TECHNICAL EVALUATION
&
PRELIMINARY DETERMINATION

APPLICANT

Tampa Electric Company (TEC)
13031 Wyandotte Road
Apollo Beach, Florida 33572-9200

Big Bend Station
Facility ID No. 0570039

PROJECT

Project No. 0570039-091-AC
Application for Minor Source Air Construction Permit
Igniter System Heat Input Modification
(Replacement of Permit No. 0570039-084-AC)

COUNTY

Hillsborough County, Florida

PERMITTING AUTHORITY

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

July 8, 2016

1. GENERAL PROJECT INFORMATION

Air Pollution Regulations

Projects at stationary sources with the potential to emit air pollution are subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The statutes authorize the Department of Environmental Protection (Department) to establish regulations regarding air quality as part of the Florida Administrative Code (F.A.C.), which includes the following applicable chapters: 62-4 (Permits); 62-204 (Air Pollution Control – General Provisions); 62-210 (Stationary Sources – General Requirements); 62-212 (Stationary Sources – Preconstruction Review); 62-213 (Operation Permits for Major Sources of Air Pollution); 62-296 (Stationary Sources - Emission Standards); and 62-297 (Stationary Sources – Emissions Monitoring). Specifically, air construction permits are required pursuant to Chapters 62-4, 62-210 and 62-212, F.A.C.

In addition, the U. S. Environmental Protection Agency (EPA) establishes air quality regulations in Title 40 of the Code of Federal Regulations (CFR). Part 60 specifies New Source Performance Standards (NSPS) for numerous industrial categories. Part 61 specifies National Emission Standards for Hazardous Air Pollutants (NESHAP) based on specific pollutants. Part 63 specifies NESHAP based on the Maximum Achievable Control Technology (MACT) for numerous industrial categories. The Department adopts these federal regulations in Rule 62-204.800, F.A.C.

Glossary of Common Terms

Because of the technical nature of the project, the permit contains numerous acronyms and abbreviations, which are defined in Appendix A of this permit.

Facility Description and Location

The Big Bend Station is an existing coal-fired steam electric generating facility, which is categorized under Standard Industrial Classification Code No. 4911. The existing Big Bend Station is located in Hillsborough County at 13031 Wyandotte Road in Apollo Beach, Florida. The UTM coordinates of the new facility are Zone 17, 363.15 kilometers (km) East, and 3074.91 km North. This site is in an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to Ambient Air Quality Standards (AAQS). Figure 1shows the location of TEC Big Bend Station in Florida while Figure 2 shows a view of the Big Bend Station.

Figure 1. Location of TEC Big Bend Station.

Figure 2. TEC Big Bend Station.

The Big Bend Station is a nominal 2,028 megawatt (MW) electric generation facility. This facility consists of four fossil fuel fired boiler electrical generating units (Units 1 – 4); four steam turbines; one simple-cycle combustion turbine (CT No. 1); solid fuels, fly ash, limestone, gypsum, slag, bottom ash storage and handling facilities; and, fuel oil storage tanks.

Units 1 through 4 have a combined electrical generating output of 1,821 MW. Units 1 through 3 each have an electrical generating design capacity of 445 MW. Unit 4 has an electrical generating design capacity of 486 MW. The fuel fired in all four units consists of coal, or a coal/petroleum coke blend containing a maximum of 20% petroleum coke by weight, or coal blended with coal residual generated from the Polk Power Station, or a coal/petroleum coke blend further blended with coal residual generated from the Polk Power Station, and on-site generated fly ash. In addition to the fuels allowed to be burned during normal operation, each unit burns natural gas during startup, shutdown, flame stabilization, and during the start of an additional solid fuel mill on an already operating unit.

