY

Addition of Control Equipment

The applicant expects emissions of SO_2 and NO_X to decrease as a result of the Phase 2 upgrades on the Unit 1 WFGD system and the installation of the SCR system. The addition of a distribution tray or wall rings as well as the SCR system constitutes addition of control equipment. A permit is required in accordance with paragraph 62-210.300 (1)(a) that states:

> *"Unless exempt from permitting pursuant to paragraph 62-210.300(3)(a) or (b), F.A.C., or Rule 62-4.040, F.A.C., an air construction permit shall be obtained by the owner or operator of any proposed new, reconstructed, or modified facility or emissions unit, or* ***any new pollution control equipment*** *prior to the beginning of construction, reconstruction pursuant to 40 CFR 60.15 or 63.2, or modification of the facility or emission unit or* ***addition of the air pollution control equipment****; or to*

establish PAL; in accordance with all applicable provisions of this chapter, Chapter 62-212, F.A.C. and Chapter 62-4 F.A.C……etc."

Definition of Modification

The definition of a modification is given in Rule 62-210.200(Definitions), F.A.C. as:

*"Modification" – Any physical change in, change in the method of operation of, or addition to a facility which would result in an increase in the **actual** emissions of any air pollutant subject to regulation under the Act, including any not previously emitted, from any emissions unit or facility. A physical change or change in the method of operation shall not include routine maintenance, repair, or replacement of component parts of an emissions unit.*

The Department concludes that the proposed project constitutes a modification and an air construction permit is required.

Major Modification and PSD Permitting Applicability

It is also necessary to determine whether the modification is subject to the Department's PSD rules at 62-212.400, F.A.C. The requirements of Sections 62-212.400(4) through (12), F.A.C., apply to major modifications of an existing major stationary source. The key criterion is a comparison of *baseline actual* to *projected actual* emissions. Baseline actual emissions are defined for electric utility steam units at Section 62-210.200(36), F.A.C. as follows:

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

Projected future actual emissions are defined at Section 62-210.200(Definitions) as follows:

*"Projected Actual Emissions" – The maximum annual rate, in tons per 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.

A *major modification* requires a PSD permit and is defined at Section 62-210.200(191), F.A.C. as follows:

*"Major Modification" – (a) Any physical change in or change in the method of operation of a major stationary source that would result in a **significant emissions increase** of a PSD pollutant and a **significant net emissions increase** of that pollutant from the major stationary source.*

Significant emissions rate, for the purpose of determining whether a significant net emissions increase (SNEI) has occurred, is defined at 62-210.200(Definitions), F.A.C. The part of the definition that includes the pollutants emitted at the greatest levels for this project is as follows:

> *"Significant Emissions Rate" – (a) With respect to any emissions increase or any net emissions increase, or the potential of a facility to emit any of the following pollutants, significant emissions rate means a rate of pollutant emissions that would equal or exceed:*

1. *A rate listed at 40 CFR 52.21(b)(23)(i), adopted by reference at Rule 62-204.800, F.A.C.; specifically, any of the following rates:*
   a. *Carbon monoxide: 100 tons per year (tpy);*
   b. *Nitrogen oxides: 40 tpy;*
   c. *Sulfur dioxide: 40 tpy;*
   d. *Particulate matter: 25 tpy;*
   e. *PM_{10}: 15 tpy;*
   f. *$PM_{2.5}$: 10 tpy of direct PM2.5 emissions, 40 tpy of sulfur dioxide emissions, or 40 tpy of nitrogen oxides emissions;*
   g. *Ozone: 40 tpy of volatile organic compounds or nitrogen oxides;*
   h. *Lead: 0.6 tpy;*
   i. *Fluorides: 3 tpy;*
   j. *Sulfuric acid mist: 7 tpy; etc.*

The significant emissions rates (SER) for CO, NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$ and Sulfuric Acid Mist (SAM) are 100, 40, 40, 25, 15, 10 and 7 TPY, respectively. While emissions of NO_X and SO_2 are clearly expected to decrease following the addition of the SCR and upgrades to the WFGD, emissions of sulfuric acid mist typically increase in the presence of the catalyst associated with the SCR. The planned injection of hydrated lime prior to the ESPs is expected to be more than sufficient to remove the SAM that forms across the catalyst. Normally, there would be a concern of increased particulate matter emissions due to the additional load on the ESPs from the injection of the hydrated lime, but preliminary testing performed by OUC with temporary lime injection indicated that that the ESP easily handled the increased PM load and that the DSI may also bind to some of the condensable PM so that it is also removed by the ESP. Past actual and projected actual emissions are shown in the Tables 2, 3 and 4, below:

