STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. Gary Lambert, Executive Vice President
CPV Gulfcoast, Ltd.
45 Braintree Hill Office Park, Suite 107
Braintree, MA 02184
_______________________________/

DEP File No. 0810194-001-AC and PSD-FL-300
245 Megawatt Combined Cycle Facility
Manatee County

Enclosed is the Final Permit Number 0810194-001-AC (PSD-FL-300) to construct a nominal 245 MW Combined Cycle Plant called the CPV Gulfcoast Power Generating Facility near Piney Point, Manatee County. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

C.H. Fancy

C.H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 2/5/01 to the person(s) listed:

Gary Lambert, CPV Gulfcoast, Ltd.*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Joe McClash, Chair, Manatee County BCC*
Karen Collins-Fleming, Director, Manatee County EMD
Scott Sumner, P.E.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 2/5/01
(Clerk) (Date)

7099 3400 0000 1449 4307

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

Article Sent To:
Mr. Gary Lambert

Postage	$	CPV Gulfcoast
Certified Fee		Postmark Here
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Restricted Delivery Fee (Endorsement Required)		
Total Postage & Fees	$	

Name (Please Print Clearly) (to be completed by mailer)
Mr. Gary Lambert
Street, Apt. No.; or PO Box No. 45 Braintree Hill Office Park-Ste 107
City, State, ZIP+4
Braintree, MA 02184

PS Form 3800, July 1999 — See Reverse for Instructions

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- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
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1. Article Addressed to:

Mr. Gary Lambert
Executive Vice President
CPV Gulfcoast, Ltd.
45 Braintree Hill Office Park
Suite 107
Braintree, MA 02184

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
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PS Form 3811, July 1999 — Domestic Return Receipt — 102595-99-M-1789

Memorandum

Florida Department of Environmental Protection

TO: Howard L. Rhodes

THRU: C. H. Fancy

FROM: Teresa Heron and A. A. Linero

DATE: January 29, 2001

SUBJECT: CPV Gulfcoast Power Generating Facility
245 MW Combined Cycle Plant
DEP File No.0810194-001-AC (PSD-FL-300)

Attached is the final permit package for construction of a nominal 245 MW Combined Cycle Plant at the CPV Gulfcoast Power Generating facility near Piney Point, Manatee County.

The basic unit is a nominal 170-megawatt General Electric 7FA gas and oil-fired combustion turbine-generator. The project includes an un-fired HRSG and a steam-electrical generator.

Emissions control include SCR on NO_X to achieve 3.5 ppm while firing gas and 10 ppm while firing fuel oil and with an ammonia slip of 5 ppm (under fuel oil and gas). A CO monitor is required. This project appears to be the best-controlled and monitored to-date.

A public meeting was held on January 8, 2000 in Palmetto. Comments received during the public notice period and during the public meeting are addressed in the Final Determination. Some of CPV's late responses to EPA and Manatee County comments are also included.

On advice of counsel, we removed the Specific Condition limiting electrical production from the steam-electrical generator to 74.9 MW. Although these matters are outside the scope of this air permitting action, the company believed that the air permit was a proper place to clarify that the project is not subject to the Siting Act. They concluded this after discussing the matter with the Siting Office prior to submitting the application. We still have reasonable assurance that CPV will comply with the condition of the permit condition we are removing. Their assurances on this matter are clear from the responses to the comments of the Manatee County Environmental Management Department.

Day 90 is February 27 so we are well ahead of schedule. We recommend your signature and approval of this Intent to Issue.

AAL/th

Attachments

Fancy, Clair

From:	Comer, Patricia
Sent:	Monday, January 29, 2001 4:37 PM
To:	Fancy, Clair
Cc:	Rhodes, Howard; Linero, Alvaro; Chisolm, Jack; Beason, Doug; Goorland, Scott
Subject:	CPV Gulf Coast permit
Sensitivity:	Confidential

CONFIDENTIAL ATTORNEY CLIENT MATERIAL
Memo to:
Clair Fancy

RE: Capacity limits on steam unit at CPV Gulf Coast

As you requested, here's the info about the consensus we reached today at the meeting of Jack, Doug, Scott and me today. We talked about a variety of issues dealing with capacity of steam generation and the PPSA thresholds, but we have specific concerns about putting capacity limits in air emissions permits on units that have no air emissions. We generally agreed that this is improper. The air program jurisdiction doesn't include limiting capacity per se. The air program jurisdiction is primarily found in 403.061 of the Florida Statutes, (with some other not matters not related to what we're talking of here taken up in 403.0872-403.0873) Besides setting air limits and protecting those limits, the program can require permits and reports and can implement the state requirements of the Clean air Act. Nothing in 403.061 specifically addresses limiting any capacity of any unit in an air construction permit, especially a unit that has no air emissions. The Clean Air Act requirements contain concepts of limiting the potential to emit regulated pollutants of an air emissions unit, and it has traditionally been accepted that the program can limit emissions of air emissions units by limiting the operational capacity of the unit in an air construction permit for purposes of determining applicability of certain Clean Air Act requirements. But there is no authority in the Clean Air Act to limit capacity of units that have no air emissions.

I understand that you have concerns about the issue of capacity and the Power Plant Siting Act, but that is a separate issue. Ihe immediate issue that we are most concerned about is the placing of limits in an air construction permit on equipment that has no air emissions. Units that have no air emissions are generally beyond the jurisdiction of the program to address. They are not emissions units and are not subject to the DARM rules. Since the program has no jurisdiction over the unit in question and since the limiting of the use of the unit will have no impact on air emissions from any other unit at the facility, placement of limits on the unit is beyond the jurisdiction of the program. The limits should not be included in the air construction permit.

We request that no such limits be included in the CPV Gulf Coast permit or in any future air construction permit.

Patricia E. Comer
Assistant General Counsel

FINAL DETERMINATI
File No. 0810194-001-AC (PSD
CPV – GULFCOAST POWER GENER
245 MW COMBINED CYCLE COMBU

Howard 11/30
Pls read cover memo
& OGC memo right behind
it. We told her if she would
give it to us in writing, then
we would remove. This verbal
stuff on these issues is
not sufficient. Clair

The Department distributed a Public Notice package on Noven
construct a nominal 245-megawatt (MW) natural gas and fuel
known as the CPV – Gulfcoast Power Generating Facility near
project consists of a nominal 170 MW General Electric 7FA c
an unfired heat recovery steam generator, a steam-electrical ge
draft cooling tower; a 1.0 million gallon fuel oil storage tank,
Public Notice of Intent to Issue was published on November 2

Written comments were received during the initial 30-day pub
of the Manatee County Board of County Commissioners, the M
Management Department and EPA Region IV.

A public meeting was held on January 8, 2000 at Blackburn Elementary School. Written and oral comments were received from the public at that meeting. CPV (by Moyle Flanigan) submitted minor written comments within the time provided after the meeting. CPV subsequently provided comments and a revised oxidation catalyst to the Department as requested by EPA. CPV also provided comments to the Department reflecting its own responses to some of the Manatee County comments.

The written comments are addressed below in the same order as received by letter. Each is followed by the Department's response (and CPV's responses where applicable). Comments received at the public meeting are addressed following the letter comments.

1. *In his letter dated December 14, 2000 Chairman McClash requests that the Department give every consideration to his concerns. The first one is that "property to be used by this plant under permit conditions has not been approved by Manatee County Board of County Commissioners."*

   The General Permit Conditions (pursuant to Rule 62-4.160, F.A.C) attached to the permit include at least one clarifying reference. According to Condition G.3, the permit does not authorize any "infringement of federal, state, or local laws or regulations." Also the permit is not a "waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit."

   It is clear that the permit will not fulfill any local approval requirements related to issues under the purview of Manatee County. It will also not impede the local approval processes in any way.

2. *The second concern in Commissioner McClash's letter is that "Manatee County has a power plant that supplies power and any new power plant should be stipulated to reduce pollution in our county/region by ensuring power production from this plant offsets power production from TECO, Big Bend or FPL Parrish Plant."*

   Refer to the attached table, "Comparison of CPV Gulfcoast and Gannon Repowering Emissions vs Conventional Units along Southwest Florida Coast." In 1999, the FPC P. L. Bartow Plant, for example, had an actual heat input approximately equal to that of the potential heat input at CPV Gulfcoast. Yet potential nitrogen oxides emissions from the CPV project will be approximately 2.5 percent compared to actual emissions measured at the mentioned FPC unit. Similarly potential emissions of sulfur dioxide from the CPV project are less than 1 percent of the actual emissions reported at the P. L. Bartow Plant in 1999.

The Department cannot on its own stipulate that power production from the CPV unit will offset an equal amount of power production from the FPL and TECO units. However the additional power capacity will compete with power from the established units including FPL Manatee. One favorable competitive factor is that the CPV plant (and FPC Hines) will have a thermal efficiency of 56 percent compared to approximately 32 percent for the conventional units. This means, for example, that the CPV plant will yield about 75 percent more electrical energy than the listed conventional units for each unit of fuel burned.

A very conservative assumption is that the CPV project will offset only 1 MW from other conventional sources units for every 10 MW produced by CPV. Based on the emissions per unit of heat input from the competing units, there will still be appreciable reductions in emissions within the airshed (that includes Manatee County) as a result of the CPV project. Though we cannot stipulate the amount of the decrease either, common sense and economic principles suggest that such decreases could be substantial.

CPV Comment: In a separate communication dated January 26, 2001, CPV states that "DEP cannot require the applicant to provide emissions offsets as part of the air permitting process because state air permitting rules can only require facilities proposed to be located in nonattainment areas to provide emissions offsets as part of the permitting process. Manatee County is not designated a nonattainment area for any air pollutants. Accordingly, DEP has not imposed an emissions offsets requirement in the CPV Gulfcoast permit."

3. *The third concern in Commissioner McClash's letter is that "the air permit should take into consideration that the Tampa Bay region has the worst air pollution from power plants and additional power plants will only increase pollution unless the plant offsets existing pollution generated."*

The Department requirements for this permit are based on the Rules for the Prevention of Significant Deterioration (PSD) of Air Quality. These apply to areas that are designated as attainment with the National Ambient Air Quality Standards (NAAQS). Accordingly a determination of the Best Available Control Technology (BACT) was performed. The result is that allowable emissions of key pollutants are very low.

Several years ago, the Tampa area was designated as non-attainment and classified as "marginal non-attainment" with respect to ozone. For reference, the Southeast Florida Region was classified as "moderate non-attainment." Both areas have been redesignated as "attainment." The Atlanta, Houston, and Los Angeles areas are presently classified as "serious," "severe," and "extreme non-attainment," respectively.

The CPV project will not increase pollution in the Tampa Bay Region if 100 megawatts produced by CPV Gulfcoast (passively) cause only 10 (and possibly even 1) megawatts of power offsets by all other Tampa region plants combined.

4. *The final concern in Commissioner McClash's letter is that "this permit is contrary to Tampa Bay National Estuary program goals to reduce nitrogen loading in Tampa Bay."*

The proposed facility will not interfere with the TBEP nitrogen loading reduction plans for Tampa Bay. The TBEP plan calls for a nitrogen loading reduction goal of approximately 17 tons per year to Tampa Bay. In the first five-year period of the plan (1994-1999), areawide reductions have exceeded the goal. Further reductions in loading over the next five-year period (2000-2004) are expected to be even greater, much of it do to emission reductions from the TECO Consent Decree that will reduce NO_X emissions by approximately 30,000 tons per year by 2004. This translates into approximately a 75 ton per year nitrogen loading reduction to Tampa Bay. Additional reductions from other sectors will further reduce loading. The CPV project, which emits a maximum of 126 tons of NO_X per year, would offset some of these other reductions by approximately 0.3 tons of nitrogen loading. This small offset will not interfere with the TBEP nitrogen loading reduction goals.

The very substantial reductions required by the 1990 Clean Air Act and the Department's Consent Decree with TECO will result in nitrogen oxides emission reduction on the order of 50,000 to 100,000 tons. Such reductions will clearly reduce the loading of nitrogen into Tampa Bay by several orders of magnitude more than the increases from the CPV project.

5. *In their letter dated December 22, 2000 the Manatee County Environmental Management Department (EMD) states "considering that Manatee County is marginally meeting the ozone standard and that neighboring counties of Pinellas and Hillsborough have already been designated non-attainment areas, Manatee County questions the Department's assumption that the facility will not cause or contribute to a violation of ambient air quality standards."*

The Department is confident that the proposed NO_X and VOC increases at the CPV 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 small increases in NO_X (126 tons per year) and VOC (15 tons per year) from the proposed CPV 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 CPV facility would result in further decreases in areawide emissions to the extent that power from higher polluting facilities is offset with power generated by the CPV facility. This will occur even if 245 MW of power generated by CPV result in just 20 MW less power generated by conventional units in the Tampa Bay Area.

To more conclusively "prove" that the 126 tons of NO_X and 15 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 CPV (from 0 to 126 TPY of NO_X, and 0 to 15 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 CPV 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 CPV project. As previously discussed, the CPV project will probably cause at least some further modest reduction in the region, based on displacement of some existing power with cleaner power.

6. *EMD points out "that steam or solar electrical generating of* ***less than 75 megawatts*** *[emphasis added] are exempt from the requirements of the Florida Electrical Power Plant Siting Act." EMD asks, "what assurance does the applicant provide that the 75 MW threshold would never be exceeded."*

In its application, **CPV stated the following**:

"The steam turbine generator (STG) output will be limited to less than 75 MW. Control of STG output will be monitored and controlled to ensure the 75 MW output limit is not exceeded. A number of control options have been investigated and the most probable are described below.

"When ambient temperature is at 59 °F or greater, excess steam generated in the HRSG will be extracted from the HRSG, bypassing the steam turbine, and injected into the CTG. This mode of operation is referred to as power augmentation. Since there is a limit on the quantity of steam that may be injected into the CTG, it may be necessary to further reduce flow to the STG to limit output or to reduce steam turbine output by other means.

"Bypass of a portion of heat exchanger surface in the HRSG is an effective method of reducing steam production by reducing the heat recovered from the combustion turbine flue gas. The proposed design will make use of a low temperature economizer bypass to limit steam production by allowing more of the heat generated by the combustion turbine to be discharged to the atmosphere with the flue gas. This will limit STG output.