For each unit, nitrogen oxide (NO_X) emissions are controlled by low NO_X burners (LNB) and a selective catalytic reduction (SCR) system (Unit 4 also has a separated overfire air system (SOFA) system to further control NO_X). Particulate matter (PM) emissions are controlled by a dry electrostatic precipitator (ESP), while sulfur dioxide (SO_2) emissions are controlled by wet flue gas desulfurization (FGD) on each unit. Continuous opacity monitoring systems (COMS) are used to measure opacity. Units 1 through 3 are equipped with continuous emissions monitoring systems (CEMS) to measure NOx, SO_2, and carbon dioxide (CO_2). Unit 4 is equipped with CEMS to measure NOx, SO_2, CO_2, and carbon monoxide (CO). Unit 1 began operation in 1970, Unit 2 began operation in 1973, Unit 3 began operation in 1976, and Unit 4 began operation in 1985.

Facility Regulatory Categories

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C.
- The facility is a major stationary source in accordance with Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The facility operates units subject to the New Source Performance Standards (NSPS) of 40 CFR 60.
- The facility operates units subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAP) of 40 CFR 63.

Project Description

TEC is requesting an operating change to increase the ignition system capacity while burning natural gas and to evaporate excess recycle water in Units 1 through 4, through revisions to several specific conditions established in permit No. 0570039-084-AC.

The following existing emissions units (EU) will be affected by this project.

EU No.	Description
001	Fossil Fuel Fired Steam Generator Unit No. 1
002	Fossil Fuel Fired Steam Generator Unit No. 2
003	Fossil Fuel Fired Steam Generator Unit No. 3
004	Fossil Fuel Fired Steam Generator Unit No. 4

Processing Schedule

6/3/2016 Department received the application for an air pollution construction permit.

2. PSD APPLICABILITY

Facility PSD Applicability

The existing Big Bend facility is a PSD-major facility.

PSD Applicability for Project

Calculations provided by the applicant show pollutant emissions from this project will decrease as a result of replacing heat input from the firing of coal for heat input from the firing of natural gas, on a Btu per Btu basis. As provided in the application, the following table summarizes potential emissions and PSD applicability for the project.

Table A. Summary of the Applicant's PSD Applicability Analysis

Pollutant	Annual Emissions, Tons/Year				Subject to PSD?
	Baseline Actual	Projected Actual	Increase	Significant Emissions Rate	
CO	10,239	6,057	(4,182)	100	No
NO_X	4,984	3,351	(1,633)	40	No
PM	466	186	(290)	25	No
PM_{10}	350	149	(200)	15	No
$PM_{2.5}$	187	99	(88.2)	10	No
SO_2	11,032	3,237	(7,795)	40	No
VOC	658	578	(79.9)	40	No
SAM	56	17	(38.8)	7	No
Pb	1	0.23	(0.63)	0.6	No
CO_2e	11,248,262	7,733,779	(3,514,483)	100,000	No

As shown in the above table, total project emissions will not exceed the PSD significant emissions rates; therefore, the project is not subject to PSD preconstruction review.

3. DEPARTMENT REVIEW

Discussion of Emissions and Project-related Changes

Boilers 1 – 4 are coal-fired boilers with design heat input capacity ratings of: Unit 1 - 4,037 MMBtu/hour, Unit 2 - 3,996 MMBtu/hour, Unit 3 - 4,115 MMBtu/hour, and Unit 4 – 4,330 MMBtu/hour. Each boiler is also equipped with a natural gas igniter system to control the combustion process. These igniter systems are capable of firing concurrently while firing coal or alone to provide heat for the generation of steam at lower loads. Air construction permit No. 0570039-065-AC authorized construction of the natural gas igniter systems on Units 1 - 4, demolition of the No. 2 fuel oil ignition systems and gas pipeline. Air construction permit No. 0570039-070-AC authorized the construction of two process heaters to pre-heat the natural gas prior to combustion. Air construction permit Nos. 0570039-073-AC, -078-AC and -081-AC made minor revisions to the previous permits. Air construction permit No. 0570039-084-AC superseded all of the previous air construction permits related to the igniter systems and made changes to remove the annual VOC testing requirement from Big Bend Units 1-4, revised the natural gas recordkeeping requirements, removed the VE testing requirement from the process heaters, revised the method of calculation for the actual NO_X emissions from the process heaters, revised the daily recordkeeping to monthly and revised the co-firing heat input threshold up to a maximum of 108,210,630 MMBtu/year. This heat input threshold was based on the heat input rate of 6,960 MMBtu/hour and the belief that the SCR unit would not be able to be operated at low loads, thereby resulting in a potential 39.1 TPY annual increase in uncontrolled NO_X emissions.

