Permitting Application - Events

Events Scheduled

15 of 90

AIRS ID: 0810199
Site Name: MANATEE ENERGY CENTER
Permit #: 0810199-001-AC
Type/Subtype: AC / 1A
Received: 03/28/2001
Project #: 001
Project Name: (MANATEE ENERGY CENTER)

> Receive Request: Done

Event	Begin Date	Period	Due Date	Rmn	Status	End Date
Receive Request	03/28/2001	1	03/29/2001		Done	03/28/2001
Fee Verification	03/28/2001	2	03/30/2001		Sufficient Fee	03/30/2001
Completeness Review	03/28/2001	30	04/27/2001		Incomplete	04/27/2001
RESET CLOCK	04/27/2001	1	04/28/2001		Done	04/27/2001
Awaiting Additional Information	04/27/2001	45	06/11/2001		Received	06/27/2001
Completeness Review	06/27/2001	30	07/27/2001		Complete	06/27/2001
Determine Agency Action	06/27/2001	90	09/25/2001		Issue	09/11/2001
Mail Public Notice of Intent to Applicant anc	09/11/2001	10	09/21/2001		Done	09/11/2001
Date of Publication	09/11/2001	999	06/06/2004		Published	09/20/2001
Awaiting Petition for Administrative Proce	09/20/2001	14	10/04/2001		Not Received	10/04/2001
Issue Final Permit	10/04/2001	14	10/18/2001		Issued	01/16/2002

FINAL DETERMINATION
File No. 0810199-001-AC (PSD-FL-318)
MANATEE ENERGY CENTER
600 MW POWER PLANT FACILITY

The Department distributed a Public Notice package on September 11, 2001 for the project to construct a natural gas electrical power plant to be known as the Manatee Energy Center in Manatee County. The project consists of three (3) nominal 170 MW General Electric 7FA combustion turbine-electrical generators, an unfired heat recovery steam generator, a separate steam-electrical generator; three 135-foot stack; a mechanical draft cooling tower; one 2600-hp diesel generator, one 250-hp diesel fire pump, one gas heater, aqueous ammonia storage tank and small diesel storage tanks and other ancillary equipment. The Public Notice of Intent to Issue was published on September 20, 2001, in the Sarasota Herald-Tribune, Manatee County.

Written comments were received during the 30-day public comment period from EPA Region IV, the Manatee County Environmental Management Department (Manatee County), and from El Paso Merchant Energy Company (El Paso).

The comments from El Paso, Manatee County, and EPA along with the Department's responses are listed below.

El Paso Comments and Department Responses:

In reference to Permit Specific Conditions III.A.2 and 17, related to minimizing startup times and control of startup emissions, El Paso submitted a letter prepared by General Electric dated September 21, 2001. The Department had suggested that this could be done by installation of a separate bypass stack and damper to facilitate startup of the steam cycle while operating the combustion turbine in low emission modes 5, 5Q, and 6Q. GE commented as follows:

"Operating the damper door as a modulating valve is not recommended. We are aware of a similar application at a project at KEPCO (Hungary?). Because of the turbulent flows, damage to the damper door and its seals allowed leakage to the atmosphere after the damper was closed resulting in a significant loss in performance".

In reference to Condition III.A.8, El Paso submitted the following comment: "The 2000 hour per year limit on steam flow augmentation may be insufficient to meet plant operational objectives. The March 2001 Air Construction permit application submitted to the Department requested up to 8,760 hours per year of steam flow augmentation".

Following discussions with the Department, El Paso proposed to install "a HRSG stack damper (without a bypass stack) to reduce the frequency of cold and warm starts" and "an oxidation catalyst control system to minimize CO and VOC emissions occurring during startups and shutdowns ..... and power augmentation operating conditions".

<u>Department Response:</u>

The Department reviewed General Electric's letter and wrote an e-mail to their representative re-framing the issue and asking <u>how</u> startup emissions can be minimized for a combined cycle configuration and whether modulating valves (instead of dampers) can be designed for this purpose. General Electric's further input will be useful when reviewing future projects, but will not come in time to implement it into the present project.

The Department has determined that El Paso oxidation catalyst proposal is a proper solution for this project. It reflects the first installation of oxidation catalyst in a GE Frame 7FA combined cycle unit in the State of Florida. The oxidation catalyst certainly will reduce high emissions of CO that can occur during the prolonged cold startup of a combined cycle unit when the basic combustion turbine is operated outside of DLN modes.

The oxidation catalyst will further minimize emissions of CO and VOC under all other modes of operation, especially power augmentation. The CO emission limits will be reduced and the permit will be revised as follows:

Section III.A. Emission Unit 001: Combined Cycle Turbine No. CC-1 (Controls): The efficient combustion of pipeline-quality natural gas at high temperature minimizes emissions of CO, PM/PM10, SAM, SO2, and VOC. A selective catalytic reduction (SCR) system combined with Dry Low NO_X combustion technology reduces NO_X emissions. An Oxidation catalyst system combined with DLN combustion technology reduces CO and VOC.

