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, 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)

U.S. Postal Service
CERTIFIED MAIL RECEIPT
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7099 3400 0000 1449 4307

Article Sent To:
Mr. Gary Lambert

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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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- 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

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Florida Department of Environmental Protection

Memorandum

TO: Howard L. Rhodes

THRU: C. H. Fancy CHF

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. The 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

11/30

Howard

pls read cover memo
& OGC memo right behind
it. We told Keri ifs he would
give it to us in writing, then
we would remove. This verbal
stuff on these issues is
not sufficient.

Clair

FINAL DETERMINATION
File No. 0810194-001-AC (PSD-FL-300)
CPV – GULFCOAST POWER GENERATING FACILITY
245 MW COMBINED CYCLE COMBUSTION TURBINE

The Department distributed a Public Notice package on November 17, 2000 for the project to construct a nominal 245-megawatt (MW) natural gas and fuel oil-fired combined cycle unit to be known as the CPV – Gulfcoast Power Generating Facility near Piney Point, Manatee County. The project consists of a nominal 170 MW General Electric 7FA combustion turbine-electrical generator, an unfired heat recovery steam generator, a steam-electrical generator; a 150-foot stack; a mechanical draft cooling tower; a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. The Public Notice of Intent to Issue was published on November 25 in The Bradenton Herald.

Written comments were received during the initial 30-day public comment period from the Chairman of the Manatee County Board of County Commissioners, the Manatee County Environmental 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 <u>without</u> 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	$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	$230,805
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	**$275,898**
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)	$376,381
BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE	154
Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6,040 hr/yr (no power augmentation)/ 15 ppm on gas for 2,000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr	
TONS OF CO REMOVED PER YEAR	123
Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency	
COST-EFFECTIVENESS	
ENVIRONMENTAL BASIS *($ per ton of CO removed)*	$3,050

2000 hr PAG 8% interest

Table E-3. CPV Gulf Coast
CO Catalyst

COST COMPONENT	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 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)	**$381,085**
BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6,040 hr/yr (no power augmentation)/ 15 ppm on gas for 2,000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr	154
TONS OF CO REMOVED PER YEAR Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency	123
COST-EFFECTIVENESS	
ENVIRONMENTAL BASIS ($ per ton of CO removed)	$3,088

2000 hr PAG 20% contingency

Table E-3. CPV Gulf Coast
CO Catalyst

	COST COMPONENT	[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	
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)	$20,104
	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)	$36,536
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	$16,687
$ 50,000	at the end of catalyst guaranteed life	
	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)	
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	**$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)	**$405,974**
	BASELINE POTENTIAL CO EMISSIONS (TPY) FROM TURBINE	**154**
	Uncontrolled General Electric 7FA Turbine Emissions = 9 ppm on gas for 6,040 hr/yr (no power augmentation)/ 15 ppm on gas for 2,000 hr/yr (power augmentation)/20 ppm on oil for 720 hr/yr	
	TONS OF CO REMOVED PER YEAR	**123**
	Controlled General Electric 7FA Turbine Emissions = assume 80% control efficiency	
	COST-EFFECTIVENESS	
	ENVIRONMENTAL BASIS	
	($ per ton of CO removed)	**$3,290**

Table E-3. CPV Gulf Coast
CO Catalyst

COST COMPONENT	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 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)	$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	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)	$3,870

Department of Environmental Protection

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

Jeb Bush
Governor

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

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.

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.

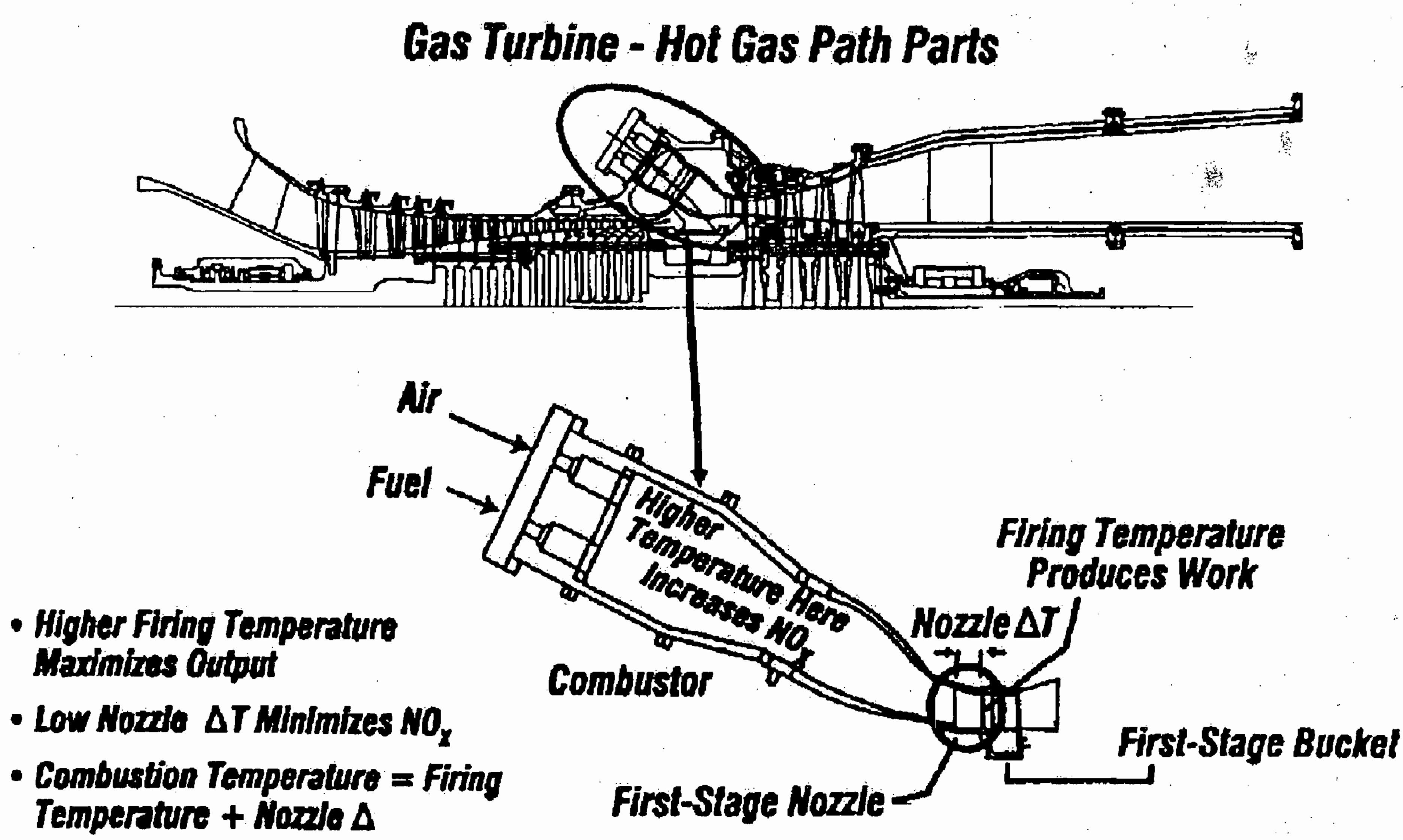


Figure 1 – Relation Between Flame Temperature and Firing Temperature

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)

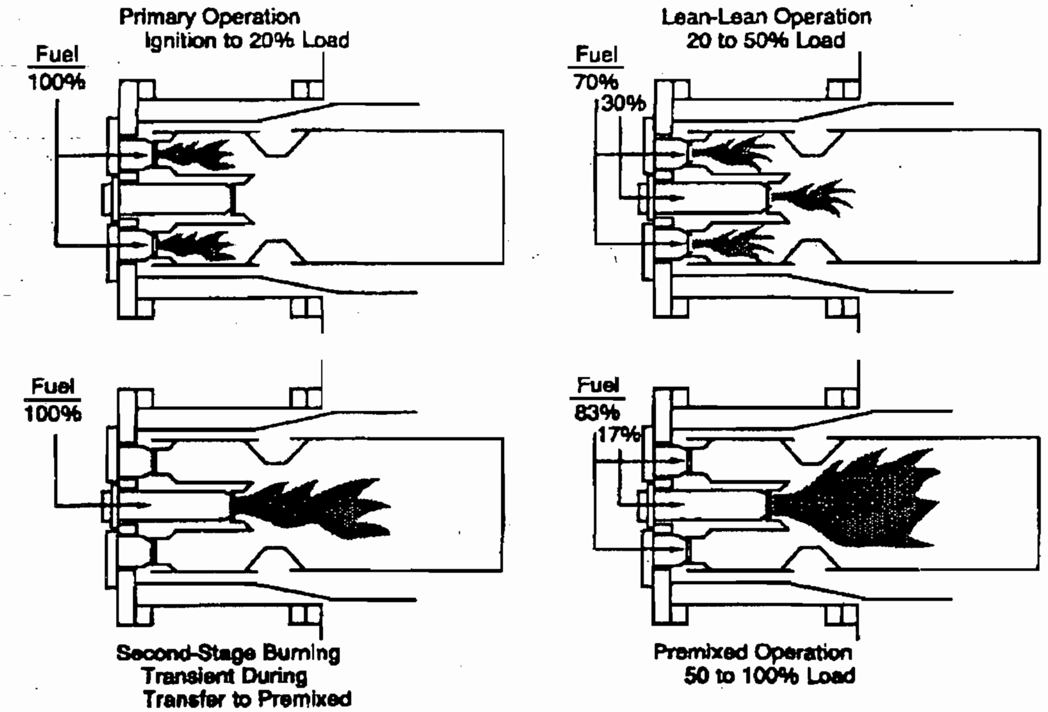
The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to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



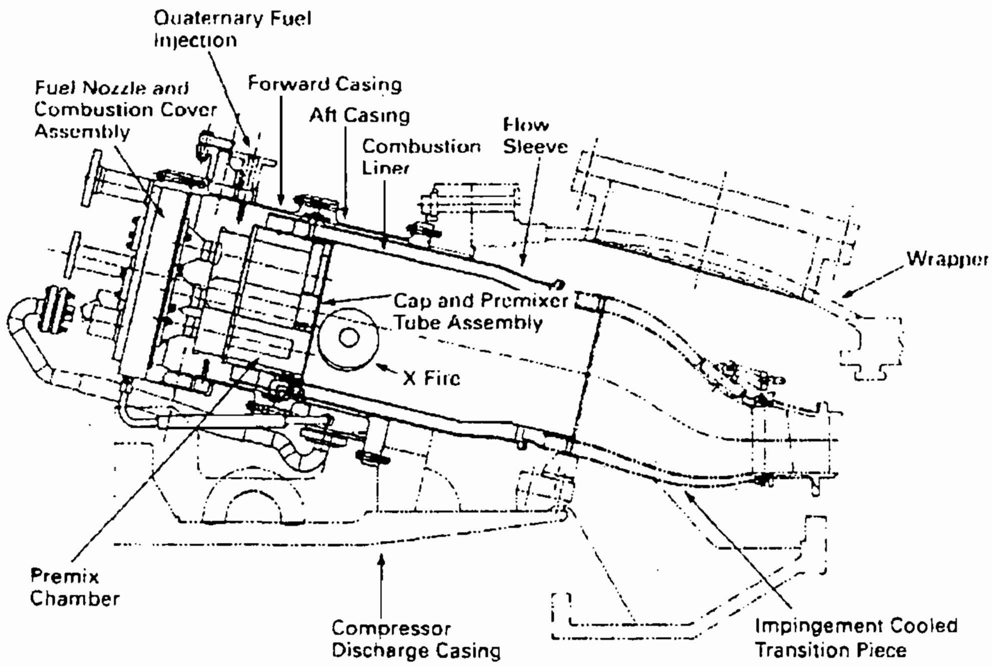


Figure 2 – Dry Low NO_X Operating Modes – DLN-1
Cross Section of GE DLN-2

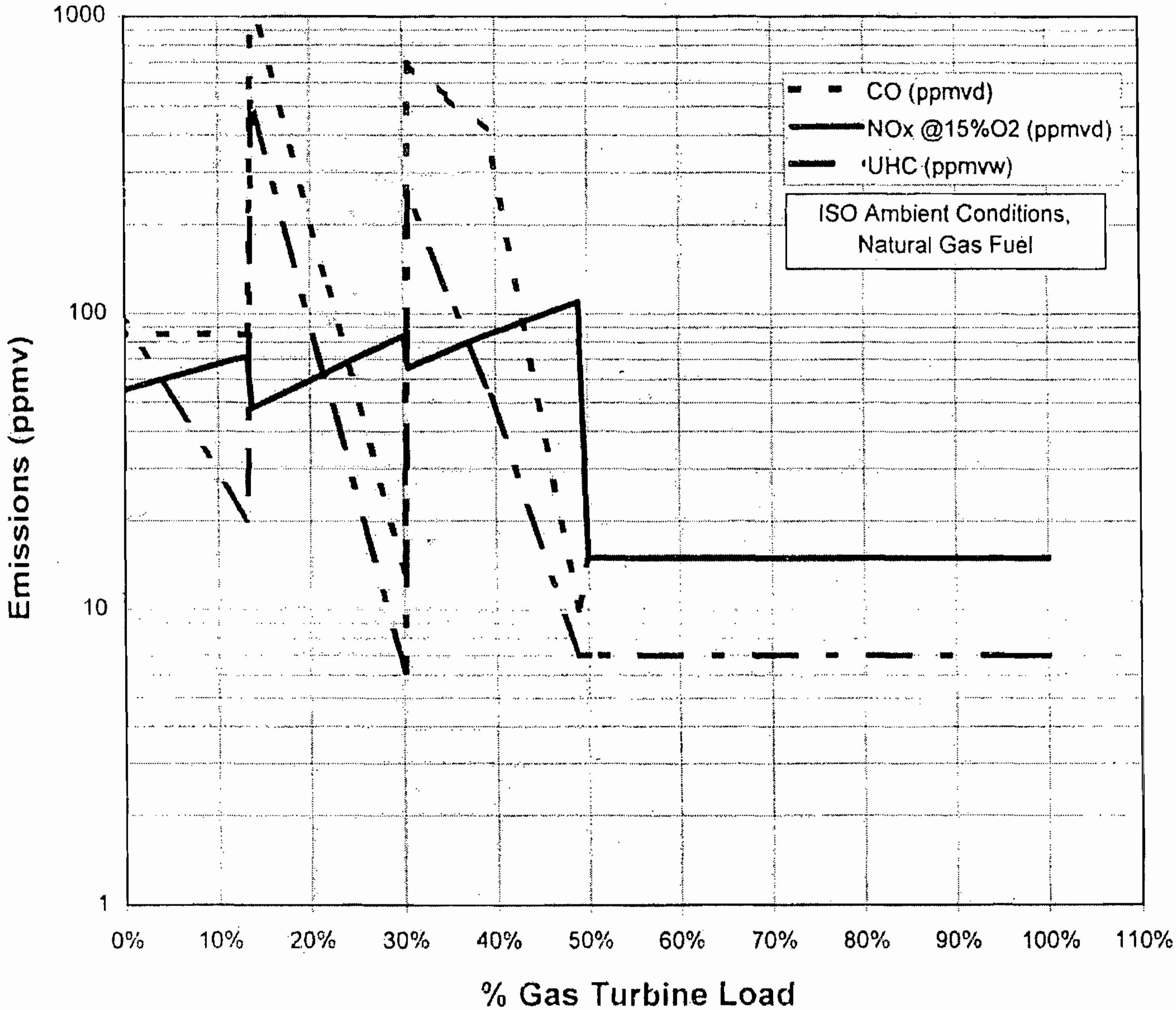


Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

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

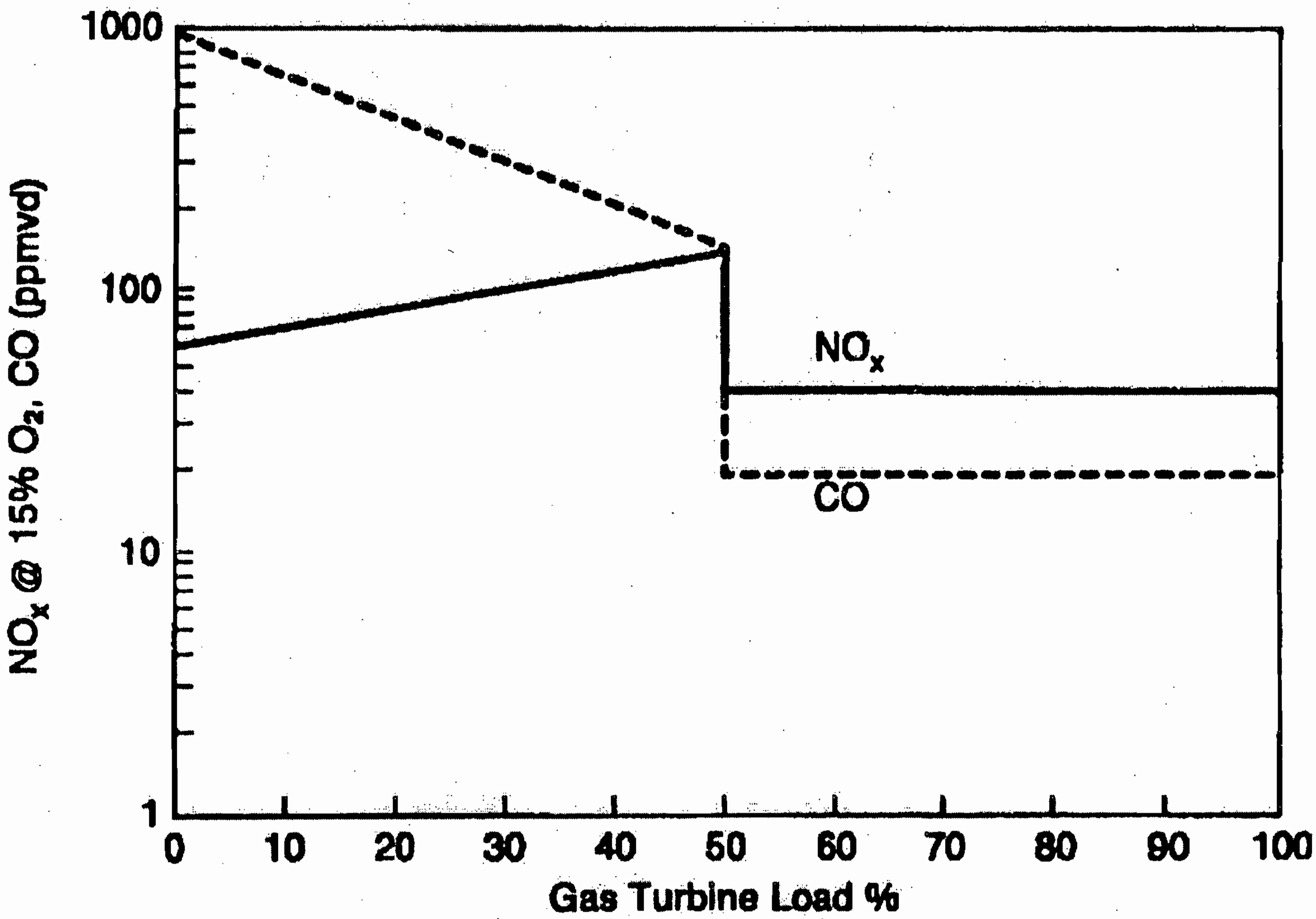


Figure 4 – Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

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

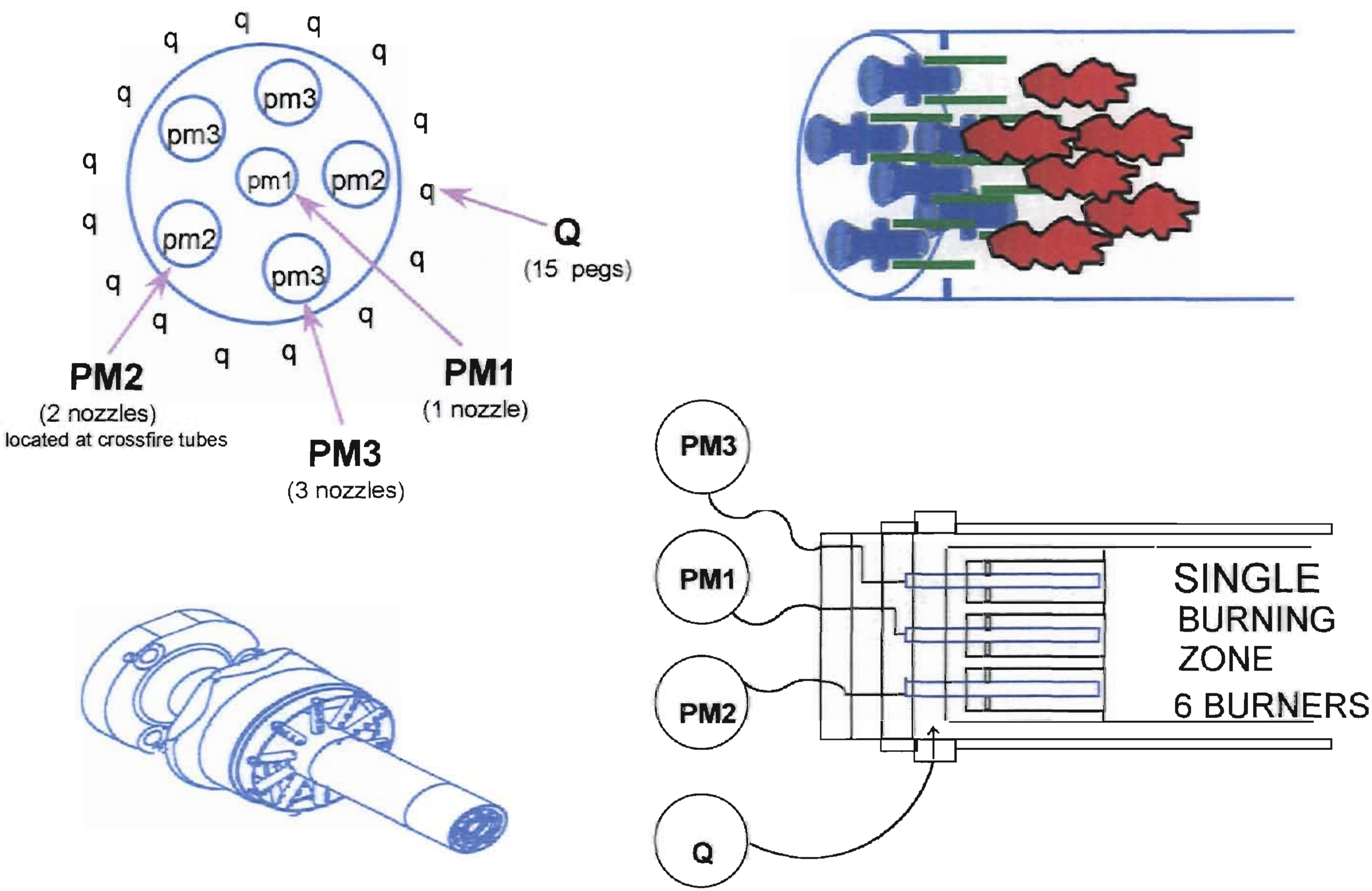


Figure 5 - DLN2.6 Fuel Nozzle Arrangement

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.

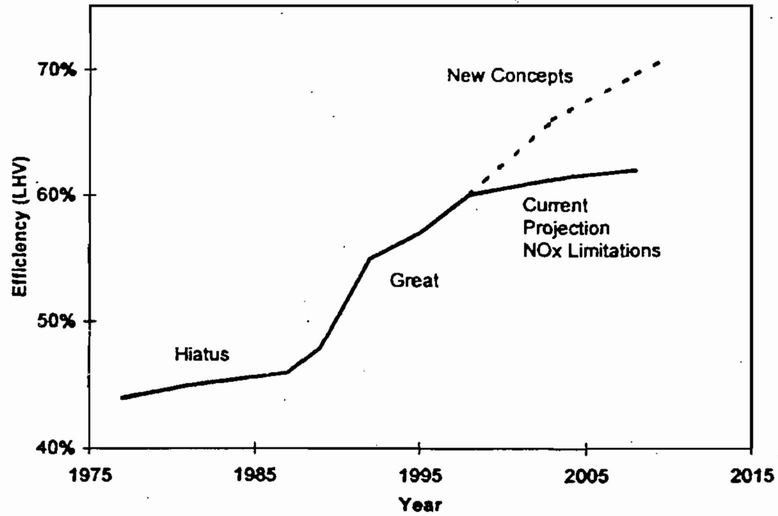


Figure 6 – Efficiency Increases in Combustion Turbines

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 Pastória 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.

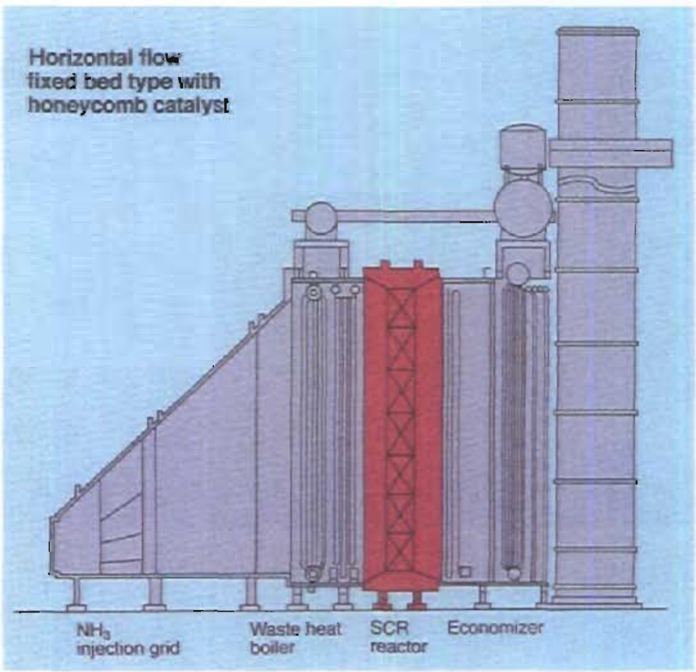


Figure 7 – SCR System within HRSG

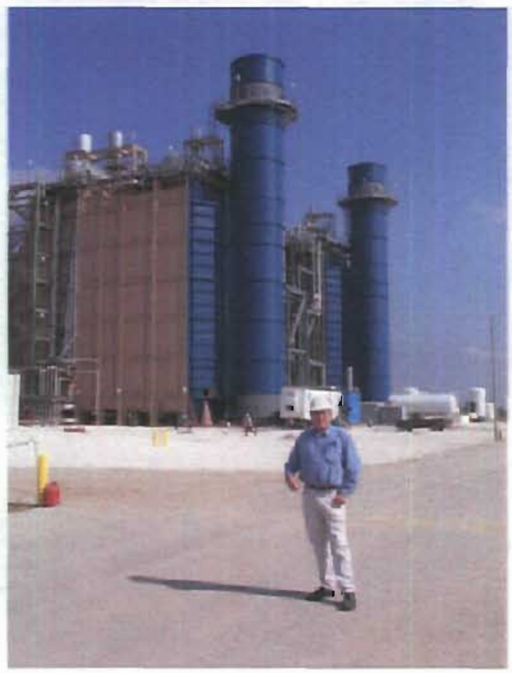


Figure 8 – FPC Hines Power Block I

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

Date: 1/30/01

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 1/31/01

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

[20] Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

[21] General Electric. Combined Cycle Startup Curves. June 19, 1998.

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.

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

May 20, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Sean Finnerty, Vice President
CPV Gulfcoast Ltd.
35 Braintree Hill Office Park, Suite 107
Braintree, Massachusetts 02184

Re: DEP File No. 0810194-003-AC (PSD-FL-300)
CPV Gulfcoast Power Generating Facility
245 MW Nominal Combined Cycle Facility – Permit Extension Request

Dear Mr. Finnerty:

On February 11, 2004 the Department responded to your request of January 19, 2004 to extend the subject permit by requiring a revised BACT Determination. According to our records, this permit has been extended on two prior occasions: July 31, 2002 and May 9, 2003.

As indicated in our letter, "Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days." The rule is stated in its entirety below:

62-4.055 Permit Processing.
(1) Within thirty days after receipt of an application for a permit and the correct processing fee the Department shall review the application and shall request submittal of additional information the Department is authorized by law to request. The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department. If an applicant requires more than ninety days in which to respond to a request for additional information, the applicant may notify the Department in writing of the circumstances, at which time the application shall be held in active status for one additional period of up to ninety days. Additional extensions shall be granted for good cause shown by the applicant. A showing that the applicant is making a diligent effort to obtain the requested additional information shall constitute good cause. Failure of an applicant to provide the timely requested information by the applicable deadline shall result in denial of the application.

Given the prior extensions, and since more than 90 days have passed without receipt of either the requested information or a timely request for additional time to respond, your application is denied.

If you have any questions regarding this matter, please contact me at (850) 921-9519.

Sincerely,

Michael P. Halpin, P.E.

Michael P. Halpin, P.E.
North Permitting Section

Copy: Sean Finnerty, CPV Gulfcoast, Ltd.*
Gregg Worley, EPA
John Bunyak, NPS
Jerry Kissell, DEP SWD
Chair, Manatee County BCC
Karen Collins-Fleming, Manatee County EMD

Adams, Patty

From: Linero, Alvaro

Sent: Monday, April 26, 2004 2:38 PM

To: Pennington, Jim; Adams, Patty

Subject: FW: CPV Gulfcoast

FYI.

-----Original Message-----
From: Sean Finnerty [mailto:sfinnerty@cpv.com]
Sent: Monday, April 26, 2004 2:24 PM
To: Linero, Alvaro
Subject: CPV Gulfcoast

Al,

I just wanted to send you a short note to let you know that in response to our request for a time extension we received a request from the permitting division regarding additional BACT information for the CPV Gulfcoast project. Given the current state of the market, we are not going to provide the requested information and instead will re-apply for a permit when the project is ready to proceed forward again. Thanks for all your help during the permitting process, it was a pleasure working together with you on this project. I look forward to doing so again in the near future.