The gas igniter systems for Units 1, 2 and 3 were designed with 24 igniters with up to 70 MMBtu/hour each for a total heat capacity of 1,680 MMBtu/hour. Unit 4 was designed with 16 igniters and 4 warmup igniter guns for a total heat input capacity of 1,920 MMBtu/hour. The original combined design heat input capacity for Units 1 to 4 was 6,960 MMBtu/hour when operating at a gas delivery pressure of 35 psi. Upon installation of the gas igniter systems, as authorized by permit No. 0570039-084-AC, it was discovered that the igniters could theoretically be operated at higher gas delivery pressures than 35 psi, which could quickly raise the combustion gas temperature to the necessary level to place the SCR systems into service. This provides the possibility of starting up the units solely on natural gas and placing the SCR systems into service prior to blending coal into the fuel mix.

With the opportunity for shorter start up periods and the ability to operate the SCR systems under all normal operating conditions (past start up) while firing gas, either alone or while co-firing solid fuels, there will be no periods of uncontrolled normal operation. Therefore, operating on natural gas as a replacement for solid fuel with the SCR systems in operation results in the emissions reductions indicated in Table A., above, rather than a potential 39.1 TPY increase in NO_X, as currently authorized by permit No. 0570039-084-AC.

Based on current information, TEC claims that the existing system is capable of firing natural gas at 50 psig up to an equivalent heat input of approximately 9,900 MMBtu/hour without any physical modifications, and likely even higher. However, the natural gas distribution system is expected to physically limit the total operation of the gas igniters and process heaters to a maximum of 12,000 MMBtu/hour. The more gas-firing that is exchanged for solid fuel-firing, the greater the reduction in actual emissions should be. The Department is in favor of TEC testing the gas igniter systems to determine the maximum possible firing rate of the installed equipment and utilizing as much natural gas as possible. However, if TEC wishes to fire more than 12,000 MMBtu/hour on gas, an air construction permit will need to be obtained in order to modify the natural gas delivery system and to install additional and/or larger gas igniters.

TEC is also requesting the authority to evaporate excess recycle water when firing gas. Co-firing coal and natural gas or natural gas alone at lower loads typically reduces the amount of recycle water that is evaporated in the FGD system. This creates a surplus of recycle water at Big Bend Station. Authorization is requested to evaporate up to a maximum of 730 million gallons/year of recycle water to maintain the water balance at Bend Station. The recycle evaporation and igniter modification projects are considered one contiguous project for emission purposes since the igniter project impacts the recycle water balance. The recycle water will be injected into each boiler using a series of lances in the lower furnace. The total dissolved solids (TDS) in the recycle water will be released as particulate matter (PM) in the boiler. The electrostatic precipitator (ESP) is expected to remove more than 99% PM through the collection of fly ash. The FGD system is also expected to remove nearly 50% PM through the scrubbing fluid. Approximately 19 tons/year of PM will be released to the atmosphere as a result of evaporating the recycle water in the boilers; however, this increase is more than offset by the lower PM emissions associated with firing natural gas. The recycle water will be evaporated in a controlled manner to maintain the same temperature profile throughout the system, including each wet stack.

State Requirements

Fossil Fuel Fired Steam Generators 1-4

Big Bend Units 1-3 are subject to Rule 62-296.405(1)(d), F.A.C., Fossil Fuel Steam Generators with More Than 250 Million Btu per Hour Heat Input (Existing Units), which requires that these emission units meet emission limits for PM, SO_2, NO_X, and visible emissions. The NO_X emission limit under this rule is 0.70 lb/MMBtu. This limit has been superseded by various permitting actions to a more stringent emission limit of 0.12 lb/MMBtu, which is currently met by the use of LNB and the SCR units. The facility is required to submit excess emissions reports to the EPCHC each quarter.