Specific Condition III.A.2 - Combined Cycle Gas Turbine: The permittee is authorized to install, tune, maintain and operate a new combined cycle unit consisting of a General Electric Model PG7241FA gas turbine-electrical generator set, an unfired heat recovery steam generator (HRSG), and a steam turbine-electrical generator set. The combined cycle unit shall be designed as a system to generate a nominal 175 MW of shaft-driven electrical power and less than 75 MW of steam-generated electrical power. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air cooling system, a single exhaust stack that is 135 feet tall and 19.0 feet in diameter, and associated support equipment. ~~A separate bypass stack and damper may be installed to facilitate startup of the steam cycle while operating the combustion turbine in Low Emissions Modes 5, 5Q, and 6Q.~~ [Applicant Request; Design]

Specific Condition III.A.8 - Power Augmentation: As an alternate method of operation, the permittee may inject steam into the combined cycle gas turbine for power augmentation. ~~Power augmentation is permitted 2000 hours per 12-consecutive months and is not limited if oxidation catalyst is installed. The 2000 hour limit may be revised at the request of the applicant based upon review of actual performance and control equipment cost-effectiveness following proper public notice.~~
~~[Rule 62-212.400 (BACT), F.A.C.]~~

Specific Condition III.A.11 - Carbon Monoxide (CO):

a. *Initial Test, Standard Operation:* When not operating in the power augmentation mode, CO emissions shall not exceed 9.7 ~~31.0~~ pounds per hour nor 2.5 ~~8.0~~ ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by an initial performance test conducted in accordance with EPA Method 10.

b. *Continuous Compliance, Standard Operation:* When not operating in the power augmentation mode, CO emissions shall not exceed 2.5 ~~8.0~~ ppmvd corrected to 15% oxygen based on a 3-hour block average as determined by valid data collected from the certified CEM system.

c. *Initial Test, Power Augmentation*: When injecting steam for power augmentation and a compressor inlet temperature of 59° F, CO emissions shall not exceed 16.1 ~~48.0~~ pounds per hour nor 4 ~~12.0~~ ppmvd corrected to 15% oxygen based on a 3-hour test average as determined by an initial performance test conducted in accordance with EPA Method 10.

d. *Continuous Compliance, Power Augmentation*: When injecting steam for power augmentation, CO emissions shall not exceed 4.0 ~~12.0~~ ppmvd corrected to 15% oxygen based on a 3-hour block average as determined by valid data collected from the certified CEM system.
[Rule 62-212.400(BACT), F.A.C.]

Section III.A.16 – Volatile Organic Compounds (VOC): The efficient combustion of clean fuels and good operating practices for the combined cycle gas turbine represent the Best Available Control Technology (BACT) requirements for VOC emissions. Compliance with the fuel specification and CO standards shall serve as indicators of good combustion. {Permitting Note: VOC emissions are expected to be less than 2.4 ~~3.0~~ pounds per hour and 1.1 ~~1.3~~ ppmvd corrected to 15% oxygen as determined by EPA Method 25A measured and reported as methane.} [Design; Rule 62-4.070(3), F.A.C.]

Specific Condition III.A.17 - Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of startup, shutdown, and malfunction of the combined cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

b. *Work Practice BACT*: ~~The unit(s) will reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire~~. A damper shall be installed on the HRSG stack to minimize the frequency of cold and warm starts. An oxidation catalyst control system shall be installed to reduce excess emissions occurring during startups, shutdowns, and malfunctions. A Best Operating Practice procedure for minimizing emissions during startup and shutdown shall be submitted to the Department within 60 days following procurement of the HRSG.
c. *Low-Load Restriction*: Except for startup and shutdown, operation ~~under DLN Modes 1, 2, 3, and 4~~ below 50 percent is prohibited.

Specific Condition III.B.13 - Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for specifically defined periods of startup, shutdown, and malfunction of the simple cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

c. *Low-Load Restriction*: Except for startup and shutdown, operation ~~under DLN Modes 1, 2, 3, and 4~~ below 50 percent is prohibited.

In reference to Condition III.A.20, El Paso submitted the following comment: "The procedure for determining NO_X compliance when data is missing or excluded appears to differ than the procedure described in Condition 20.a. for CO compliance. Clarification of these CEM compliance procedures is requested from the Department".