Sean

Sean J. Finnerty
Vice President
Competitive Power Ventures, Inc.
35 Braintree Hill Park, Suite 107
Braintree, MA 02184

Phone: 781-848-0677
Fax: 781-848-5804
Mobile: 508-472-8037

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Mr. Sean Finnerty, Vice President
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35 Braintree Hill Office Park, Suite 107
City, State, ZIP+4
Braintree, Massachusetts 02184

PS Form 3800, May 2000 See Reverse for Instructions

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1. Article Addressed to:

Mr. Sean Finnerty, Vice President
CPV Gulfcoast Ltd.
35 Braintree Hill Office Park,
Suite 107
Braintree, Massachusetts 02184

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X M. Sweeney ☐ Agent ☐ Addressee

B. Received by (Printed Name) M Sweenie

C. Date of Delivery 5/24/04

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MAY 24 2004
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PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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City, State, ZIP+4 Braintree, Massachusetts 02184

PS Form 3800, May 2000 See Reverse for Instructions

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Mr. Sean Finnerty, Vice President
CPV Gulfcoast Ltd.
35 Braintree Hill Office Park,
Suite 107
Braintree, Massachusetts 02184

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X M. Sweeney ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) M Sweenie
C. Date of Delivery 5/24/04

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If YES, enter delivery address below: ☐ No

MAY 24 2004

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4. Restricted Delivery? (*Extra Fee*) ☐ Yes

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1. Article Addressed to:

Mr. Sean Finnerty, Vice President
GPV Gulfcoast, Ltd.
35 Braintree Hill Office Park
Suite 107
Braintree, Massachusetts 02184

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by (Printed Name) C. Date of Delivery 2/17/04

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☒ No

FEB 17 2004

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4. Restricted Delivery? *(Extra Fee)* ☐ Yes

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Mr. Sean Finnerty, Vice President

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Street, Apt. No.; or PO Box No. 35 Braintree Hill Office Park
City, State, ZIP+ 4 Braintree, Massachusetts 02184

PS Form 3800, January 2001 See Reverse for Instructions

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

February 11, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Sean Finnerty, Vice President
CPV Gulfcoast Ltd.
35 Braintree Hill Office Park, Suite 107
Braintree, Massachusetts 02184

Re: DEP File No. 0810194-003-AC (PSD-FL-300)
CPV Gulfcoast Power Generating Facility.
245 MW Nominal Combined Cycle Facility – Permit Extension Request

Dear Mr. Finnerty:

The Department reviewed your request dated January 19, 2004 for extension of the referenced air construction permit. The request is to extend the dates for commencement of construction, completion of physical construction, and permit expiration.

According to our records, this permit has been extended on two prior occasions: July 31, 2002 and May 9, 2003. Accordingly, the Department is not inclined to accept your request without a re-review of the original BACT Determination which was done over 3 years ago. In order to continue processing your application, it is required that you submit a revised BACT evaluation for the Department to review; the Department will then make an updated determination. Should your response to this request require new calculations, assumptions or reference material, please include the appropriately revised pages of the application form.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days.

If you have any questions regarding this matter, please contact me at (850) 921-9519.

Sincerely,

Michael P. Halpin, P.E.
North Permitting Section

Copy: Sean Finnerty, CPV Gulfcoast, Ltd.*
Gregg Worley, EPA
John Bunyak, NPS
Jerry Kissell, DEP SWD
Chair, Manatee County BCC
Karen Collins-Fleming, Manatee County EMD

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1. Article Addressed to:

Mr. Sean Finnerty, Vice President
GPV Gulfcoast, Ltd.
35 Braintree Hill Office Park
Suite 107
Braintree, Massachusetts 02184

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) C. Date of Delivery 2/17/04

D. Is delivery address different from item 1? ☐ Yes
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PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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Mr. Sean Finnerty, Vice President

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PS Form 3800, January 2001 See Reverse for Instructions

Competitive
Power Ventures, Inc.

RECEIVED
JAN 20 2004
BUREAU OF AIR REGULATION

January 19, 2004

Mr. Alvaro A. Linero, P.E.
Program Administrator
Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399

Re: DEP PSD Permit No. 0810194-001/PSD-FL-300, for CPV Gulfcoast, Ltd.
Additional Extension of PSD Permit Expiration Date and Related Permit Dates.
0810194-008-AC

Dear Mr. Linero:

The Department of Environmental Protection, Bureau of Air Regulation issued PSD Permit No. 0810194-001 (PSD-FL-300) to CPV Gulfcoast, Ltd. ("CPV") on February 5, 2001 and subsequently granted an extention of the milestones contained therein on May 9, 2003. Due to the severe downturn in the electric power market, construction of the facility has not yet commenced.

This letter is to request that the Department extend the permit's expiration date and other specified compliance dates and deadlines in the permit, pursuant to Rule 62-4.080, Florida Administrative Code. CPV is requesting an additional extension of time for the current permit expiration date and other dates in the permit.

Following are the specific permit revisions requested in order to extend the expiration date and related deadlines:

SECTION II – CONDITION 8
PSD Approval to Construct Expiration. Approval to construct shall become invalid if construction is not commenced by March 30, 2005, or if construction is discontinued for a period of 18 months or more, or if physical construction is not completed by September 30, 2004. [40 CFR 52.21(r)(2)].

SECTION II – SPECIAL CONDITION 9
Completion of Construction. The permit expiration date is December 30,2007. Physical construction of the facility shall be completed by September 30,2007.

35 Braintree Hill Office Park, Suite 107, Braintree, MA 02184 PHONE: (781) 848-0253
FAX: (781) 848-5804

The additional time provides for testing, submittal of results, and submittal of Title V permit to the Department.

SECTION II – CONDITION 11

BACT Determination. In conjunction with extension of the December 30, 2007 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.

This request is being made by CPV due to the continuing financial crisis in the energy industry and, specifically, the electric generation sector. The current financial crisis has resulted in construction of the CPV Gulfcoast project being delayed. These market conditions, which clearly are beyond the control of CPV, constitute good cause and justification for the Department's grant of the requested permit extension and related date modifications.

CPV anticipates that construction will commence prior to the dates set forth herein and be completed within twenty four months of commencement. As required by Rules 62-4.070 and 62-4.080, F.A.C., once constructed, the CPV Gulfcoast project will install all control equipment specified in the permit, will adhere to all standards set forth in the permit, and will comply with all applicable regulatory standards and conditions.

Sincerely,

Sean Finnerty
Vice President

BEST AVAILABLE COPY

CPV GULFCOAST, LTD FLDEP Florida DEP 3207

0000013408 2/2/2004 3207

Date	Voucher #	Invoice #	Description	Outstanding Am	Amount Paid
1/27/2004	0000010579	01/27/04	Extend PSD Permit	$50.00	$50.00

RECEIVED

FEB 09 2004

BUREAU OF AIR REGULATION

$50.00	$50.00

GCST LTD CHKG

NOTICE OF PUBLIC MEETING

The Department of Environmental Protection announces a public meeting to which all persons are invited:

DATE AND TIME: January 8, 2001 - 7:00 - 9:00 p.m. Department personnel and representatives of the applicant will also be available prior to the meeting, from 6:00 to 7:00 p.m., to discuss the proposed permit and project on an informal basis.

PLACE: Blackburn Elementary School Cafetorium, 3904 17th Street East, Palmetto, Florida

PURPOSE: To accept public comments and provide status of Department's Intent to Issue an Air Construction Permit to CPV Gulfcoast, Ltd., to construct a nominal 245 megawatt (MW) combined cycle (74.9 MW steam cycle) electrical power generating plant near Piney Point in Manatee County. The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality (PSD) and Best Available Control Technology (BACT).

A copy of the agenda and the Department's proposed permit and supporting documents can be obtained by contacting: Al Linero, Department of Environmental Protection at 2600 Blair Stone Road - MS 5505, Tallahassee, Florida 32399, phone (850)921-9523, or by phoning the Bureau of Air Regulation's New Source Review Section at (850)921-9505.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist in the Bureau of Personnel at (850)488-2996. If you are hearing or speech impaired, please contact the agency by calling (800)955-8771 (TDD).

Competitive
Power Ventures, Inc.

January 26, 2001

CPV 300

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: Revisions to Final Determination, File No. 0810194-001-AC (PSD-FL-300), CPV Gulfcoast Power Generating Facility

Dear Mr. Linero:

Following are CPV Gulfcoast, Ltd.'s suggested revisions, provided in strike-through and underline format, to clarify the Final Determination for the above-referenced permit. An explanation for each revision also is provided.

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** 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.

Finally, 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.

Reasons for Revisions: The first revision clarifies the comparison between CPV emissions and emissions from other conventional sources. The new paragraph is added at the end of the response to make clear that emissions offsets are not and cannot be legally imposed on a air permittee in an area that has not been designated a non-attainment area.

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."

Additionally, 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.

Reason for Revision: This additional explanation is provided at the Department's request regarding guarantees the permittee will provide that the 74.9 steam cycle limitation will not be exceeded.

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. **Review of water sources are not within the scope of this proceeding.** ~~The Department will obtain the details from the company and provide them to EMD. It will be necessary for CPV to secure re-used water from local communities and work with SWFWMD to secure minimal amounts of groundwater.~~

Reason for Revision: Water sources are not within the scope of this air permit proceeding. CPV is in the process of exploring water source options and will provide information to EMD on the water source it ultimately determines it will use for the facility.

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 <u>from the facility's emissions</u> 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.

<u>Reason for Revision</u>: The first revision clarifies that the facility's air emissions are insignificant. The second revision clarifies that the project will be part of a systematic approach to improving Tampa Bay, rather than degrading or even maintaining the status quo.

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.*

~~No responses were submitted by CPV to EPA's comments. The Department concurs with those comments.~~ **<u>CPV submitted revised calculation related to the cost-effectiveness of oxidation catalyst to control CO emissions from the project based on EPA's concerns.</u>**

<u>Based on conservative estimates, 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.</u>

A maximum operating period of 2000 hours per year during power augmentation will be added to Section III, Specific Condition 9. **<u>This limitation will not apply if CPV chooses to install an oxidation catalyst in order to operate for a period of hours per year that will render an oxidation catalyst cost effective.</u>**

~~The net result of EPA's comments is that CPV's oxidation catalyst cost estimate of $4,350 per ton of CO removed is biased to the high side. Even if it was corrected to value closer to $3,000 per ton, the Department does not consider oxidation catalyst to be cost-effective.~~

~~Moreover,~~ 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 are on the order of 1 ppmvd, which is substantially less than even the objective by oxidation catalyst. The Department's conclusion is that CPV's costs are actually biased to the low side.

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.

<u>CPV Response</u>: CPV had documented its response to EPA Region IV concerns under separate cover dated January 26, 2001.

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.*

The following condition has been added to Section II of the permit as Condition No. 9.

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

<u>CPV Response</u>: CPV requests the following revisions be made to Section II of Condition No. 9:

> ~~Completion of Construction~~ <u>Permit Expiration Date</u>: The permit expiration date is amended from December 30, 2002 to ~~June~~ <u>December</u> 30, 2003. ~~*Physical construction* shall be complete by December 30, 2002.~~ The additional time provides for <u>a reasonable timeframe for completion of construction</u>, testing, submittal of results, and submittal of the Title V permit to the Department.

<u>Reason for Revision</u>: The Department's rule in Section 62-210.300(1)(a), Florida Administrative Code(F.A.C.), provides that "[t]he construction permit <u>shall be issued for a period of time sufficient to allow construction or modification of the facility</u> or emissions unit <u>and operation while the new or modified facility or emissions unit is conducting tests</u> or otherwise demonstrating initial compliance with the conditions of the construction permit." (Emphasis added). Section 62-4.070(4), F.A.C., further provides: " No Department permits shall be issued or a term of more than five (5) years unless otherwise specified by statute, rule, or order of the Department. <u>However, construction permits for air pollution sources may be issued for a period of time as necessary</u>." (Emphasis added). These rules make clear that the Department has the authority to issue a permit for a period of time sufficient to allow construction and testing of the air facility. CPV estimates it will take approximately 27 months from the time construction commences (estimated for October 2001) to complete construction

and test the facility for compliance with the air permit. A December 30, 2003 deadline would provide CPV the time necessary for construction and testing of the facility.

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

CC: Gary Lambert
Cathy Sellers

PUBLIC MEETING

1-18-01 @ 1:49 p.m.
Hand delivered. [illegible]

IN RE: CPV Gulfcoast, Ltd.

245-Megawatt Combined Cycle Unit

Manatee County

PURPOSE: To accept Public Comments and Provide status of the Department of Environmental Protection's intent to issue and air construction permit to CPV Gulfcoast, Ltd. in Manatee County.

Transcript of proceedings reported in the above-entitled matter at Blackburn Elementary School, Palmetto, Florida on January 8, 2001, beginning at 7 o'clock p.m.

APPEARANCES

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

A.A. LINERO, P.E. Administrator
Bureau of Air Regulation

TOM ROGERS, Meteorologist
Division of Air Resources Management

P R O C E E D I N G S

MR. FANCY: Good evening, ladies and gentlemen. My name is Clare Fancy and I'll be the moderator at this public meeting tonight.

This is a public meeting to receive comments from the public on the Department's proposed the air construction permit to be issued to CPV Gulfcoast Limited.

The permit is to construct a nominal 245 megawatt combined cycle electrical power generating plant. The project consists of a nominal 170 megawatt General Electric 7FA combustion turbine-electrical generator, an unfired heat recovery steam generator capable of raising sufficient steam to generate another 74.9 megawatts from a steam electric generator, a 150 foot stack, a mechanical draft cooling tower, a one million gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year.

The new facility will be located on a 160 acre track at the intersection of Buckeye and Bud Rhoden Roads southeast of Piney Point in Manatee County.

The main purpose of this Public Meeting is to take public comments that will be considered in issuing the final air permit to CPV Gulfcoast Limited.

There will be a few days that we are going to allow for people to submit any additional written comments that they might like to submit, if they are so inclined to do so. We have received some written comments from officials of Manatee County and the United States Environmental Protection Agency.

No one requested a formal administrative hearing for this particular project during the 14 days it was allowed to ask for the administrative hearing, so this will probably be the last formal gathering with regards to this permit.

The way we want to do this tonight is the Department will give a brief overview of the air permitting requirements for this facility and we will briefly discuss the P.S.D. issues, that's prevention and significant deterioration, the ambient air quality impacts of the proposed project and then we will discuss our draft Best Available Control Technology determination for the new plant.

We should be done with that by about 7:30 or 7:35 at the latest and then we'll take comments from any member of the public that's here that would like to make a comment.

We do have speaker cards in the back that we would appreciate you filling out so that we can get them up here so when we get done with our presentation we can call them up here and I'll call these people to speak in the order in which I receive the card.

We have a sign-up sheet in the back. We have copies of the draft permit in its entirety. We also have the draft permit on some diskettes for people who want to use them for their computer. So everyone here is more than welcome to take one or the other. Either the diskette or the copy of the permit.

There is also an agenda for the public meeting, there's a summary of this project that's about four or five pages long, if you would like to read that and maybe not read the permit in detail.

This permit is strictly an air pollution permit. This is not a water pollution permit, not a zoning permit. It's strictly an air pollution permit. That's pretty much what we'll be taking comments on this evening.

So with that I'll turn it over to Mr. Al Linero who's the administrator of our New Source Review Section who has been the primary person who's reviewed this application.

Al.

MR. LINERO: Thanks, Clare.

First I've got to do the dull stuff of just reading some of the stuff into the record here. Again my name is Al Linero. I'm with the Florida Department of Environmental Engineering, I'm the P.E. Administrator of the section that reviews these types of projects.

Competitive Power submitted an application to construct a nominal 250 megawatt combined cycle power plant near Piney Point in Manatee County. The proposed site is a 160 acre track at the intersection of Buckeye and Bud Rhoden Roads. The location is east of Highway 41 and south of Piney Point Phosphate's facility.

The Florida Department of Environmental Protection is the permitting authority for the air permit under Chapter 403 of the Florida Statutes, Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code.

All right. We received an application for the project on September 9th of last year. We distributed it to E.P.A.'s Region 4 in Atlanta, the U.S. Fish and Wildlife Services Air Quality Branch in Denver, our D.E.P. Southwest District office in Tampa and the Manatee County Environmental Management Department.

The technical evaluation and preliminary determination and the draft permit were completed and sent to the applicant on November 17th, along with the Department's intent to issue. Copies were provided to the previously mentioned agencies and the Manatee County Commission.

Copies were made available for public inspection at the D.E.P. offices in Tallahassee and Tampa and at Manatee County. We also posted these materials at our website www.dep.state.fl.us/air/permitting.

Let me put that up here. Yes, you can see it there. This is a good site. You can go to that site and actually see all of our work in progress. We probably have got about 20 entries in there of various projects that are under review or for which intent has been issued or final permit.

The Department's public notice of intent to issue an air construction permit was published by the applicant in the Bradenton Herald on November 26th. It provided -- November 25th. It provided a 30 day period for anyone to submit comments on the

Department's proposed action or to request this public meeting. It also provided a 14 day period for anyone whose substantial interests were affected by the project to file a petition for an administrative hearing. To date we have received substantial comments only from the Chair of the Manatee County Commission and the Director of the Manatee County Environmental Management Department.

I might add that we recently got some comments from E.P.A.

The applicant requested this public meeting. This public meeting was noticed in the Bradenton Herald on December 5th and again on January 5th. It was also noticed in the Florida Administrative Weekly on December 29th, and that's a publication that is available free of charge on the web at their own website, election.dos.state.fl.us.

Copies of the intent to issue package are available at this meeting. We also have a few copies on diskettes. If we run out, we'll be happy to make you copies and send them to you.

As mentioned before, you can view this entire package on our website. The actual application and entire file are available for public review and copying at our offices in Tallahassee and Tampa.

Issues such as noise and the plant location are beyond the scope of our authority in making this permitting decision. These fall within various local ordinances and the local planning and zoning authorities.

We will consider the comments specifically related to air emissions and control, which have already been submitted or are submitted here and over the next week. Comments may be submitted at this public meeting or E-Mailed or mailed to myself. Let me put my address down on here.

And there I am. Again we've got handouts with all this information over there. But feel free -- feel free to call if you have any questions about the project or E-Mail me your comments.

We've got a number of other people that you can talk to about it. On the air modeling side we have Tom Rogers, meteorologist, and he's here with us today.

Air compliance issues is Bill Proses of our Southwest District. I've got a legal contact, Doug Beason. He's our attorney in the Office of General Counsel. And our management contact is Mr. Fancy who spoke earlier.

I'm going to provide a very brief project description, again. Let me see if I can get this up here.

The main unit is a G.E. 7FA gas-fired combustion turbine electric generator which directly generates approximately 170 megawatts of electricity. The project includes an unfired heat recovery steam generator capable of raising sufficient steam to generate another 74.9 megawatts in a separate steam electrical generator.

And there's some pretty good diagrams back over there where you can get a better appreciation. It actually has two electrical generators. One is directly driven by the combustion turbine. The other one is driven by a steam cycle.

You can see a picture of these types of units, the G.E. 7FA, it's really just like a jet engine. You have air drawn in and compressed, the fuel is introduced in the combustors, the hot gas is expanded in the rotor section. And, again, a rotational motion of the shaft drives the compressor and the electrical generator normally located before the compressor section.

In the CPV project the unit will operate in combined cycle mode, meaning that the gas turbine drives an electrical generator while the exhausted gases are used to raise steam in a steam recovery -- in a heat recovery steam generator. The steam is then fed to a separate steam turbine which also drives an electrical generator, and I think I must have repeated myself.

Here's a diagram of what that cycle looks like and you really have a better version of it back over in those diagrams.

Again, we show here a basic plant which includes the combustion turbine and its electrical generator, the heat recovery steam generator. I think these guys will be using the same type of three-temperature unit. Got a stack, I believe, on the order -- I believe about 150 feet tall and you've got the steam water cycle.

This represents the design that was going to be built by Duke in New Smyrna. It differs from the CPV project in that the Duke project didn't have the same level of NOx control and didn't include the so-called catalytic reduction system.

Also the Duke Power project didn't include a concept called steam augmentation which is a way of getting additional power in this part of the cycle, in the combustion turbine cycle.

Since I didn't have a diagram at the time of the artist's rendition of this project, I took one that I had for the Duke project and, again, these guys are only going to do one of these units instead of two, okay?

Duke was going to do two of them. CPV is going to do one of these sets, and obviously their cooling requirement is probably going to require half the number of cells or so on their cooling tower.

There has to be space, of course, for storing oil which will be a back-up fuel for 720 hours a year. There will need to be ammonia storage also for the S.C.R. system.

The key air emissions will consist of Nitrogen Oxides, carbon monoxide, particulate matter and sulfur dioxide. The NOx will be controlled by select catalytic reduction to a achieve 3.5 parts per million by volume dry at 15 percent oxygen while burning gas, and 10 parts per million while burning low sulfur distillate fuel.

Emissions of carbon monoxide will be controlled to 9 and 20 parts per million while burning gas and fuel oil, respectively. Emissions of particulate matter, sulfur dioxide, sulfuric acid mix, volatile organic compounds and hazardous air pollutants will be controlled to very low levels by good combustion and use of inherently clean pipeline-quality natural gas and low sulfur .05 percent distillate fuel oil.

Ammonia emissions generated due to the NOx control will be limited to 5 parts per million.

And the following table summarizes the emissions in tons per year of regulated pollutants for this project.

As you can see, we are estimating about 102 tons of particulate matter, 12 tons of sulfuric acid mist, 76 tons of sulfur dioxide, 126 tons of nitrogen oxides, 15 tons of volatile organic compounds, 222 tons of carbon monoxide. I would say roughly 50 tons of ammonia and 8 tons of hazardous air pollutants.

The numbers on the right here are certain thresholds that kick in requirements to conduct special review under the rules for the prevention of significant deterioration of air quality. So we are required to do these reviews for particulate matter, sulfuric acid mist, sulfur dioxide, nitrogen oxides, and carbon monoxide.

What I wanted to do next was put a table on here because, you know, we've talked -- I think in talking back here with some of you, we emphasized what a clean project this is but when folks hear 200 tons per year, that still sounds like a big number or even 15 tons per year. Some people don't really have a good concept of is that a lot of pollution or is that a little.

We were basically saying it's not much, but probably the only way to show people what it really is is to put up some comparisons, so I put together a table and then corrected it at the suggestion of a well-known gentleman in the audience.

Let me go ahead and put that up. Okay.

What we have got here is a listing of some of the best known conventional units along the Southwest Florida coast. We have got the FPC Anclote plant. I think that's in the Pasco County area. The PL Bartow plant in Pinellas County, the Big Bend plant in Hillsborough County, the Gannon plant also in Hillsborough County not too far from here, the Ft. Myers plant south of here, the Manatee plant that's in the county.

And it's a busy table but I think if you just take a look at, say, the last four columns. I got these data from the E.P.A. website on acid rain and you can see, for example, just to pick the first one because it's first, Anclote emitted 16,000 tons of SO_2 in 1999, and 4,000 some odd tons of nitrogen oxides in 1999.

Again, let's say some closer to this area, I think people have heard a lot about the Gannon project. I listed six different Gannon units on there and they range anywhere from 5,000 to 16,000 tons of SO_2 and looks like from 2 to about 10,000 tons per year of NO_x.

There's a re-powering project that's underway there that's going to turn those monstrosities into seven of those units like CPV is building, and what will happen is that what will be left at Gannon is represented by the next to the last row. That will shrink down into a source that I calculate is about 700 tons of SO_2 and about a thousand tons of NO_x.

And if you look at the number on the right, that's about a hundred million million BTU heat input per year, and that's much greater than all of the existing Gannon units put together.

So what you will get is a facility that will be able to produce a lot more power at a fraction of the present emissions. And, better yet, it will also be 56 percent efficient on its energy cycle compared to perhaps 30, 32 percent at the existing units.

So the point being that I wanted to put the -- this particular project into perspective and this, of course, was suggested particularly by the questions that I got from Manatee County's Environmental Management Department and their county commission that I wanted to be able to show where this project stacks up and there it is on the bottom, 76 tons of SO2 and 126 tons of NOx.

And then I made a couple of other columns here, actually at the suggestion of Mr. Troxell, where I put these on the basis of pounds per megawatt hour and those are the numbers in parentheses, so if we look at the one with the greatest number of pounds per megawatt hour, we've got those at Big Bend, and those are about 35 pounds of sulfur dioxide for every megawatt hour produced.

Compare it, let's say with the re-powered Gannon project, well, the existing emissions per unit of electricity are 350 times as great at Units 1 and 2 at Big Bend than they are at the future Gannon plant.

We drove by the Big Bend plant today and found that they have, indeed, installed the scrubber to help the situation on Big Bend 1 and 2, so although these were the numbers in 1999, we think they are on their way to getting better so I wanted to set this here, because I think it's a good basis for some discussions.

My belief is that if you have projects like this one, that since you're getting about -- about, say one percent of the pollution compared to some of these conventional units, well, even if they only offset just a few megawatts from the conventional units in Southwest Florida, it would seem to me that with these kind of projects you will actually have somewhat lower emissions than without them.

Yes, it will be another power plant but I think it stands to reason that it just has to compete with some of these others and even if only -- even if only 20 of the megawatts of the 250 really offset some of the others, it would still mean less pollution overall.

So I'm going to leave that one up there just as being a basis for discussion. I'm not sure what's up next but --

Yes, we are going to turn it over to Tom Rogers over here to discuss a little bit on the P.S.D. issues and ambient air quality impacts.

We can make this session shorter if we want to get to the questions early or we'll leave it to Tom to decide or if people get interested in the details of modeling, we can -- okay. You're on.

MR. ROGERS: I'll just sit right here.

Part of the requirements of any permit applicant is that subject to the prevention of significant deterioration review process is to demonstrate to the Department that they will, indeed, meet air quality, that the construction and the emissions from this plant would, in fact, meet the air quality standards that apply to the area.

And also to meet what are known as P.F.D. increments, which is a smaller amount of increase that's allowed to keep relatively clean areas clean.

The applicant has in fact provided the Department with their analysis. It was in compliance with all the requirements for Department or E.P.A. approved modeling study. The results of this study, which is usually carried out using air quality dispersion models, they use, again, E.P.A. approved models in doing this.

The results were, in essence, they were in compliance, well within compliance of all the ambient air quality standards, the prevention of significant consideration increments, both locally and we also look at special areas in the state that have stricter air quality standards known as Class 1 areas. Your closest one to this area happens to be the Chassahowitzka National Wilderness area.

They were also well within standards in increments in -- in fact, in all of the areas they were not just within compliance but they were deemed insignificant in all of their impacts for all of the pollutants that they were analyzing for. So I don't think I need to say much more than that.

As I said, it was done in accordance with D.E.P. rules and we were satisfied that they made their demonstration that standards and increments were, in fact, met.

MR. FANCY: Thank you. We'll turn it back over to Al Linero who will discuss briefly the Best Available Control Technology determination and upon the conclusion of his comments we'll open it up for comments from the public, and I remind people to fill out a speaker card if you'd like to talk because I'm going to be calling them in order. Thank you.

MR. LINERO: Okay. I did go ahead and put up a diagram over here that shows what some of the impacts are from this project, what some of the modeled impacts are.

I think we made copies, or if we didn't we can provide them to you. If you just E-Mail me, I'll send you a copy. This is something that I put together here to try to show the comparisons of the modeled impact with some of the standards.

Again, now the third column from the left are the National Ambient Air Quality Standards for sulfur dioxide, particulate matter, carbon monoxide, nitrogen dioxide and ozone.

And, as Tom mentioned, there are these increments and the so-called significant impact levels. And as you can see, on the units used to measure these things are, in the case of CO, 40,000 micrograms per unit cubed. In the case of sulfur dioxide, for example, 1,300 on a 3-hour basis and as we move over we see the impacts from the project in parenthesis and all those numbers are quite low.

For example, carbon monoxide would be 23 micrograms per meter cubed, the impact from the project, whereas the one hour limit is 40,000. So this puts into perspective.

It's quite consistent with the information that I put up before on the emissions.

Just really says that the ambient impacts are about what you would expect based on the relative emissions of this project compared to the others. Okay.

Let me get the BACT up here, which is what I should have done. All right. Let's get that over here. All right. Okay.

What I'm going to do here is I'm going to go straight to the end and just show you what we determined the best available control technology is to this project. And then maybe we'll go back and tell you a little bit about how we got there.

Based on a lot of the information provided by the applicant, as well as our research through E.P.A.'s bulletin boards and technical papers that we have at our disposal, we determined that the Best Available Control Technology for nitrogen oxides is the installation of a selected catalytic reduction unit to achieve 3.5 parts per million by volume while burning gas; and 10 parts per million by volume when burning oil.

And I think, as we mentioned before, they would burn oil as much as 720 hours a year, which is maybe 8 percent of the time if they burned it as much as they're allowed to.

For reference, the 3.5 is equal to about 0.1

pound per megawatt hour of pollution. The lowest number in the country that I'm aware of, and in fact, I am sure that it's the lowest number in the country, I believe is about 2 parts per million on gas and that's what you'll see in areas like California that are in extreme non-attainment. Perhaps you see numbers like that in Atlanta and Houston, but generally you don't see too many power projects cited over there because of the difficulty of achieving these low numbers.

But on that point this project stacks up quite well. The carbon monoxide controls, we believe that the combustion controls in the project are sufficient.

The flame temperature in these units is on the order of 2800, 2700 degrees Fahrenheit. That's enough to convert effectively all the carbon monoxide into further products.

We proposed BACT limits of 9, 15 and 20 under various conditions, and even those numbers are lower.

In other words, the numbers are lower coming out of the turbine than what is actually allowed in ambient air that people breathe, but recently we received some reports from the City of Tallahassee and TECO where they built a couple of these new units and it's turning out that even though we set the limits fairly low, they're actually doing more on the order of 1 to 2 parts per million and that was actually a surprise to us, a surprise to TECO and to the City of Tallahassee. Maybe even a surprise to G.E.

So as time goes on what we'll probably do is work with the applicant and G.E. to make sure that what they get is a better contract that reflects what will be greater expectations of these units. But, again, they're going to do much better than that.

And if they had actually estimated it as I expect, they wouldn't have even been significant in terms of C.O.

Particulate matter, again that will be inherently clean fuels and combustion controls. One way to make sure that it doesn't get too high is by keeping what is called the ammonia slip low, and what that means is that the ammonia that's used to achieve a low NOx, we want to make sure that it's not putting out more ammonia such that it could aggravate a particulate situation.

The sulfur dioxide and sulfuric acid mist are controlled by the low sulfur fuels and, again, that's just pipeline-quality natural gas that, from my research, generally meets better than the spec. requested by the company. And of which they really wouldn't have any control, anyway.