"In many cases, application of both of these control modes will reduce steam output to the turbine to the required quantity. If additional reduction in STG output is required, raising STG discharge pressure by raising the condenser operating temperature will reduce turbine efficiency, reducing electrical output. Output of the STG may be tuned to the desired value by turning cooling tower cells on and off as necessary.

"When ambient temperature falls below 59 °F the manufacturer does not recommend injection of steam into the combustion turbine. If the low temperature economizer bypass combined with an increase cooling water temperature does not reduce STG output sufficiently, excess steam may bypass the steam turbine and be sent directly to the condenser.

"Output of the STG will be controlled automatically utilizing the methods described above to ensure that the electrical power produced from steam does not exceed 74.9 MW."

In its communication dated January 26, **CPV further stated:**

"Specific Condition No. 51 of the permit imposes the requirement that the electrical power from the steam-electrical generator be limited to 74.9 MW on an hourly basis. This is a legally enforceable permit condition that, if violated, would subject the permittee to enforcement action by the Department. Imposition of this condition within the permit provides the Department assurance that exceedance of the 74.9 MW limitation on steam-electrical power generation will not occur."

Note: See Item 22 below for Department action.

7. *EMD states that "according to the Southwest Water Management (SWFWMD), the proposed location of the facility is within the Most Impacted Area (MIA), which would prohibit the permitting of new groundwater withdrawals." In view of the 2-2.5 million gallon per day needed for steam condensation, EMD requests the "details as to the source and quality of water to be used at the facility."*

CPV is on a separate pursuit of approval track for obtaining water for cooling/condensation. Regardless of the source, the water will need to be treated to very stringent standards if only due to operational reasons.

In its communication dated January 26, **CPV states**:

"Review of water sources are not within the scope of this proceeding."

8. *EMD states that "due to the fact that Manatee County is marginally meeting the current ozone standard, we strongly urge that a pollutant offset or trading program be required to ensure that this facility would not cause a net increase in Manatee County."*

The Department already concluded that emissions from the facility will 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 EMD cannot be implemented unilaterally by the Department and certainly not by the time the Department is required to act on the CPV application. EMD's position will be forwarded to the appropriate "2020 Committee" members for consideration in legislation under development.

9. *EMD states "recent studies indicate that at least 29 percent of the Bay's total nitrogen load is from atmospheric deposition. EMD believes that "due to the project's proximity to the Bay and Terra Ceia Aquatic Preserve, it is essential that the applicant provide details 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."*

As previously mentioned, the Department concluded that emissions to the atmosphere are barely significant 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 Requirements, promotes repowering, enforces on polluters, and encourages clean projects will hold the line and actually improve Tampa Bay.

10. *EMD expressed concern about the hourly emissions of criteria pollutants during fuel oil firing. EMD questions "whether this additional hourly load of emissions from the use of #2 fuel oil is acceptable in terms of cumulative effects of other regional and in-County sources."*

    The No. 2 distillate fuel oil used for this project will have a maximum 0.05 percent sulfur specification and will be used as back-up for a maximum of 720 hours per year. 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)).

    The selective catalytic reduction (SCR) system must be used when firing fuel oil to reduce NO_X emissions to 10 parts per million by volume, dry, at 15 percent oxygen (ppmvd). This represents the lowest NO_X limit issued to-date for fuel oil firing in any combustion source in the State.

    Data from identical GE 7FA units installed by the City of Tallahassee, TECO at Polk County show that CO and VOC emissions are actually much lower than permitted whether oil or gas is burned and that the results during oil burning are marginally greater than values measured during gas burning.

    Previous discussions regarding the low air quality impacts assume that the facility will in fact use oil for 720 hours per year. With the very low emissions (even during oil firing) 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."

11. *EMD notes that an "issue of concern, perhaps outside of DEP's review of the CPV application, is that the applicant has yet to apply for and be granted the local land use approvals that would be required prior to construction of this facility."*

    See response to Comment 1 above.

12. *In EPA's letter dated December 27, 2000 EPA states that "Condition 22 in the draft PSD permit indicates that excess emissions during startup and shutdown are allowed for up to 4 hours in any 24-hour period. Because periods of startup and shutdown are part of normal source operation, we recommend that the Florida Department of Environmental Protection (FDEP) also consider future establishment of startup and shutdown best available control technology (BACT) emission limits for NO_X derived from monitoring results during the first few months of commercial operation. We further recommend that FDEP include definitions of what constitutes "startup and shutdown periods" as referenced in Condition 22.*

    The Department does not allow extended operation at low loads, during which such emissions typically occur. The facility must also employ good operating practices to allow excess emissions. This includes, for example, continued operation of the SCR system as long as the temperature conditions within the heat recovery steam generator allow.

    At the same time, the Department is aware that emissions are less from the GE 7FA units at low loads (< 50 percent of full load) than previously believed. This is based on reports from new installations including JEA.

    The Department will progressively implement EPA's comments for future projects as we get emissions data from facilities required to demonstrate compliance by CEMS. As drafted, the permit includes Specific Conditions (20, 22, 23, 24, 43, 45) related to excess emissions during startup, shutdown, and valid, documented malfunctions. See condition 43 of Section III of this permit for provisions that relate to excluding periods of CEM system data recorded for NO_X and CO for episodes of startup, shutdown and malfunction. However, these periods are recorded and reported as excess emissions as stated in conditions 24 and 43.

13. *EPA included five items related to the cost-effectiveness of oxidation catalyst to control CO emissions from the project. These include: a recommendation to limit operation in steam augmentation mode to 2000 hours per year; removal of costs of additional natural gas to compensate for pressure drop across catalyst; use of 8 instead of 7 percent interest rate; "double-counting" of catalyst recovery cost; and a high (20 percent) contingency fee.*

   By letter dated January 26, 2001 (attached) CPV submitted revised cost-effectiveness calculations to control CO emissions by oxidation catalyst.

   Based on the most conservative case (adoption of all EPA recommendations), the revised calculations result in an oxidation catalyst cost estimate of $3,050 per ton of CO removed. The Department does not consider oxidation catalyst to be cost-effective based on this revised calculation.

   CPV's cost effectiveness calculations are based on reduction of CO concentrations from the range of 9-20 ppmvd to the range of 2-4 ppmvd. 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. This is substantially less than even the objective by oxidation catalyst. The Department's conclusion is that the revised costs submitted by CPV are actually biased to the low side. However the Department has no data on CO emissions during power augmentation.

   A maximum operating period of 2000 hours per year during power augmentation (believed to be the actual mode of highest CO emissions) will be added to Section III, Specific Condition 9. Power augmentation will not be limited if oxidation catalyst is installed. The 2000 hour limit may be revised in the future at the request of the applicant, based upon review of actual performance and control equipment cost-effectiveness following proper public notice.

   CPV will install the first continuous CO monitor required for compliance at a combined cycle plant in Florida. The Department believes that long-term data will prove that oxidation catalyst is not cost effective for this project. The data will provide a basis for requiring future applicants to adhere to lower CO limits that will clearly increase the theoretical cost of oxidation catalyst. CPV has agreed to install a CO continuous emission monitoring (CEM) system to provide reasonable assurance that the proposed emissions will not be exceeded.

   The Department revised the BACT analysis to reflect the recent field data used to justify the position that CO catalyst is not cost effective for this project.

14. *At the January 8 hearing, Mr. Leon Kotecki of Manatee County Planning made the following (paraphrased) comment: "I noticed comparing CPV Gulfcoast to the various other units in the area, capacity of megawatts are different but the NO_X emissions are the same (e.g. 3.5 ppmvd while firing gas). He asked about a multiplication factor and basically requested an explanation on the seemingly similar emissions from different-sized facilities.*

   The Department responded that emissions appear to be the same (on a concentration basis) between the CPV Project and the Gannon Repowering project because they are controlled to the same level of technology. In a separate column in the same table, it is evident that emissions (on a tons per year basis) are correspondingly higher from the larger project.

15. *At the January 8 hearing, Mr. Kumarach, a member of the public, asked whether the permit should be changed as we gain experience like we are gaining here, and with the 2020 commission. He asked whether they (the 2020 Commission) will (or should) come up with anything that may change our philosophy in the future.*

Mr. Fancy of FDEP explained that about a year ago the Department issued a permit to a combined cycle plant with a limit of 9 ppmvd of NO_X using Dry Low NO_X technology. The CPV plant will be permitted at a NO_X limit that is a bit more than one-third of the previous value by using Selective Catalytic Reduction (SCR). As you approach a very low number, it gets more and more difficult to come up with an even lower number and the cost becomes very high.

16. *At the January 8 hearing, Mr. Troxell, a member of the public, asked the Department's experience with SCR technology, consequences of ammonia emissions, and problems at other plants with this technology.*

Mr. Linero of FDEP explained that there are other technologies such as combustion controls and reburning that have almost no consequences and can reduce emissions by roughly 80 percent. To go further, add-on control technology (such as the injection of ammonia) is the only feasible option. The products are ammonia and water. There are impacts on particulate matter. A special plan for hazard control is required.

The amount of ammonia used is nevertheless small by comparison with the (nearby) fertilizer industry and would be in the less dangerous aqueous form. Mr. Linero explained that according to EPA these types of plants are permitted with SCR in every imaginable situation in the country. Although the Department initially believed that SCR was not necessary at the similar Kissimmee Cane Island project, EPA required it and advised that it would appeal the permit if it was issued without SCR.

Mr. Linero said he was aware of only one such installation in Florida (on a combustion turbine) and had not heard of any accidents with SCR. He said that perhaps in a very congested area (with certain other very specific conditions) a case could be made (to EPA) for not using SCR.

Note that this matter was addressed separately in the BACT determination. "Ammonia is used in very large quantities at adjacent or nearby fertilizer plants in Polk, Hillsborough and Manatee Counties to make ammoniated fertilizers. Therefore there are no obvious site-specific conditions that would make it unadvisable to use ammonia at the CPV project."

17. *Mr. Troxell added that his question was actually whether or not the Department was aware of any problems that occurred in the past with plants that have this (SCR) technology and what those problems may have been.*

Mr. Linero said he had not witnessed any problems and had no first hand knowledge of any problems. He related that in certain Wisconsin or Minnesota projects with inferior designs, particulate emissions problems were allegedly aggravated.

He related that industries such as the cement industry are very reluctant to use ammonia due to alleged high opacity. He noted that the species (NO_X and SO_2) that react with ammonia to form particulate matter are present at very low levels in the combustion turbine exhaust. He stated that he doesn't see any environmental consequences to speak of. The numbers are in the

50 ton range (for ammonia) compared with the values in the 10,000 and even 40,000 range for (NO_X and SO_2) emissions from conventional facilities listed in the referenced table (see attached). (Note that emissions from the CPV project for SO_2 and NO_X are 76 and 126 respectively)

18. *At the January 8 hearing, a representative of CPV discussed the permit. Their representative, Mr. Sean Finnerty, said the permit is acceptable as drafted and that they will provide a letter with their comments. These include a change of address. The CPV letter (by Moyle Flanigan) dated January 10, 2000 affirmed the comments received at the public hearing. CPV Gulfcoast stated that they have a new mailing address. The address is: Competitive Power Ventures, Inc., 35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184, telephone 781/848-0253.*

    The Department takes note of the new address and amended the permit accordingly.

19. *CPV Gulfcoast suggests that the superscripts on the "Facility Emissions (Total TPY) and PSD Applicability" Table in Section 6.2, page TE-7 (Oil firing and Total columns) of the draft permit's Technical Evaluation and Preliminary Determination (TEPD) be changed from 3 to 2 and from 1 to 3 respectively. In addition, it is also suggested that on page TE-10 of the TEPD the word "not" be deleted from the last sentence of this page.*

    The Department acknowledges CPV's comments. These comments and our concurrence are part of the permit files since there is no final TEPD document.

20. *The Department determined that there is a need to clarify and differentiate the expiration date of the permit and the physical construction completeness date of the project. Furthermore, in its January 26 submittal to the Department, CPV estimated that it will require 27 months (from a projected October, 2001 commence construction date to complete construction.*

    The Department agrees with CPV, especially in view of the fact that CPV does not have certain local approvals to commence construction. Some contingency is also needed considering the reliance on the recently-approved Gulfstream pipeline project. The following condition has been added to Section II of the permit as Condition No. 9.

    Completion of Construction: The permit expiration date is amended from December 30, 2002 to December 30, 2003. *Physical construction* shall be complete by September 30, 2003. The additional time beyond physical construction provides for testing, submittal of results, and submittal of the Title V permit to the Department.

21. *The Department determined that there is a necessity to maintain consistency in the manner by which particulate and volatile organic emissions are limited, tested and reported.*

    For consistency with previous PM and PM_{10} BACT determinations, the Department will base the emission limits on "front-half catch" and will reduce the allowable emissions from 20 to 9 pounds per hour while firing gas and from 53 to 36 pounds per hour while firing No. 2 distillate fuel oil.

    The Department clarified that Method 18 may be used to correct the VOC concentrations determined by Method 25A (and reported as THC – propane). This allows the exclusion of methane and ethane that are not regulated as VOC from the results. PSD for VOC was not triggered regardless of the VOC testing and reporting methods used. This determination of VOC test Method applies only to this specific project and type of unit. Other industries must be evaluated on a case-by-case basis. A requirement to test for VOC prior to permit renewal (in addition to initial compliance) was added.

    The Department also extended the convention of reporting emissions as "corrected to 15 percent oxygen" to CO and VOC. There is no meaningful difference in results.

22. *The Department has determined that its jurisdiction under this air permitting action does not provide for setting and enforcing an operational or capacity limit on the steam turbine-electrical generator described in this specific project.*

Specific Condition 51 will be removed from the permit.