Department Response:

The Department agrees with El Paso and clarifies the mentioned condition as follows:

Specific Condition III.A.20 - CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring (CEM) systems to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. The CEM systems shall comply with the general monitoring requirements specified under "Gas Turbine Common Conditions" in Section III.C.

a. Compliance with the continuous CO emissions standards shall be based on a 3-hour block average starting at midnight of each operating day. The 3-hour block average shall be calculated from 3 consecutive hourly average emission rate values. If a unit operates less than 3 hours during the block, the 3-hour block average shall be the average of available valid hourly average emission rate values for the 3-hour block. The CO monitor shall have a span of no more than 25 ppmvd corrected to 15% oxygen. For purposes of determining compliance with the CEM emission standards of this permit, missing or excluded data shall not be substituted. Instead, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour block average for CO. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding CO emissions standards specified in this section. [Rule 62-212.400(BACT), F.A.C.]

Additional Department Clarifications of Permit Conditions

Based on comments received and petitions filed for several projects in Broward County, the Department reviewed the Emission Unit exemptions at Section 62-210.300, F.A.C. The Department's position is that the units mentioned in Section III.D.1-6 are not exempt from permitting and that they should be considered under the facility BACT determinations for each pollutant.

The affected units were already included in the permit. The conditions are revised as follows:

Section III D – Other Emission Units

1. Cooling Tower: BACT for the Cooling Tower was determined to be the use of fresh water and drift eliminators designed and maintained to reduce drift to 0.0005 percent of the circulating water flow rate. A not to exceed limit of 4200 mg/l total dissolved solids shall be maintained within the cooling tower. {Permitting Note: Potential emissions in tons per year are expected to be less than 1.64 for PM and 0.99 for PM_{10}}.
[Rule 62-212.400 (5) (c) F.A.C., BACT determination].

2. 2600 HP Diesel Generator: ~~This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(a)20. F.A.C., provided that fuel oil use does not exceed 32,000 gallons per year.~~ The unit will be fired with No. 2 diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.12 for PM, 3.26 for NOx, 0.73 for CO, 0.07 for SO_2 and 0.18 for TOC (total organic carbons)}. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].

3. 12.8 MMBtu/hr Gas-fired Natural Gas Fuel Heater: ~~This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(a)2 F.A.C., Categorical Exemptions.~~ This unit is subject to applicable provisions of 40 CFR 60, Subpart Dc. New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].

4. 250 HP Diesel Fire Pump: ~~This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(a)21 F.A.C., Categorical Permit Exemptions.~~ The unit will be fired with No. 2 diesel fuel with a maximum sulfur content of 0.05%. {Permitting Note: Potential emissions in tons per year are expected to be less than 0.013 for PM, 0.74 for NO_X, 0.18 for CO, 0.0014 for SO_2 and 0.08 for TOC (total organic carbons)}. [Rule 62-212.400 (5) (c) F.A.C., BACT determination].

5. Aqueous Ammonia Storage Tank: This unit will contain less than a 20 percent concentration of aqueous ammonia by volume and therefore is not subject to applicable provisions of 40 CFR 68, Chemical Accident Provisions. [Rule 62-4.070 (3) F.A.C.]

6. Two Diesel Fuel Storage Tanks (each less than 1000 gallons): ~~This unit is specifically exempted from permitting and BACT requirements according to Rules 62-210.300 (3) and 62-210.300 (3)(b)(iv) F.A.C., Generic and Temporary Exemptions.~~- This unit shall store 0.05% or less sulfur diesel fuel (by weight). [Rule 62-212.400 (5) (c) F.A.C., BACT determination].

Manatee County Environmental Management Department (MCEMD) Comments:

MCEMD Comment 1*: "The proposed facility has been determined to be a major source of air pollution, since emissions of at least one regulated air pollutant (particulate matter, sulfur dioxide, nitrogen oxides, carbon monoxide or volatile organic compounds) exceeds 100 tons per year (TPY). The Department's technical evaluation and preliminary determination is that "emissions from the facility will not cause or contribute to a violation of any state or federal ambient air quality standard".*

The new federal standard for ozone has been established at a level equivalent to 85 ppb averaged over any 8-hour period. An area will be considered non-attainment if the average of the annual fourth highest ozone readings at a monitoring site for any three year period equals or exceeds 85 ppb. Based on DEP's monitoring data, the three year running average for ozone within Manatee County has been steadily increasing. Considering that the County is marginally meeting the ozone standard and, that the neighboring counties of Sarasota and Hillsborough have already exceeded the standard for years 1999-2001, Manatee County does not concur with the Department's evaluation that the facility will not cause or contribute to violation of ambient air quality standards".

Please provide any additional information that will confirm the Department's position that these air quality standards will not be exceeded".

Department Response: The Department is confident that the proposed NO_X and VOC increases at the El Paso facility will not interfere with the Tampa Bay areawide strategy for reducing ozone concentrations. Ozone is an areawide pollution problem and the solution to reducing ozone levels is broad-based local and regional reductions in NO_X and VOC emissions (the precursors to ozone formation).