And the .05 percent sulfur fuel oil, generally what's delivered is better than that and with expecting E.P.A. standards to get the sulfur out of diesel oil it will probably be substantially lower than that.

I'm going to just put up a figure showing how this project stacks up to others throughout the country.

For example, here are a number of combined cycle units. I've got, again, the CPV Gulfcoast project there at the top, the TECO Bayside project that we're reviewing right now. I wouldn't be surprised if we were doing one of these meetings on that in a few months. The FPC Hines II project in Polk County, which will be 500 megawatts. The Calpine Osprey project in Auburndale. Santee Cooper in South Carolina. A couple of projects in Alabama. Kissimmee Cane Island, Lake Worth, Mississippi Daniel.

And generally this project stacks up quite well against them. The number for the nitrogen oxide limit is as low as any of the others, equal to the lowest. And on oil for those units that burn some oil, it is the lowest.

And so we feel comfortable that E.P.A. won't have any problem with this project with regards to the nitrogen oxide standard.

For reference the one there in South Carolina with a limit of 9, was issued earlier this year and we were a little surprised that E.P.A. allowed a facility to be permitted with such a high number such a short time ago.

I think if I -- similar diagram CO and the other pollutants would show about the same results.

Here's an interesting graph that I found and it kind of shows how the efficiencies of some of these combined cycle units have changed. It used to be sometime back that you could do a little bit like 40 percent efficiency on them, and basically these days they're pushing about 60 but the real difficulty in getting any higher, things like the limitations on NOx, it actually costs a lot of money to control the NOx, you give up some efficiency and then you have to add on that selective catalytic reduction.

Now the main part of the control system, as I said, is the S.C.R. and it's not a trivial piece of equipment. It's pretty expensive. On these types of units it's that sort of reddish or brownish piece in the heat recovery steam generator and that picture on right, of the fat man there on the right is myself over at the Hines Energy plant and you can see a lot of steel pipes going up and down that heat recovery steam generator, which is the ammonia injection grid.

And, again, as I mentioned down here, there are some consequences of using ammonia but there is really no other feasible alternative to keeping the nitrogen oxide limits down and you'll get some permit limits as low as 2 in California and non-attainment areas like that.

But that's all I have on the BACT. We can go into it in more detail, but might be better just go ahead and take some questions.

MR. FANCY: Thank you.

Do you have comment cards in the back? None filled out? I only have one comment card here, speaker card.

Sean Finnerty from CPV Gulfcoast.

MR. FINNERTY: I want to first of all thank the Department for holding the hearing tonight and hopefully answering the questions that other folks will have.

Again, I'm Sean Finnerty, the director of the project involving Competitive Power Ventures and CPV Gulfcoast Project.

We're a small development company. We've developed natural gas fired combined cycle projects.

With me tonight I have Gary Lambert, our Executive Vice President; our Environmental Consultants, Lewis Burger, consultant, Neal Collins; Larry LaBreis from TRC Environmental who did the air modeling for us; our state environmental counsel, Cathy Sellers from the Moyle, Flanigan law firm in Tallahassee and we're here to answer questions that you may have to us.

We have reviewed the draft permit. We will be providing a letter to reflect our comments and change of address for the company.

But we are accepting, you know, we think the permit is acceptable as issued in draft and hope that the Department does approve the permit and issues the permit to us.

We'll be happy to answer any questions that you may have. Our local counsel, Mark Barnebey, is also here.

MR. FANCY: Thank you.

I know there are a few people from the public in the audience. I don't know if you do have any comments you would like to give or you were just here to listen. But hearing nobody raising their hand rapidly to give comments, apparently there is no one that wants to give any comments so based upon that I believe the purpose of the meeting has been fulfilled.

And with that I believe we'll -- okay. Just was reminded to remind people that they do have a week in which to submit any written comments that they'd like to submit to the Department for those people that might feel that they want to say something in writing, but don't want to give it here in the public forum which is acceptable.

And after about a week we'll probably go ahead and issue the permit.

Yes, sir.

MR. KOTEKI: I have a question.

MR. FANCY: Yes, sir.

MR. KOTEKI: Are we recording this?

MR. FANCY: We are still recording, voice recording, and the lady's still doing the transcript.

MR. KOTEKI: Okay. I'm Leon Koteki with Manatee County Planning and I just had a chance to look over your table 1, the recent NOx limit emission limit proposals, and I noticed comparing CPV Gulfcoast to the various other units in the area, capacity of megawatts there are different sized plants, and then the third column shows the NOx limit and they are very much the same -- 3.5 for NG, 10 for FO for the CPV Gulfcoast Florida Power plant; but then when we go to TECO Bayside, it's a 1750 power plant and it's still, NOx limit is 3.5 NG and a 16.4 FO.

I was just wondering, is there a multiplication factor there or something I don't see in terms of the quantity of NOx or being emitted, between the difference between those plants. The size of the plants.

MR. FANCY: Well, the 3.5 parts per million is a concentration standard so with the bigger plant you're going to have more gases being emitted so you're going to have a bigger poundage.

MR. KOTEKI: Okay.

MR. FANCY: But the concentration in the exhaust gas would essentially be the same.

MR. LINERO: Let me add something, too.

Those two projects are right here, these two rows, so even though the concentrations are the same of NOx emissions, you can see obviously the Gannon plant, which is that TECO Bayside plant, will emit about a thousand tons of NOx versus CPV's, 126, and it will emit more SO2 simply because it's bigger.

MR. KOTEKI: Right.

MR. LINERO: But on a common basis, meaning the concentration in the exhaust gases, they're the same. They're controlled to the same level of technology.

MR. KOTEKI: Okay. So you're just describing standards here, as opposed to quantities emitted.

MR. LINERO: Yes, sir.

MR. KOTEKI: Okay. Thank you.

MR. FANCY: Yes, sir.

MR. KUMARICH: This question does not pertain to the project, but as you know every so often you change the permits for these individual plants, right?

MR. FANCY: Yes.

MR. KUMARICH: I'm wondering whether the permit should be changed as we gain experience like we're gaining here, and with the 2020 Commission that's operating right now, do you think they will come up with anything which may change our philosophy in the future?

You know what, the Energy Commission, 2020?

MR. FANCY: Yes.

MR. KUMARICH: Or maybe should they?

MR. FANCY: To give you an idea, about a year ago now we had issued a permit to a combined cycle plant with a NOx limit of 9 parts per million using dry well NOx burners for a control device. This plant is just a little bit more than a third of that allowable emission limits using a selective catalytic reduction device.

The emissions from these types of plants when you compare them to certain other types of plants, either older turbines that were built, say, in the early 90's or before, and you certainly compare them to fuel oil or natural -- or coal-fired units, even well controlled units, the limits on these are still lower than those would be.

So as you approach a very low number, it gets more and more difficult to come up with an even lower number and the costs to achieve a much -- a lower number than say three and a half before very,

very high.

So you reach a point in a graph whereby you can't -- to go much lower wouldn't be that effective. And at three and a half parts per million we are certainly approaching that number.

Did that in any way answer your question?

MR. KUMARICH: Yes. Thank you.

MR. FANCY: Thank you. Does anyone else have any questions or comments?

MR. TROXELL: One question for Mr. Linero.

The last thing you considered was the ammonia slippage of the S.E.R. technology.

Your experience with that type of technology and the potential consequences of ammonia slip, what might that be and what experience have other plants had with that particular problem?

MR. LINERO: Okay. I, myself, don't have a lot -- I can't say that I have a lot of experience with it. There aren't very many of these plants in Florida that have this level of control.

It was tried out in other parts of the country well before it was tried out here, but generally what you get, you know, ammonia has its down side but there isn't anything better to control the NOx with, down to those levels.

You can get quite a -- you can do quite well on all these other units with various types of combustion controls and technologies known as re-burning and so forth that really have no consequences at all, but you can get your emissions down maybe, maybe even by 80 percent on any of these plants. But to go further you've got to do something else in the way of add-on control technologies and the injection of ammonia is the only feasible thing.

What you have get out of there, the products, are nitrogen, which is already in the atmosphere and water. But you do aggravate the situation a little bit on particulate matter. That's a consequence.

Typically you have to have a special hazard control plan of some kind in case your ammonia tank could possibly break so there are some inherent problems with it that pretty much society decided to bear the risk because it's apparently worth the lower NOx.

I would say that the amount of ammonia used for this plant is really -- it's probably almost insignificant, let's say, compared to the amounts of ammonia used by the fertilizer industry in this area. And it will be in, I believe it would be in aqueous form so there would be less hazards around here.

We tried to make a case, as Clare mentioned we were permitting these units at 9, we tried to make a case with E.P.A. to let us continue permitting these units at 9 parts per million of NOx and not bother with the S.C.R. system, and basically E.P.A. turned that down.

They said that these types of plants are permitted with selective catalytic reduction in every possible imaginable situation in the country, and that we would need to show them that Florida is different and that the consequences in Florida are greater than other places, possibly even sites located near inner cities and so forth. So we really couldn't make the case.

And at least on this, I don't have it up there, but Kissimmee Utilities Authority project, we thought that they wouldn't need to install a S.C.R. unit. In fact, they thought they didn't need to.

And E.P.A. basically dropped the bomb on them by saying if you don't install that S.C.R. system we will go to the Environmental Appeals Court in Washington and challenge your project. And basically what that meant is they wouldn't have had a permit for 18 months if they tried to fight it and suddenly they'd be the last people getting a permit so they went ahead and made the expense and installed the unit, and it hasn't started up yet.

I think the only one of these kinds of units that has the S.C.R. system already up and running is Florida Power's Hines Engergy Complex.

But, you know, I think they run fine without them, I haven't heard of any accidents but I would say let -- I would think that if you're in a very highly congested area, maybe literally on the water and with a retirement center and elementary schools right around there, and just imagine the worse possible situation, then maybe -- maybe a case could be made for not using the S.C.R. control.

Does that take care of it?

MR. TROXELL: Yes, but I think basically my question was are you aware of any problems that have occurred in the past with plants that have this type of technology and what those problems may have been.

That is, from an environmental point of view.

MR. LINERO: I haven't heard of any problems, however, -- however, I haven't witnessed any and don't have firsthand knowledge, but there have been some projects, I think in maybe Wisconsin, Minnesota that had perhaps some inferior designs and somehow the ammonia was enough to aggravate a particulate problem. I believe I remember some cases like that.

Certain other industries, for example the cement industry, they resist S.C.R. and ammonia injection because they claim in their situation you will get highly visible plume, so they fight that at every point because they see that as a consequence.

So you can have, based on what else is there in the exhaust stack to react with ammonia, you can have a negative -- you know, aggravate a particular situation related to dust and plume opacity, but I would say what's going out with this ammonia is minimal amount of nitrogen oxides and minimal amount of sulfur products.

So I don't really see any environmental consequences to speak of and, again, the numbers will be down, maybe 50 tons a year, maybe lower. But anything is better than those 10,000's and 40,000's that you see on that list.

So compared to that, I just don't see the consequences of it.

MR. TROXELL: Thank you.

MR. FANCY: Does anyone else have anything they'd like to share with the audience?

Okay. Well, thank you all for coming. I know some of you came long distances and we appreciate the citizens in the Manatee County area for coming.

We'll consider this public meeting closed.

(WHEREUPON THE PUBLIC HEARING ADJOURNED.)

CERTIFICATION

I, MARY FRANCES SCHULTZ, Court Reporter in and for the Twelfth Judicial Circuit of the State of Florida, do hereby certify that I reported, by shorthand, the proceedings had in the above-styled cause; and that the foregoing Pages 1 through 36 constitute a true and correct transcription of my shorthand notes taken at the time and place herein set forth.

MARY FRANCES SCHULTZ
Court Reporter

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VIA TELEFAX AND HAND DELIVERY

January 10, 2001

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

Re: Comments on Draft Air Construction Permit for CPV Gulfcoast, Ltd., DEP File No. 0810194-001 and PSD-FL-300

Dear Mr. Linero:

This is to provide comments on the above-referenced draft air permit for the CPV Gulfcoast electric power generating facility.

1. The new mailing address of the applicant is Competitive Power Ventures, Inc., 35 Braintree Hill Office Park, Suite 107, Braintree, MA 02183, telephone 781-848-0253.

2. The superscripts on the "Facility Emissions (Total TPY) and PSD Applicability" chart in Section 6.2, page TE-7, of the draft permit's <u>Technical Evaluation and Preliminary Determination</u> should be changed as follows: In the Pollutants row of the chart, for Oil Firing, the superscript should be 2 rather than 3, and for Total, the superscript should be 3 rather than 1.

3. On page TE-10 of the draft permit's Technical Evaluation and Preliminary Determination, the word "not" should be deleted from the last sentence, so that that sentence should read as follows: Therefore, no further modeling was ~~not~~ required for this project in the CNWF.

We appreciate the Department making these revisions to the draft permit, and look forward to expeditious issuance of the permit. Please let me know if you have any questions or other issues you wish to discuss. Thank you.

Sincerely,

Cathy M. S

Cathy M. Sellers
Attorney for CPV Gulfcoast, Ltd.

cc: Sean Finnerty, Director, Project Development, CPV
Gary Lambert, Executive Vice President, CPV
Glenn Harkness, TRC

CPV GULFCOAST MEETING – 1/8/01

Sign In Sheet – (Name and Address)

1.	Clair Fancy FDEP Tallahassee
2.	Tom Rogers FDEP Tallahassee
3.	Sean J. Finnerty CPV Gulfcoast
4.	A. A. Linero FDEP Tallahassee
5.	C. G. Troxell Private Citizen
6.	JERRY KISSEL, FDEP TAMPA
7.	JOE McCLASH MANATEE COUNTY.
8	CAROL MASIO McGUIRE Holland & Knight, LLP
9.	SCOTT OSBOURN ENSR
10.	Mel Klein FPL [illegible] P.O. Box 1119 SARASOTA 34230
11.	Karen Collins-Fleming Manatee Co. Env. Mgmt
12.	LEON KOTECKI MANATEE COUNTY PLANNING
13.	
14.	
15.	

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1/8/01

FINAL DETERMINATION
CPV – GULFCOAST POWER GENERATING FACILITY
COMBINED CYCLE COMBUSTION TURBINE

The Department distributed a Public Notice package on November 17, 2000 for the project to construct a nominal 245-megawatt (MW) natural gas and fuel oil-fired combined cycle unit to be known as the CPV – Gulfcoast Power Generating Facility near Piney Point, Manatee County. The project consists of a nominal 170 MW General Electric 7FA combustion turbine-electrical generator, an unfired heat recovery steam generator, a steam-electrical generator; a 150-foot stack; a mechanical draft cooling tower; a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. The Public Notice of Intent to Issue was published on November 25 in The Bradenton Herald.

Written comments were received during the public comment period from the Chairman of the Manatee County Board of County Commissioners, the Manatee County Environmental 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. These were considered prior to issuance of the Public Notice package.

The comments are addressed below in the same order as received by letter. They are followed by the Department's responses. 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 FPC Hines with Conventional Units along Southwest Florida Coast." In 1999, one of the units at the FPC P.L. Bartow Plant 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

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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 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.

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 designated as "moderate non-attainment." Both areas have been redesignated as "attainment." The Atlanta, Houston, and Los Angeles areas are presently designated 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 1 megawatt 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).

The Tampa Bay area is marginally in violation of the 8-hour ozone standard. The Department will need to address this violation 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 indutrial sources, and meteorlogy. 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 Final Judgement, 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."*

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The 170 MW generated from the combustion turbine-electrical generator are exempt from the Siting Act. In its application, CPV described a set of practices to "ensure the 75 MW output limit is not exceeded" from the separate steam cycle. During hot weather, the unit cannot produce enough steam to operate a 75 MW steam turbine-electrical generator. At other times steam flow will be diverted back to the combustion turbine, or wasted or, in some other manner, reduced to the steam turbine-electrical turbine. According to the applicant, "output of the STG will be controlled automatically ...... to ensure that the electrical power produced from steam does not exceed 74.9 MW."

The Department included a condition in the draft permit requiring that "electrical power from the steam-electrical generator shall be limited to 74.9 MW on an hourly basis. CPV shall be capable of demonstrating to the Department, continuous compliance with the 74.9 MW limit by the stored information in the power plant's electronic data system."

The Department contacted General Electric and CPV requesting that they develop additional details regarding the measures and the method to demonstrate achievement of the requirement. Among the possibilities are making the electrical power production data instantly available to the Department and Manatee County via a modem.

These measures together provide reasonable assurance that the 75 MW threshold will not be reached.

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. The Department will obtain the details from the company and provide them to EMD. It will be necessary for CPV to secure re-used water from local communities and work with SWFWMD to secure minimal amounts of groundwater.

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*

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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 limit set by Manatee County for fuel sulfur of 1 percent.

The selective catalytic system (SCR) 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). For comparison, the most recent similar project permitted by the Department was Kissimmee Utilities Authority Cane Island Unit 3. The NO_X limit for that project while firing back-up fuel oil is 15 ppmvd.

The new FPC Hines Energy units (listed in attached table) are required to control NO_X emissions to 42 ppmvd when burning back-up fuel oil. In fact, permitted NO_X, CO, and VOC emissions from CPV while burning oil (10 ppmvd) are less than FPC Hines while burning gas (~12-25 ppmvd based on load). Despite the seemingly high limits at FPC Hines, emissions are actually very low compared with conventional units in the Tampa Bay Area. CPV can be expected to actually perform better than permitted and compare even more favorably with conventional units.

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 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 be be required prior to construction of this facility."*

See response to Comment 1 above.

12. *In their 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,*

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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.

DEP Response:

13. *EPA comments: The uncontrolled CO emission level used in the cost analysis is based on operation in power augmentation mode for 2,000 hours per year, 720 hour per year of fuel oil firing and 6,040 hours per year of natural gas firing. The draft PSD permit does not limit the number of hours the CT can operate in power augmentation mode. In order for the cost analysis to remain valid, a permit condition limiting operation in power augmentation mode to 2,000 hours per year should be included.*

    The Department concurs with EPA and a maximum operating period of 2000 hours per year during power augmentation will be added to Section III. Specific Condition 9.

14. *EPA Comment: Table E-3 includes a lost figure which accounts for the lost revenue from a "Pressure Drop Derate". Although it is appropriate to calculate the cost of using additional natural gas to compensate for the power consumption resulting from pressure drops across the catalyst bed, lost revenue should not be included in the cost analysis and should be omitted.*

15. *EPA notes that "an interest rate of 8 percent may be appropriate for the CPV-Gulfcoast facility; however, it should be noted that the current version of the U.S. Environmental Protection Agency's (EPA's) OAQPS Control Cost Manual uses an interest rate of 7 percent. If there is justification for CPV-Gulfcoast to use a higher interest rate, documentation should be provided."*

    The Department agrees with EPA. Attached is CPV's documentation on the matter. It is noted that differences of 1 percent in interest rates would not affect conclusionds regarding cost-effectiveness of available control technologies for this project. The Department will require such documentation in futeur projects when they differ from established rates.

16. *EPA Comment: The capital recovery cost in Table E-3 is too high because it contains a double-counting of catalyst cost. Catalyst cost is already included in the annualized "Replacement Catalyst" cost and should be deducted from the "Total Capital Investment" when calculating capital recovery. This concept is explained in the following excerpt from the OAQPS Control Cost Manual: "However, whenever there are parts in the control system that must be replaced before the end of its useful life, Equation 2.2 [the capital recovery cost calculation equation] must be adjusted, to avoid double-counting."*

    The Department agrees with EPA. Attached is a revised calculation. It does not affect the control technology conclusions for this specific project.

17. *EPA Comment: The "Total Capital Investments" section of Table E-3 includes a 20 percent contingency fee. This is inconsistent with the OAQPS Control Cost Manual, which includes a 3 percent contingency fee. CPV-Gulfcoast's 20 percent contingency fee is much higher than what is normally used in CO catalytic oxidation cost analyses and should be reduced unless the need for such a high contingency fee can be well documented.*

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The Department agrees with EPA. Attached is a revised calculation. It does not affect the control technology conclusions for this specific project. Although the Department did not adopt the consultant's cost estimates, it concluded that the levelized costs of the oxidation catalyst for CO (VOC) are not justifiable for this project.

Recent tests were conducted for volatile organic compounds (VOC) and carbon monoxide (CO) at an identical unit installed at the TECO Polk Power Project. Emissions of VOC were between 0.1 and 0.5 ppm at various loads between 50 and 100 percent of full load. CO ranged from 0.3 to 1.7 ppm. Actual CO (and VOC) emissions will likely be much less than permitted. Although this does not affect the cost calculations based on accepted estimating techniques, it does corroborate that, on a real basis, actual CO control is not cost-effective.

CPV has agreed to install a CO continuos emission monitoring (CEM) system to provide reasonable assurance that the proposed emissions will not be exceeded.

18. *Additional DEP Action: The following condition has been added to Section II of the permit as Condition No. 9. The Department believes that this new condition will clarify and differentiate the expiration date of the permit and the physical construction expiration date of the proposed project.*

<u>Completion of Construction</u>: The permit expiration date is June 30, 2003. Physical construction shall be complete by December 30, 2002. The additional time provides for testing, submittal of results, and submittal of the Title V permit to the Department.

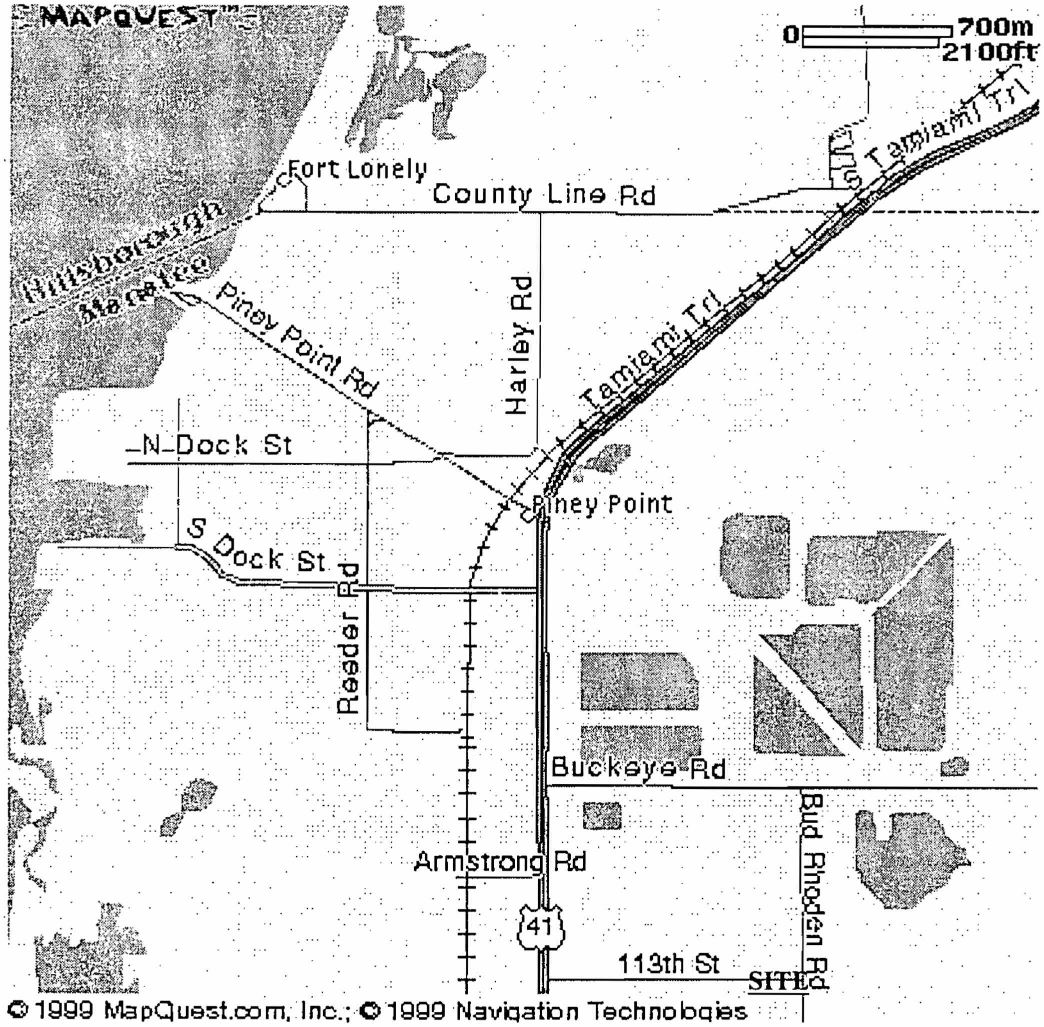
CONCLUSION

FLORIDA DEP AIR PERMITTING SUMMARY SHEET

CPV GULFCOAST POWER GENERATING FACILITY
NOMINAL 250 MEGAWATT COMBINED CYCLE PLANT
PUBLIC MEETING – PALMETTO, MANATEE COUNTY

JANUARY 8, 2001

Competitive Power Ventures (CPV) submitted an application to construct a nominal 250 megawatt (MW) combined cycle power plant and ancillary equipment near Piney Point in Manatee County.



The proposed site is a 160-acre tract at the intersection of Buckeye and Bud Rhoden Roads. The location is East of Highway 41 and South of the Piney Point Phosphates facility.

The Florida Department of Environmental Protection (DEP) is the permitting authority for the air construction permit under Chapter 403 of the Florida Statutes, Chapters 62-4, 62-210 and 62-212 of the Florida Administrative Code.

The DEP Bureau of Air Regulation in Tallahassee received the application on September 9 of last year. We distributed it to the EPA Region 4 office in Atlanta, the U.S. Fish and Wildlife Service's Air Quality Branch in Denver, Colorado, our DEP Southwest District Office in Tampa, and the Manatee County Environmental Management Department.

The Technical Evaluation and Preliminary Determination and the draft air permit were completed and sent to the applicant on November 17 along with the Department's Intent to Issue. Copies were provided to the previously - mentioned agencies and to the Manatee County Commission. Copies were made available for public inspection at DEP offices in Tallahassee and Tampa and at the Manatee County EMD. We also posted these materials at our website: www.dep.state.fl.us/air/permitting.htm

The Department's Public Notice of Intent to Issue Air Construction Permit was published by the applicant in the Bradenton Herald on November 25. It provided a 30-day period for anyone to submit comments on the Department's proposed action or to request this public meeting. It also provided a 14-day period for anyone whose substantial interests were affected by the project to file a petition for an administrative hearing.

To-date, we have received substantial comments only from the Chair of the Manatee County Commission and the Director of the Manatee County Environmental Management Department. The applicant requested this public meeting.

This public meeting was noticed in Bradenton Herald on December 5 and again on January 5. It was also noticed in the Florida Administrative Weekly on December 29 (this publication is available free of charge on the web at http://election.dos.state.fl.us).

Copies of the Intent to Issue package are available at this meeting. We also have a few copies on diskette. If we run out, we will be happy to make you copies and send them to you. As mentioned before, you can view this package on our website. The actual application and entire file are available for public review and copying at our offices in Tallahassee and Tampa.

Issues such as noise and the plant location are beyond the scope of our authority in making this permitting decision. These fall within local ordinances and local planning and zoning authorities.

DEP will consider comments specifically related to air emissions and control, which have already been submitted or are submitted here and over the next week. Comments may be submitted at this public meeting, E-Mailed, or mailed to:

CONTACT: A. A. Linero, P.E Administrator
New Source Review Section
Bureau of Air Regulation
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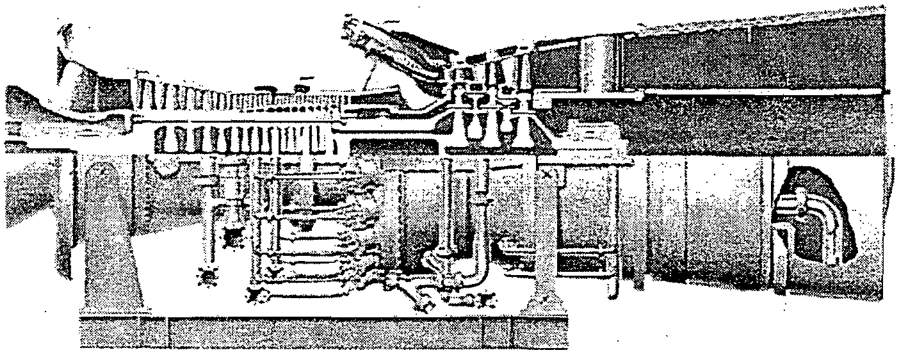
Internet: alvaro.linero@dep.state.fl.us

AIR MODELING:	Tom Rogers, Meteorologist Division of Air Resources Management, Tallahassee Tel: (850)921-9537
AIR COMPLIANCE:	Bill Proses DEP S.W. District, Tampa Tel: (813)744-6100
LEGAL CONTACT:	Douglas Beason, Attorney Office of General Counsel, Tallahassee Tel: (850)921-9624
MANAGEMENT CONTACT:	C. H. Fancy, P.E., Chief Bureau of Air Regulation Tel: (850)921-9503

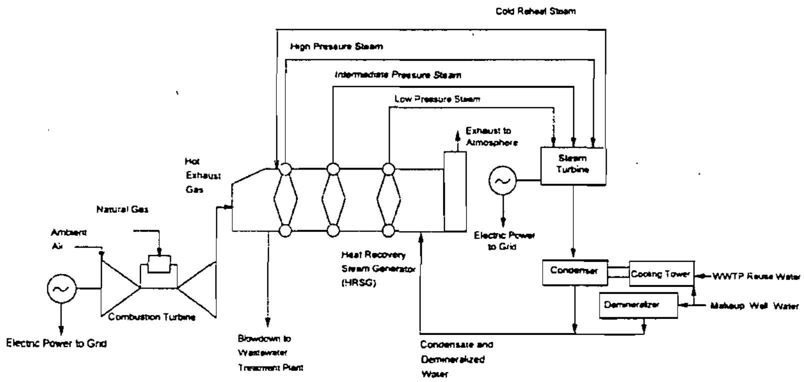
PROJECT DESCRIPTION

The main unit is a General Electric 7FA gas-fired combustion turbine-electric generator, which directly generates approximately 170 MW. The project includes an unfired heat recovery steam generator capable of raising sufficient steam to generate another (maximum) 74.9 MW in a separate steam-electrical generator. The project also includes a 150-foot stack, a mechanical draft cooling tower, a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year.

Following is a picture of a GE 7FA.