CONCLUSION

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

CPV Gulfcoast and Gannon Repowering Emissions vs Conventional Units along SW Florida Coast

Plant Name	Boiler Type	Primary Fuel	SO2 Controls	NOx Controls	1999 SO2 Rate #/Mbtu (#/MWH)	1999 SO2 (tons)	1999 NOx Rate #/MBtu (#/MWH)	1999 NOx (tons)	1999 Heat Input (mmBtu)
Anclote	T	O	U	U	1.28 (14)	16,230	0.30 (3.2)	4,275	25,432,652
Anclote	T	O	U	U	1.31 (14)	18,310	0.30 (3.2)	4,623	27,948,159
PL Bartow	DB	O	U	U	2.15 (23)	7,853	0.28 (3.0)	1,123	7,300,495
PL Bartow	T	O	U	U	2.22 (24)	6,479	0.33 (3.5)	1,017	5,825,049
PL Bartow	T	O	U	U	2.01 (22)	14,335	0.45 (4.8)	3,561	14,269,751
Big Bend	T	C	WLS	O	3.29 (35)	39,897	0.72 (7.8)	9,103	24,289,751
Big Bend	T	C	WLS	O	3.25 (35)	40,806	0.72 (7.8)	9,310	24,843,034
Big Bend	WBT	C	WLS	LNB	0.57 (6)	6,360	0.53 (5.7)	6,242	22,280,740
Big Bend	T	C	WLS	O	0.57 (6)	8,550	0.44 (4.9)	6,633	29,950,140
Gannon	C	C	U	U	1.81 (20)	5,503	1.05 (11.2)	3,276	6,126,261
Gannon	C	C	U	U	1.75 (19)	5,437	0.90 (9.6)	2,845	6,205,655
Gannon	C	C	U	U	1.77 (19)	7,456	0.90 (9.6)	3,891	8,415,640
Gannon	C	C	U	U	1.75 (19)	7,470	0.84 (8.9)	3,678	8,533,763
Gannon	WBT	C	U	U	1.92 (21)	12,601	0.73 (7.7)	5,186	13,115,273
Gannon	WBT	C	U	U	1.11 (12)	16,029	1.13 (12.0)	10,310	16,999,246
Ft Myers	DB	O	U	U	2.01 (22)	6,388	0.45 (4.8)	1,518	6,380,185
Ft Myers	DB	O	U	U	2.02 (22)	26,578	0.82 (8.9)	11,883	26,339,199
Manatee	DB	O	U	U	0.99 (11)	13,813	0.23 (2.5)	4,109	27,853,349
Manatee	DB	O	U	U	1.07 (12)	16,403	0.23 (2.5)	4,319	30,768,019
Gannon RP	7CTs	G	Low S Fuel	DLN/SCR	~0.01 (~0.1)	~700	<0.02 (~0.14)	~1000	~100,000,000
CPV Gulf	CT	G	Low S Fuel	DLN/SCR	0.01 (<0.1)	76	<0.02 (0.13)	126	~15,000,000

Assumes that CPV unit will run continuously (100 percent availability) and will burn fuel oil during 720 hours per year.

Gannon RP will repower Gannon Units 5 and 6 and be renamed Bayside. Units 1, 2, 3, and 4 will shut down by 2005

NOx emissions at CPV and Bayside will be 0.10 pounds per megawatt-hour when firing natural gas.

Assumed that conventional units are as efficient as a relatively new unit and operated near capacity for higher efficiency.

Very substantial reductions are expected due to Ft. Myers Repowering, Big Bend scrubber, and Phase II

Sources: EPA Acid rain data at www.epa.gov/acidrain and FDEP Draft Package

Competitive
Power Ventures, Inc.

January 26, 2001

Mr. Alvaro Linero
Administrator,
New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Re: CPV Gulfcoast, Ltd. Response to EPA Region IV comments dated December 27, 2000
File No. 0810194-001-AC (PSD-FL-300),
CPV Gulfcoast Power GeneratingFacility

Dear Mr. Linero:

Following are CPV Gulfcoast, Ltd.'s response to EPA Region IV comments filed in a letter to DEP dated December 27, 2000.

CPV has revised the BACT calculations to incorporate the concerns raised by EPA Region IV. The revisions include four cases based on the EPA comments. The cases are attached.

Case 1: All comments of EPA Region IV are incorporated into the calculations of oxidation catalyst cost effectiveness. The revised calculations result in an oxidation catalyst cost estimate of $3,050 per ton of CO removed.

Case 2: All comments of EPA region IV are incorporated into the calculations of oxidation catalyst cost effectiveness with the exception of the change in interest rate. The interest rate is maintained at 8% in this case. CPV believes this interest rate is an appropriate representation of the rates available to merchant generating facilities. The revised calculations result in an oxidation cost estimate of $3,088 per ton of CO removed.

Case 3: All comments of EPA Region IV are incorporated into the calculations of oxidation catalyst cost effectiveness with the exception of the reduction in contingency costs. The contingency cost is maintained at 20% in this case. CPV believes this level of contingency is appropriate given the level of activity and uncertainty in the generating industry at this time. The revised calculations result in an oxidation cost estimate of $3,290 per ton of CO removed.

Case 4: All comments of EPA Region IV are incorporated into the calculations of oxidation catalyst cost effectiveness with the exception of the change in derate. CPV has maintained the original derate as it represents a true cost to the facility. The revised calculations result in an oxidation catalyst cost estimate of $3,870 per ton of CO removed.

CPV does not believe an oxidation catalyst is cost effective for this project in any of the four cases presented.

If DEP has any questions regarding these revisions, please do not hesitate to contact me at 781-848-0253. We appreciate the opportunity to work with you to resolve these issues and we look forward to expeditious issuance of the permit.

Sincerely,

Sean Finnerty
Director, Project Development

Attachements.

CC: Gary Lambert
Cathy Sellers

Base Case 2000 hr PAG

Table E-3. CPV Gulf Coast
CO Catalyst

DIRECT COSTS	
Purchased Equipment Costs	
CO Catalyst (Engelhard Budgetary Quote)	$560,000
Sales Tax (6% of purchased equipment costs)	$33,600
Freight (4% of purchased equipment costs)	$22,400
Subtotal-Purchased Equipment Costs (PEC)	$616,000
Direct Installation Costs	
Installation/Foundation (35% of Catalyst Capital Cost)	$196,000
Subtotal-Direct Installation Costs	$196,000
TOTAL DIRECT COSTS (TDC)	$812,000
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	$30,800
Contingency (3% per pg 3-50 of EPA 453/B-96-001, reduced from 20% item 2e of EPA letter dated 12-27-00)	$24,360
TOTAL INDIRECT COSTS	$56,160
TOTAL CAPITAL INVESTMENT (TCI)	$867,160
DIRECT ANNUAL COSTS	
100% Capacity factor	
6,760 Equivalent Operating Hours per Year (per CTG)	
720 Oil-Fired operating hours/year	
Maintenance Materials and Labor (2% of TCI)	$17,343
Replacement Catalyst (3 Year Service Life)	$160,000
$ 480,000 * Capital Recovery Factor (0.3880 for n = 3 & i = 8%)	
3 Guaranteed catalyst life	
Pressure Drop Derate (Lost Revenue From Sale Of Power)	$0
0.7 Pressure drop across catalyst, inches H2O	
206,300 Full load CTG output (annual average) kW	
275 Output reduction for pressure drop, kW/inch H20	
193 kW derate	
1,686,300 kW-hr output lost per year	
6 cents per kW-hr	
0 zero out per item 2b of EPA letter dated from R.D. Neeley dated 12-27-2000	
Fuel Penalty (Increase Fuel Consumption due to back pressure heat rate impact)	$36,596
1.807E+09 Annual CTG output, kW-hr	
9 Btu/kW-hr	
16,265 mmBtu/yr natural gas	
2.25 $/mmBtu natural gas	
Catalyst Disposal	$16,667
$ 50,000 at the end of catalyst guaranteed life	
TOTAL DIRECT ANNUAL COSTS	$230,805
INDIRECT ANNUAL COSTS	
Overhead (60% of labor and maintenance materials)	$10,406
Property Tax (1% of TCI)	$8,672
Insurance (1% of TCI)	$8,672
Administration (2% of TCI)	$17,343
TOTAL INDIRECT ANNUAL COSTS	$45,092
TOTAL ANNUAL COSTS	$275,896
CAPITAL RECOVERY FACTOR, CFR = (i * (1+i)n)/((1+i)n - 1)	
10 Equipment Life (years)	
7 Interest Rate (%) (Changed from 8% per item 2c of EPA letter dated 12-27-00)	
Capital Recovery Factor	0.1424
CAPITAL RECOVERY COSTS (Catalyst replaced cost subtracted per item 2d of EPA letter dated 12-27-00)	
TOTAL CAPITAL REQUIREMENT	$867,160
CATALYST REPLACEMENT COST	-$160,000
TOTAL CAPITAL REQUIREMENT MINUS CATALYST REPLACEMENT COST	$707,160
TOTAL ANNUALIZED CAPITAL REQUIREMENT	$100,684
TOTAL ANNUALIZED COST (Total annual O&M cost and annualized capital cost)	$376,581
BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE	154
Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6,040 hr/yr (no power augmentation)/ 15 ppm on gas for 2,000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr	
TONS OF CO REMOVED PER YEAR	123
Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency	
COST-EFFECTIVENESS	
ENVIRONMENTAL BASIS ($ per ton of CO removed)	$3,050

2000 hr PAG 8% interest

Table E-3. CPV Gulf Coast
CO Catalyst

[illegible]	
DIRECT COSTS	
Purchased Equipment Costs	
CO Catalyst (Engelhard Budgetary Quote)	$560,000
Sales Tax (6% of purchased equipment costs)	$33,600
Freight (4% of purchased equipment costs)	$22,400
Subtotal-Purchased Equipment Costs (PEC)	$616,000
Direct Installation Costs	
Installation/Foundation (35% of Catalyst Capital Cost)	$196,000
Subtotal-Direct Installation Costs	$196,000
TOTAL DIRECT COSTS (TDC)	$812,000
INDIRECT INSTALLATION COSTS	
Engineering Costs (5% of PEC)	$30,800
Contingency (3% per pg 3-50 of EPA 453/B-96-001, reduced from 20% item 2e of EPA letter dated 12-27-00)	$24,360
TOTAL INDIRECT COSTS	$55,160
TOTAL CAPITAL INVESTMENT (TCI)	**$867,160**
DIRECT ANNUAL COSTS	
100% Capacity factor	
8,760 Equivalent Operating Hours per Year (per CTG)	
720 Oil-Fired operating hours/year	
Maintenance Materials and Labor (2% of TCI)	$17,343
Replacement Catalyst (3 Year Service Life)	$160,000
$ 480,000 * Capital Recovery Factor (0.3880 for n = 3 & i = 8%)	
3 Guaranteed catalyst life	
Pressure Drop Derate (Lost Revenue From Sale Of Power)	$0
0.7 Pressure drop across catalyst, inches H2O	
206,300 Full load CTG output (annual average), kW	
275 Output reduction for pressure drop, kW/inch H20	
193 kW derate	
1,686,300 kW-hr output lost per year	
6 cents per kW-hr	
0 zero out per item 2b of EPA letter dated from R.D. Neeley dated 12-27-2000	
Fuel Penalty (Increase Fuel Consumption due to back pressure heat rate impact)	$36,596
1.807E+09 Annual CTG output, kW-hr	
9 Btu/kW-hr	
16,265 mmBtu/yr natural gas	
2.25 $/mmBtu natural gas	
Catalyst Disposal	$16,667
$ 50,000 at the end of catalyst guaranteed life	
TOTAL DIRECT ANNUAL COSTS	$230,605
INDIRECT ANNUAL COSTS	
Overhead (60% of labor and maintenance materials)	$10,406
Property Tax (1% of TCI)	$8,672
Insurance (1% of TCI)	$8,672
Administration (2% of TCI)	$17,343
TOTAL INDIRECT ANNUAL COSTS	$45,092
TOTAL ANNUAL COSTS	**$275,698**
CAPITAL RECOVERY FACTOR, CFR = (i * (1+i)n)/((1+i)n - 1)	
10 Equipment Life (years)	
8	
Capital Recovery Factor	0.1490
CAPITAL RECOVERY COSTS (Catalyst replaced cost subtracted per item 2d of EPA letter dated 12-27-00)	
TOTAL CAPITAL REQUIREMENT	$867,160
CATALYST REPLACEMENT COST	-$160,000
TOTAL CAPITAL REQUIREMENT MINUS CATALYST REPLACEMENT COST	$707,160
TOTAL ANNUALIZED CAPITAL REQUIREMENT	$105,388
TOTAL ANNUALIZED COST (Total annual O&M cost and annualized capital cost)	$381,085
BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE	154
Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6,040 hr/yr (no power augmentation)/ 15 ppm on gas for 2,000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr	
TONS OF CO REMOVED PER YEAR	123
Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency	
COST-EFFECTIVENESS	
ENVIRONMENTAL BASIS ($ per ton of CO removed)	$3,088

2000 hr PAG 20% contingency

Table E-3. CPV Gulf Coast
CO Catalyst

[illegible]		[illegible]
DIRECT COSTS		
Purchased Equipment Costs		
CO Catalyst (Engelhard Budgetary Quote)		$560,000
Sales Tax (6% of purchased equipment costs)		$33,600
Freight (4% of purchased equipment costs)		$22,400
Subtotal-Purchased Equipment Costs (PEC)		$616,000
Direct Installation Costs		
Installation/Foundation (35% of Catalyst Capital Cost)		$196,000
Subtotal-Direct Installation Costs		$196,000
TOTAL DIRECT COSTS (TDC)		$812,000
INDIRECT INSTALLATION COSTS		
Engineering Costs (5% of PEC)		$30,800
Contingency (20%)		$162,400
TOTAL INDIRECT COSTS		$193,200
TOTAL CAPITAL INVESTMENT (TCI)		**$1,005,200**
DIRECT ANNUAL COSTS		
Capacity factor	100%	
Equivalent Operating Hours per Year (per CTG)	8,760	
Oil-Fired operating hours/year	720	
Maintenance Materials and Labor (2% of TCI)		$20,104
Replacement Catalyst (3 Year Service Life)		$160,000
* Capital Recovery Factor (0.3880 for n = 3 & I = 8%)	$ 480,000	
Guaranteed catalyst life	3	
Pressure Drop Derate (Lost Revenue From Sale Of Power)		$0
Pressure drop across catalyst, inches H2O	0.7	
Full load CTG output (annual average), kW	206,300	
Output reduction for pressure drop, kW/inch H20	275	
kW derate	193	
kW-hr output lost per year	1,686,300	
cents per kW-hr	6	
zero out per item 2b of EPA letter dated from R.D. Neeley dated 12-27-2000	0	
Fuel Penalty (Increase Fuel Consumption due to back pressure heat rate impact)		$36,596
Annual CTG output, kW-hr	1.807E+09	
Btu/kW-hr	9	
mmBtu/yr natural gas	16,265	
$/mmBtu natural gas	2.25	
Catalyst Disposal		$16,667
at the end of catalyst guaranteed life	$ 50,000	
TOTAL DIRECT ANNUAL COSTS		$233,366
INDIRECT ANNUAL COSTS		
Overhead (60% of labor and maintenance materials)		$12,062
Property Tax (1% of TCI)		$10,052
Insurance (1% of TCI)		$10,052
Administration (2% of TCI)		$20,104
TOTAL INDIRECT ANNUAL COSTS		$52,270
TOTAL ANNUAL COSTS		**$285,637**
CAPITAL RECOVERY FACTOR, CRF = (i * (1+i)n)/((1+i)n - 1)		
Equipment Life (years)	10	
Interest Rate (%) (Changed from 8% per item 2c of EPA letter dated 12-27-00)	7	
Capital Recovery Factor		0.1424
CAPITAL RECOVERY COSTS (Catalyst replaced cost subtracted per item 2d of EPA letter dated 12-27-00)		
TOTAL CAPITAL REQUIREMENT		$1,005,200
CATALYST REPLACEMENT COST		-$160,000
TOTAL CAPITAL REQUIREMENT MINUS CATALYST REPLACEMENT COST		$845,200
TOTAL ANNUALIZED CAPITAL REQUIREMENT		$120,337
TOTAL ANNUALIZED COST (Total annual O&M cost and annualized capital cost)		**$408,974**
BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE		184
Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6,040 hr/yr (no power augmentation)/ 15 ppm on gas for 2,000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr		
TONS OF CO REMOVED PER YEAR		123
Controlled General Electric 7FA Turbine Emissions = assume 60% control efficiency		
COST-EFFECTIVENESS		
ENVIRONMENTAL BASIS ($ per ton of CO removed)		$3,290