Based on recent monitoring data, the Tampa Bay area is marginally out of attainment of the 8-hour ozone standard. The area is still classified by EPA as in attainment. The Department will need to address this situation by requiring sufficient areawide reductions of NO_X and/or VOC to bring the area into compliance. Although the regulatory process is delayed because of court challenges to the 8-hour standard, the Department can identify a number of existing requirements that will significantly reduce ozone precursors in the Tampa Bay area. These requirements include the massive NO_X reductions from the TECO Order, low sulfur gasoline (low sulfur gasoline reduces NO_X emissions in cars and trucks), low sulfur diesel fuel, and more restrictive new car and truck emissions (Tier II standards).

In total, these reductions (mostly of NO_X) amount to tens of thousand tons per year or more over the next decade. The NO_X (365 tons per year) and VOC (29 tons per year) emissions increases from the proposed El Paso facility would not significantly reduce the total areawide reductions expected in the future. In fact, an argument can be made that the operation of the more efficient El Paso facility would result in further decreases in areawide emissions to the extent that even a small amount of power from higher polluting facilities is offset with power generated by the El Paso facility.

To more conclusively "prove" that the 365 tons of NO_X and 29 tons of VOC will not cause or contribute to a violation a very sophisticated and expensive model would need to be run for the entire region. The key inputs to the model would be traffic, power plants throughout the region, other industrial sources, and meteorology. Variations of the input from El Paso (from 0 to 365 TPY of NO_X, and 0 to 29 TPY of VOC) would not make any appreciable difference in the results. The uncertainty in any regional ozone model would be much greater than any contribution from this project.

Interestingly, emissions of NO_X from the El Paso project are primarily NO that tends to reduce ozone on a very localized basis. As the NO transforms to NO_2 miles downwind, it tends to increase ozone.

Variations in the emissions from the major conventional plants would make a difference. The reductions of 50,000 to 100,000 of NO_X caused by the Clean Air Act, the Department's Consent Decree, repowering of some conventional units, and competition from cleaner units will reduce the contribution of power plants to violations of the NAAQS in the Tampa Bay area. These reductions are about three orders of magnitude greater than the increase from the El Paso project. As previously discussed, the El Paso project will probably cause at least some further modest reduction in the region, based on displacement of some existing power with cleaner power.

<u>MCEMD Comment 2</u> *"The design for the proposed facility includes a steam turbine generator and an unfired heat recovery steam generator capable of a maximum of 120MW. According to Chapter 403.503, F.S., steam or solar electrical generating facilities of less than* ***75 megawatts*** *[emphasis added] is exempt from the criteria under the Florida Electrical Power Plant Siting Act. What control systems will be used to ensure that the 75 MW threshold is not exceeded?"*

<u>Department Response</u>: The Department required from El Paso a clear description of the manner by which electrical power from the steam turbine-electrical generator will be limited to less than 75 MW. Therefore, on the June 26, 2001, El Paso's letter in response to the Department's request for additional information stated the following:

"The steam turbine electrical generator (STG) planned for the Manatee Energy Center (BEC) combined cycle (CC) unit will have a maximum generating capacity of 120 megawatts (MW). The CC unit will have a modern distributed control system (DCS) that will serve as a means to control STG operation utilizing plant instrumentation and equipment. In conjunction with the steam turbine governor, a control management system will be implemented that will limit the STG output to less than 75 MW. The power output of the STG will be recorded on the plant DCS for records purposes and reporting needs as required. The CC unit will feature hardware provisions that will allow diversion of steam produced by the heat recovery steam generator (HRSG) from the STG thereby limiting its output. The main hardware features that will limit STG electrical output include CTG steam mass augmentation, STG controls, and a STG steam bypass system. Each of the systems is described in the following sections.

"The CC unit CTG will incorporate steam injection nozzles and design features that will allow a portion of the high-pressure steam generated by the HRSG to be diverted from the STG to the CTG. This introduction of steam to the CTG allows for a mass flow enhancement. The increased mass flow that results from steam injection will increase CTG output as well as fuel consumption. At ambient temperatures of about 50°F or less, steam mass flow augmentation will be limited by CTG equipment limitations. For instance, CTG backpressures could increase to levels beyond those recommended by the vendor. At these colder ambient temperature conditions, steam injection into the CTG will be curtailed and alternate means of steam diversion from the STG will be called on to a greater extent.

"The specifics of the limitations on CTG steam injection will be developed by the CTG vendor. Additionally, the specifics of steam introduction will be developed in conjunction with the CTG control systems for proper coordination with the Dry Low-NO_X (DLN) combustor control algorithms.

"Steam flow to the CTG steam injection nozzles, including CTG control integration, will be controlled from a signal generated within the DCS. This control signal will operate a control valve that regulates steam flow by modulation of the valve seat or opening area thereby allowing steam flow modulation.