Table 2. Recent Historical Emissions from OUC Stanton Units 1 and 2 (in tons per year)

Historical Emissions from Stanton Unit 1							
Year	**NO_X**	**SO_2**	**H_2SO_4**	**CO**	**$PM/PM_{10}/PM_{2.5}$**	**VOC**	**Hours of Operation**
2007	5,804	4,563	NR	306	62/60/	45	7,846
2008	6,022	4,051	NR	297	91/62/28	36	7,750
2009	5,030	2,590	NR	1,011	89/60/26	37	8,642
2010	4,107	2,406	NR	1,013	80/54/24	32	7,361
2011	3,163	1,461	NR	759	65/44/19	26	7,228
Historical Emissions from Stanton Unit 2							
Year	**NO_X**	**SO_2**	**H_2SO_4**	**CO**	**$PM/PM_{10}/PM_{2.5}$**	**VOC**	**Hours of Operation**
2007	2,555	1,845	79	368	216/216/	44	7,546
2008	2,377	2,172	513	290	88/59/26	35	7,326
2009	2,372	2,007	175	1,040	88/59/26	15	7,841
2010	2,417	2,082	182	674	122/82/35	15	8,079
2011	1,895	934	153	664	103/69/30	13	7,720

Historical Emissions from Stanton Units 1 and 2 Combined							
Year	**NO_X**	**SO_2**	**H_2SO_4***	**CO**	**$PM/PM_{10}/PM_{2.5}$**	**VOC**	**Hours of Operation**
2007	8,350	6,408	79	674	278/138	89	15,392
2008	8,399	6,223	512	587	90/61/27	71	15,076
2009	7,402	4,597	175	2,051	89/60/26	52	16,483
2010	6,524	4,488	182	1,687	101/68/30	47	15,440
2011	5,058	2,395	153	1,423	84/57/25	39	14,948

Source: Air Resource Management System (ARMS) data
Note: NR means not reported. H_2SO_4 emissions reported are only for Unit 2. Data from Unit 1 is not reported.

Unit 1 is described as a nominal 468 MW unit in the facility Title V operation permit and as a nominal 465 MW unit in the facility site certification. Unit 1 is presently limited in its ability to accept fuel by permit limitations rather than by mechanical limitations. It is, therefore, unlikely that modifications to the ID fan will cause short-term heat input increases that would in turn cause long-term emission increases.

According to the applicant, Units 1 and 2 are, and will continue to be, base load units. This project conservatively assumes that no adjustments to the baseline are made as the units would continue to operate as they have done historically. The applicant's analysis also conservatively assumes that the units will have a flat (zero) natural demand growth into the future, essentially making their anticipated future annual heat input equal to the units' baseline heat input.

On December 12, 2010, the Department issued a permit allowing a higher heat input rate for both boilers, increasing the rate from 4,268 MMBtu/hr to 4,800 MMBtu/hr (4-hr block average). According to the application, this project will not result in any additional increases in the Unit 1 or Unit 2 short-term heat input rate that could cause annual increases.

The applicant further believes that any increase in unit use over time would be due to an increase in natural demand growth; and as such, any emission increases associated with increased operation will be excludable when determining any future net emissions increases. Since the project is not expected to increase demand growth upon the units, the increased operation of the units due to demand growth caused by the project is non-existing (zero).

The applicant elected the 24-month period (2007-2009) as the baseline actual emissions (BAE) in Table 3 and considers the excludable emissions (EE) equal to the BAE as shown in Table 4.