Table E-3. CPV Gulf Coast CO Catalyst		
COST COMPONENTS		COST
DIRECT COSTS		
Purchased Equipment Costs		
CO Catalyst (Engelhard Budgetary Quote)		$560,000
Sales Tax (6% of purchased equipment costs)		$33,600
Freight (4% of purchased equipment costs)		$22,400
Subtotal-Purchased Equipment Costs (PEC)		$616,000
Direct Installation Costs		
Installation/Foundation (35% of Catalyst Capital Cost)		$196,000
Subtotal-Direct Installation Costs		$196,000
TOTAL DIRECT COSTS (TDC)		$812,000
INDIRECT INSTALLATION COSTS		
Engineering Costs (5% of PEC)		$30,800
Contingency (3% per pg 3-50 of EPA 453/B-96-001, reduced from 20% item 2a of EPA letter dated 12-27-00)		$24,360
TOTAL INDIRECT COSTS		$55,160
TOTAL CAPITAL INVESTMENT (TCI)		**$867,160**
DIRECT ANNUAL COSTS		
	100%	Capacity factor
	8,760	Equivalent Operating Hours per Year (per CTG)
	720	Oil-Fired operating hours/year
Maintenance Materials and Labor (2% of TCI)		$17,343
Replacement Catalyst (3 Year Service Life)		$160,000
$	-480,000	* Capital Recovery Factor (0.3880 for n = 3 & i = 8%)
	3	Guaranteed catalyst life
Pressure Drop Derate (Lost Revenue From Sale Of Power)		$101,178
	0.7	Pressure drop across catalyst, inches H2O
	206,300	Full load CTG output (annual average), kW
	275	Output reduction for pressure drop, kW/inch H2O
	193	kW derate
	1,686,300	kW-hr output lost per year
	6	cents per kW-hr
	1	
Fuel Penalty (Increase Fuel Consumption due to back pressure heat rate impact)		$36,596
	1.807E+09	Annual CTG output, kW-hr
	9	Btu/kW-hr
	16,265	mmBtu/yr natural gas
	2.25	$/mmBtu natural gas
Catalyst Disposal		$16,667
$	50,000	at the end of catalyst guaranteed life
TOTAL DIRECT ANNUAL COSTS		$331,783
INDIRECT ANNUAL COSTS		
Overhead (60% of labor and maintenance materials)		$10,406
Property Tax (1% of TCI)		$8,672
Insurance (1% of TCI)		$8,672
Administration (2% of TCI)		$17,343
TOTAL INDIRECT ANNUAL COSTS		$45,092
TOTAL ANNUAL COSTS		**$376,876**
CAPITAL RECOVERY FACTOR, CFR = (i * (1+i)n)/((1+i)n - 1)		
	10	Equipment Life (years)
	7	Interest Rate (%) (Changed from 8% per item 2c of EPA letter dated 12-27-00)
Capital Recovery Factor		0.1424
CAPITAL RECOVERY COSTS (Catalyst replaced cost subtracted per item 2d of EPA letter dated 12-27-00)		
TOTAL CAPITAL REQUIREMENT		$867,160
CATALYST REPLACEMENT COST		-$160,000
TOTAL CAPITAL REQUIREMENT MINUS CATALYST REPLACEMENT COST		$707,160
TOTAL ANNUALIZED CAPITAL REQUIREMENT		$100,684
TOTAL ANNUALIZED COST (Total annual O&M cost and annualized capital cost)		**$477,559**
BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE		184
Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6,040 hr/yr (no power augmentation)/ 15 ppm on gas for 2,000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr		
TONS OF CO REMOVED PER YEAR		123
Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency		
COST-EFFECTIVENESS		
ENVIRONMENTAL BASIS ($ per ton of CO removed)		$3,870

FLORIDA

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

PERMITTEE:

CPV Gulfcoast, Ltd.
35 Braintree Hill Office Park, Suite 107
Braintree, MA 02184

File No.	0810194-001-AC
Permit No.	PSD-FL-300
SIC No.	4911
Expires:	December 30, 2003

Authorized Representative:

Gary Lambert, Executive Vice President

PROJECT AND LOCATION:

Air construction permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD) for the construction of a nominal 245-megawatt (MW) gas-fired combined cycle electrical power plant. The plant will be known as the CPV Gulfcoast Power Generating Facility.

The project will be located at the intersection of Buckeye and Bud Rhoden Roads, East of Highway 41 near Piney Point, Manatee County. UTM coordinates are Zone 17; 348.5 km E; 3057.0 km N.

STATEMENT OF BASIS:

This permit is issued under the provisions of Chapter 403 of the Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

The attached Appendices are made a part of this permit:

Appendix GC	Construction Permit General Conditions
Appendix BD	BACT Determination

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

The proposed CPV facility is a nominal 245 MW combined cycle plant. Key components include:

- One nominal 170-MW gas-fired combustion turbine-electrical generator with an un-fired heat recovery steam generator (HRSG) and 150-foot stack;
- A selective catalytic reduction unit located within the HRSG;
- A 1-million gallon storage tank for backup No. 2 distillate fuel oil;
- A steam-electrical generator;
- A five-cell mechanical draft cooling tower; and
- Ancillary facilities including equipment including buildings, ammonium storage, demineralized water storage, fire water storage, diesel-fired fire water pump, and a 500 kW emergency generator

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
001	Power Generation	One 170-megawatt combustion turbine-electrical generator with unfired heat recovery steam generator
002	Water Cooling	One five-cell mechanical cooling tower
003	Fuel Storage	One 1-million gallon fuel oil storage tank

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). With respect to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of NO_X and SO_2, 25/15 TPY of PM/PM_{10}, 100 TPY of CO, and 7 TPY of sulfuric acid mist. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This facility is also subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

PERMIT SCHEDULE

- 01/29/01 Air Construction Permit Issued
- 01/08/01 Public Hearing (Meeting)
- 11/25//00 Notice of Intent to Issue published in the Bradenton Herald
- 11/17/00 Distributed Intent to Issue Permit
- 11/06/00 Application deemed complete
- 09/11/00 Received PSD Application

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but are not incorporated into this permit. These documents are on file with the Department.

- Application received on September 11, 2000
- Department letter to CPV dated October 9, 2000
- Comments from the Fish and Wildlife Service dated October 6, 2000
- CPV Responses dated November 3, 2000
- Department's Intent to Issue and Public Notice Package dated November 17, 2000.
- Letter from EPA Region IV dated December 27, 2000
- Letter from Manatee County Environmental Management Department dated December 22, 2000
- Letter from Chair, Manatee County Board of County Commissioners dated December 14, 2000
- Letter from CPV (by Moyle Flanigan) dated and January 10, 2001.
- CPV Responses dated January 26, 2001 to EPA Comments of December 27
- Additional CPV Comments dated January 26, 2001.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

SECTION II. COMMON SPECIFIC CONDTIONS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114.

2. Compliance Authority: All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District Office, 3804 Coconut Palm Dr, Tampa, Fl 33619-8218 and phone number 813/744-6100. Copies of these items shall also be submitted to the Manatee County Environmental Management Department, 202 Sixth Avenue East, Bradenton, Fl 34208, and phone number 813/742-5980.

3. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

4. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

5. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

6. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]

7. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

8. PSD Approval to Construct Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

9. Completion of Construction: The permit expiration date is December 30, 2003. Physical construction shall be completed by September 30, 2003. The additional time provides for testing, submittal of results, and submittal of the Title V permit to the Department.

10. Permit Expiration Date Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

11. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, the extension of the December 30, 2002 permit expiration date, or any increases in MW generated by steam, heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes; the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source.
[40 CFR 52.21(j)(4); 40CFR 51.166(j) and Rule 62-4.070 F.A.C.]

12. Application for Title IV Permit: An application for a Title IV Acid Rain Permit must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]

13. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Southwest District Office. [Chapter 62-213, F.A.C.]

OPERATIONAL REQUIREMENTS

14. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify the Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

15. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

16. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without the applicable air control device operating properly. [Rule 62-210.650, F.A.C.]

17. Unconfined Particulate Matter Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.
[Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

18. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and conducting the test.
[Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.7, 60.8]

19. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

20. Applicable Test Procedures

   (a) *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be sixty (60) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
   [Rule 62-297.310(4)(a)1. and 2., F.A.C.]

   (b) *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet. [Rule 62-297.310(4)(b), F.A.C.]

   (c) *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C. [Rule 62-297.310(4)(d), F.A.C.]

21. Determination of Process Variables

   (a) *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. [Rule 62-297.310(5)(a), F.A.C.]

   (b) *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value. [Rule 62-297.310(5)(b), F.A.C.]

22. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit

issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

23. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

24. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit; corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

RECORDS

25. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2., F.A.C.]

REPORTS

26. Emissions Performance Test Results Reports: A report indicating the results of any required emissions performance test shall be submitted to the *Compliance Authority* no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

27. Annual Operating Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Southwest District Office by March 1st of each year.

28. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7)(c) (2000 version), shall be submitted to the *Compliance Authority*.

APPLICABLE STANDARDS AND REGULATIONS:

1. Regulations: Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.

2. Applicable Requirements: Issuance of a permit does not relieve the owner or operator of an emissions unit from complying with any applicable requirements, any emission limiting standards or other requirements of the air pollution rules of the Department or any other such requirements under federal, state, or local law, notwithstanding that these applicable requirements are not explicitly stated in this permit. In cases where there is an ambiguity or conflict in the specific conditions of this permit with any of the above-mentioned regulations, the more stringent state, federal or local requirement applies.
[Rules 62-204.800; 62-4.070(3), and Rule 62-210.300, F.A.C.]

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emissions Unit 001. Power Generation, consisting of a nominal 170-megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. ARMS Emission Unit 002. Fuel Storage, consisting of a 1.0 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.

6. ARMS Emission Unit 003. Five-Cell Mechanical Draft Cooling Tower.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit.
[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

8. Combustion Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to this Unit at ambient conditions of 25°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,700 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,918 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil.

   These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing.
[Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Hours of Operation: The combined cycle power plant may operate 8760 hours per year while firing natural gas. Fuel oil firing is permitted 720 hours per year. Power augmentation while firing gas is permitted 2000 hours per year 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.
[Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

10. Dry Low NO_X (DLN) combustors shall be installed to reduce NO_X emissions from the combustion turbine exhaust entering the heat recovery steam generator (HRSG).
[Design, Rules 62-4.070 and 62-212.400, F.A.C.]

11. A wet injection system shall be installed for use during fuel oil firing to reduce NO_X emissions from the combustion turbine exhaust entering the HRSG.
[Design, Rules 62-4.070 and 62-212.400, F.A.C.]

12. The permittee shall design and install a selective catalytic reduction (SCR) within the HRSG to comply with the NO_X limits listed in Specific Condition 16.

13. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions Nos. 16 through 21. [Rule 62-4.070, Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

14. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize simple cycle NO_X emissions and CO emissions.
[Rule 62-4.070, and 62-210.650 F.A.C.]

15. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions.