"Steam flow to the CTG injection nozzles will be measured with classical steam flow measurement devices such as an orifice plate or an annubar. The steam flow measurement device will have a differential pressure transmitter attached to pressure sensing lines that will monitor the process and produce a proportional 4-20 milliamp (ma) signal that will tie in to the plant DCS. This signal will be converted to flow and signals will be transmitted to the CTG combustion control systems as well as to the balance of the plant DCS. During base load operations, the steam flow to the CTG injection nozzles will likely be a fixed steam mass flow or fixed percent of CTG mass flow. Injection of steam will occur at 100 percent load only. During upsets/startups and conditions such as low ambient temperatures, the steam flow will be controlled to coordinate with CTG combustion control to allow stable operation and avoid surge and stall within the CTG. During these periods, alternate STG steam diversion paths will be used.

"The STG will be fitted with an electronic governor and control system that will control the steam flow into the STG and hence the STG electrical output. Additional instrumentation will be used to adjust this control loop. For instance, condenser back pressure, intermediate pressure and low pressure steam flows, steam temperatures and pressure will each have a significant impact on the determination of the proper steam flow to the STG.

"The primary measurement of STG electrical output will be the main input to the STG governor control loops. This power measurement will be feed to the STG governor to compare to the primary set point. As an example, the primary set point may have a value of 74.9 MW. Following control system tuning, the set point will be adjusted to allow for control swings and upsets such that the hourly STG electrical production average will never exceed 75 MW.

"Whenever steam to the CTG injection nozzles and to all other locations are not sufficient to reduce STG output to the set point, the primary means of final control will be a STG steam bypass system. The STG steam bypass system will allow steam flow from the HRSG to bypass the STG and "dump" directly into the condenser. The DCS will generate a final control signal that will modulate this steam dump. A CC plant typically includes this hardware to allow for steam dumping during upsets or malfunctions. Additional control signals and associated hardware will regulate this dump steam as the final means of disposal of excess HRSG steam. In addition, an economizer bypass system may be used to reduce the flow of water passing through the economizer stage of the HRSG, which will reduce the flow-of steam produced.

"The control systems described above will typically scan each instrument every second and recalculate and update the status and driving signals going to each field device. Following control system tuning, the control systems will regulate STG output to the required level".

<u>MCEMD Comment 2</u>: *"The proposed facility will employ cooling towers for the purpose of cooling and condensing steam. Much of this cooling water is evaporated and must be replaced. According to the Southwest Florida Water Management District (SWFWMD), the proposed location of the facility is within the Most Impacted Area (MIA) which prohibits the permitting of new groundwater withdrawals. Please provide details as to the source and quality of water to be used at the facility".*

<u>Department Response</u>:

The Manatee Energy Center plans to use reclaimed water provided by the City of Bradenton Water Reclamation Facility (El Paso's e-mail dated December 3, 2001).

<u>MCEMD Comment 3</u>: *"How will this new supplier of electrical energy interact with the current regional suppliers? Will this facility displace energy being supplied these existing facilities? Does this facility have a local client base or will the energy be transmitted outside the region? Will a "needs determination" evaluation be conducted? Due to the fact that Manatee County is marginally meeting the current ozone standard, we would support an offset or pollutant trading so that the development of this facility would not cause a net increase in air emissions.*

Department Response

A "Need" determination pursuant to Sections 403.501-518, Florida Power Plant Siting Act is outside of the authority of the Department. The project was reviewed by the Department in accordance with the air permitting regulations applicable to projects are exempt from the Act.

The Department already concluded that emissions from the facility would not cause or contribute to a violation of the ozone standard. The Department also believes that the project will tend to reduce emissions in the Tampa Bay area if it displaces even 1 megawatt from conventional plants for every 10 megawatts that it generates. The plan proposed by MCEMD cannot be implemented unilaterally by the Department and certainly not by the time the Department is required to act on the El Paso.

Attachment I is a response from El Paso to the County's comments. The Department does not necessarily agree or disagree with the explanation provided by El Paso, but appreciates the effort to answer the County's questions.

MCEMD Comment 4: *"The Tampa Bay Estuary Program (TBEP) is charged with ensuring that Bay conditions are protected and in some instances improved. The TBEP determined that excessive nitrogen loading to the Bay is of special concern. This nutrient causes algal blooms, decreased water clarity and generally degrades water quality, resulting in habitat and fisheries losses. Recent studies indicate that at least 29 percent of the Bay's total nitrogen load is from atmospheric deposition. Due to the proximity to the Bay and Terra Ceia Aquatic Preserve, it is essential that the applicant provide detailed information on expected depositional impacts from nitrogen components (NO_X and ammonia) and other pollutants, along with their plans to offset these impacts in order to meet the TBEP's goal of "holding the line" on pollutant inputs to the Bay. Why couldn't Best Available Control Technology (BACT) be replaced with Maximum Available Control Technology (MACT) in this sensitive area? For example, $SCONO_X$ is considered to be a better control device and does not contribute bio-available ammonia through "ammonia slip". Can the Department require MACT for facilities located in sensitive areas?"*

Department Response:

As previously mentioned, the Department concluded that emissions to the atmosphere will be relatively low and that impacts on ambient air are less than significant. The Department does not dispute the assertions regarding deposition into the Bay. However a systematic approach that implements Clean Air Act requirements, promotes repowering, enforces on polluters, and encourages clean projects will hold the line and actually improve Tampa Bay.

