TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Orlando Utilities Commission
Curtis H. Stanton Energy Center

Unit 1 Scrubber Upgrades, Phase 2

Orange County

DEP File No. 0950137-012-AC

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

November 28, 2007

1.0 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.

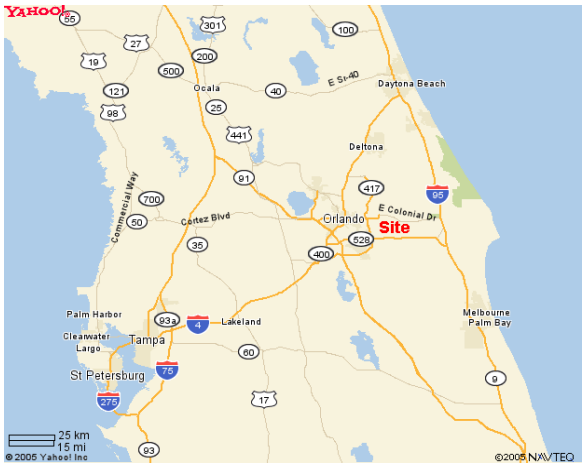

Figure 1. OUC Curtis H. Stanton Energy Center Location and Stanton Units 1 and 2.

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 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).

CAMR: The facility is subject to the Clean Air Mercury Rule (CAMR) set forth 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 (LNBs), overfire air (OFA), forced oxidation, ash loadout system and wet flue gas desulfurization (WFGD) systems 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.

09/06/07: Separated out requests into three different projects including the present for the Phase 2 upgrades on the Unit 1 WFGD system.

11/28/07: Distributed public notice package for the Phase 2 upgrades on the Unit 1 WFGD system.

Wet Flue Gas Desulfurization (WFGD) Limestone Scrubbing for SO_2 Control

Stanton Units 1 and 2 utilize WFGD limestone-based scrubbers to control SO_2 emissions. The figure on the following page is a simplified flow diagram of a design from the early 1990s 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. Authority to inject dibasic acid (DBA) was given under permit No. 0950137-011 issued January 10, 2007. Authority to install a forced oxidation system was given under permit No. 0950137-014-AC.

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.

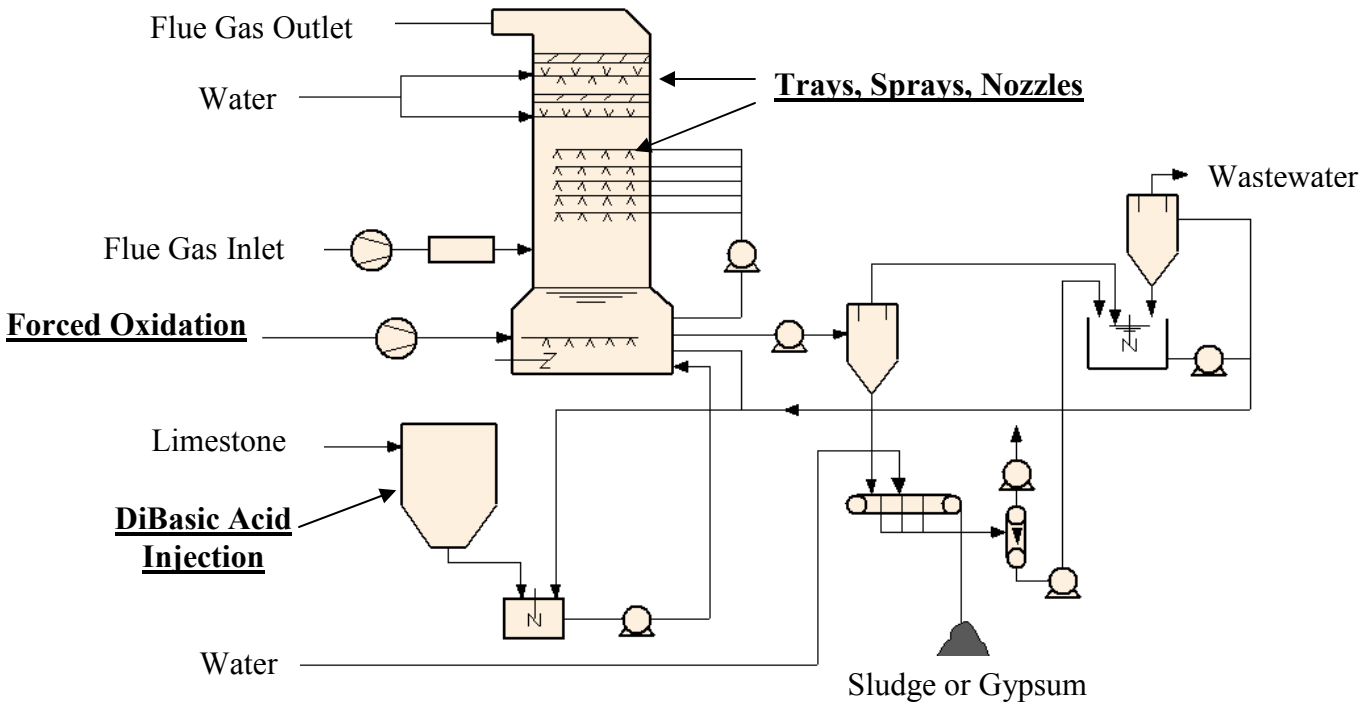

Figure 2. Diagram of a WFGD Limestone Scrubber System (Soud and Takeshita, 1994).