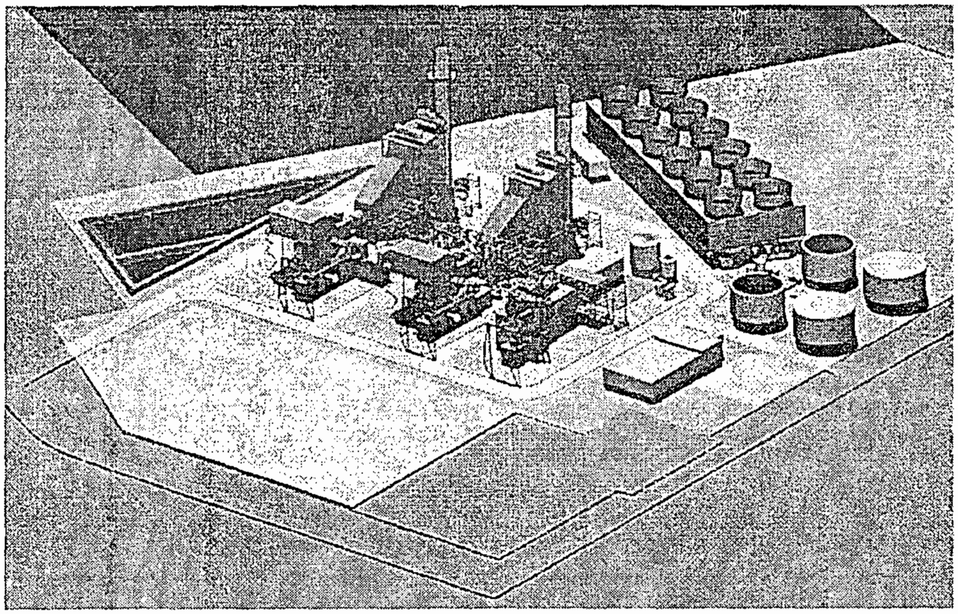
Basically these units are like jet engines. Air is drawn in and compressed. Fuel is introduced in the combustors. Hot exhaust gases expand in the rotor section. The rotational motion of the shaft drives the compressor and the electrical generator normally located before the compressor section. In the CPV project, the unit will operate in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The steam is then fed to a separate steam turbine, which also drives an electrical generator.



Process Flow Diagram of a Basic Combined Cycle Power Plant

(gas-only, without SCR, and no power augmentation)

We do not have an artist's rendition of the site. Following is a picture borrowed from a proposed project for two of these units in Volusia County. The Duke project differs in that it does not include fuel oil storage or a selective catalytic reduction system (SCR).



The key air emissions will consist of nitrogen oxides, carbon monoxide, particulate matter, and sulfur dioxide. NO_x emissions will be controlled by selective catalytic reduction (SCR) to achieve 3.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 10 ppmvd while burning low sulfur distillate fuel oil. Emissions of CO will be controlled to 9 and 20 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM_{10}, SO_2, sulfuric acid mist, volatile organic compounds, hazardous air pollutants (HAP), and will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and low sulfur (0.05 percent) distillate fuel oil. Ammonia emissions generated due to NO_X control will be limited to 5 ppmvd.

The following table summarizes the maximum emissions (in tons per year) of regulated air pollutants as a result of this project.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	102	25/15
Sulfuric acid mist	12	7
SO_2	76	40
NO_x	126	100
VOC	15	40
CO	222	100
NH_3		NA
HAP	8	NA

FAX Cover Sheet

USEPA - Region 4
61 Forsyth St., SW
Atlanta, Georgia 30303

TO: Teresa Heron
FDEP

FAX #: 850-922-6979

RE: CPV-Gulfcoast

FROM: Katy Forney
Air Permits Section, Region 4 USEPA

Phone #: 404-562-9130

Date: 12-27-00

# of Pages (including cover): 4

COMMENTS:

If this FAX is poorly received, please call
Katy Forney: 404-562-913

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

DEC 27 2000

4 APT-ARB

A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft PSD Permit for CPV-Gulfcoast, Ltd. (PSD-FL-300) located in Manatee County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for CPV-Gulfcoast November 17, 2000. The preliminary determination is for the proposed construction and operation of one combined cycle combustion turbine (CT) with an unfired heat recovery steam generator and a total nominal generating capacity of 250 MW to be located near Piney Point, FL. The combustion turbine proposed for the facility is a General Electric (GE), frame 7FA unit. The CT will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CT will be allowed to fire natural gas up to 8,760 hours per year and fire No. 2 fuel oil a maximum of 720 hours per year. The CT will be allowed to operate in power augmentation mode for a maximum of 8,760 hours/year. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}) and volatile organic compounds (VOC).

Based on our review of the preliminary determination and draft PSD permit, we have the following comments:

1. 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.

2. Our comments concerning the CO catalytic oxidation cost analysis are as follows:

   a. The uncontrolled CO emission level used in the cost analysis is based on operation in power augmentation mode for 2,000 hours per year, 720 hour per year of fuel oil firing and 6,040 hours per year of natural gas firing. The draft PSD permit does not limit the number of hours the CT can operate in power augmentation mode. In order for the cost analysis to remain valid, a permit condition limiting operation in power augmentation mode to 2,000 hours per year should be included.

   b. Table E-3 includes a cost figure which accounts for the lost revenue from a "Pressure Drop Derate". Although it is appropriate to calculate the cost of using additional natural gas to compensate for the power consumption resulting from pressure drops across the catalyst bed, lost revenue should not be included in the cost analysis and should be omitted.

   c. An interest rate of 8 percent may be appropriate for the CPV-Gulfcoast facility; however, it should be noted that the current version of the U.S. Environmental Protection Agency's (EPA's) *OAQPS Control Cost Manual* uses an interest rate of 7 percent. If there is justification for CPV-Gulfcoast to use a higher interest rate, documentation should be provided.

   d. The capital recovery cost in Table E-3 is too high because it contains a double-counting of catalyst cost. Catalyst cost is already included in the annualized "Replacement Catalyst" cost and should be deducted from the "Total Capital Investment" when calculating capital recovery. This concept is explained in the following excerpt from the *OAQPS Control Cost Manual*: "However, whenever there are parts in the control system that must be replaced before the end of its useful life, Equation 2.2 [the capital recovery cost calculation equation] must be adjusted, to avoid double-counting."

   e. The "Total Capital Investments" section of Table E-3 includes a 20 percent contingency fee. This is inconsistent with the *OAQPS Control Cost Manual*, which includes a 3 percent contingency fee. CPV-Gulfcoast's 20 percent contingency fee is much higher than what is normally used in CO catalytic oxidation cost analyses and should be reduced unless the need for such a high contingency fee can be well documented.

Thank you for the opportunity to comment on the CPV-Gulfcoast preliminary determination and draft PSD permit. If you have any questions regarding these comments, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

for Gregg M. Worley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: J. Heron
C. Carlson
G. Lambert, CPV Gulf Coast
B. Thomas, SWD
C. Sellers
NPS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

RECEIVED

JAN 02 2001

BUREAU OF AIR REGULATION

DEC 27 2000

4 APT-ARB

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Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
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R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

MANATEE COUNTY GOVERNMENT

"To Serve With Excellence"

ENVIRONMENTAL MANAGEMENT DEPARTMENT

RECEIVED
DEC 29 2000
BUREAU OF AIR REGULATION

December 22, 2000

Mr. A. A. Linero, P. E., Administrator
Bureau of Air Regulation
New Source Review Section
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: DEP File No. 0810194-001-AC (PSD-FL-300)
CPV Gulfcoast Power Generating Facility
245 Megawatt Combined Cycle Power Project

Dear Mr. Linero:

The Manatee County Environmental Management Department (EMD) offers the following comments on the referenced project:

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

   A new federal ozone standard has been established at a level equivalent to 85 ppb averaged over any 8-hour period. An area will be considered non-attainment if the average of the annual fourth highest ozone readings at a monitoring site for any 3-year period equals or exceeds 85 ppb. Based on EMD's monitoring data, the 3-year running average for ozone within the County has been steadily increasing: from 75 ppb (1993-95) to 84 ppb (1997-99). **Considering that Manatee County is marginally meeting the ozone standard and that the 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.**

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

202 6th Avenue East • Bradenton, Florida 34208 • (941) 742-5980 • Fax (941) 742-5996

P.O. Box 1000 • Bradenton, Florida 34206-1000

2. Design for the proposed facility includes a 74.9 MW steam-electrical generator. According to Chapter 403.503, F.S., steam or solar electrical generating facilities of **less than 75 megawatts** [emphasis added] are exempt from requirements of the Florida Electrical Power Plant Siting Act. **What assurance does the applicant provide that the 75 MW threshold would never be exceeded?**

3. The proposed facility will employ cooling towers for the purpose of cooling and condensing steam. Much of this cooling water is evaporated and must be replaced. CPV representatives estimate that approximately 2-2.5 million gallons per day (GPD) of water will be required to operate the facility. According to the Southwest Florida Water Management District (SWFWMD), the proposed location of the facility is within the Most Impacted Area (MIA), which would prohibit the permitting of new groundwater withdrawals. **Please provide details as to the source and quality of water to be used at the facility.**

4. How will this new supplier of electrical energy interact with the current regional suppliers? Will this facility displace energy being supplied by these existing facilities? Does this facility have a local client base or will the energy be transmitted outside the region? **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 pollutant emissions in Manatee County.**

5. The Tampa Bay Estuary Program (TBEP) is charged with ensuring that Bay conditions are protected and, wherever possible, improved. The TBEP has determined that excessive nitrogen loading to the Bay is of special concern. This nutrient causes algal blooms, decreases water clarity and generally degrades water quality, resulting in habitat and fisheries losses. Recent studies indicate that at least 29 percent of the Bay's total nitrogen load is from atmospheric deposition. We have seen no modeling or other projections of atmospheric deposition of nitrogen attributable to operation of this facility. **Due to this project's proximity to the Bay and the Terra Ceia Aquatic Preserve, it is essential that the applicant provide detailed information on expected depositional impacts from nitrogen components (NOx 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.**

6. Although the proposal is for a predominantly gas-fired power plant, the permit would allow combustion of #2 fuel oil. Although operation using fuel oil would be limited to 720 hours per year, the <u>hourly</u> emissions of criteria pollutants would be significantly greater than levels of those pollutants when the plant is firing natural gas. **We question 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.**

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

8. Another issue of concern, perhaps outside the purview 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.

We appreciate the opportunity to comment on this important proposal, and look forward to the public meeting your office has scheduled for 6:00 p.m., January 6, 2001 at Blackburn Elementary School, in Bradenton.

Sincerely,

Karen Collins-Fleming
Director

KCF:RCB

cc: County Commission members
Ernie Padgett, County Administrator
Tedd Williams, County Attorney
Rob Brown, EMD Water Quality Administrator
Marion Forthoffer, EMD Air Quality Manager
J. Heron
C. Carlson
B. Thomas, SWD
EPA
NPS

MANATEE COUNTY GOVERNMENT

"To Serve With Excellence"

ENVIRONMENTAL MANAGEMENT DEPARTMENT

December 22, 2000

Mr. A. A. Linero, P. E., Administrator
Bureau of Air Regulation
New Source Review Section
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Re: DEP File No. 0810194-001-AC (PSD-FL-300)
CPV Gulfcoast Power Generating Facility
245 Megawatt Combined Cycle Power Project

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NPS

Environmental Management Department
MANATEE COUNTY GOVERNMENT

FAX MEMORANDUM

DATE: December 22, 2000

TO: Al Linero, P.E., Administrator
DEP Bureau of Air Regulation
FAX: (850) 922-6979

FROM: Karen Collins-Fleming, Director KCF
FAX: (941) 742-5996

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

Attached are comments from the Manatee County Environmental Management Department on the referenced proposal. Should you have questions, please give me or Rob Brown a call. We can both be reached at (941) 742-5980.

Thank you for the opportunity to comment on this important proposal.

kcf/

attached: 3 pages

PUBLIC MEETING

AGENCY: Florida Department of Environmental Protection

PURPOSE: Receive comments from the public on the Department's proposed air construction permit to be issued to CPV Gulfcoast Ltd. The permit is to construct a nominal 245 megawatt (MW) combined cycle electrical power generating plant. The project consists of: a nominal 170 MW General Electric 7FA combustion turbine-electrical generator; an unfired heat recovery steam generator capable of raising sufficient steam to generate another (maximum) 74.9 MW from a steam-electrical generator; a 150-foot stack; a mechanical draft cooling tower; a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year. This new facility will be located on a 160-acre tract at the intersection of Buckeye and Bud Rhoden Roads, southeast of Piney Point in Manatee County.

DATE: January 8, 2001

TIME: 7:00 – 9:00 p.m. (see note below)

PLACE: Blackburn Elementary School Cafeteria, 3904 17th Street East, Palmetto

MEETING AGENDA

7:00 p.m. Introduction/Moderator

- *C. H. Fancy, P.E., Chief, Bureau of Air Regulation*
- *FDEP, Tallahassee*

7:05 p.m. Discussion of application and air permitting requirements for the CPV Gulfcoast Ltd. combined cycle project.

- *A. A. Linero, P.E., New Source Review Section,*

  FDEP, Tallahassee.

7:10 p.m. Discussion of PSD issues and ambient air quality impacts of proposed project.

- *Tom Rogers (or Cleve Holladay), Meteorologist*

  FDEP, Tallahassee

7:15 p.m. FDEP's Draft Best Available Control Technology (BACT) determination for the new plant.

- *A. A. Linero, New Source Review Section,*

  FDEP, Tallahassee

7:30 p.m. Comments from the public.

9:00 p.m. Adjourn.

(Note: Department personnel and representatives of the applicant will also be available prior to the meeting, from 6:00 to 7:00 p.m., to discuss the proposed permit and project on an informal basis.

BACT

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

From: FGT Phase IV Expansion Project
Florida Gas Transmission Company
An Enron / Sonat Affiliate

pollutants still go down, substantially, for example, in the case of sulfur dioxide. (See column 2 versus column 4).

Either way, these emission reductions are possible because the repowering project calls for updating the generating technology and using natural gas, which burns much cleaner than oil. The natural gas-fired, combined-cycle technology is more efficient and generates less pollution than the older, oil-fired traditional electric generating technology it is replacing.

Column 1	Column 2	Column 3	Column 4	Column 5	Column 6
Pollutant	Actual 1996-1997 (tons per year)	Actual 1996-1997 (lb. / Mwh	Repowered Units (tons per year)	Repowered Units (lb. / Mwh)	Percent Reduction (column 3 compared to column 5)
PM	607	0.62	313	0.04	93.5
NOx	7095	7.23	1,845	0.26	96.4
SO2	20,561	20.94	137	0.02	99.9
CO	1,507	1.53	1,267	0.18	88.2
VOC	46.7	0.05	82.2	0.01	80.0
CO2	1,690,935	1,722	5,236,931	774	55.1

Of the five air pollutants FPL is required by the government to monitor and report on, four will be reduced in quantity as a result of the repowering. Emissions of sulfur dioxide, particulate matter, nitrogen oxide and carbon monoxide will all go down.

In the case of the fifth -- volatile organic compounds (VOCs) -- emissions will increase very slightly. Even though there are fewer VOCs in natural gas than in oil, the slight increase in emissions will be due to operating the highly efficient plant more often and thus using more fuel. Neither the U.S. Environmental Protection Agency, nor the Florida Department of Environmental Protection, considers the minimal anticipated increase to be significant.

The bottom line is that the air permit FPL has applied for will set limits on and require future monitoring of these pollutants in a manner similar to the monitoring we conduct today and provide to the Florida Department of Environmental Protection.

There will be some other emissions that FPL tracks but is not required to report. For example, since the generating capacity of the repowered plant will triple, more fuel will be burned, so we expect a local increase in plant emissions of carbon dioxide. Like VOCs, carbon dioxide is a byproduct of burning any fossil fuel. It is not deemed a pollutant, but rather is referred to as a "greenhouse gas" and studied for its potential contribution to climate change.

Interestingly, we should see overall reductions in both VOCs and carbon dioxide from FPL's total fleet of generators with the repowering of the Fort Myers plant. An anticipated 13 percent reduction in carbon dioxide from FPL generation statewide is considered significant by experts who view climate change from a "global" perspective.

These overall improvements would occur because natural gas-fired plants like the repowered Fort Myers plant typically tend to displace oil-fired plants, which emit more VOCs and more carbon dioxide.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
PURCHASE ORDER REQUISITION

PAGE 1 OF ______ (THIS IS NOT A PURCHASE ORDER) REF. NO. PC 001 - 284

VENDOR NAME: Bradenton Herald	FEID/SSN: 59-1487839
ADDRESS: 102 Manatee West	
CITY: Bradenton STATE: FL ZIP: 34205	PHONE: (941) 746-7355

SHIP: DEP-DARM	INVOICE: DEP-DARM
ATTN: Charlotte Hayes CODE: 176	ATTN: Mary Fillingim CODE: 176
PHONE: (850) 488-0114 SC:	PHONE: (850) 488-0114 SC:
111 S. MAGNOLIA Dr M/S: 5505	2600 Blair Stone Road M/S: 5500
ROOM:	ROOM:
CITY: Tallahassee STATE: FL ZIP: 32311	CITY: Tallahassee STATE: FL ZIP: 32399-2400

PURCHASING USE ONLY | P/C: | MESSAGES: | B/C

QUANTITY	UNIT	CLASS / GROUP	DESCRIPTION / DEP PROPERTY # FOR EACH ITEM	UNIT COST	TOTAL
1	day	973-040	Legal advertisement to be published Jan. 5, 2001		$145.84
			Need proof of publication and itemized invoice		

RECYCLED CONTENT: ____ YES ____ NO CMBE: ____ YES ____ NO GRAND TOTAL $ $145.84

DELIVERY: ______ DAYS ARO OR WPU | F. O. B.: DEST / SP / VENDOR | DEP / DMS CONTRACT NO.:

FOR FCO USE ONLY | PROJECT NO.: CATEGORY NO.: /9____ FUND NO.:

JUSTIFICATION: To inform public of a public meeting

FISCAL YEAR FOR ENCUMBRANCE: 00 / 01

LINE	ORGANIZATION CODE					EO	OBJECT	AMOUNT
0001	37	55	02	04	000	A7	133100	$145.84
0002	37							

LINE	FUND	CATEGORY	MODULE	GRANT NO.
0001	035001	040000	AP255	AIR01
0002				

APPROVALS		DATE
REQUESTOR:	Patty Adams	12/22/00
COST CENTER:	37550204000	
SECTION:	[signature]	12/22
BUREAU:	[signature]	12/27/00
DIV. / SEC.:		
PURCHASING:		

11-003 (REV. 7/94) ORIGINAL-TO PURCHASING; OTHER COPIES FOR YOUR FILES OR DISTRIBUTION

RECYCLED PAPER

BRADENTON HERALD

CLASSIFIED ADVERTISING

Legal Advertising Memo Bill

Order Information					
Order #:	130530911	Class:	4995	P.O. #:	
Phone:	(850) 488-0114	Start Date:	01/05/2001	Rate:	LE
Account:	H310280	Stop Date:	01/05/2001	Charges:	$ 0.00
Name:	Adams, Patty	Insertions:	1	Net Price:	$ 145.84
Firm:	Fl. Dept. Of Environmental	Lines:	124	Payments:	$ 0.00
Run-dates:	1/5 1x	Inches:	12.087	Balance:	$ 145.84

Text

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION NOTICE OF PUBLIC MEETING CPV GULFCOAST LTD. POWER PROJECT The Department of Environmental Protection gives notice that a public meeting to which all persons are invited will be held regarding the

102 Manatee Avenue West
Bradenton, FL 34205
Classified Dept. (941) 746-SELL (7355)
Classified Legal and Official Advertising (941) 745-7064
Fax: (941) 745-7090 E-mail: bhclassified@bradentonherald.com

BRADENTON HERALD

www.bradenton.com
P.O. Box 921
Bradenton, FL 34206-0921
102 Manatee Avenue West
Bradenton, FL 34205-8894
941/748-0411 ext. 7065

RECEIVED

JAN 10 2001

BUREAU OF AIR REGULATION

Bradenton Herald
Published Daily
Bradenton, Manatee, Florida

STATE OF FLORIDA
COUNTY OF MANATEE:

Before the undersigned authority personally appeared Sandy Riley, who on oath says that she is a Legal Advertising Representative of the Bradenton Herald, a daily newspaper published at Bradenton in Manatee County, Florida; that the attached copy of the advertisement, being a Legal Advertisement in the matter of STATE OF FLORIDA DEPT. OF ENVIRONMENTAL PROTECTION NOTICE OF PUBLIC MEETING in the Court, was published in said newspaper in the issues of 1/5/01.

Affiant further says that the said publication is a newspaper published at Bradenton, in said Manatee County, Florida, and that the said newspaper has heretofore been continuously published in said Manatee County, Florida, each day and has been entered as second-class mail matter at the post office in Bradenton, in said Manatee County, Florida for a period of 1 year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sandy Riley
(Signature of Affiant)

Sworn to and subscribed before me this 5th Day of January, 2000

DIANE S. BACRO
Notary Public - State of Florida
My Commission Expires Aug 15, 2003
Commission # CC863180

Diane S. Bacro
SEAL & Notary Public
Personally Known X OR Produced Identification ______
Type of Identification Produced ______

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION NOTICE OF PUBLIC MEETING CPV GULFCOAST LTD. POWER PROJECT

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The meeting will be held at **7:00 p.m., Monday, January 8, 2001, at Blackburn Elementary School,** in the Cafetorium, 3904 17th Street East, Palmetto, Florida. Department staff will be available from 6:00 p.m. to 7:00 p.m. to discuss the proposed permit on an informal basis. CPV Gulfcoast Limited also will have representatives present to discuss the project from 6:00 pm to 7:00 p.m. Beginning at 7:00 p.m., the Department will accept oral and written public comments and provide the status of the Department's Intent to Issue an air Construction Permit.

The Public Notice of Intent to Issue an Air Construction Permit was published in the Bradenton Herald on November 25, 2000 and the First Notice of Public Meeting was published on December 5. The public meeting was requested pursuant to the procedures described in the Public Notice. A copy of the agenda and the Department's proposed permit and supporting documents are available for review during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Fl 32301
Telephone:(850) 488-0114
Fax: (850) 922-6979

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Fl. 33619-8218
Telephone:(813) 744-6100
Fax: (813) 744-6084

The Department's technical evaluations and Draft Permit can be viewed at www.dep.state.fl.us/air/permitting.htmby clicking on Utility and Other Facility permits.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodation to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist in the Bureau of Personnel at (850) 488-2996. If you are speech or hearing impaired, please contact the agency by call (800) 955-8771 (TDD).
1/5/01

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
SECOND NOTICE OF PUBLIC MEETING
CPV GULFCOAST LTD. POWER PROJECT

The Department of Environmental Protection gives a second notice that a public meeting to which all persons are invited will be held regarding the Department's Intent to Issue an Air Construction Permit to CPV Gulfcoast, Ltd., to construct a nominal 245 megawatt (MW) combined cycle (74.9 MW steam cycle) electrical power generating plant near Piney Point in Manatee County, Florida. The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality (PSD) and Best Available Control Technology (BACT).

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Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301
Telephone: (850) 488-1344
Fax: (850) 922-6979

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, FL 33619-8218
Telephone: (813) 744-6100
Fax: (813) 744-6084

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Adams, Patty

From: Linero, Alvaro
Sent: Saturday, December 16, 2000 8:35 PM
To: Adams, Patty
Cc: Fancy, Clair; Ladner, Kysandra; Rogers, Tom; Holladay, Cleve; Carlson, Chris; Beason, Doug; Goorland, Scott
Subject: CPV-Gulfcoast Public Meeting

MeetNot.doc

Patty. Please get the attached notice published in the Bradenton Herald on Friday, January 5th. This is the second publication in local newspaper and is in addition to the FAW Notice we will publish. Please send this notice to the Chair of the County Commission, the County Administrator, and the head of the Manatee County Environmental Program, Dr. Karen Collins (I think).

To cc list: Clair will chair this meeting. I will handle BACT and permitting questions. Right now I think Chris will handle modeling issues, but we may need help from Cleve or Tom. Sandy - if you are available, we can sure use your help.

Doug or Scott. The original Intent Notice was published on November 25 so the 14 day period is up. I'll let you know if we need help. However, if you think we need help, feel free to come. I can tell you that Cathy Sellers of Moyle, Flanagan is quite involved and I would feel more comfortable having at least some legal presence.

This meeting was requested by CPV because they did not want to run the risk of having a member of the public request it on Day 30 and then taking another 30+ days to hold it. There may be very little interest in this meeting. On the other hand, there are groups in Manatee County that are very interested in what goes on in their county.

Thank you. Al Linero.

BEST AVAILABLE COPY

COST $145.84

BRADENTON HERALD CLASSIFIED ADVERTISING

Order:	130529854	Pubs:	1	Rate:	LE
Phone:	(941) 999-9999	Class:	4995	Charges:	$ 0.00
Account:	7056	Start Date:	01/05/2001	List Price:	~~$ 140.88~~
Name:	n/a,	Stop Date:	01/05/2001	Payments:	$ 0.00
Firm:	FL DEPT ENVIROMENTAL	Insertions:	1	Balance:	~~$ 140.88~~

pmt ~~$ 143.85~~
$ 145.84

Patty

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION NOTICE OF PUBLIC MEETING CPV GULFCOAST LTD. POWER PROJECT

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The Public Notice of Intent to Issue an Air Construction Per... was published ... Bradenton ... mber 25, ... st Notice ... ng was ... mber 5, ... ng was ... t to the ... bed in ... copy ... d the ... posed ... orting ... lable ... rmal ... a.m. ... nday ... day, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Fl 32301
Telephone:(850) 488-0114
Fax: (850) 922-6979

Department of Environmental Protection
Southwest District Office
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Tampa, Fl 33619-8218
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Call finance
941-748-0411
Ext 6203
finance

216.075, F.S.
Sandy
941-745-7065

Classified Dept. (941) 746-SELL (7355)
Fax: (941) 745-7090
E-mail: bhclassified@bradentonherald.com

contacting the Personnel Service Specialist in the Bureau of Personnel at (850) 488-2996. If you are speech or hearing impaired, please contact the agency by call (800) 955-8771 (TDD).
1/5/01

FAW NOTICE COVER SHEET

DATE RECEIVED BY OGC: ________________

DATE TO BE FILED: December 20, 2000

DATE TO BE PUBLISHED IN THE FAW: December 29, 2000

1. Person Originating Notice: Al Linero
2. Subject of Notice: Public Meeting
3. Type of Notice:

____ Rulemaking 120.54, F.S.
____ Rulemaking 403.8055, F.S.
_X_ Workshop
____ Variance 120.542, F.S
____ Variance 403.201, F.S.
____ Receipt of Rule Petition 120.54(7). F.A.C.
____ Declaratory Statement 120.565, F.S.
____ Other

PCC REVIEW

(Date)

4. Explain need: ________________________________

5. Comments: ________________________________

APPROVALS:

DIVISION DIRECTOR: ________________________

OGC ATTORNEY: ________________________

DEPUTY GENERAL COUNSEL: ________________________

\\TLH_BDG1\USERS\LONG_M\RULES\FORMS\FAWCOV.DOC
11/97

MEMORANDUM

TO: Liz Cloud, Chief, Bureau of Administrative Code

DATE: December 20, 2000

SUBJECT: Notice to be Published in F. A. W.

Agency's Title No.: 62

PLEASE PUBLISH THE ATTACHED NOTICE IN THE December 29, 2000 ISSUE OF THE FLORIDA ADMINISTRATIVE WEEKLY.

____ Rule Development	X Meeting/Workshop/Hearing
____ Proposed Rule	____ Declaratory Statement
____ Notice of Change\Withdrawal	____ Bid\Request for Proposal
____ Emergency Rule	____ Miscellaneous

LIST OF FILES ON DISK: FAWNOT

**** Name and Phone Number of Person to be contacted regarding the attached notice:** Al Linero 921-9523

****

BILLING INFORMATION

The invoice for cost of publication should be sent to:
(please fill out complete address)

Department: Department of Environmental Protection

Division\Bureau: Division of Air Resources Management

Contact Person: Al Linero

Address: 2600 Blair Stone Road, M.S. 5505, Tallahassee, FL 32399-2400

Phone No.: (850) 488-0114

Purchase Order No.: 300035

****

*THIS SECTION TO BE COMPLETED BY THE BUREAU OF ADMINISTRATIVE CODE

FAW FILE NAME ____________ lines per notice ____________

****

NOTICE OF PUBLIC MEETING

The Department of Environmental Protection announces a public meeting to which all persons are invited:

DATE AND TIME: April 19, 2000 - 7:00 - 9:00 p.m.

PLACE: DeSoto County Administrative Building, 201 East Oak Street, Room 103, Arcadia Florida

PURPOSE: To accept public comments and provide status of Department's Intent to Issue an Air Construction Permit to IPS Avon Park Corporation to construct three 170 megawatt simple cycle combustion turbine-electrical generators East of Arcadia in unincorporated DeSoto County, Florida. The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality and Best Available Control Technology (BACT).

A copy of the agenda and the Department's proposed permit and supporting documents can be obtained by contacting: Al Linero, Department of Environmental Protection at 2600 Blair Stone Road - MS 5505, Tallahassee, Florida 32399, phone (850)921-9529, or by phoning the Bureau of Air Regulation's New Source Review Section at (850)921-9533.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist in the Bureau of Personnel at (850)488-2996. If you are hearing or speech impaired, please contact the agency by calling (800)955-8771 (TDD).

MANATEE COUNTY
BOARD OF COUNTY COMMISSIONERS

December 14, 2000

RECEIVED
DEC 18 2000
BUREAU OF AIR REGULATION

C. H. Fancy, P.E., Chief
FL Dept. of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: **DEP File No. 0810194-001-AC (PSC-FL-300)**
CPV Gulfcoast Power Generating Facility
245 Megawatt Combined Cycle Power Project

Dear Mr. Fancy:

After reading a copy of the public notice of intent to issue an air construction permit in Manatee County, I'd like to have every consideration given to my concerns:

1) Property to be used by this plant under the permit conditions has not been approved by the Manatee County Board of County Commissioners.

2) 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.

3) 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.

4) This permit is contrary to Tampa Bay National Estuary program goals to reduce nitrogen loading in Tampa Bay.

Thank you in advance for considering my concerns when making your deliberations.