EMISSION LIMITS AND STANDARDS

16. Nitrogen Oxides (NO_X) Emissions:
    - The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas exceed neither 3.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd @15% O_2) nor 24.1 pounds per hour (lb/hr expressed as NO_2) on a 3-hr block average. Initial and annual stack test. Continuous compliance shall be determined by a CEMS. [Rule 62-212.400, F.A.C., BACT Determination]
    - The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on fuel oil gas exceed neither 10 parts per million by volume, dry, at 15 percent oxygen (ppmvd @15% O_2) nor 80 pounds per hour (lb/hr expressed as NO_2) on a 3-hr block average. Initial and annual stack test. Continuous compliance shall be determined by a CEMS. [Rule 62-212.400, F.A.C, BACT Determination]
17. Carbon Monoxide (CO) Emissions:
    - Emissions of CO in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 9 ppmvd @ 15% O_2 nor 26 lb/hr on a 3-hr block average during periods when the unit is not operating in the Power Augmentation Mode. Initial and annual stack test as specified in Specific Condition No. 33. Continuous compliance shall be determined by CEMS. [Rule 62-212.400, F.A.C, BACT Determination]
    - Emissions of CO in the stack exhaust gas with the combustion turbine operating on natural gas and in the Power Augmentation Mode shall exceed neither 15 ppmvd @ 15% O_2 nor 49 lb/hr on a 3-hr block average during periods when the unit is operating in the Power Augmentation Mode. Initial and annual stack tests as specified in Specific Condition No. 33. Continuous compliance shall be determined by CEMS. [Rule 62-212.400, F.A.C, BACT Determination]
    - Emissions of CO in the stack exhaust gas with the combustion turbine operating on fuel oil shall not exceed 20 ppmvd @ 15% O_2 nor 70 lb/hr on a 3-hr block average. Initial and annual stack tests as specified in Specific Condition No. 33. Continuous compliance shall be determined by CEMS. [Rule 62-212.400, F.A.C, BACT Determination]
    - The concentration of CO in the stack exhaust gas with the combustion turbine operating on fuel oil shall exceed neither 20 ppmvd @ 15% O_2 at 90-100 percent of full load, 22 ppmvd at 75-89 percent of full load nor 29 ppmvd @ 15% O_2 at 50-74 percent of full load. Continuous compliance shall be determined by CEMS. Initial and annual stack tests as specified in Specific Condition No 33. [Rule 62-212.400, F.A.C, BACT Determination]
18. Volatile Organic Compounds (VOC) Emissions:
    - Emissions of VOC in the stack exhaust gas with the combustion turbine operating on natural gas shall exceed neither 1.4 ppmvd @ 15% O_2 nor 3 lb/hr to be demonstrated by stack test. EPA Method 25A and 18 shall be conducted simultaneously with correction allowed by deducting methane and ethane measured by EPA Method 18. [Rule 62-212.400, F.A.C., BACT]

- Emissions of VOC in the stack exhaust gas with the combustion turbine operating on fuel oil shall exceed neither 3.6 ppmvd @ 15% O_2 nor 8 lb/hr to be demonstrated by stack test. EPA Methods 25A and 18 shall be conducted simultaneously with correction allowed by deducting methane and ethane measured by EPA Method 18. [Rule 62-212.400, F.A.C., BACT]

19. Sulfur Dioxide (SO_2) and Sulfuric Acid Mist Emissions (SAM):
    - Emissions of SO_2 in the stack exhaust gas shall exceed neither 10 lb/hr when operating on natural gas nor 99 lb/hr when operating on fuel oil. Compliance shall be demonstrated as specified in Specific Condition No. 31. [Rule 62-212.400, F.A.C., BACT]
    - Emissions of sulfuric acid mist in the stack exhaust gas shall exceed neither 2 lb/hr when operating on natural gas nor 11 lb/hr when operating on fuel oil. Compliance shall be demonstrated as specified in Specific Condition No. 31. [Rule 62-212.400, F.A.C., BACT]

20. PM/PM_{10} and Visible Emissions (VE):
    - Emissions of PM/PM_{10} in the stack exhaust gas shall exceed neither 11 lb/hr while firing natural gas nor 36 lb/hr while firing fuel oil. Compliance shall be demonstrated by stack tests as specified in Specific Condition No. 31. [Rule 62-212.400, F.A.C., BACT]
    - VE from the stack exhaust gas shall not exceed 10 percent opacity. VE shall serve as the surrogate for compliance with the PM/PM_{10} emission rates following the initial compliance test. Compliance shall be demonstrated by stack tests as specified in Specific Condition No. 36. [Rules 62-204.800(7), 62-4.070, and 62-212.400, F.A.C., BACT]

21. Ammonia Emissions: The concentration of ammonia in the stack exhaust gas shall not exceed 5 ppmvd @15% O_2. The compliance procedures are described in Specific Condition 50. [Rules 62-4.070 and 62-212.400, F.A.C., BACT]

EXCESS EMISSIONS

22. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except for the following modes of operation:
    - *Cold Startup and Shutdown*: During cold *start-up* to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. During *shutdowns* from combined cycle operation, up to three hours of excess emissions are allowed.
    - *Warm Startup and Shutdown*: During warm start up to combined cycle operation, up to two hours of excess emissions are allowed. Warm start-up is defined as a startup to combined cycle operation following a complete shutdown lasting 8 hour or more, but less than 48 hours. During *shutdowns* from combined cycle operation, up to three hours of excess emissions are allowed.

- *Hot Startup and Shutdown*: During hot start up to combined cycle operation, up to one hour of excess emissions are allowed. Hot start-up is defined as a startup to combined cycle operation following a complete shutdown lasting less than 8 hours. During *shutdowns* from combined cycle operation, up to three hours of excess emissions are allowed.
- *Low Load Operation*: Excluding startup and shutdown, operation below 50% base load is prohibited.

  [G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.]

23. Excess Emissions Prohibited: Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 3-hr average for NO_X and for CO.

24. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify the *Compliance Authority* within one (1) working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day) of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 16 and 17. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (2000 version)].

COMPLIANCE DETERMINATION

25. Test Compliance Schedule: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of *initial* operation of the unit, and annually thereafter as indicated in this permit or as required by the *Compliance Authority.* [Rule 62-4.070(3) F.A.C and 40CFR60, Subpart A]

26. Initial (I) and Annual (A) Compliance Tests: Initial (I) performance tests (for both fuels) shall be conducted in accordance with 40CFR 60.8 and 40 CFR60.335 for pollutants subject to New Source Performance Standards (NSPS) in Subpart GG for gas turbines. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on this unit as indicated. [Rules 62-4.070(3) and 62-204.800, F.A.C., and 40CFR60, Subpart A].

27. Test After Substantial Modifications: All performance tests required for initial start up shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as installation of an oxidation catalyst or change of combustors.

28. Tests Prior to Permit Renewal: Prior to renewing air operation permits, performance tests shall be conducted for this combustion turbine to demonstrate compliance with the CO, NO_X, VOC and visible emissions standards for normal gas firing (standard and power augmentation modes), and backup oil firing. All tests shall be conducted within the 12 months prior to renewing the air operation permit.
[Rule 62-297.310(7)(a)3., F.A.C.]

29. Test Methods: The following reference methods as described in 40 CFR 60, Appendix A (2000 version), and adopted by reference in Chapter 62-204.800, F.A.C. shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.
    - EPA Reference Method 5 , "Determination of the Opacity of Emissions from Stationary Sources" (front half catch) (I)
    - EPA Reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" (A) or through annual RATA testing.
    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A) or through annual RATA testing.
    - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines.". Initial tests for compliance with 40CFR60 Subpart GG. Initial and annual test for compliance with the BACT standard.
    - EPA Reference Method 18 and 25A, "Determination of Volatile Organic Concentrations." Initial (I) and upon permit renewal tests.
    - EPA Method CTM-027 (conditional test method) for ammonia with a minimum detection limit of 1 ppmvd (I, A)

30. Testing Modes of Operation: The permittee shall conduct all required tests for each mode of operation defined below:

    (a) **Standard Operation**: Separate tests shall be conducted when firing the combustion turbine with natural gas as well as low sulfur distillate oil.

    (b) **Alternate Mode of Operation**: Separate tests shall be conducted when firing the combustion turbine with natural gas and implementing the power augmentation with steam injection. Hourly rates for steam injection for power augmentation (pounds of steam) shall be restricted to the rates that demonstrated compliance during the test for this alternate mode of operation. The maximum steam injection rate (lb steam/hour) for power augmentation shall be established in the operation permit.

    Note: Alternate mode of operation is not allowed when firing low sulfur oil.

    [Rule 62-4.070(3), F.A.C.]

31. Compliance with the SO_2 SAM and PM/PM_{10} Emission Limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas as the primary fuel with a maximum sulfur content of 0.0065 percent by weight and the restricted use (720 hour/year) of No. 2 or superior grade distillate fuel oil with a maximum sulfur content of 0.05 percent sulfur is the method for determining compliance for SO_2 and PM/PM_{10}. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 47 and 48 will demonstrate compliance with the NSPS SO_2 emissions limitations from the combustion turbine. Initial PM stack test is required.

    [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

32. Test Method for Natural Gas and Fuel Oil Sulfur Content For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM 2880-71 (or equivalent) for sulfur content of *liquid fuel* and ASTM Methods D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of *gaseous fuel* shall be utilized in accordance with the EPA-approved custom fuel monitoring schedules. Natural gas supplier data or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be submitted when demonstrating compliance with this fuel. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (2000 version).

33. Compliance with CO Emission Limit: An initial stack test for CO shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. The RATA tests required for the CO monitor shall be performed using EPA Method 10, of Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of Section 10.1 may be used in lieu of the silica gel and ascarite traps. The span for the CO monitor shall not be greater than 50 ppm, as corrected to 15% O_2. Continuous compliance by CEMS shall be determined as specified in Specific Conditions 41 through 44.

34. Compliance with the NO_X Emission Limit: Compliance with the NO_X limit shall be determined by stack tests and a CEMS as specified in specific conditions Nos. 29, and 41 - 44. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E, of Appendix A of 40 CFR 60. The NO_X monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% O_2.

35. Compliance with the VOC Emission Limit: An initial test and upon permit renewal are required to demonstrate compliance with the VOC emission limit. The CO emission limit and periodic tuning data will be employed as surrogate and no annual testing is required. Initial tests for CO, NO_X, and VOC emissions shall be conducted concurrently.

36. Compliance with the Visible Emission Limit: Initial and annual compliance shall be demonstrated by stack test. VE shall serve as a surrogate for PM/PM_{10} annual compliance test. Initial tests for PM and visible emissions shall be conducted concurrently.

37. Compliance with the Ammonia Emissions: The permittee shall calculate and report the ppmvd ammonia slip @ 15% O_2 at the measured lb/hr emission rate as a means of compliance with the BACT standard. The permittee shall also be capable of calculating ammonia slip according to Specific Condition 50.

NOTIFICATION, REPORTING, AND RECORDKEEPING

38. Records: All measurements, records, and other data required to be maintained by CPV shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

39. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

40. NSPS Notifications: All notifications and reports required by the 40CFR 60, Subpart A applicable requirements shall be submitted to the Department's District Office and to the Manatee County Environmental Management Department.

MONITORING REQUIREMENTS

41. Required Continuous Monitoring System for NO_X and CO: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen (NO_X) and carbon monoxide (CO) from this unit. Each device shall properly function prior to the initial performance tests and comply with the applicable monitoring system requirements of 40 CFR 75.62 and 40 CFR 60, Appendix B, Performance Specifications. Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 62-4.130, F.A.C and 40CFR75]

42. Continuous Monitoring System Certification and Quality Assurance Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

43. Continuous Monitoring System Operation: The continuous monitoring systems (CEMS) for NO_X and CO shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. These CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. These excess emissions periods shall be reported as require in Specific Conditions 24 and 45. [Rules 62-4.130, 62-4.160(8), 62-204.800, 62-210.700, 62-4.070 (3), and 62-297.520, F.A.C.; 40 CFR 60.7; 40 CFR 60.13, 40 CFR 75]

44. Continuous Compliance with the CO and NO_X Emission Limits: Continuous compliance with the CO and NO_X emission limits shall be demonstrated with the CEM system on a 3-hr average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hr period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 3-hr period. A valid hourly emission rate shall be calculated for each hour in which at least two measurements are obtained at least 15 minutes apart.
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

45. CEMS for Reporting Excess Emissions: The NO_X CEMS may be used in lieu of the requirement for reporting excess emissions in 40 CFR 60.334(c)(1), Subpart GG (2000 version). Excess Emissions and Monitoring System Performance Reports shall be submitted as specified in 40 CFR 60.7(c). CEM monitor downtime shall be calculated and reported according to the requirements of 40 CFR 60.7(c)(3) and 40 CFR 60.7(d)(2). Periods when NO_X emissions (ppmvd @ 15 % oxygen) and CO emissions are above the permit limits listed in Specific Conditions 16 and 17, shall be reported to the *Compliance Authority* as required in Specific Condition 24.

46. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (2000 version). The calibration of the water/fuel-monitoring device required in 40 CFR 60.335 (c)(2) (2000 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. [EPA approval dated February 10, 1999]

47. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, which commits to using a primary fuel of pipeline-supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).

- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

This custom fuel-monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

48. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

49. Selective Catalytic Reduction (SCR) System

The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods, as dictated by the manufacturer's guidelines and in accordance with this permit. During turbine start-up, permittee shall begin use of SCR (i.e., commence ammonia injection) as soon as possible and within two (2) hours of the initial turbine firing or when the temperature of the catalyst bed reaches a suitable predetermined temperature level, whichever occurs first. During turbine shutdown, permittee shall discontinue use of the SCR (i.e., discontinue ammonia injection) when the catalyst bed temperature drops below the predetermined temperature levels, but no more than one hour prior to the time at which the fuel feed to the turbine is discontinued. Suitable temperature for activation and deactivation of the SCR shall be established during performance testing. The permittee shall, whenever possible, operate the facility in a manner so as to optimize the effectiveness of the SCR unit while minimizing ammonia slip to below the emission limit.

50. Ammonia Stack Tests and Injection

- An initial and quarterly stack emission test for ammonia shall be conducted for natural gas and fuel oil firing. The initial and annual (one of the four quarters) NO_X and ammonia stack tests shall be conducted at four points within the operating range of the combustion turbine. The ammonia injection rate necessary to comply with the NO_X standard for each test load, shall be established.

- The permittee shall install and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. It shall be maintained and calibrated according to the manufacturer's specifications.

CPV Gulfcoast Power Generating Facility
PSD-FL-300 and 0810194-001-AC
Manatee County, Florida

BACKGROUND

The applicant, CPV Gulfcoast, Ltd, proposes to install a construct a nominal 245-megawatt (MW) (net) combined cycle power plant at a new facility near Piney Point, Manatee County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary unit to be installed is a nominal 170 MW, General Electric 7FA combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an unfired heat recovery steam generator (HRSG) connected to a steam turbine-electrical generator to produce an additional 74.9 MW of electrical power. The project also includes a 1 million gallon storage tank for backup No. 2 fuel oil, cooling tower, a 150-foot stack, and a mechanical draft cooling tower and other ancillary equipment. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated November 17, 2000, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on September 11, 2000 and included a proposed BACT proposal prepared by the applicant's consultant, TRC.

REVIEW GROUP MEMBERS:

Teresa Heron, Permit Engineer and A. A. Linero, P.E.

BACT REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Selective Catalytic Reduction	3.5 ppmvd @15% O_2 (gas) 10 ppmvd@15% O_2 (oil)
Carbon Monoxide	Combustion Controls	9 ppmvd (gas) 20 ppmvd (oil)
Particulate Matter	Inherently Clean Fuels Combustion Controls	20 lb/hr (gas) 53 lb/hr (oil)
Sulfur Dioxide/Sulfuric Acid Mist	Low Sulfur Fuels	0.0065% sulfur (gas) 0.05% sulfur (oil)

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the CPV is consistent with the NSPS, which allows NO_X emissions in the range of 110 ppmvd for the high efficiency unit to be purchased by CPV. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

There is a National Emission Standard for Hazardous Air Pollutants (NESHAP) under development by EPA, but it is not applicable to this project. Because emissions of HAP are less than 10 tons per year, there is no requirement to conduct a case-by-case maximum achievable control technoiogy determinaion.