The Department determined that MACT is not applicable because the facility will emit less than 10 tons per year of any hazardous air pollutant (HAP). The EPA has advised that MACT for certain types of combustion turbines (such as the GE 7FA) will likely be the use of Dry Low NO_X (DLN) technology. For certain other types of turbines, MACT will be the use of oxidation catalyst.

The Department notes that MACT for hazardous air pollutants (HAPs) is typically less stringent than BACT for PSD pollutants. However, the Department notes that DLN technology will be installed on the simple cycle units and both DLN and oxidation catalyst will be installed on the combined cycle unit.

Please refer to the enclosed BACT determination. The Department considered $SCONO_X$, but found that it is not technically feasible on the simple cycle units. It is not cost-effective on the combined cycle unit.

El Paso reviewed the County's comment and replied as follows: "Based on the use of reclaim water currently discharged to Tampa Bay, operation of the Manatee Energy Center will result in a net decrease in total nitrogen loading to Tampa Bay. Reclaim water used by the Manatee Energy Center will be managed such that surface discharges to Tampa Bay will not occur".

El Paso also stated that "a report evaluating nitrogen loading on Tampa Bay due to operation of the Manatee Energy Center is being prepared and will be provided to the Department when available". The Department does not necessarily agree or disagree with El Paso's assessment of this issue, but is appreciative of the effort made in responding to the County's comment. The Department will provide a copy of the future El Paso report.

MCEMD Comment 5: *"Although the proposal is for a predominantly gas- fired power plant, the permit would allow combustion of diesel fuel in a 2600 HP diesel-fired electric generator and a 250HP diesel water pump. The hourly emissions of criteria pollutants would be significantly greater. We question whether these increased emissions from the use of diesel fuel is acceptable in terms of cumulative effects of other regional and in-County sources?"*

Department Response:

It is anticipated that each of these units will consume less than 32,000 gallons per year which would normally make them exempt from permitting if they were constructed at existing facilities. The No. 2 distillate fuel oil used for this project will have a maximum 0.05 percent sulfur specification and will be used only for these small units. This compares with the maximum limit set by Manatee County for fuel sulfur of 1 percent (Manatee County Code of Ordinances – Section 1-32-5(d)).

As stated previously, the 2600 HP Emergency Generator potential emissions in tons per year are expected to be less than 0.12 for PM, 3.26 for NO_X, 0.73 for CO, 0.07 for SO_2 and 0.18 for TOC (total organic carbons). Emissions from the 250 HP Fire Water Pump Diesel Engine emissions in tons per year are expected to be less than 0.013 for PM, 0.74 for NO_X, 0.18 for CO, 0.0014 for SO_2 and 0.08 for TOC.

With the very low emissions and the likelihood of (passively) offsetting even some power from nearby conventional units, it is clear that the project as designed is acceptable "in terms of cumulative effects of other regional and in-county sources."

MCEMD Comment 6 : *"In several sections, the permit requires that reports and notifications be submitted to the Department of Environmental Protection. We would ask that the Manatee County Environmental Management Department also is listed as a recipient of such reports, documents, and notifications, according to the same time frames required for submittal the Department".*

Department Response:

The Department will review and revise the permit to include the Manatee County Environmental Management Department as a recipient of the various documents, reports and notifications.

Environmental Protection Agency (EPA) Comments

Many of EPA's comments are favorable critiques of the Department's approach in preparing the draft permit and BACT determination. Following are certain EPA comments that the Department has determined require clarification or a response.

EPA Comment 4 - Oxidation Catalysis: "The draft permit CO emission limit of 8 ppmvd for the simple cycle combustion turbines and for the combined cycle combustion turbine when not operating in power augmentation mode is among the lower BACT limits established in Region 4 for combustion turbines. We further understand Florida Department of Environmental Protection's (FDEP) expectation that the turbines will in fact typically operate with even lower emissions based on inherent combustor design and good combustion practices alone. However, please note that the use of catalytic oxidation for further control of combustion turbine CO emissions, especially for combined cycle combustion turbines, has become much more common as part of BACT determinations for combustion turbine projects. Catalytic oxidation has the added advantage of controlling volatile organic compound (VOC) emissions including volatile organic hazardous air pollutants

Further related to the CO draft permit emission limit of 8 ppmvd, we note that Appendix BD (the BACT determination) indicates an emission rate of 7.4 ppmvd at full load for either combined cycle or simple cycle combustion turbines. Based on our understanding that the draft permit has precedence over Appendix BD, we presume that 8 ppmvd will be the enforceable limit.