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).

$$2H_2SO_3 + 2CaCO_3 \rightarrow 2CaSO_3 \cdot 0.5H_2O + 2CO_2 + H_2O$$

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

$$2CaSO_3 \cdot 0.5H_2O + O_2 + H_2O \rightarrow 2CaSO_4 \cdot H_2O$$

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 $CaSO_3 \cdot 0.5H_2O$.

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.

2.0 PROJECT DESCRIPTION

The following description is based on information provided by Black and Veatch (BV) for OUC.

Description of Phase 2 Scrubber Upgrades on Unit 1

Based on 2004 data from the continuous emissions monitoring system (CEMS), the Unit 1 absorbers are removing an average of 82.4% of SO_2. The previously approved Phase 1 scrubber upgrades consist of installation of a DBA chemical feed system and a forced oxidation system to improve scrubber efficiency and performance.

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 for Unit 1. This study was performed by BV with assistance from Wheelabrator Air Pollution Control Company (WAPC). The goals for this study were to identify the most cost effective means to improve SO_2 removal performance, mitigate process problems, improve reliability, and reduce operating costs. Based on this study, OUC plans the following modifications.

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 in conjunction with spray header modifications. 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.

Based on review of the absorber arrangement, removal of the bottom internal spray header would be required to allow the distribution trays to have adequate space between the flue gas inlet and the "new" first recycle spray level. The spray header elevations for the three higher levels will remain in place and use existing support steel.

The bottom header replaced by the distribution tray will be relocated higher in the module. This modification will require new absorber penetrations and possible internal support modifications.

Additional Spray Level

As an alternative to a distribution tray, addition of an additional spray level and an increase in recycle pump capacity is also being considered which would also increase the liquid-to-gas (L/G) ratio and provide significant improvement in SO_2 control performance. This option will be studied in more depth to verify the structural integrity of the scrubbers. This additional spray level would have some space restrictions and would probably only be used as a spare except at higher SO_2 loadings due to the potential for erosion of the adjacent lower header.

Modification of Nozzle Arrangement, Piping and Pumps

In addition to the perforated tray, a modified nozzle arrangement with more modern nozzles can be used to maximize spray coverage via a modified spray nozzle arrangement. Current industry practice for recycle spray nozzles is to use silicon carbide material, with a hollow cone spray pattern that have a large free passage, usually greater than 2 inches. This modification may allow the existing pumps to produce higher flow rates (thus increasing the L/G) without changing the current pump operating speeds. Additional modifications such as replacing existing piping with larger piping or modifying the pumps will also be considered.

Induced Draft (ID) Fan Modifications

The addition of a distribution tray to each absorber module will cause the absorber pressure drop to increase, which will require additional fan static pressure. ID fan modifications would probably be 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, estimated at approximately 18 inches water column of additional static pressure capability. The precise modifications needed would be determined during detailed design.

The described measures will increase the mass transfer capability of the existing scrubber modules. Preliminary modeling by the WFGD system supplier indicated that SO_2 removal efficiencies of 85 to 94 percent could be expected when operating two of the three absorbers. With the previously approved addition of DBA, removal rates near 95 percent can be expected with coal sulfur levels up to 4 pounds of SO_2 per million Btu heat input.

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.

3.0 MODIFICATION AND PERMITTING APPLICABILITY

Addition of Control Equipment

The applicant expects emissions of SO_2 to decrease as a result of the Phase 2 upgrades on the Unit 1 WFGD system. The addition of a distribution tray or spray level constitutes addition of control equipment. A permit is required in accordance with paragraph 62-210.300 that states:

> *"Unless exempted from permitting pursuant to paragraph 62-210.300(3)(a) or (b), F.A.C., or Rule 62-4.040, F.A.C., or unless specifically authorized by provision of Rule 62-210.300(4), F.A.C., or Rule 62-213.300, F.A.C., the owner or operator of any facility or emissions unit which emits or can reasonably be expected to emit any air pollutant shall obtain an appropriate permit from the Department prior to beginning construction, reconstruction pursuant to 40 CFR 60.15 or 63.2, modification,* ***or the addition of pollution control equipment****; …… 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.*

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 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; etc.*

The significant emissions rates (SER) for CO, NO_X and SO_2 are 100, 40 and 40 TPY respectively. The SER for these three pollutants are very low especially compared with the emissions from Units 1 and 2 during recent years as shown in the following table. Therefore the possibility of a SNEI for NO_X or CO (if not for SO_2) is a consideration.