DETERMINATIONS BY STATES:

The following table is a sample of information on some recent applications, proposals, and determinations in the Southeast for combined cycle projects. The CPV Gulfcoast Project is included for reference.

TABLE 1

RECENT NO_X EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS IN THE SOUTHEAST

Project Location	Capacity Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
CPV Gulfcoast, FL	245	3.5 – NG 10 – FO	SCR	170 MW GE 7FA CT Under Review
TECO Bayside, FL	1750	3.5 – NG 16.4 - FO	SCR	7x170 MW GE 7FA CTs Repowering Review. Possibly SCONO$_X$ on 1 CT
FPC Hines II, FL	500	3.5 - NG 15 - FO	SCR	2x170 MW WH501F Under Review
Calpine Osprey, FL	527	3.5 – NG	SCR	2x170 MW WH501F Draft 5/00
Santee Cooper, SC	~500	9 – NG	DLN	2x170 MW GE 7FA CTs ~ 4/00
Mobile Energy, AL	~250	~3.5 - NG ~11 – FO	SCR	178 MW GE 7FA CT 1/99
Alabama Power Barry	800	3.5 - NG	SCR	3x170 MW GE 7FA CTs 11/98
Alabama Power Theo	210	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98
KUA Cane Island 3, FL	250	3.5 – NG (12 – simple cycle) 15 - FO	SCR	170 MW GE 7FA. 11/99 DLN on simple cycle
Lake Worth LLC, FL	250	9 or 3.5 – NG 9.4 or 3.5 – NG (CT&DB) 42 or 16.4 - FO	DLN or SCR DLN or SCR WI or SCR	170 MW GE 7FA. 11/99 Increase allowed for DB under DLN.
Miss Power Daniel	1000	3.5 – NG	SCR	4x170 MW GE 7FA CTs 11/98

DB = Duct Burner
NG = Natural Gas
FO = Fuel Oil
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
CT = Combustion Turbine

TABLE 2

RECENT CO, VOC, AND PM EMISSION LIMIT PROPOSALS AND DETERMINATIONS FOR "F-CLASS" COMBINED CYCLE PROJECTS

Project Location	CO - ppmvd (or lb/mmBtu)	VOC - ppmv (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
CPV Gulfcoast, FL	9 - NG (50 - 100% load)) 15 - NG (PA) 20 – FO	1.4 – NG 3.5 FO	11 lb/hr – NG (front) 36 lb/hr – FO (front) 5 ppmvd Ammonia Slip	Clean Fuels Good Combustion
TECO Bayside, FL	7.2 – NG 14.2 - FO	1.2 – NG 2.8 FO	20 lb/hr – NG 53 lb/hr - FO	Clean Fuels Good Combustion
FPC Hines II, FL	10 - NG (100% load)) 50 - NG (60% load) 30 – FO (100% load)	1.8 - NG (100% load)) 3 – NG (60% load) 10 – FO (100% load)	10% Opacity – NG 20% Opacity - FO	Clean Fuels Good Combustion
Calpine Osprey, FL	10 – NG 17 – NG (DB&PA)	2.3 – NG 4.6 – NG (DB&PA)	24 lb/hr – NG (DB&PA) 10 percent Opacity 9 ppmvd Ammonia Slip	Clean Fuels Good Combustion
Mobile Energy, AL	~18 – NG ~26 – FO	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
Alabama Power Barry	~15 – NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
Alabama Power Theo	~36 – CT & DB	~12.5 CT & DB		Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Lake Worth LLC, FL	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
Miss Power Daniel	~15 - NG(CT) ~25 – NG(DB & CT	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion

All of the projects listed above control SO_2 and sulfuric acid mist by limiting the sulfur content of the fuel. In every case, pipeline quality natural gas is used and has a sulfur content less than 2 grains per 100 cubic. In some cases, the limits are even lower or are expressed in different terms. However all ultimately rely on a fairly uniform gas distribution network and have very little flexibility in actually controlling sulfur content. Similarly, emissions of these two pollutants are controlled by using 0.05 percent sulfur distillate fuel oil.

Some of the projects listed above include front and back half catch for PM limits. Therefore comparison is not simple.

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Comments from the National Park Service dated September 27, 2000
- Comments from from EPA Region IV dated December 27, 2000
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. *Thermal* NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. *Prompt* NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 1 which is from a General Electric discussion on these principles.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although, low sulfur fuel oil (which has more fuel-bound nitrogen than natural gas) is limited to no more than 30 days or 720 hours per year.

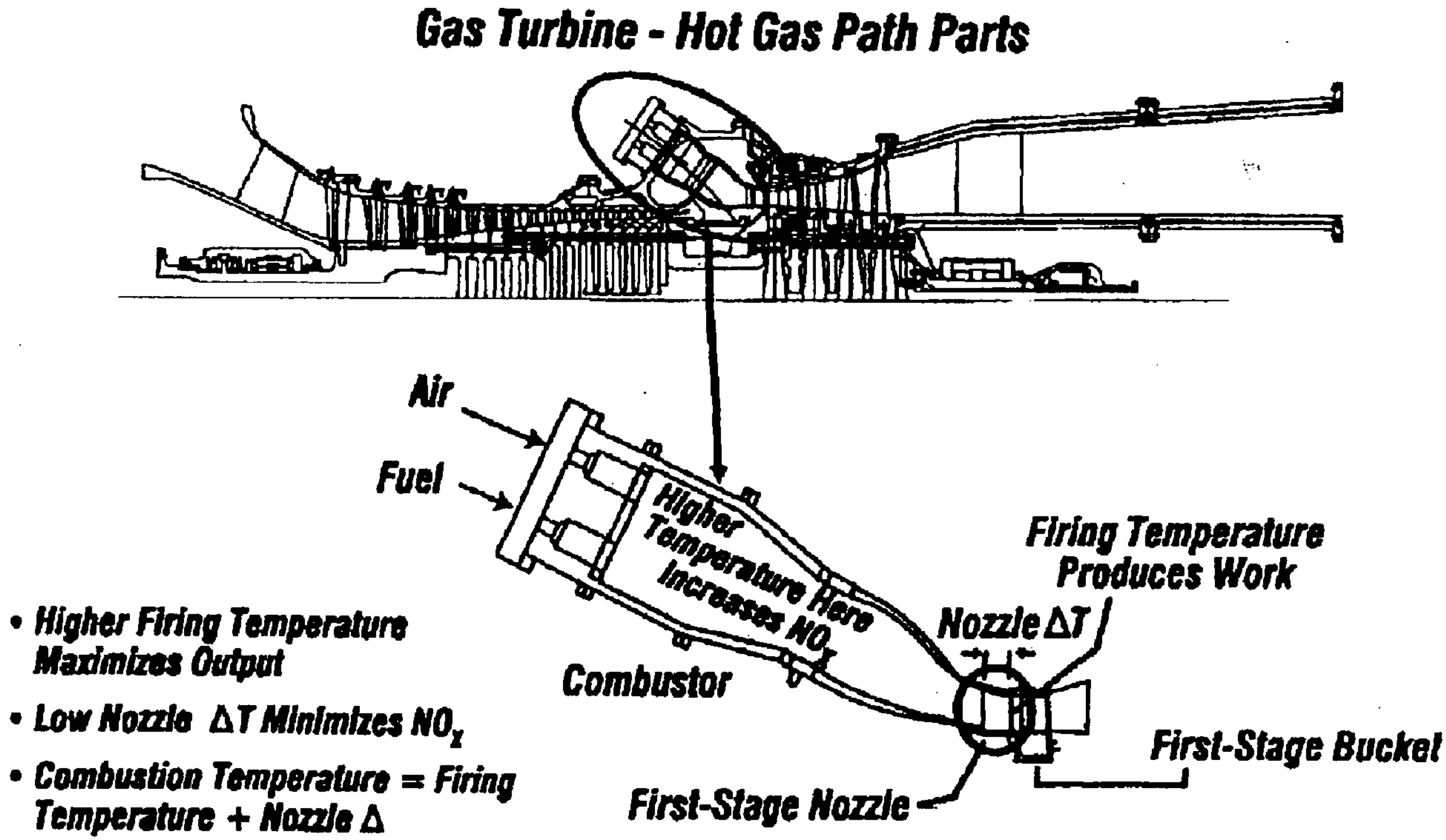


Figure 1 – Relation Between Flame Temperature and Firing Temperature

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for the turbine of the CPV Gulfcoast Project. The proposed NO_X controls will significantly reduce these emissions.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls: Dry Low NO_X (DLN)

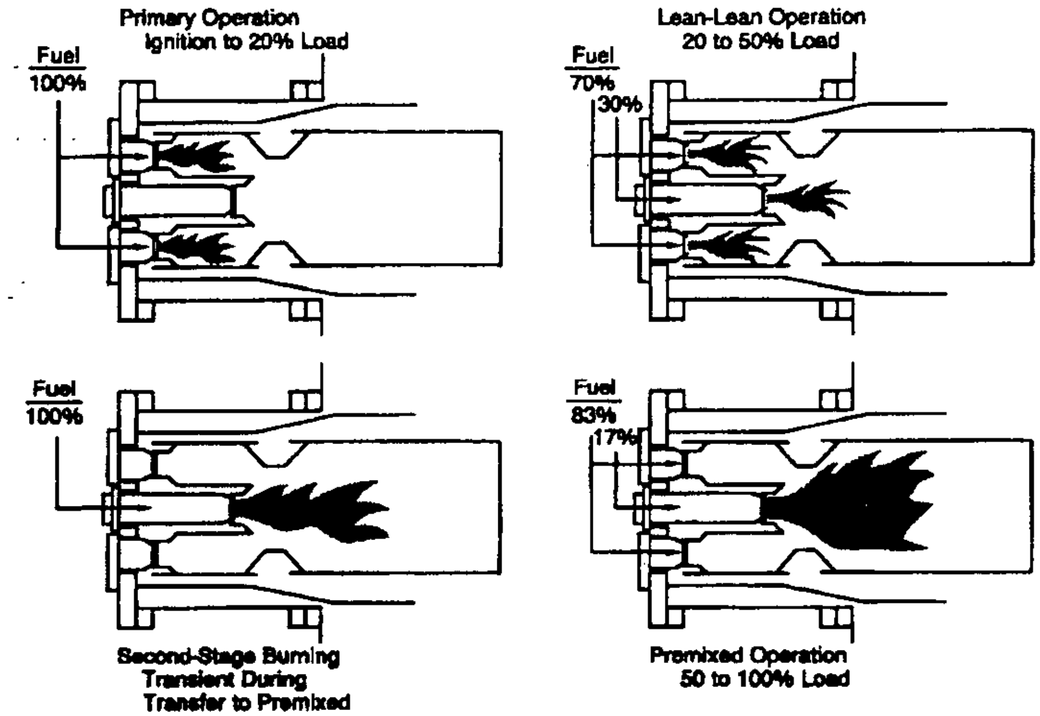
The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 2 for a General Electric DLN-1 can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 2) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the CPV Gulfcoast project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 3 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.