Sincerely,

Joe

JOE McCLASH
Chairman

P.O. Box 1000, Bradenton, Florida 34206 • Fax (941)745-3790 • Ph. (941)745-3700

BRADENTON HERALD
CLASSIFIED ADVERTISING

Legal Advertising Memo Bill

Order Information

Order #:	130518892	Class:	4995	P.O. #:	
Phone:	(941) 746-0828	Start Date:	12/05/2000	Rate:	LE
Account:	H302550	Stop Date:	12/05/2000	Charges:	$ 0.00
Name:	Beebe, Larry	Insertions:	1	Net Price:	$ 137.52
Firm:	CPV Gulfscoast, Ltd.	Lines:	122	Payments:	$ 0.00
Run-dates:	12/5 1x	Inches:	11.892	Balance:	$ 137.52

Text

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102 Manatee Avenue West
Bradenton, FL 34205
Classified Dept. (941) 746-SELL (7355)
Classified Legal and Official Advertising (941) 745-7064
Fax: (941) 745-7090 E-mail: bhclassified@bradentonherald.com

BRADENTON HERALD

www.bradenton.com
P.O. Box 921
Bradenton, FL 34206-0921
102 Manatee Avenue West
Bradenton, FL 34205-8894
941/745-7064

RECEIVED

DEC 12 2000

BUREAU OF AIR REGULATION

Bradenton Herald
Published Daily
Bradenton, Manatee, Florida

STATE OF FLORIDA
COUNTY OF MANATEE;

Before the undersigned authority personally appeared Sheila Dalesio, who on oath says that she is a Legal Advertising Representative of the Bradenton Herald, a daily newspaper published at Bradenton in Manatee County, Florida; that the attached copy of the advertisement, being a Legal Advertisement in the matter of NOTICE OF PUBLIC MEETING in the Court, was published in said newspaper in the issues of DECEMBER 5, 2000.

Affiant further says that the said publication is a newspaper published at Bradenton, in said Manatee County, Florida, and that the said newspaper has heretofore been continuously published in said Manatee County, Florida, each day and has been entered as second-class mail matter at the post office in Bradenton, in said Manatee County, Florida for a period of 1 year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sheila Dalesio
(Signature of Affiant)

Sworn to and subscribed before me this
6th Day of December, 2000

DIANE S. BACRO
Notary Public - State of Florida
My Commission Expires [illegible] 2003
Commission [illegible]

Diane S. Bacro
SEAL & Notary Public
Personally Known X OR Produced Identification ______
Type of Identification Produced ______

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Department of Environmental Protection
Southwest District Office
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Tampa, Fl. 33619-8218
Telephone:(813) 744-6100
Fax: (813) 744-6084

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12/5/00

The Law Offices of
MOYLE
FLANIGAN
KATZ
RAYMOND
&SHEEHAN
P.A.

THE PERKINS HOUSE
118 NORTH GADSDEN STREET
TALLAHASSEE, FLORIDA 32301

TELEPHONE (850) 681-3828
FACSIMILE (850) 681-8788

West Palm Beach Office
Telephone (561) 659-7500
Facsimile (561) 659-1789

PETER L. BRETON
JOHN R. EUBANKS, JR.
JOHN F. FLANIGAN
MYRA GENDEL
MARTIN V. KATZ
PAUL A. KRASKER
JON C. MOYLE
JON C. MOYLE, JR.
MARSHALL J. OSOFSKY
MARK E. RAYMOND
CATHY M. SELLERS
THOMAS A. SHEEHAN, III
ROBERT J. SNIFFEN
MARTA M. SUAREZ-MURIAS
WILTON L. WHITE
BRIAN L. WOLINETZ

OF COUNSEL:
THOMAS A. HICKEY
WILLIAM J. PAYNE

RECEIVED
NOV 28 2000
BUREAU OF AIR REGULATION

VIA HAND DELIVERY

November 28, 2000

Mr. A. A. Linero
Administrator,
New Source Review Section
Bureau of Air Regulation
Department of Environmental Protection

Re: Proof of Publication of Public Notice of Intent to Issue Air Construction Permit
DEP File No. 0810194-001-AC and PSD-FL-300

Dear Mr. Linero:

Please find attached the Proof of Publication of the Public Notice of Intent to Issue Air Construction Permit, for the above-referenced file, for the CPV Gulfcoast Power Generating Facility.

Please call me if you have any questions.

Sincerely,

Cathy M. L

Cathy M. Sellers

cc: Sean Finnerty (w/out enclosure)
Mark Barnebey (w/out enclosure)
Jon C. Moyle (w/out enclosure)

BRADENTON HERALD

www.bradenton.com
P.O. Box 921
Bradenton, FL 34206-0921
102 Manatee Avenue West
Bradenton, FL 34205-8894
941/748-0411 ext. 7065

Bradenton Herald
Published Daily
Bradenton, Manatee, Florida

STATE OF FLORIDA
COUNTY OF MANATEE;

Before the undersigned authority personally appeared Sandy Riley, who on oath says that she is a Legal Advertising Representative of the Bradenton Herald, a daily newspaper published at Bradenton in Manatee County, Florida; that the attached copy of the advertisement, being a Legal Advertisement in the matter of PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT in the Court, was published in said newspaper in the issues of 11/25/00.
Affiant further says that the said publication is a newspaper published at Bradenton, in said Manatee County, Florida, and that the said newspaper has heretofore been continuously published in said Manatee County, Florida, each day and has been entered as second-class mail matter at the post office in Bradenton, in said Manatee County, Florida for a period of 1 year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sandy Riley
(Signature of Affiant)

Sworn to and subscribed before me this
27th Day of November, 2000

DIANE S. BACRO
Notary Public - State of Florida
My Commission Expires Aug 15, 2003
Commission # CC863180

Diane S. Bacro
SEAL & Notary Public
Personally Known X OR Produced Identification______
Type of Identification Produced______________________

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0810194-001-AC and PSD-FL-300

CPV Gulfcoast Power Generating Facility 245 Megawatt Combined Cycle Power Project

Manatee County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to CPV Gulfcoast Ltd. The permit is to construct nominal 245 megawatt (MW) combined cycle electrical power generating plant near Piney Point in Manatee County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration of Air Quality (PSD), for emissions of particulate matter (PM/PM 10) carbon monoxide (CO), sulfur dioxide (SO2), sulfuric acid mist, and nitrogen oxides (NOx). A maximum achievable control technology (MACT) determination for hazardous air pollutants was not required. The applicant's name and address are CPV Gulfcoast Ltd., 45 Bristol Road, Suite 101, Easton, MA 02375.

The project consists of: a nominal 170 MW General Electric 7FA combustion turbine-electrical generator; an unfired heat recovery steam generator capable of raising sufficient steam to generate another (maximum) 74.9 MW from a steam-electrical generator; a 150-foot stack; a mechanical draft cooling tower; a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year.

NOx emissions will be controlled by selective catalytic reduction (SCR) to achieve 3.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 10 ppmvd while burning low sulfur distillate fuel oil. Emissions of CO will be controlled to 9 and 20 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM 10, SO2, sulfuric acid mist, volatile organic compounds, hazardous air pollutants (HAP), and will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and low sulfur (0.05 percent) distillate fuel oil. Ammonia emissions generated due to NOx control will be limited to 5 ppmvd.

The following table summarizes the maximum emissions (in tons per year) of regulated air pollutants as a result of this project.

POLLUTANTS	MAXIMUM POTENTIAL EMISSIONS	PSD Significant Emission Rate
PM/PM 10	102	25/15
Sulfuric acid mist	12	7
SO 2	76	40
NO x	126	100
VOC	15	40
CO	222	100
HAP	8	NA

An air quality impact analysis was conducted. Maximum impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels for all applicable pollutants. Therefore no increment consumption analysis was required. Emissions from the facility will not cause or contribute to a violation of any state or federal ambient air quality standards. The project has no significant impact on the PSD Class I Chassahowitzka National Wilderness Area.

The Department will issue the FINAL permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Fl. 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

This project is not subject to Chapter 403, Sections 403.501-518, "Florida Electrical Power Plant Siting Act", because the steam (electrical) generating capacity is less than 75 MW.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice sections 120.60F(3) of the Florida statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F. S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28.106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information; (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) a concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m. Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection Bureau of Air Regulation
111 S. Magnolia Drive,Ste4
Tallahassee, FL 32301
Ph. (850)488-1344
Fax: (850) 922-6979

Dept. of Environmental Protection Southwest District Office
3804 Coconut Drive
Tampa, FL. 33619-8218
Ph. (813) 744-6100

Manatee County Environment Management Department
202 Sixth Ave. E.
Bradenton, FL 34208
Ph. (941) 742-5980
Fax; 941-742-5996

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolio Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The Department's technical evaluations and Draft Permit can be viewed at www.dep.state.fl.us/air/permitting.htm by clicking on Utility and Other Facility Permits.

11/25/00

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 27, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gary Lambert, Executive Vice President
CPV Gulfcoast, Ltd
45 Bristol Road, Suite 101
Easton, MA 023750

Re: DEP File No. 0810194-001-AC (PSD-FL-300)
CPV Gulfcoast Power Generating Facility
245 Megawatt Combined Cycle Power Project

Dear Mr. Lambert:

Enclosed is a replacement page 17 for the draft permit we sent you on November 17, 2000. Please replace the original version.

We acknowledge the verbal request by CPV Gulfcoast for a public meeting and will schedule one for the second week of January 2001.

If you have any questions, please call me at 850/921-9523.

Sincerely,

A. A. Linero, P.E. Administrator,
New Source Review Section

AAL/al

Enclosure

Cc: Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Marion Forthoffer, Manatee County EMD
Scott Sumner, P.E., TRC
Cathy Sellers, Esq., Moyle Flanigan

7099 3400 0000 1453 3525

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

Article Sent To:
Mr. Gary Lambert, Exe. V.P.

Postage	$	CPV Gulfcoast
Certified Fee		Postmark Here
Return Receipt Fee (Endorsement Required)		
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 Bristol Road, Suite 101
City, State, ZIP+4
Easton, MA 02375

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: ***COMPLETE THIS SECTION***

- 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.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Gary Lambert, Exe. V.P.
CPV Gulfcoast, Ltd
45 Bristol Road, Suite 101
Easton, MA 02375

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 11-30

C. Signature
X
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1453 3525

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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.

51. Continuous Compliance with the 74.9 MW Steam Power Generated Limitation:

Electrical power from the steam-electrical generator shall be limited to 74.9 MW on an hourly basis. CPV shall be capable of demonstrating to the Department, continuous compliance with the 74.9 MW limit by the stored information in the power plant's electronic data system.

Attached are the comments from the U.S. Fish and Wildlife Service. We will send you the comments from EPA Region IV as soon as they are received.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Permit applicants are advised that Rule 62-4.055(1), F.A.C. now requires applicants to respond to requests for information within 90 days. If there are any questions, please call me at 850/921-9519. Matters regarding modeling issues should be directed to Chris Carlson (meteorologist) at 850/921-9537 and e-mail chris.carlson@dep.state.fl.us. Matters regarding the technical information may be directed to Teresa Heron at 850/921-9529 and e-mail teresa.heron@dep.state.fl.us

Sincerely,

A A Linero 10/9

A. A. Linero, P.E. Administrator
New Source Review Section

AAL/th

cc: Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, SWD
Marion Forthoffer, Manatee County
Scott Sumner, P.E.

7099 3400 0000 1453 2337

U.S. Postal Service

CERTIFIED MAIL RECEIPT

(Domestic Mail Only; No Insurance Coverage Provided)

Article Sent To:

Gary Lambert

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

10/9/00
Gulfcoast-
Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Mr. Gary Lambert
Street, Apt. No.; or PO Box No.
45 Bristol Rd., Ste. 101
City, State, ZIP+4
Easton MA 02375

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- 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.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Gary Lambert
Executive Vice President
CPV Gulfcoast, Ltd
45 Bristol Rd, Ste 101
Easton, MA 02375

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 11-12

C. Signature

X Darcy J Campbell

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*

7099 3400 0000 1453 2337

PS Form 3811, July 1999 — Domestic Return Receipt — 102595-99-M-1789

The Law Offices of
MOYLE
FLANIGAN
KATZ
RAYMOND
&SHEEHAN
P.A.

THE PERKINS HOUSE
118 NORTH GADSDEN STREET
TALLAHASSEE, FLORIDA 32301

TELEPHONE (850) 681-3828
FACSIMILE (850) 681-8788

West Palm Beach Office
Telephone (561) 659-7500
Facsimile (561) 659-1789

VIA HAND DELIVERY

October 5, 2000

Ms. Teresa Heron
Engineer
Bureau of Air Quality Management
Department of Environmental Protection
Tallahassee, FL 32399

Re: Revised Site Maps for CPV Gulfcoast Power Generating Facility, Application for Air Permit, Document ID: CPV-GC.

Dear Ms. Heron:

Please find attached two copies each of two drawings, Figure 2-1, which is the Site Location Map, and Figure 4-1, the 3-Kilometer Radius Map, both drawings of which have been revised to accurately reflect the proposed electric power generating facility's site location. These drawings replace those previously submitted as part of the application that was filed with the Department on September 11, 2000.

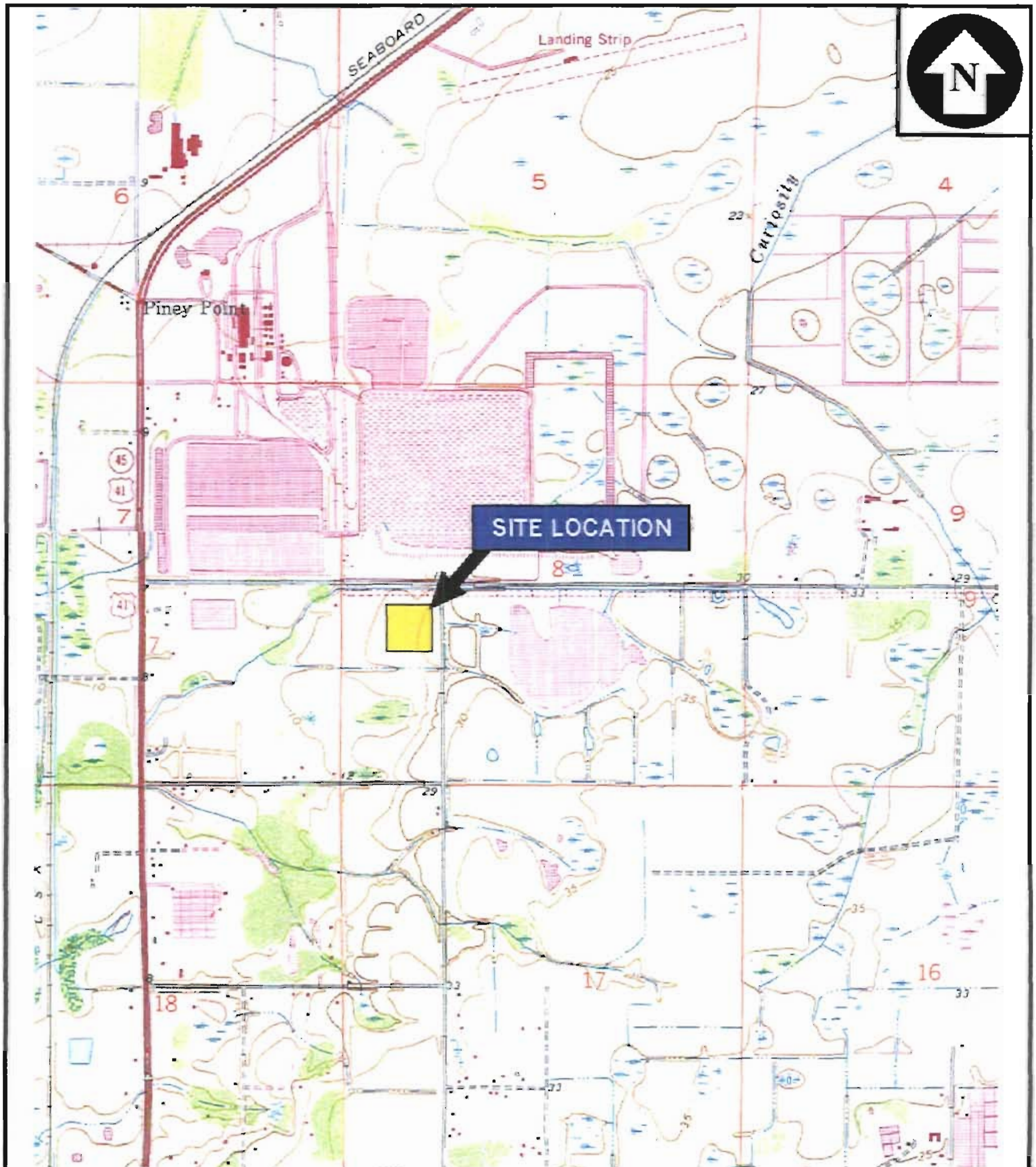
Thank you for your attention to this matter, and please call me if you have any questions.

Sincerely,

Cathy M. Sellers

Cathy M. Sellers
Attorney for CPV Gulfcoast, Ltd.

cc: Sean Finnerty
Laurence Labrie



BASE MAP IS A PORTION OF THE FOLLOWING 7.5' USGS TOPOGRAPHIC QUADRANGLES: RUSKIN, FLA, 1956, PHOTOREVISED 1987; PARRISH, FLA, 1973, PHOTOREVISED 1987; PALMETTO, FLA, 1964, PHOTOREVISED 1987; COCKROACH BAY, FLA, 1956, PHOTREVISED 1981

0 2000 4000

scale in feet

QUADRANGLE LOCATION

L00-250/topo

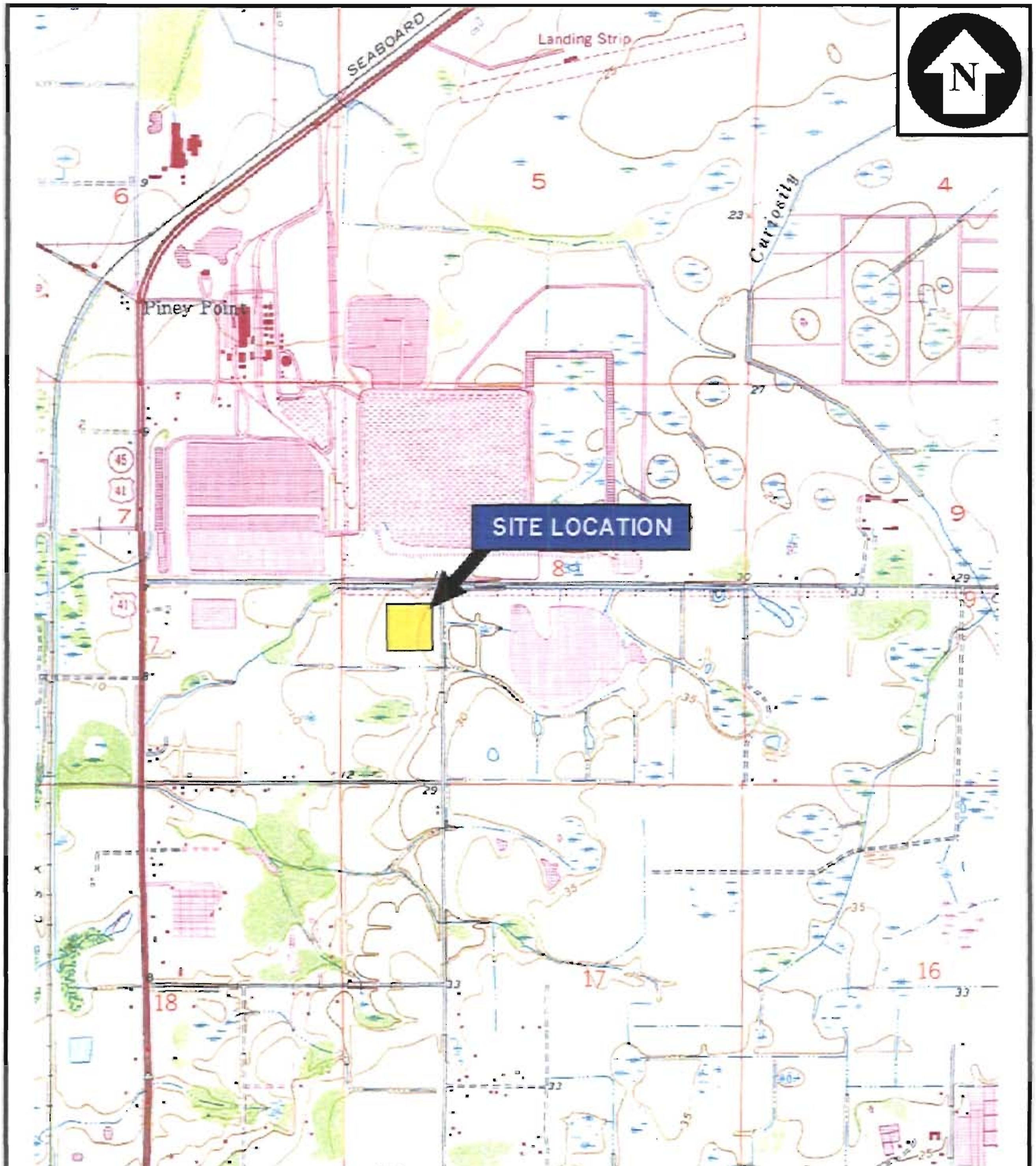
TRC

Boott Mills South
Foot of John Street
Lowell, MA 01852
978-970-5600

SITE LOCATION MAP

COMPETITIVE POWER VENTURES
GULF COAST PROJECT
PINEY POINT, FLORIDA

FIGURE 2-1	PROJ. NO. 28365



BASE MAP IS A PORTION OF THE FOLLOWING 7.5' USGS TOPOGRAPHIC QUADRANGLES: RUSKIN, FLA, 1956, PHOTOREVISED 1987; PARRISH, FLA, 1973, PHOTOREVISED 1987; PALMETTO, FLA, 1964, PHOTOREVISED 1987; COCKROACH BAY, FLA, 1956, PHOTREVISED 1981

0 2000 4000

scale in feet

QUADRANGLE LOCATION

L00-250/topo

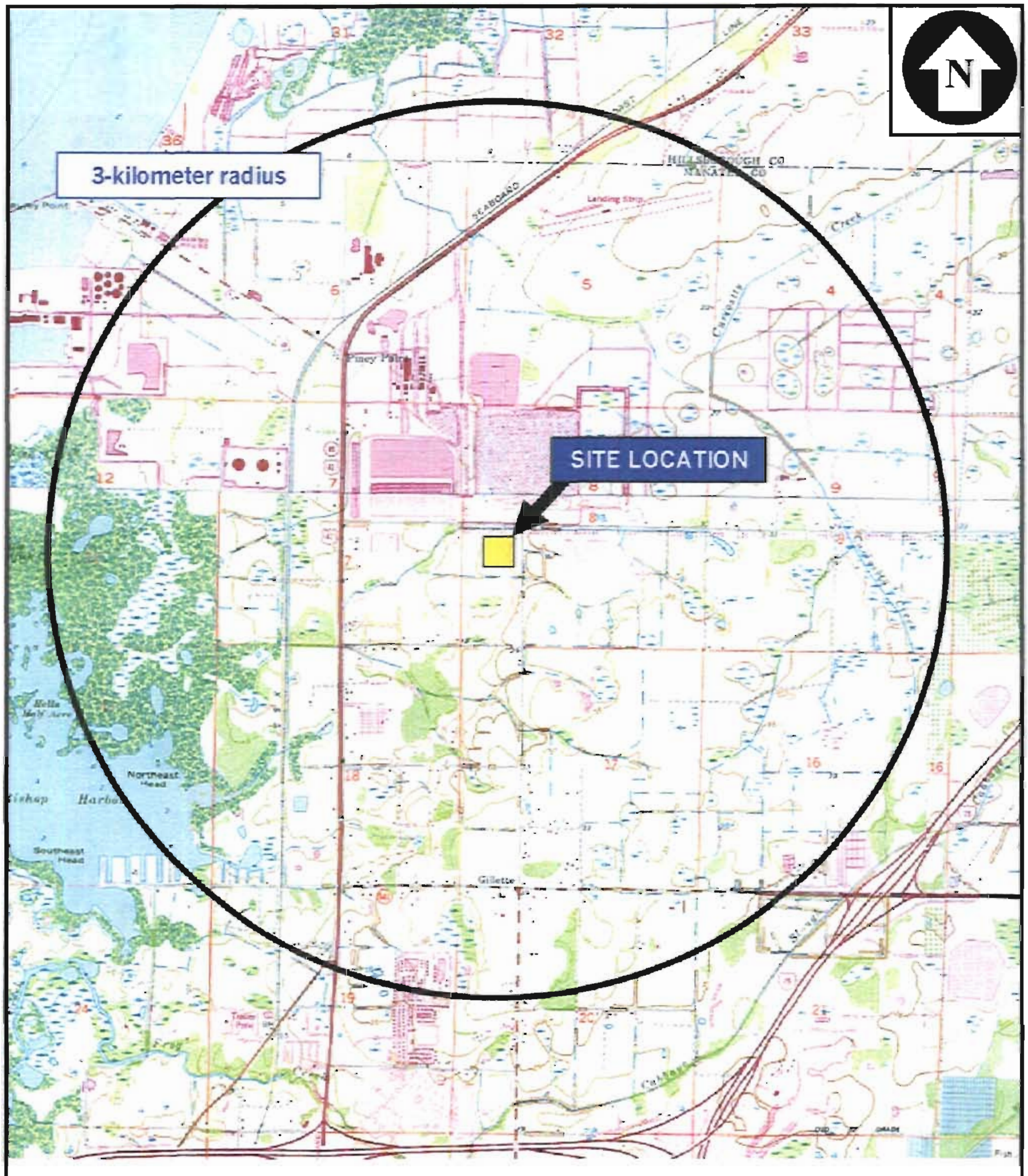
TRC

Boott Mills South
Foot of John Street
Lowell, MA 01852
978-970-5600

SITE LOCATION MAP

COMPETITIVE POWER VENTURES
GULF COAST PROJECT
PINEY POINT, FLORIDA

FIGURE 2-1	PROJ. NO. 28366



BASE MAP IS A PORTION OF THE FOLLOWING 7.5' USGS TOPOGRAPHIC QUADRANGLES: RUSKIN, FLA, 1956, PHOTOREVISED 1987; PARRISH, FLA, 1973, PHOTOREVISED 1987; PALMETTO, FLA, 1964, PHOTOREVISED 1987; COCKROACH BAY, FLA, 1956, PHOTREVISED 1981

0 1 2

scale in kilometers

L00-250/3 kilo

QUADRANGLE LOCATION

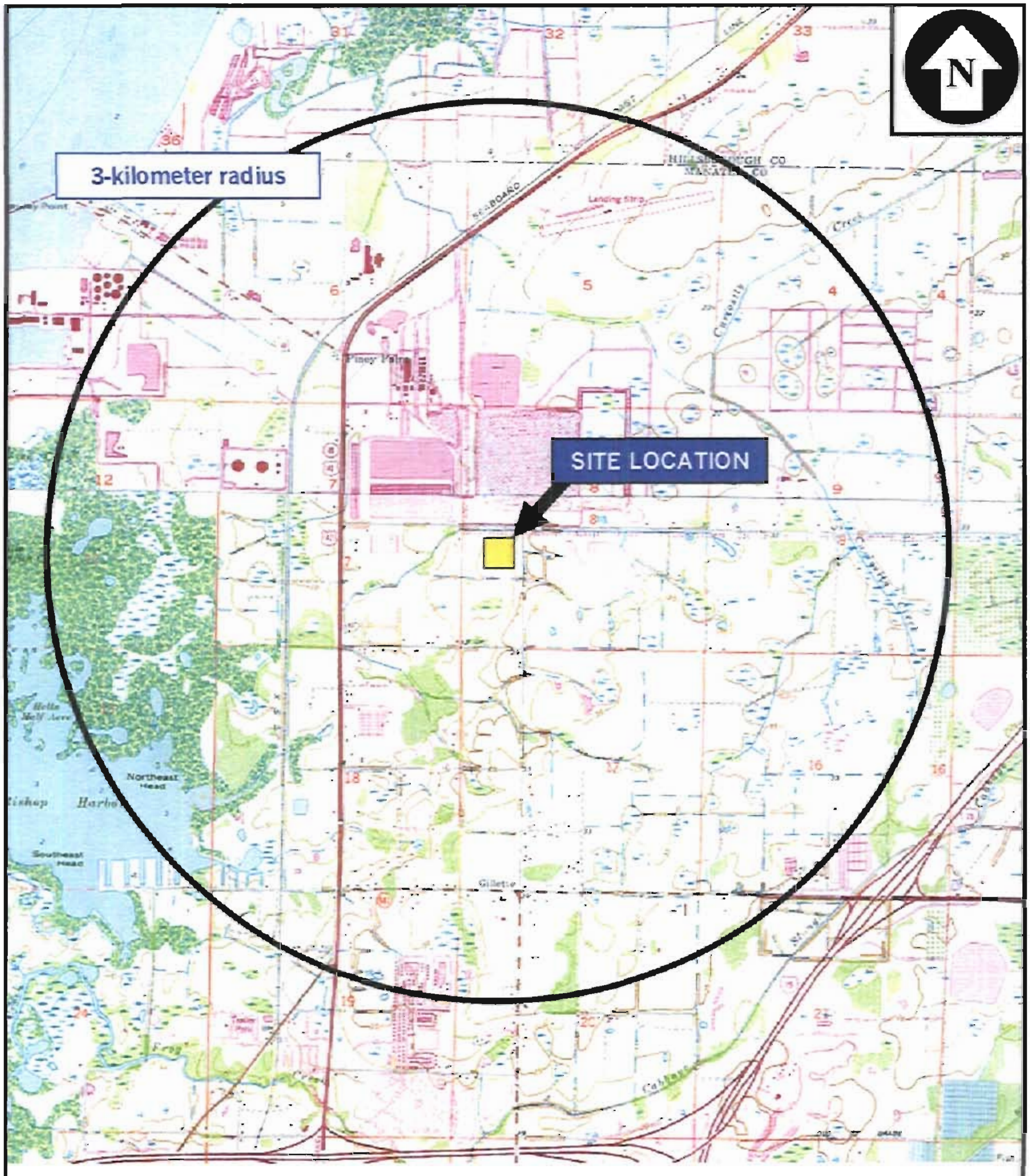
TRC

Boott Mills South
Foot of John Street
Lowell, MA 01852
978-970-5600

3-KILOMETER RADIUS MAP

COMPETITIVE POWER VENTURES
GULF COAST PROJECT
PINEY POINT, FLORIDA

FIGURE 4-1 | PROJ. NO. 28366



BASE MAP IS A PORTION OF THE FOLLOWING 7.5' USGS TOPOGRAPHIC QUADRANGLES: RUSKIN, FLA, 1956, PHOTOREVISED 1987;
PARRISH, FLA, 1973, PHOTOREVISED 1987;
PALMETTO, FLA, 1964, PHOTOREVISED 1987;
COCKROACH BAY, FLA, 1956, PHOTREVISED 1981

0 1 2

scale in kilometers

L00-250/3 kilo

TRC
Boott Mills South
Foot of John Street
Lowell, MA 01852
978-970-5600

3-KILOMETER RADIUS MAP

COMPETITIVE POWER VENTURES
GULF COAST PROJECT
PINEY POINT, FLORIDA

FIGURE 4-1 | PROJ. NO. 28365

U.S.FISH&WILDLIFE SERVICE
AIR QUALITY BRANCH
P.O. BOX 25287, Denver, CO 80225-0287

Date: September 27, 2000

Telephone: (303) 969-2617
Fax: (303) 969-2822

To: Al Linero
Patty Adams
Cleve Holladay

From: Ellen Porter

Subject: CPV Gulfcoast, Ltd. PSD-FL-300

We have reviewed the Prevention of Significant Deterioration Application for CPV Gulfcoast, Ltd. Proposed combined-cycle 250 MW power generation facility in Manatee County. The facility is located 110 km south of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. Emissions increases include 126 tons per year (tpy) of nitrogen oxides (NOx), 76 tpy of sulfur dioxide, and 102 tpy of PM-10.