Big Bend Unit 4 is subject to Rule 62-296.405(2)(d), F.A.C., Fossil Fuel Steam Generators with More Than 250 Million Btu Per Hour Heat Input (New Units), which requires that this emission unit meet the emission limits for PM, SO_2, NO_X, and visible emissions pursuant to 40 CFR 60, Subpart Da. The NO_X emission limit under this rule is 0.60 lb/MMBtu. This limit has been superseded by various permitting actions to a more stringent emission limit of 0.10 lb/MMBtu, which is currently met by the use of LNB, SOFA, and SCR. The facility is required to submit excess emissions reports to the EPCHC each quarter.

State Rules for the Process Heaters

The process heaters are subject to the general 20% visible emissions limitation in accordance with Rule 62-296.320(4)(b)1., F.A.C., and are *not* subject to Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 MMBtu/hour Heat Input, New and Existing Emission Units since the heaters do not produce steam, but indirectly heat pipeline natural gas above the dew point to prevent condensation in the pipeline. This opacity limit will met by firing pipeline quality natural gas, using good combustion practices and a biennial (every two years) tune-up.

Federal NSPS Requirements

Unit 4 is subject to and has met the applicable requirements of NSPS Subparts A (General Provisions) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978) in 40 CFR 60; however, Units 1 – 3 are not subject to NSPS Subpart Da. In order to determine if Units 1 – 3 can become subject to NSPS Subpart Da if the existing units are "*modified*" or "*reconstructed*", the following factors need to be considered:

> Modification is defined as *any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification. .....use the following to determine emission rate: Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors," EPA Publication No. AP-42.... where utilization of emission factors demonstrates that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase*.
>
> Reconstruction is defined as *the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and it is technologically and economically feasible to meet the applicable standards set forth in this part.*

NSPS Subpart Da of 40 CFR 60

NSPS Subpart Da regulates emissions of NO_X, SO_2 and PM. The addition of the natural gas igniters under permit No. 0570039-084-AC was a physical change to Units 1 - 3. However, the change did not cause an increase in emissions of NO_X, SO_2 or PM on a maximum hourly basis. Per U.S. EPA AP-42 emission factors for the external combustion sources, natural gas has lower emission factors for these pollutants when compared to No. 2 fuel oil (Link to AP 42 External Combustion Sources Emission Factors). Increasing the amount of natural gas that is allowed to be fired in the igniters through this project could result in an increase in actual emissions, but TEC has committed to being able to use the SCRs when firing natural gas under regular operation, which will result in additional decreases in actual emissions. Therefore, the proposed project is not considered a modification to Units 1 – 3 under the NSPS. Additionally, there is no equipment cost related to this project since the igniters are already installed, so the proposed project will not constitute reconstruction. For these reasons, the proposed project will not result in Units 1 – 3 being subject to the applicable requirements of NSPS Subpart Da. Nevertheless, the NO_X emission limit under Subpart Da is 0.60 lb/MMBtu, whereas the current emission limit for Units 1-3 is 0.12 lb/MMBtu and is met by using the current LNB and SCR units.

Federal NESHAP Requirements

NESHAP for the Fossil Fuel Fired Steam Generators 1-4

Big Bend Units 1-4 are subject to 40 CFR 63, Subpart UUUUU National Emission Standards for Hazardous Air Pollutants: Coal and Oil-Fired Electric Utility Steam Generating Units. However, this regulation does not have a NO_X emissions limit. Therefore, this regulation does not apply to this project.

NESHAP for Process Heaters

The process heaters are subject to, and shall comply with, the applicable requirements in NESHAP Subpart A

(General Provisions) and NESHAP Subpart DDDDD (Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters) of 40 CFR 63, which are identified in Appendices E and F of the permit. Natural gas-fired process heaters are required to undergo a periodic (biennial) tune-up to minimize emissions.

4. 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. No air quality modeling analysis is required because the project does not result in a significant increase in emissions. Jon Holtom, P.E., is the project engineer responsible for reviewing the application and drafting the permit. 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 at 850/717-9079 or by email jon.holtom@dep.state.fl.us.