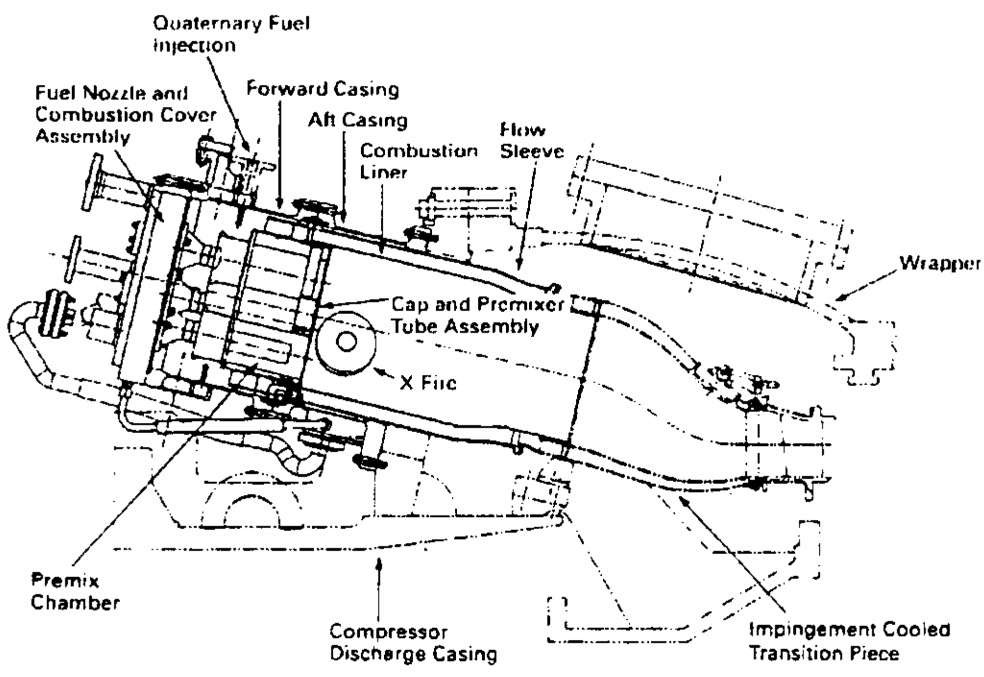


Figure 2 – Dry Low NO_X Operating Modes – DLN-1
Cross Section of GE DLN-2

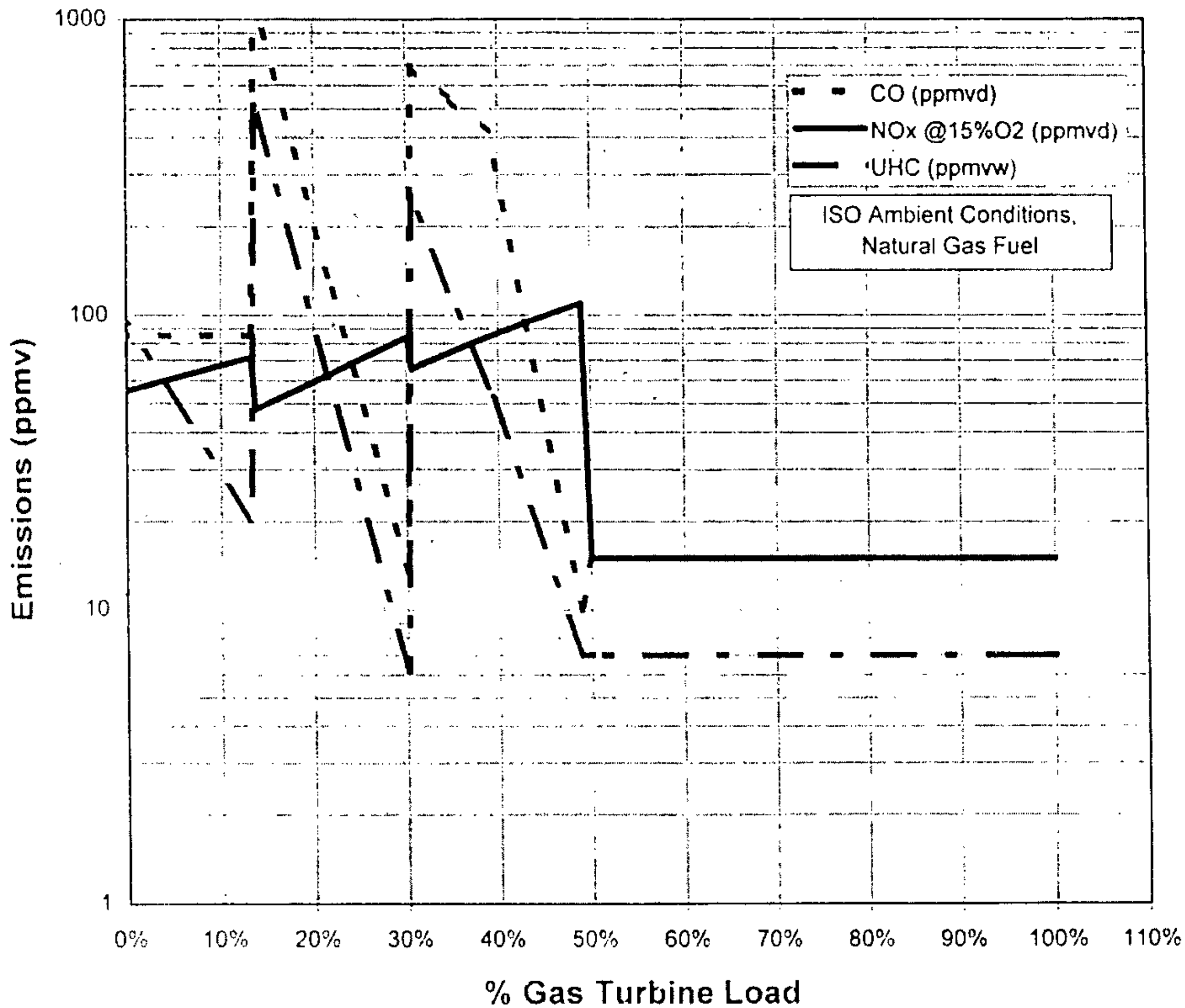


Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_X)

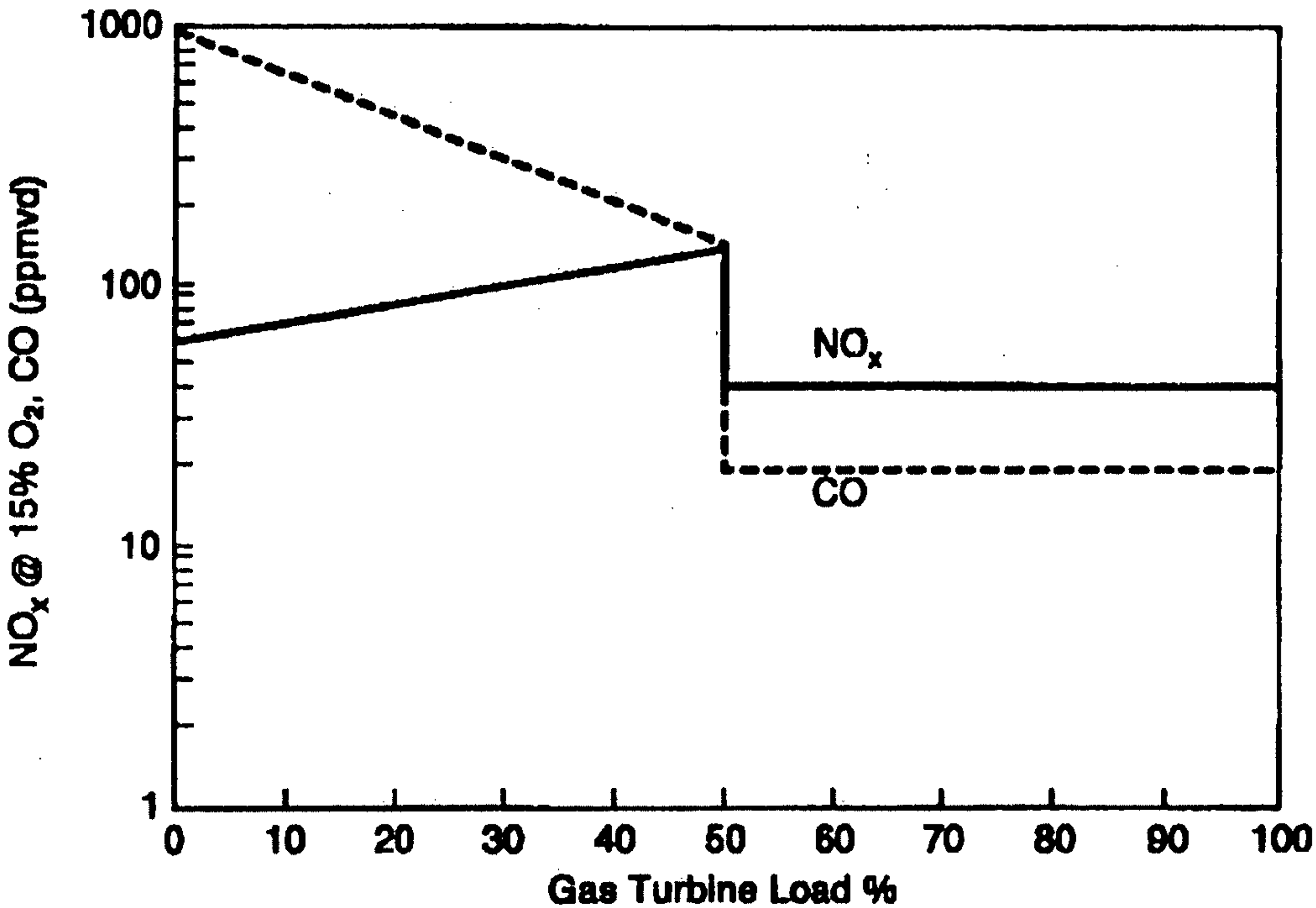


Figure 4 – Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.[1] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 12 ppmvd. The results are all superior to the emission characteristics given in Figure 3.

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)
70	7.2	
80	6.1	
90	6.6	
100	8.7	0.85
Limit	12	25

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[2] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 10.5 ppmvd. Again, the results are all superior to the emission characteristics given in Figure 3.

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

Recent conversations with other operators indicate that the Low NO_X characteristics extend to operations less than 50 percent of full load, though such operation is not (yet) guaranteed by GE.[3]

Emissions characteristics by wet injection NO_X control while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 4. Simplified cross sectional views of the totally premixed (while firing natural gas) DLN-2.6 combustor to be installed at the CPV Gulfcoast project are shown in Figure 5.

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 6 from an EPRI report.[4] Basically developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix

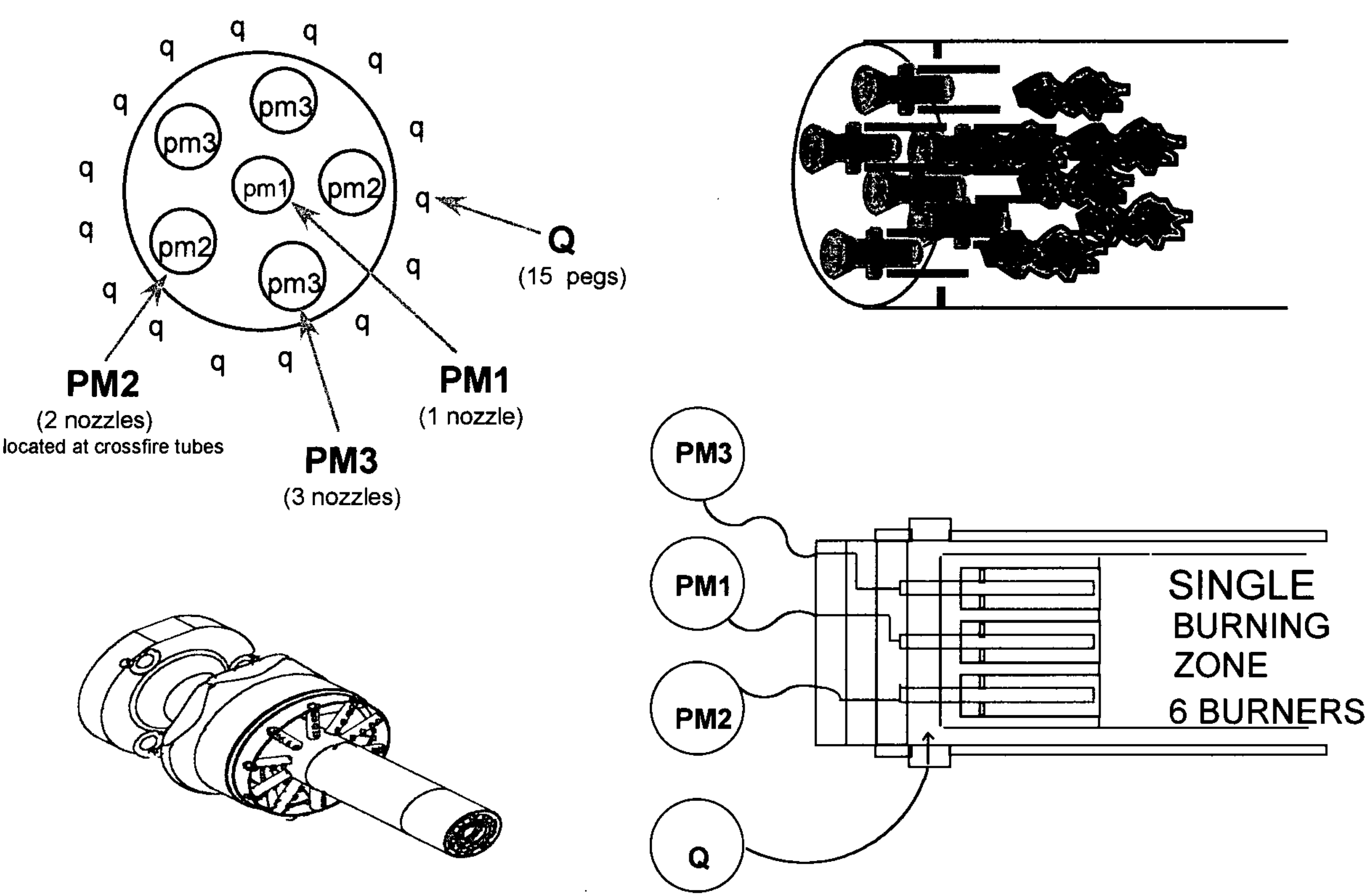


Figure 5 - DLN2.6 Fuel Nozzle Arrangement

combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 6.

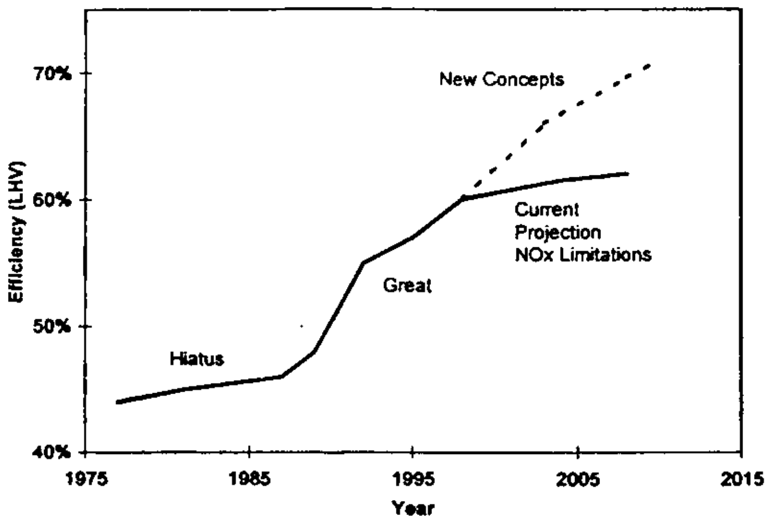


Figure 6 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (Westinghouse G or General Electric H Class technology) than the units planned by CPV. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to figure 1). At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from large gas turbines, such as the GE 7FA line. Specialized dual fuel DLN burners were installed in a project in Israel[5], but the Department does not know their performance on fuel oil. Mitsubishi (who also make a 501F) is also developing a dual-fuel DLN. Optimization of premix fuel-air nozzle and performance was verified in high-pressure combustion tests. Commissioning tests on gas and oil burning were completed at an undesignated site.[6] The details are not available in English.

<u>Catalytic Combustion: XONON ™</u>

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described in the DLN technology above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[7] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents. Westinghouse is working to replace the central pilot in its DLN technology with a catalytic pilot in a project with Precision Combustion Inc.

Catalytica has developed a system know as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[8] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. Previously, this turbine and XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests at a project development facility in Oklahoma which documented XONON's ability to limit emissions of NO_X to less than 3 ppmvd.

Recently, Catalytica and GE announced that the XONON™ combustion system has been specified as the *preferred* emissions control system with GE 7FA turbines that have been ordered for Enron's proposed 750 MW Pastoria Energy Facility.[9] The project will enter commercial operation by the summer of 2001. However actual installation of XONON on the Pastoria project is doubtful.

In principle, XONON™ will work on a simple cycle project. However, the Department does not have information regarding the status of the technology for fuel oil firing and cycling operations.

Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Kissimmee Utilities Authority (KUA) will install SCR at the Cane Island Unit 3 project as a result of insistence by EPA that DLN technology to achieve 9 ppmvd of NO_X was not BACT. The KUA project will meet a limit of 3.5 ppmvd with a combination of DLN and SCR. Since then, the Department has consistently advised prospective applicants that BACT is 3.5 ppmvd. Accordingly, FPC submitted an application for the Hines Power Block II project with a BACT NO_X proposal of 3.5 ppmvd by SCR. CPV proposes the same for the present project by SCR. The Department required TECO to meet the same limit by SCR for its Bayside Repowering Project.

Figure 7 below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 8 is a photograph of FPC Hines Energy Complex. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country.

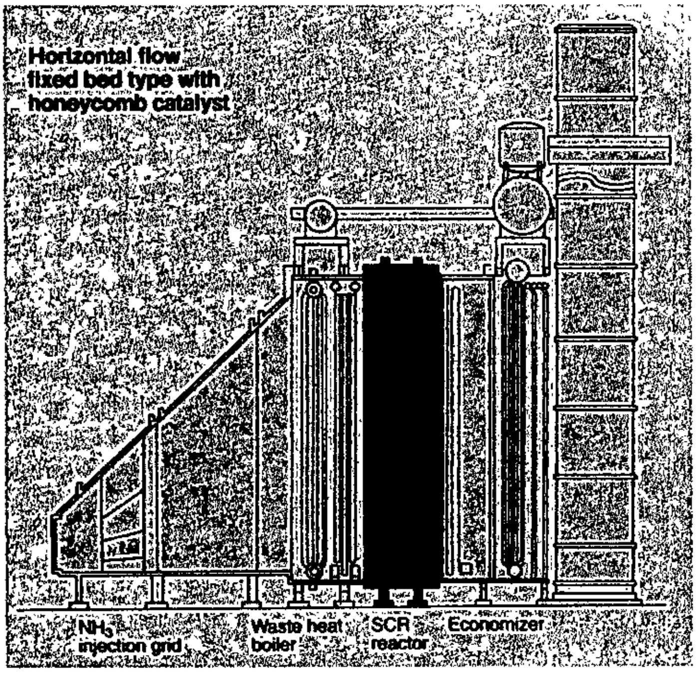


Figure 7 – SCR System within HRSG

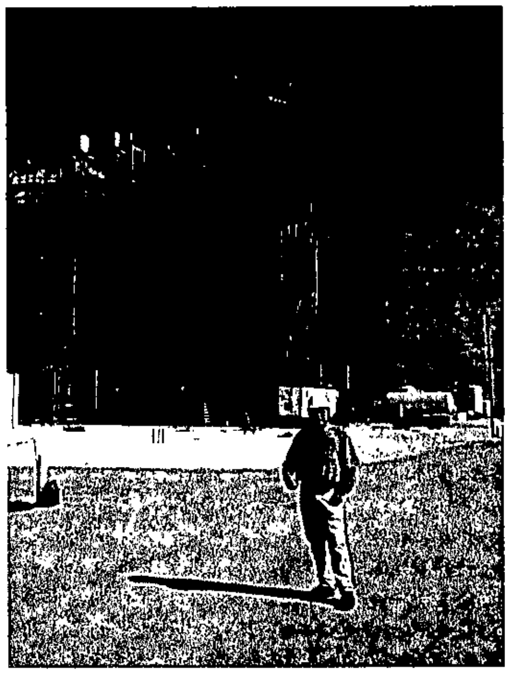


Figure 8 – FPC Hines Power Block I

Selective Non-Catalytic Reduction (SNCR)

Selective non-catalytic reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The acceptable temperature for the removal reactions is between 1400 and 2000 °F. Temperatures on the order of 1800 °F can be achieved in supplementally-fired HRSGs with very large duct burners. An example is the Santa Rosa Energy Center, which incorporates a 585 mmBtu/hr duct burner. SNCR is not feasible for un-fired HRSG planned for the CPV project.

$SCONO_X$™

$SCONO_X$ is a catalytic add-on technology (and registered trademark) that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[10]

California regulators and industry sources have stated that the first 250 MW block to install $SCONO_X$ will be at PG&E's La Paloma Plant near Bakersfield.[11] The overall project includes several more 250 MW blocks with SCR for control.[12] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine equipped with $SCONO_X$™.

$SCONO_X$ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the $SCONO_X$ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of VOC and CO emissions.

Recently EPA Region IX acknowledged that $SCONO_X$ was demonstrated in practice to achieve 2.0 ppmv NO_X.[13] Permitting authorities planning to issue permits for future combined cycle gas turbine systems firing exclusively on natural gas, and subject to LAER must recognize this limit which, in most cases, would result in a LAER determination of 2.0 ppmv. More recently, Goal Line submitted information to EPA and states in support of its contention that the technology has achieved 1 ppmvd in practice.[14]

According to a recent press release, the Environmental Segment of ABB Alstom Power offers the technology (with performance guarantees) to "all owners and operators of natural gas-fired combined cycle combustion turbines, regardless of size."[15] The technology is under consideration for one of the seven combined cycle units to be installed at the TECO Bayside Project (repowering of coal-fired Gannon Station Units 5 and 6).

REVIEW OF SULFUR DIOXIDE (SO_2) AND SULFURIC ACID MIST (SAM)

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed as BACT the use of 0.05% sulfur oil and pipeline natural gas. The applicant estimated total emissions for the project at 76 TPY of SO_2 and 12 TPY of SAM. The Department expects that emissions will be lower because of the limited oil consumption and because typical natural gas distributed in Florida that contains less than the 0.0065% sulfur specification proposed as BACT.

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 720 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. As previously mentioned, the NO_X control technology of SCR increases PM/PM_{10} emissions due to formation of ammonium nitrates and ammonium sulfates. The problem is more significant when firing fuel oil (despite the low sulfur specification). This effect will be minimized by limiting fuel oil firing to less than 720 hours per year and limiting ammonia emissions (slip) to 5 ppmvd.

REVIEW OF CARBON MONOXIDE (CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO. There is a great deal of uncertainty regarding actual CO emissions from installed units. Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions have actually been reported from several facilities without use of oxidation catalyst. For example, although Westinghouse does not offer a single digit CO guarantee on the 501F, the units installed at the FPC Hines Energy Complex achieved CO emissions in the range of 1-3 ppmvd on both gas and fuel oil.[16] As previously discussed, GE 7FA units achieved similar results when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2.

CO emissions *should* be low (at least at full load) because of the very high combustion temperatures characteristic of "F-Class" turbines. It appears that contract writing has not yet "caught up" with the field experience to consistently guarantee low CO emissions for F-Class units, at least at high loads.

One alternative is to complete the combustion by installation of an oxidation catalyst. Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[17]

The limit proposed by CPV when firing natural gas is 9 ppmvd at the entire operating range between 50 and 100 percent of full load. This is consistent with the description of the DLN-2.6 technology. A higher limit of 15 ppmvd is proposed during power augmentation. Under this mode, steam from the HRSG is re-injected into the combustors to boost power production. One consequence is that CO emissions can increase. The emission limit of 20 ppmvd during limited fuel oil firing appears reasonable, although much lower values are likely to be achieved.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by CPV for this project are 1.4 ppmvw for gas and 3.6 ppmvw for oil firing. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[18]

Based on the chosen equipment, the Department believes that annual VOC emissions will be less than 40 TPY. Therefore a BACT determination is not required.

BACKGROUND ON SELECTED GAS TURBINE

CPV plans to the purchase a 170 MW (nominal) General Electric 7FA combined cycle gas turbine with an unfired heat recovery steam generator (HRSG). Per the discussion above, such units are capable of achieving and have achieved (with DLN and SCR technology) all of the emission limits proposed by CPV as BACT.

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark V also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values prior to the SCR unit.[19]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the CPV project assuming full load. Values for NO_X, CO and VOC are corrected to 15% O_2. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 16 through 21.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Nitrogen Oxides	Selective Catalytic Reduction	3.5 ppmvd (gas) 10 ppmvd (oil)
Carbon Monoxide	Combustion Controls	9 ppmvd (gas) 15 ppmvd (power augmentation) 20 ppmvd (oil)
Particulate Matter	Inherently Clean Fuels Combustion Controls Ammonia Slip < 5 ppmvd	11 lb/hr (gas) 36 lb/hr (oil) 10 percent Opacity
Sulfur Dioxide and Sulfuric Acid Mist	Low Sulfur Fuels	0.0065% sulfur (gas) 0.05% sulfur (oil)

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd while firing natural gas. It has been achieved at the 32 MW Federal Merchant Plant in Los Angeles. The owner, Goal Line has requested recognition of a 1.3 ppmvd NO_X value as *achieved in practice.*
- There are several projects for large turbines requiring SCR with a NO_X emission limit of 2 ppmvd.
- The "Top" technology in a top/down analysis will achieve 2 ppmvd by either $SCONO_X$ or SCR.
- CPV chose SCR over $SCONO_X$ for technical and economic reasons. The Department does not necessarily accept the technical rationale. The Department does not necessarily accept the economic figures submitted by CPV of $2,835 and $24,916 per ton of NO_X removed by SCR and $SCONO_X$ respectively.
- If the costs submitted by CPV were *doubled* to $5,600 per ton by SCR and *halved* to $12,500 per ton by $SCONO_X$, the former control technology would still be more cost-effective than the latter. The difference of almost $7,000 per ton of NO_X removed is sufficient reason to select SCR over $SCONO_X$ for this project.
- CPV proposes a NO_X limit of 3.5 ppmvd while firing natural gas. This is equal to the lowest emission rate in Florida and nearby states to-date.
- Based on previous projects such as KUA Cane Island, the Department believes that the costs of NO_X control by SCR are on the order of $6,000 per ton when ammonia emissions are held to 5 ppmvd.
- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[20]
- Although further reduction to 2 ppmvd is possible (though difficult to measure), the marginal costs escalate rapidly and ammonia emissions increase.
- The Department agrees with CPV that 3.5 ppmvd (with 5 ppmvd ammonia slip) while firing natural gas constitutes BACT. This value for the SCR option takes into consideration the uncertainties mentioned above and minimize the negative effects of ammonia emissions.
- The Department previously documented the environmental and cost impacts associated with the use of SCR to achieve 3.5 ppmvd of NO_X at the KUA Cane Island Project in comparison with DLN to achieve 9 ppmvd NO_X.
- EPA Region IV determined that there are no there were "no unusual site-specific conditions associated with the KUA project to indicate that the use of SCR to achieve NO_X emissions of 3.5 ppm would cause greater problems than experienced elsewhere at other similar facilities."
- Ammonia is used in very large quantities at adjacent or nearby fertilizer plants in Polk, Hillsborough and Manatee Counties to make ammoniated fertilizers. Therefore there are no obvious site-specific conditions that would make it unadvisable to use ammonia at the CPV project.
- The conclusion is that the cost and environmental impacts of SCR for this project are acceptable in view of the NO_X reduction.

- The CO limits of 9 ppmvd while firing natural gas and 15 ppmvd under power augmentation are low and within the range of recent BACT determinations for combustion turbines in the Southeast. The CO limit during the limited hours of fuel oil firing will be set at 20 ppmvd (full load).
- The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, or PM_{10}.
- CPV initially estimated levelized costs for CO catalyst control at $4,350 to reduce emissions from the 9-20 range to a 2-4 ppm range. EPA made several comments regarding cost estimation techniques used by CPV that suggest the estimate is biased to the high side. Revised CPV estimates (see Final Determination) range from $3,050 to 3,870.
- In view of the performance of GE 7FA units cited in the discussion above (Tallahassee and TECO Polk Power data) without add-on control (~ 1 ppmvd), it appears to the Department that oxidation catalyst costs are substantially biased to the low side based on *actual* emissions.
- The measured CO values (~ 1 ppmvd) at Tallahassee and TECO Polk Power *without control* are less than the objective to be obtained by catalytic reduction (e.g. reducing CO from 20 to 4 ppm or from 9 to 2 ppm).
- The Department will set CO limits reflecting the "new and clean test" guarantees rather than actual performance because GE will not (yet) guarantee the lower values. The Department will gather more information and may substantially reduce CO limits in future projects if such performance is maintained at the new installations throughout the state. The Department will also limit the extent to which CPV can operate in power augmentation mode to 2000 hours unless CPV installs oxidation catalyst or proves that actual performance is much better than guaranteed (thus rendering control not cost effective).
- There is no benefit is penalizing the applicant with a lower limit at this time just because the performance at another site was far better than guaranteed or expected. There also appears to be no benefit in installing a catalytic oxidation system. The applicant will be the first to install a continuous CO monitor. It is expected that data from continuous measurement will conclusively show that oxidation catalyst is not needed and is not cost effective for this project.
- The Department agrees that inlet air filtration, good combustion, and use of inherently clean fuels is BACT for PM/PM_{10}. Furthermore, the Department will set the ammonia limit at 5 ppmvd to minimize additional PM formation.
- PM_{10} emissions will be very low and difficult to measure. The PM values of 11 and 36 lb/hr for natural gas and oil respectively will be included in the permit. These values include front half catch only.
- The Department will set a visible emissions BACT limit at 10 percent. The Department will rely on VE observation as a surrogate for PM/PM_{10} BACT compliance (after the initial PM/PM_{10} test).

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
PM/PM_{10}	Method 5 (Front half catch, Initial test, thereafter VE as surrogate)

VOC	Method 25A corrected by methane from Method 18)
SO_2/SAM	Record keeping for the sulfur content of fuels delivered to the site
CO (continuous 3-hr)	Method 10, CO CEMS
NO_X (continuous 3-hr)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (initial and annual)	Annual Method 20 (can use RATA if at capacity); Method 7E

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Specific Condition 24 of the Permit. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C. and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: One hour following a shutdown less than or equal to 8 hours.
Warm Start: Two hours following a shutdown between 8 and 48 hours.
Cold Start: Four hours following a shutdown greater than or equal to 48 hours.

The *starts* are defined by the amount of time the HRSG has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[21]

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Teresa Heron, Review Engineer, New Source Review Section
A. A. Linero, P.E. Administrator, New Source Review Section 1/27
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

1/30/01

Date:

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

1/31/01

Date:

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[19] Rowen, W.I. "General Electric Speedtronic™ Mark V Gas Turbine Control System. 1994."

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G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.