Table 3. Baseline Actual Emissions (BAE) Units 1 and 2

Pollutant	BAE Period	Unit 1 and 2 Heat Input MMBtu/yr	Unit 1 (tpy)	Unit 2 (tpy)	Combined Units 1 an 2 (tpy)
NO_X	May 2007 – April 2009	63,500,000	5,662.32	2,633.58	8,295.89
SO_2	May 2007 – April 2009	63,500,000	3,955.58	2,108.51	6,064.08
CO	Jan 2009 – Dec 2010	63,500,000	1,012.09	856.96	1,869.04
VOC	May 2007 – April 2009	63,500,000	38.38	16.43	54.81
PM	May 2007 – April 2009	63,500,000	249.66	327.60	577.26
PM_{10}	May 2007 – April 2009	63,500,000	230.17	308.25	538.42
$PM_{2.5}$	Jan 2009 – Dec 2010	60,600,000	187.11	253.32	440.43
H_2SO_4	May 2007 – April 2009	63,500,000	177.23	190.62	367.84
CO_2	May 2007 – April 2009	63,500,000	3,228.13	3,285,67	6,513.80

Table 4 shows the BAE (EE), the projected actual emissions (PAE), and the total emissions decrease due to Units 1 and 2 projects. According to the applicant, there are no projected emissions increases from Units 1 and 2.

Table 4. Unit 1 and 2 Projected Emissions Increase/Decrease (TPY)

Pollutant	(BAE) (EE)	(PAE)	Projected Emission Increase/Decrease Units 1 and2	SER
NO_X	8,295.89	3,262.84	-5,033.05	40
SO_2	6,064.08	5,254.84	-809.24	40
CO	1,869.04	1,869.04	0	100
VOC	54.81	54.81	0	40
PM	577.26	577.26	0	25
PM_{10}	538.42	538.42	0	15
$PM_{2.5}$	440.43	440.43	0	10
H_2SO_4	367.84	367.84	0	7
CO_2	6,513.80	6,513.80	0	75,000

The procedure for determining whether a project results in a significant emission increase for a pollutant, also known as Step 1 of the PSD applicability determination process, requires that only emissions increases for a pollutant resulting from the units in a Project be added to determine if the resulting increase is a significant emissions increase. The applicant has taken this step in calculating the project total emission increase, and states: *"In accordance with the regulations of the NSR reform rule for Step 1 emissions calculations (i.e., emissions calculations not involving netting), the emissions decreases associated with reductions from Units 1 and 2 were reset to a zero TPY increase such that the decreases cannot be combined with other Project increases to show a Project total less than significance*.".

Based on the above, the Department does not have any concerns about net emissions increases for Units 1 and 2 and believes that the addition of these control devices that will be installed to reduce emissions of SO_2 and NO_X will not trigger a major modification.

Table 5. Total Projected Net Emissions Increase (TPY)

Pollutant	Units 1 and 2 Projected Emissions Increase	Material Handling Projected Emissions Increase	Total Project Projected Emission Increase	PSD SER	PSD Major
NO_X	0	0	0	40	No
SO_2	0	0	0	40	No
CO	0	0	0	100	No
VOC	0	0	0	40	No
PM	0	7.56	7.56	25	No
PM_{10}	0	3.0	3.0	15	No
$PM_{2.5}$	0	0.81	0.81	10	No
H_2SO_4	0	0	0	7	No
CO_2	0	0	0	75,000	No

From this project, there is only a slight projected emissions increase of particulate matter due to materials handling operations, which is below the PSD applicability levels (i.e., SER).

4.0 CONCLUSION

The Department's preliminary determination considered the facts and representations provided by OUC, information on file regarding the other OUC CAIR-related projects at Units 1 and 2, and historical data available through the Department. This determination is based on a technical review of the application, the preliminary design information, reasonable assurances provided by the applicant, and the conditions specified in the draft permit. No air quality modeling analysis is required because the project does not result in a significant increase in emissions.

The Department will issue a draft air construction permit to the applicant for the Phase 2 scrubber upgrade modifications to Unit 1, the installation of the SCR system for Unit 1, and the installation of the DSI systems for Units 1 and 2. The draft permit requires OUC to update the Department with final design specifications and any major changes made to the final design specifications during the actual construction phase.

The Department has made a preliminary determination that the proposed project will comply with applicable state and federal air pollution regulations. The Department's determination is strictly limited to this specific case and should not be used as a precedent for other cases, or lead to unintended consequences construed from the language contained in this determination. Teresa Heron, is the project engineer responsible for reviewing the application and drafting the permit documents. Jonathan Holtom, P.E., is the Air Permitting Supervisor responsible for reviewing, editing and approving these documents. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Office of Permitting and Compliance at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.