CPV is proposing to use selective catalytic reduction to control NOx emissions to 3.5 ppm while burning gas and 10 ppm while burning oil. We agree that this represents best available control technology.

CPV evaluated potential impacts to Class I increments. Predicted impacts were below the significant impact levels for nitrogen dioxide, sulfur dioxide, and PM-10. CPV also evaluated its potential contribution to haze at Chassahowitzka. Their analysis, using IWAQM Phase 2, predicted a 2% change in light extinction. Because this is less than the 5% screening level recommended by FWS, CPV will not contribute significantly to haze at Chassahowitzka.

Thank you for giving us the opportunity to comment on this project.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 17, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gary Lambert, Executive Vice President
CPV Gulfcoast, Ltd
45 Bristol Road, Suite 101
Easton, MA 02375

Re: DEP File No. 0810194-001-AC (PSD-FL-300)
CPV Gulfcoast Power Generating Facility
245 Megawatt Combined Cycle Power Project

Dear Mr. Lambert:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the CPV Gulfcoast Power Generating Facility to be located near Piney Point in Manatee County. The Department's Intent to Issue Air Construction Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" are also included.

The "PUBLIC NOTICE" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Teresa Heron at 850/921-9529.

Sincerely,

A. A. Linero

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

CHF/th

Enclosures

7099 3400 0000 1452 9931

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

Article Sent To:

Mr. Gary Lambert

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

CPV Gulfcoast, :

Postmark
Here

Name (Please Print Clearly) (to be completed by mailer)
Mr. Gary Lambert
Street, Apt. No.; or PO Box No.
45 Bristol Road, Ste 101
City, State, ZIP+4
Easton, MA 02375

PS Form 3800, July 1999 See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- 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.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Gary Lambert
Executive Vice President
CPV Gulfcoast, Ltd
45 Bristol Road, Suite 101
Easton, MA 02375

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 1-6-2

C. Signature
X
☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1452 9931

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

In the Matter of an
Application for Permit by:

Mr. Gary Lambert, Executive Vice President
CPV Gulfcoast, Ltd.
45 Bristol Road, Suite 101
Easton, MA 02375

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

______________________________/

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of DRAFT Permit attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, CPV Gulfcoast, Ltd, applied on September 11, 2000 to the Department to construct nominal 245 megawatt (MW) combined cycle electrical power generating plant consisting of a nominal 170 MW combustion turbine-electrical generator, an unfired heat recovery steam generator capable of raising sufficient steam to generate another (maximum) 74.9 MW from a steam-electrical generator, a 150-foot stack, a mechancal draft cooling tower, a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. The project will be located at a new site near Piney Point in Manatee County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue Air Construction Permit. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11/17/00 to the person(s) listed:

Gary Lambert, CPV Gulfcoast, Ltd.*
Gregg Worley, EPA
John Bunyak, NPS
Bill Thomas, DEP SWD
Chair, Manatee County BCC
Marion Forthoffer, 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 11/17/00
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0810194-001-AC and PSD-FL-300

CPV Gulfcoast Power Generating Facility
245 Megawatt Combined Cycle Power Project

Manatee County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to CPV Gulfcoast Ltd. The permit is to construct nominal 245 megawatt (MW) combined cycle electrical power generating plant near Piney Point in Manatee County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration of Air Quality (PSD), for emissions of particulate matter (PM/PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist, and nitrogen oxides (NO_X). A maximum achievable control technology (MACT) determination for hazardous air pollutants was not required. The applicant's name and address are CPV Gulfcoast Ltd., 45 Bristol Road, Suite 101, Easton, MA 02375.

The project consists of: a nominal 170 MW General Electric 7FA combustion turbine-electrical generator; an unfired heat recovery steam generator capable of raising sufficient steam to generate another (maximum) 74.9 MW from a steam-electrical generator; a 150-foot stack; a mechanical draft cooling tower; a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year.

NO_x emissions will be controlled by selective catalytic reduction (SCR) to achieve 3.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 10 ppmvd while burning low sulfur distillate fuel oil. Emissions of CO will be controlled to 9 and 20 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM_{10}, SO_2, sulfuric acid mist, volatile organic compounds, hazardous air pollutants (HAP), and will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and low sulfur (0.05 percent) distillate fuel oil. Ammonia emissions generated due to NO_X control will be limited to 5 ppmvd.

The following table summarizes the maximum emissions (in tons per year) of regulated air pollutants as a result of this project.

Pollutants	Maximum Potential Emissions	PSD Significant Emission Rate
PM/PM_{10}	102	25/15
Sulfuric acid mist	12	7
SO_2	76	40
NO_x	126	100
VOC	15	40
CO	222	100
HAP	8	NA

An air quality impact analysis was conducted. Maximum impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels for all applicable pollutants. Therefore no increment consumption analysis was required. Emissions from the facility will not cause or contribute to a violation of any state or federal ambient air quality standards. The project has no significant impact on the PSD Class I Chassahowitzka National Wilderness Area.

The Department will issue the FINAL permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

This project is not subject to Chapter 403, Sections 403.501-518, "Florida Electrical Power Plant Siting Act," because the steam (electrical) generating capacity is less than 75 MW.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station # 35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301 .

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: (850)488-1344
Fax: (850)922-6979

Dept. of Environmental Protection
Southwest District Office
3804 Coconut Drive
Tampa, Florida 33619-8218
Telephone: (813)744-6100
Fax: (813)744-6084

Manatee County Environmental
Management Department
202 Sixth Avenue, East
Bradenton, Florida 34208
Telephone: 941/742-5980
Fax: 941/742-5996

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The Department's technical evaluations and Draft Permit can be viewed at www.dep.state.fl.us/air/permitting.htm by clicking on Utility and Other Facility Permits.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

CPV Gulfcoast, Ltd.

245-Megawatt Combined Cycle Unit

Manatee County

Facility I.D. No. 0810194-001-AC
PSD-FL-300

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

November 17, 2000

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

CPV Gulfcoast, Ltd.
45 Bristol Road, Suite 101
Easton, MA 02375

Authorized Representative: Mr. Gary Lambert, Executive Vice President

1.2 Reviewing and Process Schedule

09-11-00: Date of Receipt of Application
10-09-00: Request for Additional Information (RAI)
11-06-00: Received CPV Response to Department RAI
11-17-00: Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figure 1. This new facility will be located on a 160-acre tract at the intersection of Buckeye and Bud Rhoden Roads, southeast of Piney Point in Manatee County. This site is approximately 120 kilometers south of the Chassahowitzka National Wilderness Area, a Class I PSD Area. The UTM coordinates are Zone 17; 348.5 km E; 3057.0 km N.

Figure 1 – Location of Piney Point   Figure 2 – Vicinity of Piney Point

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.3 Facility Category

This new facility will generate electric power from one nominal 245 MW combined cycle unit including an unfired heat recovery steam generator (HRSG). The combustion turbine will be fired primarily with natural gas as the primary fuel, with distillate fuel as backup.

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 TPY. The facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because present emissions are greater than 100 TPY for CO and NO_X, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

As a Major Facility, project emissions greater than: Significant Emission Rates given in Table 212.400-2 (100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC, 25/15 TPY of PM/PM_{10}) require review per the PSD rules and a determination of Best Available Control Technology (BACT). This facility is also subject to the Title IV Acid Rain Program, 40 CFR 72 and must apply for an Acid Rain Permit at least 24 months prior to start up.

3. PROJECT DESCRIPTION

This permit addresses the following emissions 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	Cooling tower
003	Fuel Storage	One 1-million gallon fuel oil storage tank

Competitive Power Ventures (CPV), Gulfcoast Ltd proposes to construct a nominal 245-megawatt (MW) combined cycle combustion turbine at their new site located near Piney Point in Manatee County. The project includes: a nominal 170-MW General Electric 7FA combustion turbine-electrical generator, an un-fired heat recovery steam generator (HRSG) capable of generating sufficient steam to generate another 74.9 MW from a steam-electrical generator, a 150-foot stack, a mechanical draft cooling tower, a 1-million gallon fuel oil storage tank, and other ancillary equipment.

The main fuel will be natural gas and the unit will operate up to 8760 hours per year, of which no more than 720 represent fuel oil operation (30 days). The turbine will have a nominal heat input rating of 1,700 million Btu per hour (mmBtu/hr), lower heating value (LHV), while firing natural gas and 1918 mmBtu/hr, LHV, while firing fuel oil at 25 °F while operating at 100% load.

The turbine will be equipped with Dry Low NO_X (DLN-2.6) combustors and Selective Catalytic Reduction (SCR) to control NO_X emissions to 3.5 parts per million by volume, dry, at 15% O_2 (ppmvd) while burning natural gas and 10 ppmvd while burning fuel oil.

Emission increases will occur for CO, SO_2, sulfuric acid mist (SAM), PM/PM_{10}, VOC, and NO_X.

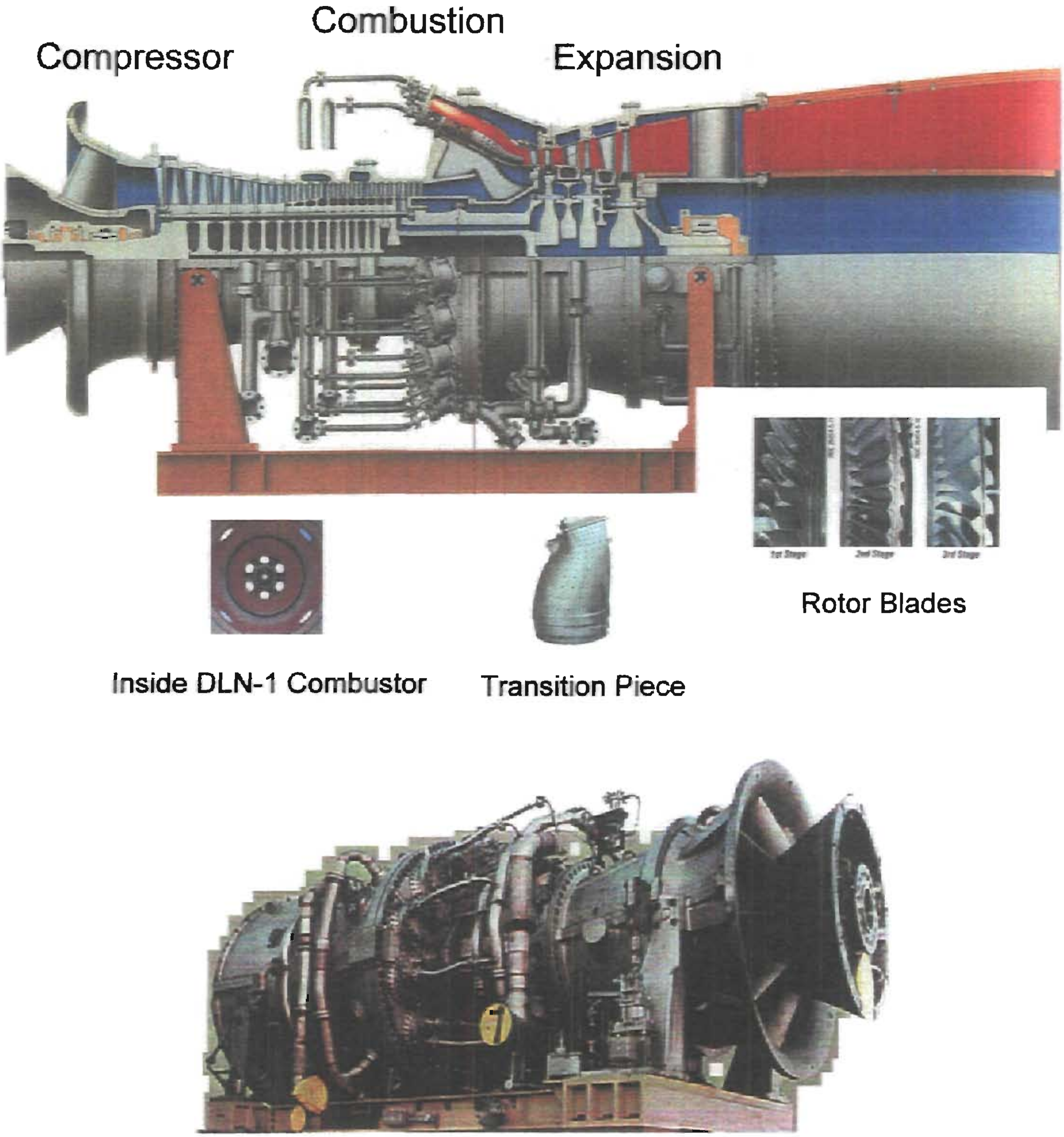


Figure 3 - Internal and External Views of Early GE 7FA

4. PROCESS DESCRIPTION

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines. Project specific information is interspersed where appropriate.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA (Figure 3) where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors. Figure 4 is photograph from the GE website of a "7FA on the half-shell" as viewed from the compressor section.

Figure 4 – Internal View of GE 7FA. **(GE Website)**

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower <u>flame</u> temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

There are three basic operating cycles for gas turbines. These are simple, regenerative and combined cycles. In the CPV project, the unit will operate primarily in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The steam is then fed to a separate steam turbine, which also drives an electrical generator.

Figure 5 is a process flow diagram for a combined cycle unit basically similar similar to the proposed CPV project. CPV will also include fuel oil back-up, SCR, and power augmentation.

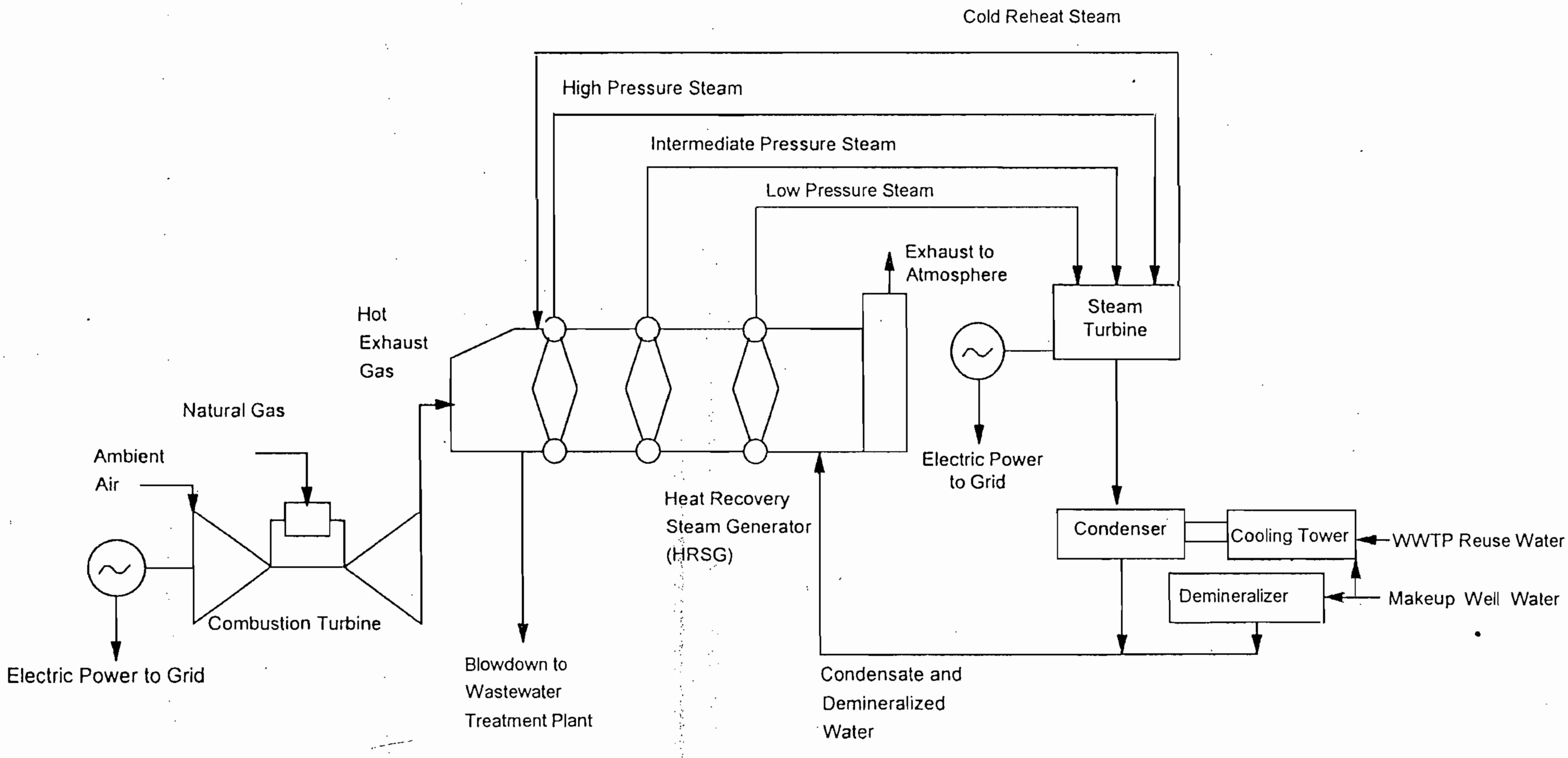


Figure 5 - Process Flow Diagram of a Basic Combined Cycle Power Plant

(gas-only, without SCR, and no power augmentation)

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet air density. To partially compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), a chilling unit or evaporative inlet fogger may be installed ahead of the combustion turbine inlet to increase air density. Neither of these features is planned for the CPV project.

Another possibility is to include a gas-fired duct burner between the combustion turbine and the HRSG. This would raise more steam, however additional steam is not needed because the unit will be easily capable of producing enough steam to drive the undersized steam-electrical turbine.

Other methods of increasing power include power augmentation and peaking. Power augmentation is accomplished by injecting some steam from the HRSG into the rotor (power) section of the combustion turbine. Peaking is simply running the unit at greater than design fuel input.

According to CPV, power augmentation will be employed in this project at temperatures above 59 °F "to make additional electrical output that is lost due to increasing temperature." Power augmentation also provides the opportunity to divert excess steam that cannot be used in the steam cycle (to avoid exceeding 74.9 MW electrical power production by steam-electrical generation). The diversion allows additional power production via the combustion turbine-electrical generator (Brayton Cycle).

The project includes highly automated controls, described as the GE Mark V Control System. The SPEEDTRONIC Mark V Gas Turbine Control System is designed to fulfill all of the gas turbine control requirements.

Additional process information related to the combustor design, and control measures to minimize NO_X formation are given in the draft BACT determination distributed with this evaluation.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 40 CFR 52.21, Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in Manatee County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the potential emission increases for PM/PM_{10}, CO, SO_2, SAM and NO_X exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM/PM_{10}, SO_2, SAM, CO, and NO_X. An analysis of the air quality impact from proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth. This project is exempt from review for Site Certification under the Power Plant Siting Act (Chapter 62-17 F.A.C) because the power (MW) generated from steam is less than the 75 MW threshold..

The emission units affected by this PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.260	Prevention of Significant Deterioration Increments
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-212.400	Prevention of Significant Deterioration
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 60	NSPS Subparts GG and Kb
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, sulfuric acid mist, carbon monoxide, and negligible quantities of, mercury and lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units are summarized in the Draft BACT document and Specific Conditions Nos. 16 through 21 of Draft Permit PSD-FL-300.

6.2 Emission Summary

The emissions for all PSD pollutants as a result of the construction of this facility are presented below:

FACILITY EMISSIONS (TOTAL TPY) AND PSD APPLICABILITY

Pollutants	Gas Firing[1]	Oil Firing[3]	Total[1]	PSD Significance	PSD REVIEW?
PM/PM_{10}	88	19	102[4]	25	Yes
SO_2	44	36	76	40	Yes
NO_X	106	29	126	40	Yes
CO	197	25	222	100	Yes
Ozone (VOC)	13	3	15	40	No
Sulfuric Acid Mist	8	4	12	7	Yes
Mercury	<<0.1	<<0.1	<0.1	0.1	No
Lead	<<0.6	<<0.6	<0.6	0.6	No
HAPs			8[5]	NA	NA

1. Based on 8760 hours of gas firing. Reference Temperature is 25 °F.
2. Based on 720 hours of fuel oil firing. Reference Temperature is 25 °F
3. Based on 8040 hours of gas firing and 720 hours of fuel oil firing. Reference Temperature is 25 °F.
4. Includes 3.5 TPY of PM/PM10 from the cooling tower.
5. Less than 10 TPY for any single HAP and less than 25 TPY for all HAPs. Case-by-case MACT does not apply.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of inherently clean fuels. During gas operation, the combustors will operate in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. The DLN-2.6 combustors will control combustion turbine emissions of CO and NO_X to 9 ppmvd @15% O_2 between 50 and 100% of full load under normal operating conditions and during gas burning. Further control for NO_X will be achieved by SCR to 3.5 (gas) and 10 (oil) ppmvd @15% O_2. Emissions of CO during oil burning are expected not to exceed 20 ppmvd. A full discussion is given in the Draft Best Available Control Technology (BACT) Determination (see Permit Appendix BD). The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2, and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. There are no applicable PSD increments or AAQS for SAM.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS impact and PSD increment analyses for these pollutants were not required. Also, the maximum predicted impacts for all of the pollutants listed above were below their respective *de minimis* ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality analyses required by the PSD regulations for this project were the following:

- A significant impact analysis for PM_{10}, CO, SO_2, and NO_X;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.4.2 <u>Models and Meteorological Data Used in the Air Quality Analysis</u>

PSD Class II Area

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Tampa, Florida (surface data) and Ruskin, Florida (upper air data). The 5-year period of meteorological data was from 1987 through 1991. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

PSD Class I Area

The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Chassahowitzka National Wilderness Area (CNWA). CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources. The CALPUFF model has the capability to treat time-varying sources. It is also suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanisms.

The meteorological data used in the CALPUFF requires the use of the California Meteorological (CALMET) model for preparation of meteorological data. However, the model can also be used in a screening mode known as CALPUFF Lite. The screening mode utilizes the same meteorological data that is input into the ISCST3 model. As a result, CALPUFF Lite often overestimates impacts and is adequate for use as a screening tool. For this project, the applicant utilized CALPUFF Lite screening mode and the same meteorological data set that was described in the preceding section.

6.4.3 Significant Impact Analysis

Typically, in order to conduct a significant impact analysis, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and Class II Areas. If this modeling at worst load conditions shows significant impacts, additional modeling that includes the emissions from surrounding facilities is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant does not have to conduct any further modeling.

The significant impact analysis submitted for this project contained two separate analyses; one for the surrounding Class II Area, and another for the CNWA, which is the nearest Class I Area. The following paragraphs explain the results of these two analyses:

PSD Class II Area

Receptors were placed around the proposed facility, which is located in a PSD Class II Area. A combination of fence line, near-field, mid-field, and far-field receptors were utilized for predicting maximum concentrations in the vicinity of the project. The fence line and near field receptors consisted of discrete Cartesian receptors spaced at 50 meter intervals near the facility property boundary. The mid field receptors consisted of discrete Cartesian receptors spaced at 330 meter intervals starting at the end of near field receptor network out to a distance of about 8.3 km from the facility. The remaining receptors consisted of a polar receptor grid with 7 logarithmically spaced rings and 10° spacing radials out to a distance 40 km from the facility. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility. The table below shows the results of the significant impact modeling for the Class II Area:

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.02	1	NO
	24-Hour	2.0	5	NO
	3-Hour	10.4	25	NO
PM_{10}	Annual	0.05	1	NO
	24-Hour	1.6	5	NO
CO	8-Hour	7.2	500	NO
	1-Hour	22.8	2000	NO
NO_2	Annual	0.04	1	NO

The results of the significant impact modeling show that there are no significant impacts predicted due to the emissions from this project; therefore, no further modeling was required in the surrounding Class II Area.

PSD Class I Area

The Chassahowitzka National Wilderness Area (CNWA) is the closest PSD Class I Area, and is located approximately 109 km north-northwest of the project. The maximum predicted impacts for all applicable pollutants due to the proposed project were compared to the Class I significant impact levels to determine whether there was a significant impact in the CNWA. The table below shows the results of the Class I significant impact modeling:

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (CNWA)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
SO_2	Annual	0.004	0.1	NO
	24-Hour	0.1	0.2	NO
	3-Hour	0.4	1.0	NO
PM_{10}	Annual	0.004	0.2	NO
	24-Hour	0.05	0.3	NO
NO_2	Annual	0.003	0.1	NO

The results of the significant impact modeling revealed that there were no significant impacts predicted due to the emissions from this project in the CNWA Class I Area. Therefore, no further modeling was not required for this project in the CNWA.

6.4.4 Additional Impacts Analysis

Impact On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS).

The project impacts are also less than the significant impact levels for PM_{10}, CO, NO_X, and SO_2, which in-turn, are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare, and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Effects from sulfuric acid mist are expected to be minor. Ammonia emissions will result as a result of NO_X control. The impacts of ammonia on soils, vegetation, and wildlife will be in the same range as the effects of NO_X on the same media.

Nearby fertilizer operations are is a larger source of SO_2 and sulfuric acid mist emissions and use large quantities of ammonia. The impacts from the CPV project on non-air media will be smaller by comparison.

Impact On Visibility

Natural gas is a clean fuel and produces little particulate emissions. The low NO_X and SO_2 emissions will also minimize plume opacity. Due to the large distance between this source and the nearest PSD Class I Area, plus the type and amount of emissions from the source, the U.S. Fish & Wildlife Service believes that there is a low potential for visibility impacts. Therefore, a regional haze analysis was not required for this project.

The effects on visibility due to additional particulate matter from ammonia use are very difficult to quantify. These will be minimized by limiting ammonia emissions (slip) to 5 ppmvd.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the combustion turbine will require few permanent employees, which will cause no significant impact on the local Area.

This project is a response to state-wide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint," and the lowest air emissions per unit of electric power generating capacity.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any maximum achievable control technology (MACT) requirements pursuant to Department rules or Section 112 of the Clean Air Act.

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations.

Teresa Heron, Engineer
A. A. Linero, P.E.
Chris Carlson, Meteorologist

PERMITTEE:

CPV Gulfcoast, Ltd.
45 Bristol Road, Suite 101
Easton, MA 02375

File No.	0810194-001-AC
Permit No.	PSD-FL-300
SIC No.	4911
Expires:	December 30, 2002

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

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 limited to less than 75 MW;
- 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 Project is not subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is less than 75 MW. [Chapter 403.503.(12), F.S., Definitions]

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

PERMIT SCHEDULE

- xx/xx/xx Air Construction Permit Issued
- xx/xx/xx Notice of Intent to Issue published in ______________
- 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 ______________
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

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. 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.).

10. 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.]

11. 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]

12. 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

13. 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.]

14. 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.]

15. 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.]

16. 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

17. 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]

18. 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.]

19. 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.]

20. 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.]

21. 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.]

22. 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

23. 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

24. 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.].

25. 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.

26. 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 for a maximum of 720 hours per year.
[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 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) 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) 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 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 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 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 at 90-100 percent of full load, 22 ppmvd at 75-89 percent of full load nor 29 ppmvd 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 ppmvw nor 3 lb/hr be demonstrated by initial stack test using EPA Method 25A with correction allowed by deducting methane 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 ppmvw nor 8 lb/hr be demonstrated by initial stack test using

EPA Method 25A with correction allowed by deducting methane 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 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 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 20 lb/hr while firing natural gas nor 53 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.
    - *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, 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 and back half catch) (I)
    - EPA Reference Method 7E, "Determination of Nitrogen Oxides Emissions from Stationary Sources" (A).
    - 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, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
    - EPA Method 26A (modified) for ammonia sample collection (I, A)
    - EPA Draft Method 206 for ion chromatographic analysis for ammonia. (I, Quarterly)
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

Competitive
Power
Ventures, L.P.

September 7, 2000

Cathy Sellers
Law Offices of Moyle, Flanigan et al.
The Perkins House
118 North Gadsden St.
Tallahassee, FL 32301

Dear Cathy:

Enclosed please find check #112 payable to the Florida Department of Environmental Protection, per Sean Finnerty's request.