Table 1. Recent Historical Emissions from OUC Stanton Units 1 and 2

Historical Emissions from Stanton Unit 1						
Year	NO_X	SO_2	CO	PM	PM_{10}	VOC
2001	7,460	6,661	388	135	30	44
2002	6,494	5,321	413	43	27	45
2003	6,375	4,833	413	47	30	45
2004	5,860	4,274	395	40	40	44
2005	7,533	6,059	327	67	64	49
Highest 2 years	6,977	5,991	401	89	52	47
Historical Emissions from Stanton Unit 2						
Year	NO_X	SO_2	CO	PM	PM_{10}	VOC
2001	2,826	3,268	383	67	42	44
2002	2,349	2,359	371	102	64	43
2003	2,520	2,305	359	95	64	41
2004	2,566	2,501	399	113	111	44
2005	2,692	2,779	385	78	78	44
Highest 2 years	2,629	2,814	392	96	95	44

Combined Historical Emissions from Stanton Units 1 and 2						
Year	NO_X	SO_2	CO	PM	PM_{10}	VOC
2001	10,285	9,929	771	202	73	88
2002	8,843	7,679	784	145	91	88
2003	8,895	7,138	771	143	95	86
2004	8,426	6,774	794	152	151	88
2005	10,225	8,838	712	145	142	94
Highest 2 years	9,564	8,804	783	174	146	91

An NO_X emissions cap of 8,300 TPY was established on Unit 1 and 2 in permit No. 0950137-011-AC, Section III, Specific Condition 4. Clearly most of the NO_X reductions will come from Unit 1 following a planned project to install low NO_X burners (LNB) and overfire air (OFA) pursuant to draft permit 0950137-015-AC. The latter permit action includes a draft determination of best available control technology (BACT) for CO on both units.

According to the applicant, Units 1 and 2 are and will continue to be base load units. The applicant also believes there will be no increase in the unit demand due to the project. The applicant 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 emissions increases.

According to the applicant, the project will not result in an increase in the Unit 1 or Unit 2 short-term heat input rate. The various projects at the facility, including those covered by other permits are for the purpose of facilitating compliance with CAIR or to the Unit 1 and 2 NO_X cap. To test the applicant's claim that there will be no increase in short-term heat input rate that could cause annual increases, the Department developed the following heat input and power output diagrams using data available from the EPA Clean Air Markets website for 2003.

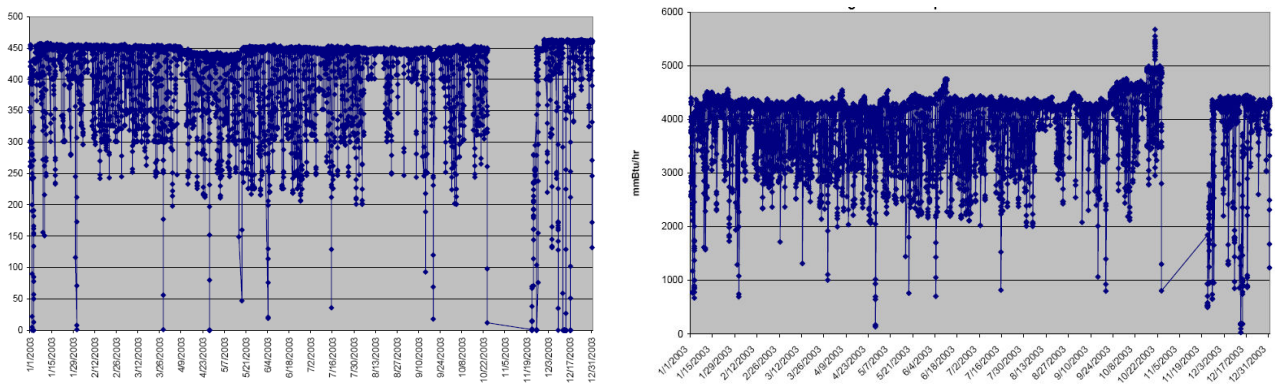

Figure 3. Hourly Power (MW) and Heat Input Values (mmBtu/hr) for Unit 1 in 2003

Units 1 is described as nominal 468 MW unit in the facility Title V operation permit and as a nominal 465 MW unit in the facility site certification. Heat input to Unit 1 is limited by enforceable permits to 4,268 mmBtu/hr. It is clear from Figure 3 that Unit 1 consistently runs near its nominal rating and near the maximum allowable heat input limit. It appears that at times Unit 1 actually registers heat input rates above the permitted limits.

The reasons for apparent exceedances of the permitted heat input limits in October 2003 (just before an outage) are unknown, but it is noted that they occurred with no concurrent increase in power production. After the outage, the recorded heat input values returned to their previous levels.

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.

4.0 CONCLUSION

The Department has made a determination that the proposed project will comply with applicable state and federal air pollution regulations. The Department's preliminary determination is based on 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 EPA Air Markets Program. The Department will issue a Draft air construction permit to the applicant for the Phase 2 scrubber upgrades to Unit 1. Recordkeeping will be required for determining in future years whether any SNEI are caused by the project, particularly the modifications of the ID fan. 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.