Emissions of CO from combustion turbines increase sharply below a certain load level (unless an add-on control device is in use). For GE 7FA combustion turbines, this sharp increase occurs with operation below about a 50-percent load level. It is not clear to us that the draft permit restricts normal operation (that is, operation other than during startup and shutdown) to load levels of 50 percent and higher. Condition A.17.c. prohibits operation of the combined cycle combustion turbine at "DLN Modes 1, 2, 3, and 4" (except during startup and shutdown), and Condition B.13.c. specifies a similar restriction for the simple cycle combustion turbines. Since the load levels equivalent to these modes are not specifically stated, however, we are not certain what load levels are prohibited. Furthermore, we would appreciate your identifying which monitoring requirements in the draft permit serve to track compliance with the low-load restrictions.

Department Response: In their application, El Paso, submitted cost-effectiveness calculations to control CO emissions by oxidation catalyst. Based on the most conservative case the calculations result in an oxidation catalyst cost estimate of $2,475 per ton of CO removed (combined cycle operation) and $8,981 (simple cycle operation). The Department does not consider oxidation catalyst to be cost-effective for simple cycle operation based on these calculations.

El Paso's cost effectiveness calculations are based on reduction of CO concentrations from the range of 11.7 to 1.2 ppmvd under combined cycle (steam power augmentation mode) and from 7.4 to 0.7 ppmvd under simple cycle operation. Based on data available to the Department, actual emissions without oxidation catalyst are on the order of 1 ppmvd while firing gas or fuel oil at least under normal modes of operation (not steam power augmentation). This is substantially less than even the objective by oxidation catalyst.

The Department has actual no data on CO emissions during steam power augmentation and initially limited operation under this mode to 2000 hours per year. However as discussed in the first comment by El Paso on Page 1, the company will install oxidation catalyst on the combined cycle unit and the Department will reduce CO emission limits while allowing continuous operation under steam power augmentation mode. This will also reduce VOC and HAP emissions. A CO monitor will be installed on the combined cycle unit.

The Department believes that with SCR and oxidation catalyst, there is less reason to limit operations to less than 50 percent of full load. However, El Paso has agreed to a condition that operation at loads less than 50 percent is not allowed except during startup and shutdown.

Startup under simple cycle operation will be short (less than 15 minutes), while emissions under full load operation will be very low even without oxidation catalyst. The Department will require El Paso to install a CO monitor at the El Paso Broward to collect information regarding CO emissions during simple cycle startup and shutdown. The data may be used to set startup limitations at future projects.

<u>EPA Comment 5 - Startup and Shutdown Data Inclusion and Exclusion</u>: *"As we have often commented, startup and shutdown are part of normal combustion turbine operation and need to be addressed in PSD permits. FDEP has done so for this project by establishing a work practice standard and by limiting the number of hours of emissions that can be excluded from NO_X and CO compliance demonstrations for the combined cycle combustion turbine and from NO_X compliance demonstration for the simple cycle combustion turbines. Other permit options that could be considered include limitations on the number of startups and shutdowns in any 12-month period; mass emission limits for NO_X and CO emissions during any 24-hour period to include emissions during startup and shutdown; and future establishment of startup and shutdown BACT emission limits for NO_X and CO derived from test results during the first few months of commercial operation. In addition, compliance with any explicit or implicit annual emissions limits should be assessed with startup and shutdown emissions included. Regarding the option of mass emission limits, we acknowledge FDEP's comments that such limits may be difficult to quantify.*

"The only definition of startup that we find is in Appendix BD of the package. As mentioned previously, we understand that the provisions of Appendix BD are not necessarily enforceable. Furthermore, the definition in Appendix BD denotes when startup commences but does not state the operating level or other characteristic marking the end of startup and the beginning of normal operation. We recommend that a more complete definition be developed so that the emission measurements eligible for exclusion under the excess emissions provisions can be confirmed easily.

"Conditions 17d of the combined cycle section and 13d of the simple cycle section contain provisions allowing certain data during periods of startup and shutdown to be excluded from compliance demonstrations". Condition 17d for the combined cycle combustion turbine exempts up to 2 hourly emission rate values in a calendar day, except for combined cycle cold startups, in which case up to 4 hourly emission rate values in a calendar day can be exempted. Additionally, Condition 17d indicates that no more than a total of 4 hourly emission rate values shall be exempted in a calendar day. It is unclear to us the purpose of the latter restriction on total hourly emission rate values. Also, it should be clarified in what case a total of 4 hours can be exempted when there is no combined cycle cold startup during the calendar day.