Sincerely,

Julia M. Scott, CPA
Controller

4061 Powder Mill Road • Suite 700 • Calverton, Maryland 20705
(301) 273-2084 • Fax (301) 273-2082 • e-mail: cpventures@erols.com

Department of

Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: CPV Gulfcoast, Ltd.	
2. Site Name: CPV Gulfcoast	
3. Facility Identification Number: [X] Unknown	
4. Facility Location: Street Address or Other Locator: City: County: Manatee Zip Code:	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [ ] Yes [X] No

Application Contact

1. Name and Title of Application Contact: Sean Finnerty, Director of Development
2. Application Contact Mailing Address: Organization/Firm: CPV Gulfcoast, Ltd. Street Address: 45 Bristol Road, Suite 101 City: Easton State: MA Zip Code: 02375
3. Application Contact Telephone Numbers: Telephone: (508) 238 - 0194 Fax: (508) 238 - 2844

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

2.0 PROJECT DESCRIPTION

CPV Gulfcoast, Ltd. proposes to construct a generation facility in Manatee County using state-of-the-art combined-cycle power generation technology and air pollution control systems. The major components of the Project include a new combustion turbine generator, a heat recovery steam generator (HRSG), and state-of-the-art air pollution controls. Natural gas will be used as the primary source of fuel. To enhance overall reliability, the system will also be capable of burning very low sulfur content distillate as backup fuel for up to an equivalent of 30 days at full load each year.

2.1 Site Description

The CPV Gulfcoast power generation facility will be located in Manatee County, Florida. CPV Gulfcoast, Ltd. identified a tract of land approximately 120 acres in size located near Piney Point for the development of a power plant facility. The project is bounded on the west side undeveloped land, by Buckeye Road to the north, Bud Rhoden Road to the east, and Chapman Road to the south. Figure 2-1 shows the site location.

2.2 Equipment Description

To maximize efficiency and energy conservation, the Project facilities will include both gas and steam cycles. In the gas cycle, the new combustion turbine will fire natural gas as its primary fuel to produce approximately 170 megawatts (MW). The steam cycle will consist of a new HRSG and steam turbine generator. This cycle provides exceptional efficiency by employing the HRSG to recover otherwise lost heat from the gas turbine exhaust and using it to create steam and drive the steam turbine generator to produce an additional 74.9 MW. The steam that exhausts the steam turbine generator is cooled and condensed for re-use in the steam cycle. The combined-cycle technology achieves an operational efficiency on a unit of energy output per unit of energy input basis greater than operational efficiency for older plants.

A description of each major Project component is provided below.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: Gary Lambert, Executive Vice President
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: CPV Gulfcoast, Ltd. Street Address: 45 Bristol Road, Suite 101 City: Easton State: MA Zip Code: 02375
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (508) 238 - 0194 Fax: (508) 238 - 2844
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* ____________________ ____________________ Signature Date

* Attach letter of authorization if not currently on file.

RECEIVED

SEP 11 2000

BUREAU OF AIR REGULATION

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: Gary Lambert, Executive Vice President
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: CPV Gulfcoast, Ltd. Street Address: 45 Bristol Road, Suite 101 City: Easton State: MA Zip Code: 02375
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (508) 238 - 0194 Fax: (508) 238 - 2844
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* [signature] SEPT 8, 2000 Signature Date

* Attach letter of authorization if not currently on file.

RECEIVED

SEP 11 2000

BUREAU OF AIR REGULATION

Professional Engineer Certification

1. Professional Engineer Name: SCOTT GREGORY SUMNER Registration Number: 44352	
2. Professional Engineer Mailing Address: Organization/Firm: TRC Street Address: 21 TECHNOLOGY DRIVE City: IRVINE State: CA Zip Code: 92618	
3. Professional Engineer Telephone Numbers: Telephone: (949) 727 - 9336	Fax: (949) 727 - 7399

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [ ], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

SCOTT G. S... No. 44... STATE OF ...

Signature — SEPTEMBER 11, 2000
Date

(seal)

* Attach any exception to certification statement.

RECEIVED

SEP 11 2000

BUREAU OF AIR REGULATION

4. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this Application for Air Permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [ ], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

SCOTT G. SU... No. 44352 STATE OF ... REGISTERED ENG...

Signature ______   SEPTEMBER 11, 2000
Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

<table>
<tr><td colspan="4">1. Facility UTM Coordinates:
Zone: 17   East (km): 348.5   North (km): 3057.0</td></tr>
<tr><td colspan="4">2. Facility Latitude/Longitude:
Latitude (DD/MM/SS):   Longitude (DD/MM/SS):</td></tr>
<tr><td>3. Governmental Facility Code:
0</td><td>4. Facility Status Code:
C</td><td>5. Facility Major Group SIC Code:
49</td><td>6. Facility SIC(s):
4911</td></tr>
<tr><td colspan="4">7. Facility Comment (limit to 500 characters):

CPV Gulfcoast, Ltd. will install a single, efficient gas turbine with heat recovery steam generator (HRSG). The gas turbine will provide approximately 170 MW of electrical power. The HRSG recovers otherwise lost heat from the gas turbine exhaust and provides steam energy to drive a steam turbine with an operationally controlled generating capacity of 74.9 MW.

The new power generation equipment will be designed to meet federal Best Available Control Technology (BACT) standards, as appropriate for emissions control. The combustion turbine and HRSG will be built on a 10-acre portion of the Manatee County property. The new power generation facility includes a 150-foot stack. The steam turbine will be enclosed in its own building, approximately 100 feet in height.</td></tr>
</table>

Facility Contact

<table>
<tr><td>1. Name and Title of Facility Contact:
Sean Finnerty, Development Director</td></tr>
<tr><td>2. Facility Contact Mailing Address:
Organization/Firm: CPV Gulfcoast, Ltd.
Street Address: 45 Bristol Road, Suite 101
City: Easton   State: MA   Zip Code: 02375</td></tr>
<tr><td>3. Facility Contact Telephone Numbers:
Telephone: (508) 238 - 0194   Fax: (508) 238 - 2844</td></tr>
</table>

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
8. Facility Regulatory Classifications Comment (limit to 200 characters): Combustion turbine subject to 40 CFR Part 60 Subpart GG.	

List of Applicable Regulations

Not Applicable	

INTEROFFICE MEMORANDUM

Date: 11-Sep-2000 02:33pm
From: Joseph Kahn TAL
KAHN_J
Dept: Air Resources Management
Tel No: 850/921-9519

Subject: FWD: CPV Gulfcoast Application for Air Permit

Here is the e-mail submittal that includes the application, supporting information and modeling files, for the CPV Gulfcoast PSD permit application.
The e-mail addresses for forwarding to the appropriate parties are:
Manatee County Air Quality Division: marion.forthoffer@co.manatee.fl.us
National Park Service/Fish and Wildlife Service: John_Bunyak@nps.gov
EPA Region 4: worley.gregg@epa.gov
Thanks.

INTEROFFICE MEMORANDUM

Date: 11-Sep-2000 01:43am
From: Labrie, Laurence
LLabrie@TRCSOLUTIONS.com
Dept:
Tel No:

Subject: CPV Gulfcoast Application for Air Permit

As we discussed in our last meeting, the attached document contains the regulatory forms and technical information required to secure approval for a new electric power generation facility proposed by CPV Gulfcoast, Ltd. with a net electrical output of 250 megawatts.

Also attached is a ZIP file containing air quality modeling input and output files.

Cathy Sellers from Moyle Flanigan will be delivering the original forms signed by the applicant and Professional Engineer and a check for the application fee. If you have any questions, please contact me.

<<CPVGulfcoastAirApp.pdf>> <<CPVGulfcoastModelingFiles.zip>>

Larry Labrie
Certified Consulting Meteorologist
TRC Environmental Corporation
Boott Mills South, Foot of John Street
Lowell, MA 01852
Voice: (978) 656-3644
FAX: (978) 453-1995
e-mail: llabrie@trcsolutions.com

Name	Size	Modified	Comment
Class1Impacts.zip	233,637	9/11/2000 1:06 AM	
CTCoolingTowerPMImpacts.zip	56,428	9/11/2000 1:10 AM	
CTGasFiringImpacts.zip	61,476	9/11/2000 1:07 AM	
CTOilFiringImpacts.zip	59,607	9/11/2000 1:08 AM	

RFC-822-headers:
Delivery-receipt-to: LLabrie@TRCSOLUTIONS.com
Received: from epic50.dep.state.fl.us ([199.73.169.50])
by mail.epic1.dep.state.fl.us (PMDF V5.2-33 #37976)
with ESMTP id <01JU11UJEG3O000LN1@mail.epic1.dep.state.fl.us> for
KAHN_J@a1.epic1.dep.state.fl.us (ORCPT rfc822;joseph.kahn@dep.state.fl.us)
; Mon, 11 Sep 2000 01:24:57 EDT
Received: from trc-mail1.trcsolutions.com ([12.3.196.172])
by mail.epic50.dep.state.fl.us (PMDF V5.2-32 #31508)
with ESMTP id <01JU11SWJS66008MZM@mail.epic50.dep.state.fl.us> for
KAHN_J@a1.epic1.dep.state.fl.us (ORCPT rfc822;joseph.kahn@dep.state.fl.us)
; Mon, 11 Sep 2000 01:24:03 -0400 (EDT)
Received: by TRC-MAIL1 with Internet Mail Service (5.5.2650.21)
id <R7GMXB3D>; Mon, 11 Sep 2000 01:23:13 -0400
X-Mailer: Internet Mail Service (5.5.2650.21)

5.2.12.2.11 Gas Analyzers

The gas purity analyzer utilizes the principle of fixed geometry diffused flow thermal conductivity to measure the purity of a known component of a binary gas mixture. Digital acquisition at the sensor level by precision components, rather than the previous Wheatstone bridge arrangement, increases measurement accuracy. A novel aspect of the analyzer is its ability to operate in a redundant configuration; the two, identical, microcontroller based subsystems which comprise the analyzer are interconnected by a communications channel to enable the analyzer to confirm an alarm condition, (i.e. two out of two voting). This communications channel also allows the analyzer to negotiate and report possible malfunctions in the measurement system.

5.2.12.3 Fault Detection and Reporting

Each subsystem within the analyzer is self-supervising and continuously checks itself for acceptable processor functioning, internal voltages, analog to digital conversion accuracy, integrity of cabling and relay operation. Any faults are immediately annunciated at the cabinet and a contact signal indicating analyzer trouble is opened. A faults log, which maintains a date/time stamp of detected failures can be viewed at any time. The analyzer can also execute detailed self-diagnostics.

5.2.13 Hydrogen Control Manifold

Hydrogen is admitted to the generator casing through the use of the hydrogen gas manifold. The following instrumentation is provided and is located in the collector compartment:

- Generator gas pressure gage
- High and low generator gas pressure switches

5.2.14 Carbon Dioxide Control Manifold

A carbon dioxide system is used for purging the generator casing of air before admitting hydrogen, and also to purge hydrogen before admitting air. The following instrumentation is provided:

- Purging control valve assembly
- Relief valve

5.2.15 Detraining System

The air-side seal oil and the generator bearing oil drain to a bearing drain enlargement mounted under the generator casing. This bearing drain enlargement is a detraining chamber and provides a large surface area for detraining the oil before it is returned to the main oil tank.

Two seal drain enlargements are provided for removing entrained hydrogen from the oil which drains from the hydrogen-side seal rings. They are drained through a common line to a float trap which then drains to the bearing drain enlargement for further detraining. A high liquid level alarm switch is provided to detect abnormal oil level in the seal drain enlargement.

Piping is factory fitted and the system is well-proven to assure that no hydrogen can enter into the oil system.

5.2.16 Generator Collector Compartment

An exciter-end, enclosure is provided with the generator. It will contain the following assemblies:

- Hydrogen control panel
- Seal oil control unit, regulator and flowmeter
- Seal oil drain system, float trap and liquid level detector
- H2 and CO2 feed and purge system, valves and gauges
- Switch and gauge, block and porting system
- Collector housing and brush rigging assembly
- Collector filters and silencers
- Level-separated electrical junction boxes
- Turning gear

The above items are packaged in the enclosure. The completed enclosure is assembled to the generator at the customer site. The enclosure has been designed to simplify interconnecting wiring and piping between the enclosure and the generator.

The enclosure is designed with a removable end wall section and roof to allow ease of rotor removal without moving the housing. Position of all the above hardware is spaced to allow easy access for maintenance and to prevent any unnecessary disassembly during rotor removal. Two doors are provided on the end wall to allow access from either side. Safety latches are provided on the inside of the doors to provide easy exit from the enclosure. AC lighting is standard.

5.2.17 Generator Terminal Enclosure

The Generator Terminal Enclosure (GTE) is a reach–in weather–protected enclosure made of steel and/or aluminum and is located on the generator. The GTE is convection cooled through ventilation louvers to the outside of the enclosure. The louvers are designed to inhibit debris from entering into the compartment.

The GTE houses the following major electric components:

- Neutral current transformers (CTs)
- Line CTs
- Lightning arresters
- Neutral grounding transformer with secondary resistor
- Fixed voltage transformers (VT)
- 89SS LCI disconnect switch
- Motor operated neutral disconnect switch

5.2.17.1 Interface Points

The primary interface points to the GTE are:

- The line bus exits the GTE on the right side as viewed from the collector end of the generator
- The orientation of the line bus is right-center-left as viewed from the side of the GTE from which the bus exits

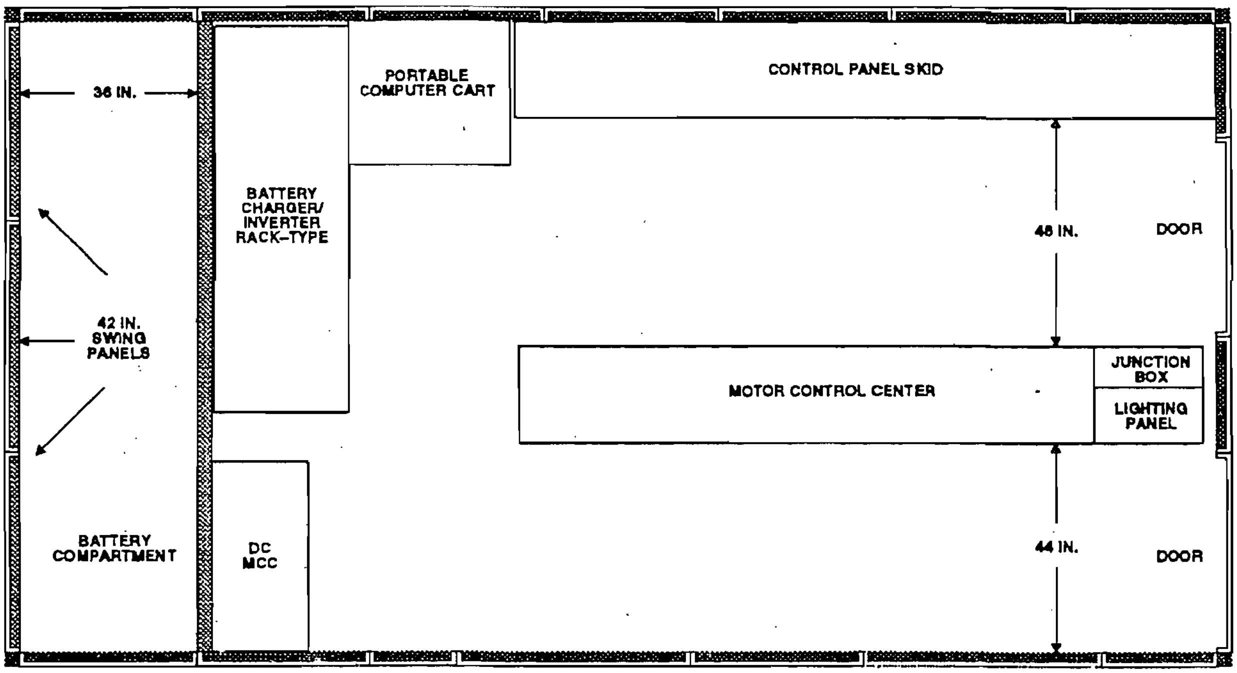
5.3 Gas Turbine-Generator Controls and Electric Auxiliaries

5.3.1 Packaged Electronic and Electrical Control Compartment (PEECC)

The PEECC is a completely enclosed compartment suitable for outdoor installation. Heating, air conditioning, compartment lighting, power outlets, temperature alarms, and smoke detectors are provided for convenience and protection of the equipment in the PEECC.

Electrical monitoring and control of the unit are accomplished by the turbine control panel and the generator control panel, which are mounted on a common skid and located in the PEECC. The customer control local interface HMI is also located in the PEECC. In addition to the control systems, the PEECC also houses the gas turbine motor control centers and batteries, rack and charger (s). The arrangement of the equipment is shown in the typical compartment layout below.

Packaged Electronic and Electrical Control Compartment (PEECC)
(Typical)



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5.3.2 SPEEDTRONIC™ Mark V Gas Turbine Control System

The gas turbine control system is a state–of–the–art Triple Modular Redundant (TMR) microprocessor control system. The core of this system is the three separate but identical controllers called <R>, <S>, and <T>. All critical control algorithms, protective functions, and sequencing are performed by these processors. In so doing, they also acquire the data needed to generate outputs to the turbine. Protective outputs are routed through the <P> protective module consisting of triple redundant processors <X>, <Y>, and <Z>, which also provide independent protection for certain critical functions such as overspeed.

The three control processors, <R>, <S>, and <T>, acquire data from triple–redundant sensors as well as from dual or single sensors. All critical sensors for

™ A trademark of the General Electric Company continuous controls, as well as protection, are triple–redundant. Other sensors are dual or single devices fanned out to all three control processors. The extremely high reliability achieved by TMR control systems is due in considerable measure to the use of triple sensors for all critical parameters.

5.3.2.1 Electronics

All of the microprocessor–based controls have a modular design for ease of maintenance. Each module or controller contains up to five cards, including a power supply. Multiple microprocessors reside in each controller which distribute the processing for maximum performance. Individual microprocessors are dedicated to specific I/O assignments, application software communications, etc., and the processing is performed in a real–time, multi–tasking operating system. Communication between the controller's five cards is accomplished with ribbon cables and gas–tight connectors. Communication between individual controllers is performed on high–speed Arcnet links.

5.3.2.2 Shared Voting

Software Implemented Fault Tolerance (SIFT) and hardware voting are utilized by the SPEEDTRONIC Mark V TMR control system. At the beginning of each computing time frame, each controller independently reads its sensors and exchanges these data with the data from the other two controllers. The median value of each analog input is calculated in each controller and then used as the resultant control parameter for that controller. Diagnostic algorithms monitor a predefined deadband for each analog input to each controller, and if one of the analog inputs deviates from this deadband, a diagnostic alarm is initiated to advise maintenance personnel.

Contact inputs are voted in a similar manner. Each contact input connects to a single terminal point and is parallel wired to three contact input cards. Each card optically isolates the 125 or 24 V dc input, and then a dedicated 80196 processor in each card time stamps the input to within 1 ms resolution. These signals are then transmitted to the <R>, <S>, and <T> controllers for voting and execution of the application software. This technique eliminates any single point failure in the software voting system. Redundant contact inputs for certain functions such as low lube oil pressure are connected to three separate terminal points and then individually voted. With this SIFT technique, multiple failures of contact or analog inputs can be accepted by the control system without causing an erroneous trip command from any of the three controllers as long as the failures are not from the same circuit.

Another form of voting is accomplished through hardware voting of analog outputs. Three coil servos on the valve actuators are separately driven from each controller, and the position feedback is provided by three LVDTs. The normal position of each valve is the average of the three commands from <R>, <S>, and <T>. The resultant averaging circuit has sufficient gain to override a gross failure of any controller, such as a controller output being driven to saturation. Diagnostics monitor the servo coil currents and the D/A converters in addition to the LVDTs.

5.3.2.3 PC Based Operator Interface

The operator interface, HMI, consists of a PC, color monitor, cursor positioning device, keyboard, and printer. The keyboard is primarily used for maintenance such as editing application software or alarm messages. While the keyboard is not necessary, it is convenient for accessing displays with dedicated function keys and adjusting setpoints by entering a numeric value rather than issuing a manual raise/lower command. Setpoint and logic commands require an initial selection which is followed by a confirming execute command.

5.3.2.4 Direct Sensor Interface

Input/output (I/O) is designed for direct interface to turbine and generator devices such as thermocouples, RTDs and vibration sensors, flame sensors, and proximity probes. Direct monitoring of these sensors eliminates the cost and potential reliability factors associated with interposing transducers and instrumentation. All of the resultant data are visible to the operator from the SPEEDTRONIC Mark V operator interface.

5.3.2.5 Built–in Diagnostics

The control system has extensive built–in diagnostics and includes "power–up", background and manually initiated diagnostic routines capable of identifying both control panel, sensor, and output device faults. These faults are identified down to the board level for the panel, and to the circuit level for the sensor or actuator component. On–line replacement of boards is made possible by the triply redundant design and is also available for those sensors where physical access and system isolation are feasible.

5.3.2.6 Generator Interface and Control

The primary point of control for the generator is through the operator interface. However, the control system is integrated with the digital static bus fed excitation system over an Arcnet local area network (LAN). The SPEEDTRONIC Mark V is used to control megawatt output and the digital excitation system is used to control megavar output. The generator control panel is used to provide primary protection for the generator. This protection is further augmented by protection features located in the digital excitation system and the SPEEDTRONIC Mark V.

5.3.2.7 Synchronizing Control and Monitoring

Automatic synchronization is performed by the <X>, <Y>, and <Z> cards in conjunction with the <R>, <S>, and <T> controllers. The controllers match speed and voltage and issue a command to close the breaker based on a predefined breaker closure time. Diagnostics monitor the actual breaker closure time and self–correct each command.

Another feature of the system is the ability to synchronize manually via the operator interface instead of using the traditional synchroscope on the generator protective panel. Operators can choose one additional mode of operation by selecting the monitor mode, which automatically matches speed and voltage, but waits for the operator to review all pertinent data on the CRT display before issuing a breaker close command.

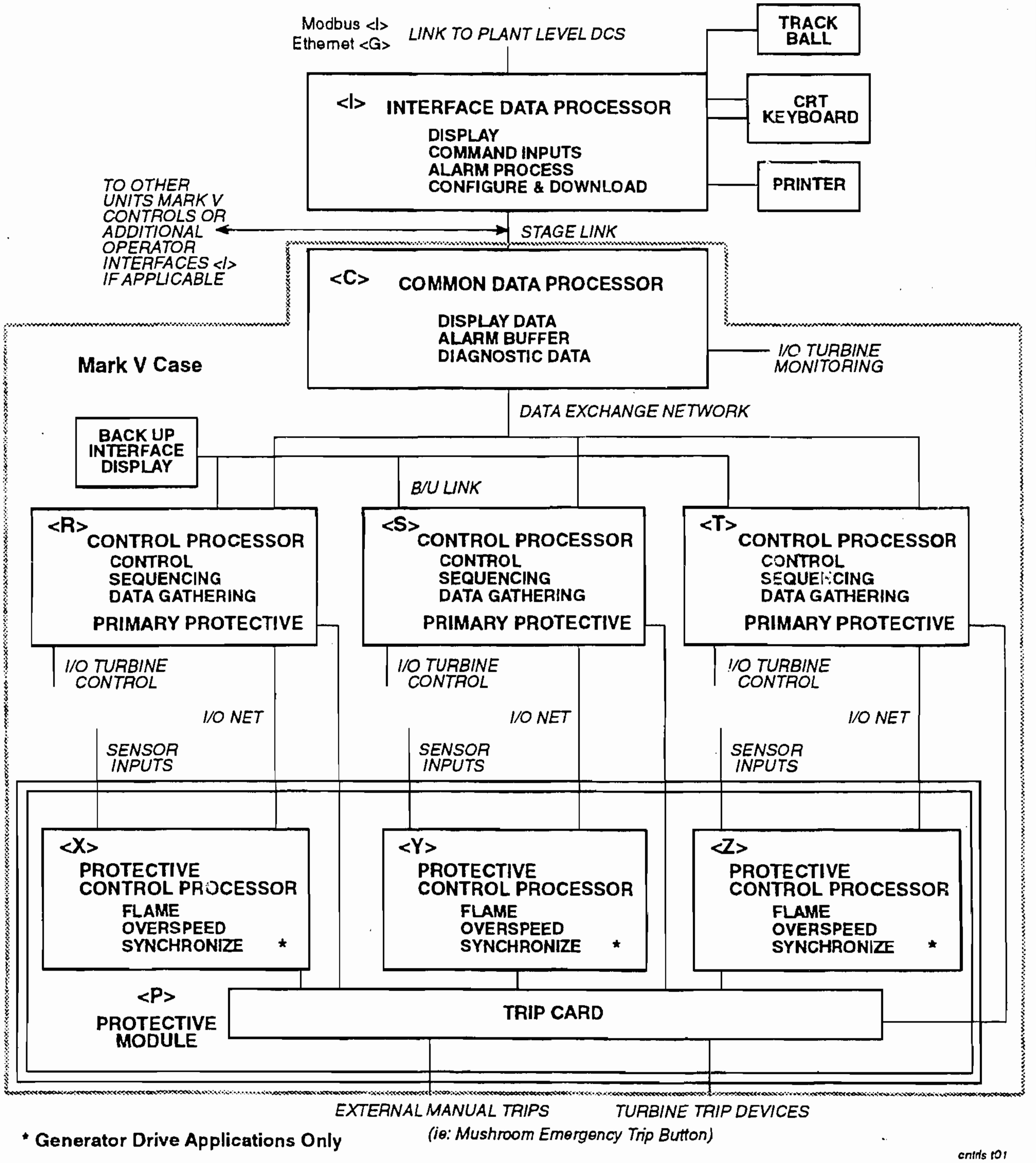
5.3.2.8 Architecture

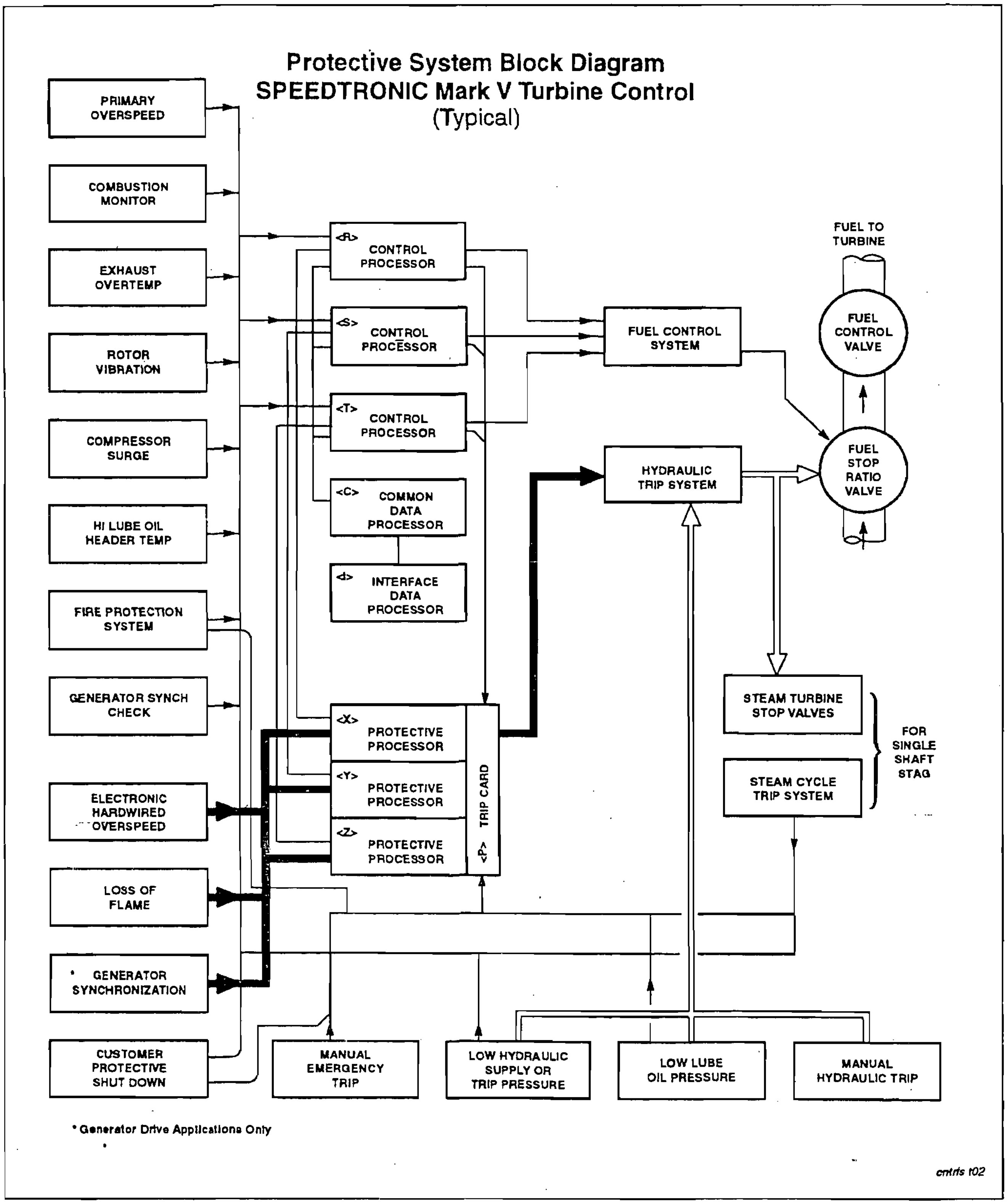
The SPEEDTRONIC Mark V control configuration diagram depicts several advantages for increased reliability and ease of interface. For example:

- Multiple unit control from a single HMI
- Back–up display wired directly to <R>, <S>, and <T> controllers
- Hard wire protective signal from <R> <S> <T> controllers
- Additional protective processors <X>, <Y>, <Z>

The protective block diagram shows the built-in redundancy/reliability of the SPEEDTRONIC Mark V control system. For example, if there is an overspeed condition requiring a trip of the unit, the first line of defense would be the primary overspeed protection via the <R>, <S>, and <T> controllers. All three trip signals then pass to the <P>protective module trip card where two out of three voting occurs prior to sending the automatic fuel supply trip signal. The secondary overspeed protection is via the <X>, <Y>, and <Z> protective control processor cards which similarly send their independent trip signals to the <P>protective module trip card for voting.