"Condition 13d for the simple cycle combustion turbines exempts "no more than 2 hourly emission rate values" from the NO_X compliance demonstration as well as restricting the exemption to "no more than a total of 3 hourly emission rate values" in a calendar day. The purpose of the latter restriction is unclear, since the NO_X compliance period is a 24-hour block average. Finally, to remain consistent with previous FDEP simple cycle combustion turbine permits, no more than 2 hours out of a 24-hour period (or calendar day) should be exempted from compliance demonstrations".

<u>Department Response</u>: The Department does not allow extended operation at low loads for the simple cycle units during which higher emissions typically occur. Startup for the simple cycle units is simply the time it takes to reach DLN Mode 5Q (roughly corresponds to 50 percent of full load). The Work Practice BACT requires that this mode be reached within 15 minutes. Both emissions and the DLN Modes are tracked by the Mark VI control system.

General Electric did not agree with the Department's Work Practice BACT to minimize startup time of the combined cycle unit (i.e. time to achieve Mode 5Q). El Paso proposed the alternative of installing oxidation catalyst for CO and VOC reduction. The facility must also employ good operating practices during periods of excess emissions. This includes, for example, operation of the SCR system on the combined cycle unit as soon and for as long as the temperature conditions within the heat recovery steam generator allow.

The Department believes that the measures described (in addition to exclusive firing of natural gas) will result in the lowest emissions (whether in startup or steady state modes) from any combined or simple cycle projects permitted in the Southeast.

The Department has been progressively implementing EPA's comments regarding startups, high emission modes, inclusion and exclusion of data, etc. The present permit represents a major effort in this regard. Further efforts will be made as emissions data are received from facilities required to demonstrate compliance with NO_X and CO limits by CEMS.

The following sentence of Specific Condition 13.d. for the simple cycle turbines was revised as suggested: " No more than a total of two ~~three~~ hourly average emission rate values shall be excluded from the continuous NO_X compliance demonstrations for such periods in any calendar day".

EPA Comment 6 - Initial and Annual Testing: "Draft permit Condition 14 pertaining to simple cycle combustion turbines requires testing initially and at permit renewal for PM/PM_{10}, CO, NO_X, and VOC. The draft permit conditions for the combined cycle combustion turbine do not require PM/PM_{10} and VOC initial and renewal testing. We have agreed with FDEP in the past that PM/PM_{10} and VOC testing is not required for combined cycle combustion turbines with continuous emission monitoring systems (CEMS) for CO. However, a permit for a project with both combined cycle and simple cycle combustion turbines that has different initial and renewal testing requirements for the two types of turbines may be perceived as inconsistent. On a related point, we recommend that FDEP give consideration to requiring CO CEMS for the simple cycle combustion turbines as well as for the combined cycle combustion turbine in view of the fact that the simple cycle combustion turbines will be allowed to operate up 5,000 hours per year at full load (and even more hours at a combination of full and partial loads)".

Department Response: The Department agrees with EPA and revises these conditions to include initial and renewal testing for PM/PM_{10} and VOC emissions for all turbines. The Department will require El Paso to install a CO monitor at the El Paso Broward to collect information regarding CO emissions during the very short simple cycle startup and shutdown periods. The data may be used to set startup limitations at future projects. The Department notes that after the startup period, emissions will be approximately 1 - 2 ppmvd (although the limit is 7.4 ppmvd) based on actual test data. The continuous collection of CO data at all simple cycle units does not appear justified except at those that exhibit inherently higher emissions than the GE 7FA.

EPA Comment 7- Pipeline Natural Gas: "The term "pipeline-quality natural gas" appears several times in the draft permit. We have sought in the past for a government agency or industry trade group definition of "pipeline-quality" and have never succeeded in finding such a definition. We presume that the term "pipeline-quality natural gas" means natural gas obtained from an intrastate or interstate commercial natural gas pipeline."

Department Response: The Department confirms that such gas is obtained from a FERC-regulated natural gas pipeline.

EPA Comment 8 - Ammonia Emissions: "The draft permit contains an emission limit for ammonia of 5 ppmvd. Ammonia is not regulated under the PSD program, and we do not have a definitive policy on ammonia emissions. However, we can comment that the limit in the draft permit is consistent with (although not equal to the lowest) ammonia limits we are aware of from projects outside Region 4."

EPA Comment 9 - Air Quality Impact:: "In the air quality impact evaluations prepared for this project, we see no acknowledgment that NO_X emissions are precursors to ground-level ozone formation. Such acknowledgment would help demonstrate why control of NO_X emissions from combustion turbines is important".

Department Response:

The Department certainly acknowledges that NO_X emissions and VOC emissions are the key precursors in the formation of ground-level ozone.

CONCLUSION

The final action of the Department is to issue the permit with the changes noted above.