Standard SPEEDTRONIC Mark V Control Configuration
(Typical)




Protective System Block Diagram
SPEEDTRONIC Mark V Turbine Control
(Typical)
PRIMARY OVERSPEED
COMBUSTION MONITOR
EXHAUST OVERTEMP
ROTOR VIBRATION
COMPRESSOR SURGE
HI LUBE OIL HEADER TEMP
FIRE PROTECTION SYSTEM
GENERATOR SYNCH CHECK
ELECTRONIC HARDWIRED OVERSPEED
LOSS OF FLAME
* GENERATOR SYNCHRONIZATION
CUSTOMER PROTECTIVE SHUT DOWN
<R> CONTROL PROCESSOR
<S> CONTROL PROCESSOR
<T> CONTROL PROCESSOR
<C> COMMON DATA PROCESSOR
<I> INTERFACE DATA PROCESSOR
<X> PROTECTIVE PROCESSOR
<Y> PROTECTIVE PROCESSOR
<Z> PROTECTIVE PROCESSOR
<P> TRIP CARD
FUEL CONTROL SYSTEM
HYDRAULIC TRIP SYSTEM
FUEL TO TURBINE
FUEL CONTROL VALVE
FUEL STOP RATIO VALVE
STEAM TURBINE STOP VALVES
STEAM CYCLE TRIP SYSTEM
FOR SINGLE SHAFT STAG
MANUAL EMERGENCY TRIP
LOW HYDRAULIC SUPPLY OR TRIP PRESSURE
LOW LUBE OIL PRESSURE
MANUAL HYDRAULIC TRIP
* Generator Drive Applications Only
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5.3.2.9 Scope of Control

The SPEEDTRONIC Mark V control system provides complete monitoring control and protection for gas turbine–generator and auxiliary systems. The scope of control is broken down into three (3) sections: Control, Sequencing and Protection.

- Control
  - Start–up control
  - Speed/load setpoint and governor
  - Temperature Control
  - Guide vane control
  - Fuel control
  - Generator excitation setpoints
  - Synchronizing control (speed/voltage matching)
  - Emissions control
- Sequencing
  - GT auxiliary systems (MCC starters)
  - Start–up, running and shutdown
  - Purge and ignition
  - Fuel changeover
  - Alarm management
  - Synchronizing
  - Turning gear
  - Static start
  - H2 sequencing
  - Maintain starts, trips and hours counters
  - Event counters
    - Manually initiated starts
    - Fired starts
    - Fast load starts
    - Emergency trips
  - Time meters
  - Fired time
  - Time in premix

- Protection
  - Overspeed, redundant electronic
  - Overtemperature (including generator)
  - Vibration
  - Loss of flame
  - Combustion monitor
  - Redundant sensor CO2 fire protection
  - Low lube oil pressure, high lube oil temperature, etc.

5.3.2.10 Communications

5.3.2.10.1 Internal Communications

Internal communications consist of a high speed Arcnet link. The SPEEDTRONIC Mark V's internal Arcnet communication link is isolated from external communication links at the HMI processor.

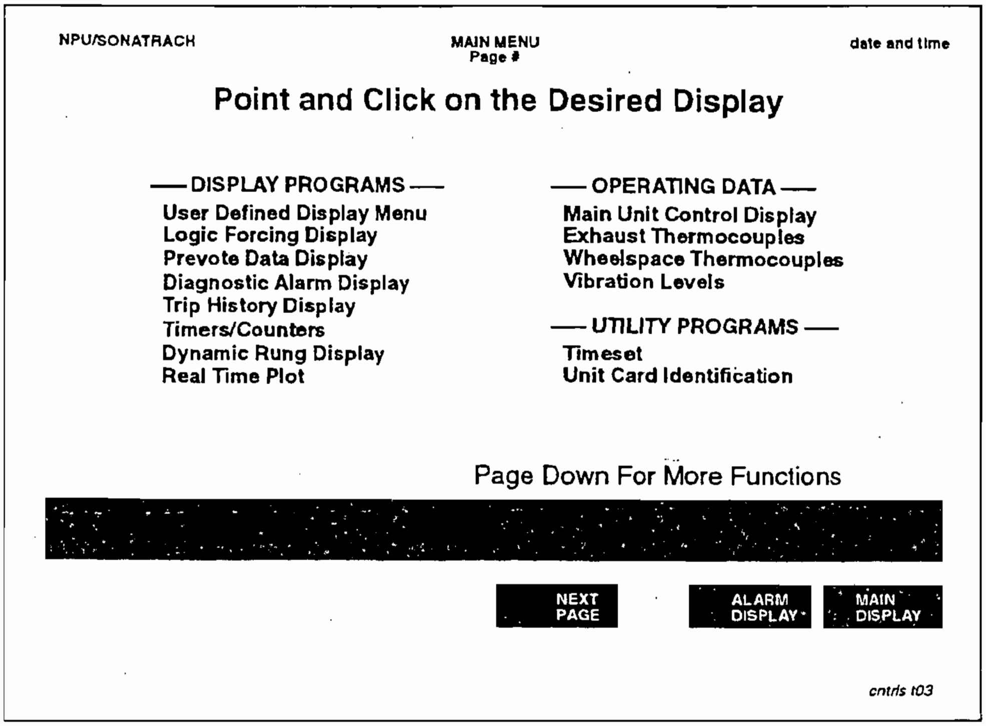
5.3.2.10.2 External Communications

The open architecture of the HMI processor facilitates a wide range of external communication links.

5.3.2.11 Operator Displays

Two (2) out of the typical forty (40) available displays are shown on the following pages. The first screen is the main menu display. From the main menu all operation/maintenance and user defined screens can be reached. The main menu screen is made up of three (3) major areas:

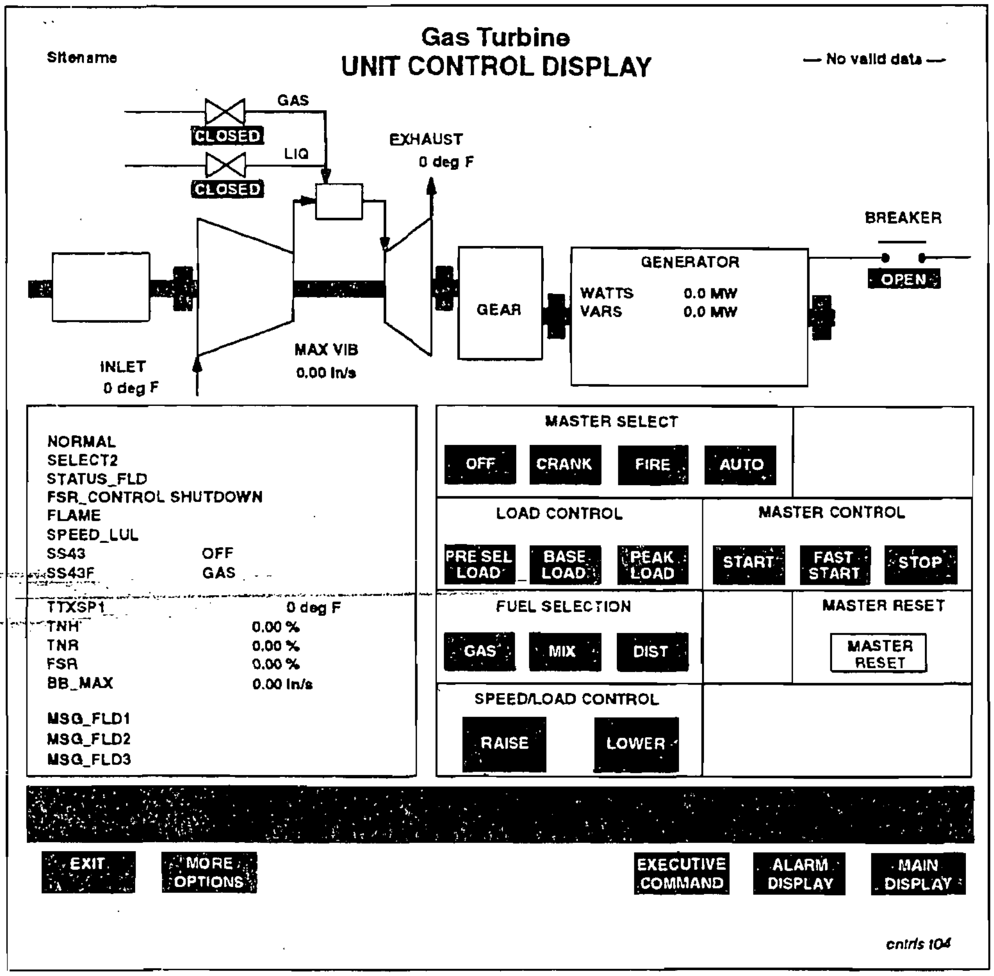
- List of available displays
- Alarm field shows the three (3) latest unacknowledged alarms (Black band near bottom of the screen)
- Function control keys (bottom of screen)



The second screen shown is a typical operating screen. Note that the alarm list and function control key fields are also shown below the primary display field on this screen. Control target values are shown in the primary display field. Selecting and executing commands is simple. For example, to go to baseload, you would move the cursor to the "Baseload" target and click on it. Then before the control times out, you would move the cursor to the "Execute Command" target and click on it. The "Execute Command" step protects against accidental activation of the wrong command that might occur with a one step (point/click) command. Signals that require an Execute command in order to be activated are:–

- Start
- Stop
- Operation Selection
  - Off
  - Crank
  - Fire
  - Auto
  - Remote

- Fuel Selection
- Load Selection
  - Preselected Load
  - Base
- Guide Vane Control
  - Temp Control Off
  - Temp Control On
- Governor Type Selection
  - Droop (nominal 4%)



5.3.2.12 Backup Interface

In the unusual event that the operator interface becomes unavailable, a small backup interface is provided on the SPEEDTRONIC Mark V cabinet door. It uses a liquid crystal display with two (2) lines of forty (40) characters per line to display key control parameters and alarms. The control panel accepts operator commands from this backup interface.

5.3.2.13 Printer

The standard operator interface printer has these convenient features:

- Alarm logging
- Event logging
- Historical trip display printing capability
- User defined display printing capability
- Periodic log display printing capability
- CRT screen copy

Each alarm and event is logged with a high resolution time tag. Contact inputs are logged to 1 millisecond. Separate alarm queues are maintained for turbine/generator system alarms and for SPEEDTRONIC Mark V internal self–diagnostic alarms. System alarms can be silenced, acknowledged and reset locally. Any intermittent alarms can be locked out with a permanent lockout message residing in the alarm queue.

If a trip occurs, the historical trip display automatically captures in memory all key control parameters and alarm messages at the time of the trip and at several time intervals preceding the trip. The operator can print the historical trip display when required. A start signal triggers the display to start collecting new data and all previous data is deleted from the current log. Display logs can be saved at any time to a memory buffer.

A user–defined display allows selection of any desired data for viewing or printing. The periodic log allows a user to define points to be collected and printed periodically to a printer. The period of each list is defined in minutes, from 1 to 10,080 (one week).

5.3.2.14 Human Machine Interface (HMI)

The Human Machine Interface is a single powerful, flexible and user friendly operator interface which brings together all of the displays and functions needed for real-time control and monitoring of turbomachinery processes, auxiliary equipment, driven devices and process alarms associated with power plant control.

The HMI system provides the infrastructure needed to meet the demanding requirements of delivering process information from a broader spectrum of controllers and compute platforms as well as accessing and delivering information to a customer's business enterprise system and balance of plant control system.

Designed with an open system concept, the system uses standard open hardware and operating system software. The HMI's software system uses the Windows NT client-server architecture from Microsoft which provides built-in multi-tasking, networking and security features. The ability to run the system on conventional PC based platforms minimizes cost, promotes open interfaces, permits system scalability, and ensures longevity of investment and future enhancement.

5.3.2.14.1 HMI Product Structure

GE Fanuc's CIMPLICITY HMI system serves as the basic core system, which is enhanced by the addition of power plant control hardware and software from GE Industrial Systems. The HMI configuration consists of several distinct elements:

- HMI Server - The server is the hub of the system and provides data support and system management. The HMI server also has the responsibility for device communication for both internal and external interchanges. The gas turbine control system can have redundant communications with two HMI servers.

5.3.2.14.2 HMI Product Features

- Graphics - The key functions of the HMI system are performed by its graphic system, which provides the operator with process visualization and control in a real-time environment. In the HMI system this important interface is accomplished using CimEdit, a graphics editing package, and CimView, a high performance runtime viewing package.
- Alarm Viewer - The alarm management functions of the HMI system are provided by Alarm Viewer. Alarm Viewer handles routing of alarms to the proper operator and alarm sorting and filtering by priority, plant unit, time, or source device.

- Trending - HMI trending, based on object linking and embedding technology, provides powerful data analysis capabilities. Trending capabilities include graphing collected data and making data comparisons between current and past variable data for quick identification of process problems.

- Point Control Panel - The HMI point panel provides a listing of points in the system with dynamically updating point values and alarm status. Operators have the ability to view and set local and remote points, enable and disable alarm generation, modify alarm limits, and filter and sort points selectively.

- Basic Control Engine - The basic control engine allows users to define control actions to take in response to system events. It monitors event occurrence and executes configured actions in response. The basic control engine is supported by an event editor for defining actions in response to system events and a program editor for programming more complex actions.

- User Roles and Privileges - CIMPLICITY allows configuration of system users to control access and privileges.

- DDE Application Interface - The DDE Interface allows other Windows applications that use Microsoft standard and Advanced DDE to obtain easy access to HMI point data. Users can integrate software that supports DDE to monitor, analyze, report or modify the HMI point data. In addition the HMI provides advances DDE client communication for data collection from third party devices.

5.3.2.14.3 Operator Functions

- Display Management - Display management provides overall display functions to meet the needs of the turbine plant. Displayed data is a combination of data received over Ethernet from GE third party servers and over the Stage Link from gas turbine controllers. Alarm display includes both connection to gas turbine alarm queues and external PLC systems.

- Hold List Display - The hold list is a set of conditions which must be met at certain times, speeds and operating modes in the turbine startup for systems which have Automatic Turbine Startup functions. The HMI provides for creation, modification, display, printing, down and uploading, compiling and reverse translation of a hold list of up to 64 points.

- Timer, Counter, Accumulator Display - This function shows the settings and totals in the turbine controllers.

- Screen Copy - Screen copy makes a copy of screen image and stores it in the Window clipboard for display, printing, directing to a file, or electronic transmission
- Trip History - Trip history data collected from each turbine controller can be plotted, printed as tabular data, or transmitted electronically for remote analysis.
- Process Alarm Management - The features of process alarm management help the operator to make a proper response to alarms and include the following:
  - Alarm queue display for each turbine unit controller
  - Main alarm display including all plant alarms
  - Alarm lockout for toggling alarm conditions
  - Alarm notepad function for adding explanatory notes to each active alarm drop number for each panel
  - Linking alarms to pre-selected display screens
  - Alarm help utilities for storing more detailed descriptions of alarms and their intended functions
  - Distinguishing display of control system diagnostic alarms from regular alarm or events

5.3.2.14.4 Hardware

- Intel based PC with 266 MHz Pentium II processor (or better)
- 64 MB RAM with 512 KB cache memory
- Hard drive 4.3GB or greater
- Floppy drive 1.44 MB
- Video card with 2 MB DRAM
- 17 inch monitor
- CD- 24x (or better), with multi-read capability
- 2 serial and 1 parallel port
- Windows NT operating system
- Keyboard and mouse
- Modems on HMI servers

5.3.2.14.5 Communications Interfaces

The HMI uses Stage Link as its mechanism for communication with GE turbine controllers and ancillary equipment. Stage Link allows the HMI to be located remotely and enables a single HMI to communicate with up to eight turbine controllers.

The HMI allows Modbus interfaces with other systems such as DCS.

5.3.3 Bently Nevada 3500 Monitoring System

The gas turbine and generator are equipped with orthogonal proximity probes at each bearing to detect radial motion of the shaft relative to the bearing. Axial position of the gas turbine rotor is sensed by two axial position proximity probes. Each probe is connected to a proximitor.

The Bently Nevada 3500 Monitor is a 19 in., sixteen position (fourteen available), panel mount rack containing four proximitor cards each of which can accept up to four channels. (The cards must be programmed for the application.) The system has one monitor card for each of the two turbine rotor axial position probe inputs, one monitor card for the radial X-Y probes from the two turbine bearings and one monitor card for the radial X-Y probes from the two generator bearings. The radial bearing monitor provides values for the overall amplitude, 1X amplitude, 1X phase, 2X amplitude and 2X phase.

Features of the system include:

- Alert and danger relay outputs – one pair for the axial position monitor and one pair which is shared by all the radial monitors
- A communication card for serial data interface to the GE on-site monitor
- AC power supply
- KeyPhasor card
- Rack configuration software for programming the rack functions including a serial interface cable for connecting the RIM card to the customer's computer. (A customer-supplied Microsoft Windows based computer is required.)
- A local display panel is provided at the 3500 rack

5.3.4 Performance Monitoring Package

In conjunction with a centralized control system, the performance monitoring package provides signals which are used to compare turbine airflow versus performance. These data can be used to determine the need for maintenance such as compressor water wash. The package is connected to a control compartment wall-mounted cabinet which contains transducers for 4-20 ma signals.

The following equipment is provided:

- Barometer
- Compressor inlet total pressure and static pressure probes
- Compressor discharge pressure probe
- Exhaust pressure probe
- Algorithms provided via the Mark V control panel
- Natural gas flow measurement
- Barometric pressure transmitter (96AP)
- Compressor bellmouth differential pressure transmitter (96BD)
- Compressor inlet air total pressure transmitter (96CS)
- Compressor discharge pressure transmitter (96CD)
- Exhaust pressure transmitter (96EP)
- Compressor temperature inlet flange (CT-IF-3/R)

5.3.5 Motor Control Center

The motor control center contains circuit protective devices and power distribution equipment to supply electrical power to all packaged power plant devices as defined on the electrical one line diagram. The motor control center is manufactured and tested in accordance with NEMA ICS–2 and UL Standard No. 845. Vertical sections and individual units will be UL (CSA) Labeled where possible. The motor control center is located in the PEECC.

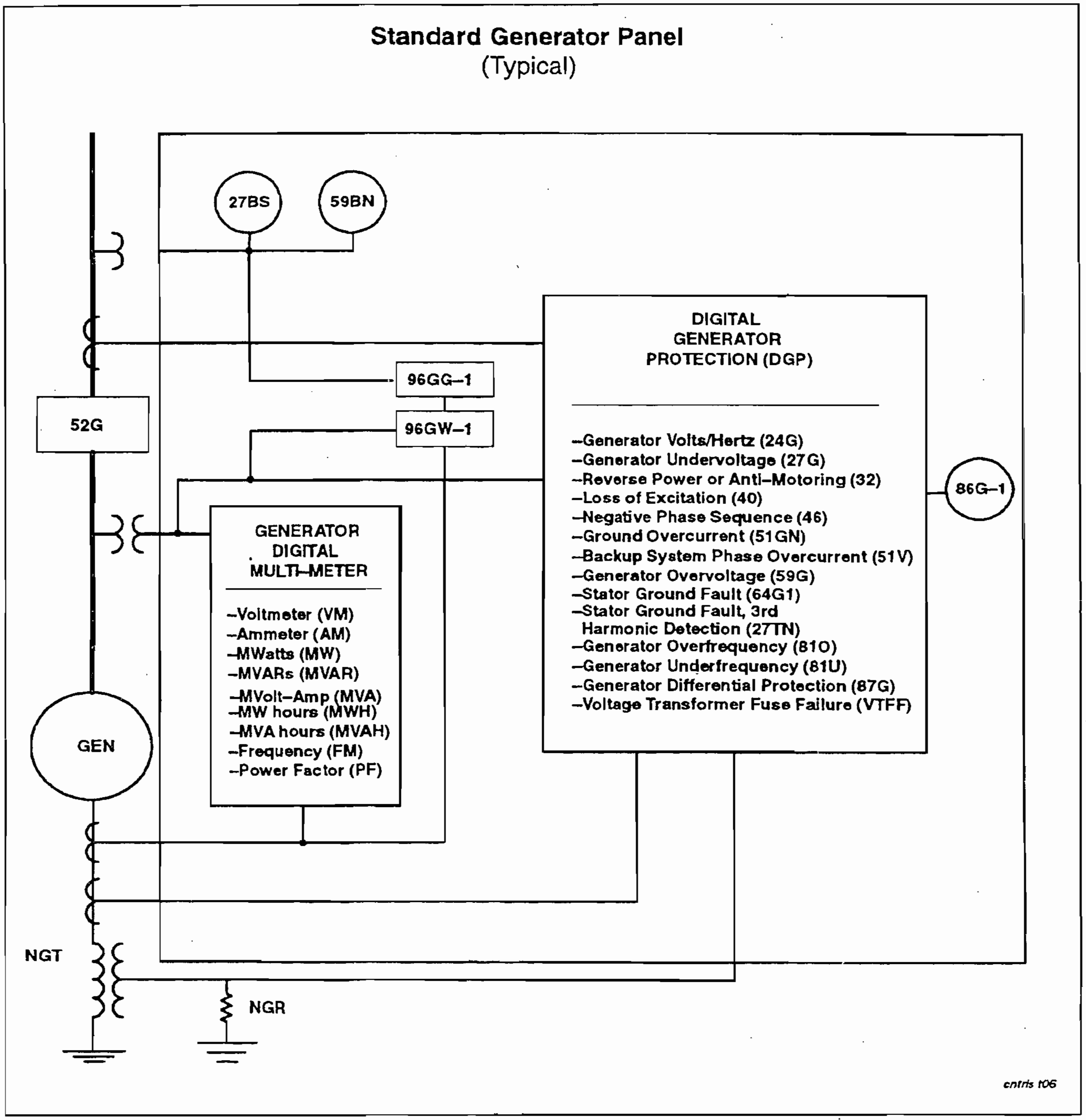
5.3.6 Generator Protection Panel

The heart of the generator protection panel is the digital multifunction relay integration with the gas turbine control system panel. The generator protection panel incorporates this feature along with generator metering and watt and VAR transducers for turbine control.

In addition, the panel includes pre-engineered protective modules for the following:

- Generator step-up transformer
- Auxiliary transformer
- Excitation transformer
- Starting transformer

The following page presents a typical one-line diagram for the generator protection panel. The diagram and the tables which follow it illustrate the digital protection features and metering. For job-specific details please refer to the oneline diagram in the drawings section of the proposal.



5.3.6.1 Digital Generator Protection (DGP) Features

Measurement	Value
Overexcitation	24

Generator Undervoltage	27G
Reverse Power / Anti-Motoring	32-1
Loss of Excitation	40-1,2
Current Unbalance / Negative Phase Sequence	46
System Phase Fault	51V
Generator Overvoltage	59
Stator Ground Detection	64G/59GN
Generator Over Frequency	81O-1,2
Generator Differential	87G
Voltage Transformer Fuse Failure	VTFF

5.3.6.2 Generator Digital Multimeter

Measurement	Value
Generator Volts	VM
Generator Amps	AM
Generator megawatts	MW
Generator megaVARs	MVAR
Generator MVA	MVA
Generator frequency	FM
Generator Power Factor	PF

5.3.6.3 Digital Generator Protection (DGP)

The digital generator protection system uses microprocessor technology to obtain a numerical relay system for a wide range of protection, monitoring, control and recording functions for the generator. Redundant internal power supplies and extensive diagnostic and self-test routines provide dependability and system security.

The DGP provides the commonly used protective functions in one package. Adaptive frequency sampling is used to provide better fault protection during off-normal frequencies such as startup.

The DGP can store in memory the last 100 sequence of events, 120 cycles of oscillography fault recording, and the last three fault reports

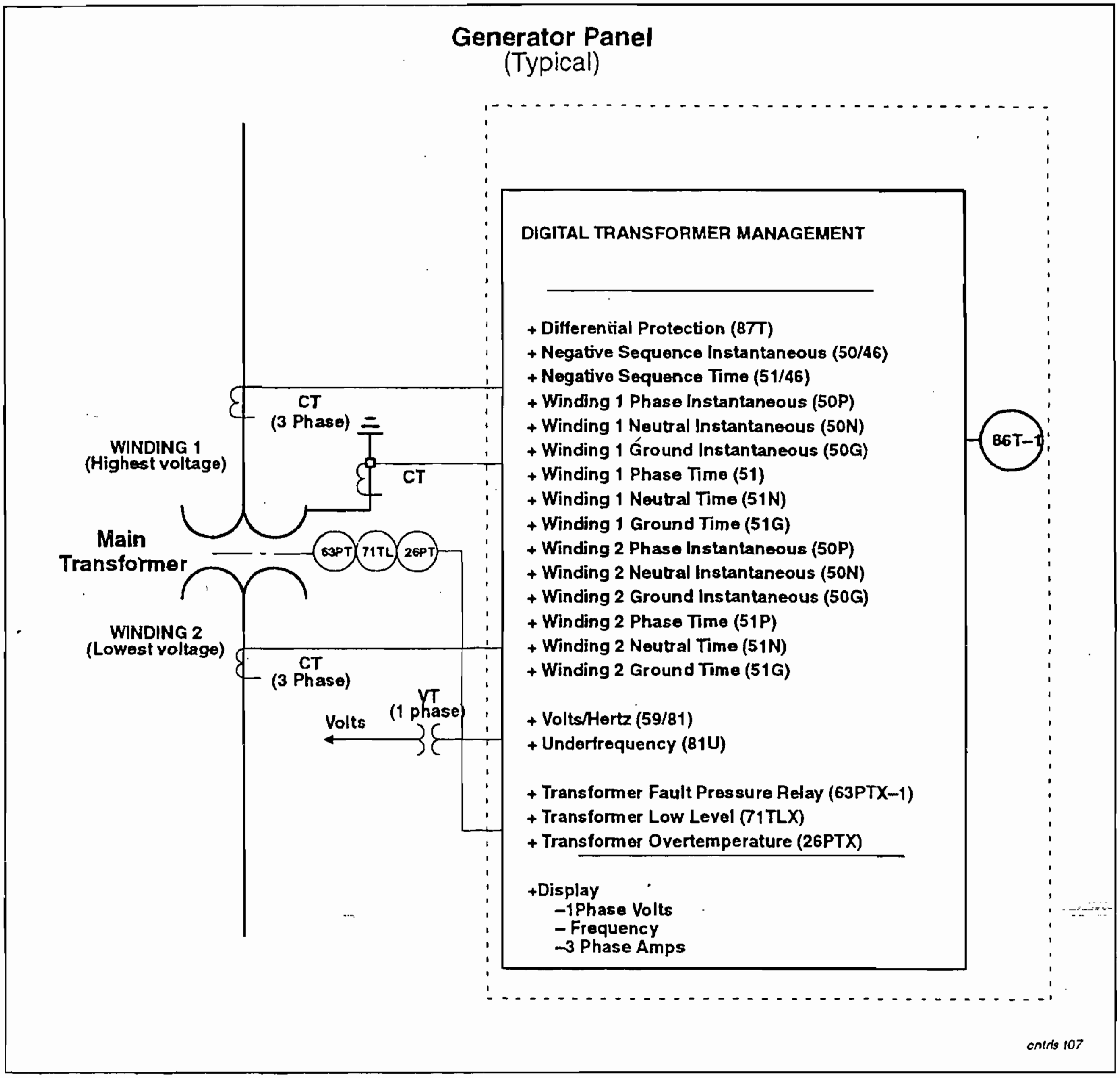
The system features a local Human-Machine Interface with integral keypad, 16 character display, and target LEDs for entering settings, displaying present values, viewing fault target information, and accessing stored data. In addition, two RS-232 serial communication ports are provided for local and remote computer access. (Please Note: The Personal Computer (PC) is not part of this offering.)

5.3.6.4 Digital Transformer Protection (DTP)

Generator step-up transformer protection is provided by a Digital Transformer Protection module. This module is a digital, three-phase current differential relay with harmonic and through-current percentage restraints. The DTP provides high speed differential protection for internal transformer faults and a high-set, unrestrained, differential overcurrent function. In addition the DTP includes oscillography, fault reporting and event recording.

Similar to the DGP, the DTP includes a human-machine interface with integral keypad, and two RS-232 serial communication ports.

A typical one-line diagram for the DTP is provided below. The digital transformer protection features are listed in Table 3. For job specific details, please refer to the oneline diagram provided in the Drawings section of the proposal.



5.3.6.5 Digital Transformer Management (SR 745)

Measurement	Value
Neutral Fault	50/51N
Transformer Fault Pressure Relay	63PTX
Transformer Low Level	71TL-3

Transformer Differential / Lockout	86T/87T

5.3.6.6 Auxiliary Transformer Protection

Auxiliary transformer protection is provided by a digital non-directional overcurrent relay which protects against overloads and faults. The module includes four measuring units, one for each of the three phase currents and one for ground or residual current. The phase and ground units contain settings for time overcurrent (TOC) and instantaneous overcurrent (IOC). In addition, the module has control inputs and outputs that can be used for a zone interlocking scheme. A local user interface is included with scrolling display and eight LEDs.

5.3.6.7 Out-of-Step Protection (78)

The out-of-step relay utilizes an impedance measuring unit and logic circuitry to evaluate the progressive change in impedance as would occur during a loss of synchronism and/or to initiate tripping when the angle between the generator and system voltages is 90 or less. Switching at this angle is generally recommended in order to minimize the duty on the circuit breaker. When properly applied, this scheme is capable of initiating tripping during the first half slip cycle of a loss of synchronism condition. Since this condition is essentially a balanced three phase phenomenon, the relay units used in the scheme are, and only need be, single phase devices. The standard relay is an LPSO digital relay.

5.3.6.8 System Backup Distance Protection (21)

Distance relays are typically used instead of overcurrent with voltage restraint when the lines leaving the station bus have distance or pilot relay protection schemes and the generator ties the station bus through a step-up transformer. This protection scheme is designed to protect the generator from faults in the adjacent system which are not cleared by the first line relays. The standard relay is an LPSO three phase digital relay with internal timing function.

5.3.6.9 Generator Breaker Failure Protection (50/62BF)

A digital breaker failure relay is used for timing and detecting current flow in conjunction with a lockout relay (86BF). The timer initiation is accomplished using an auxiliary high speed relay (94BFI) in parallel with the breaker trip coil. If the generator breaker remains closed and/or the current level detectors sense a current, the (50/62BF) relay starts timing. At the end of the time out period, the (50/62BF) relay trips the lockout relay (86BF). Contacts from this lockout are brought out to terminal boards for customer use in tripping associated breakers. Lockout relay (86BF) also trips the turbine.

Most faults involving the generator require tripping the generator breaker. Failure of the protection schemes to trip this breaker results in loss of protection to the generator. Also, if one or two poles of the breaker fail to open, the result can be a single phase load and negative sequence current on the generator stator. The purpose of the breaker failure protection is to act as a backup to any of the other generator protection schemes. This serves to protect the generator when the breaker fails to open properly.

5.3.6.10 Gas Turbine Control System Integration

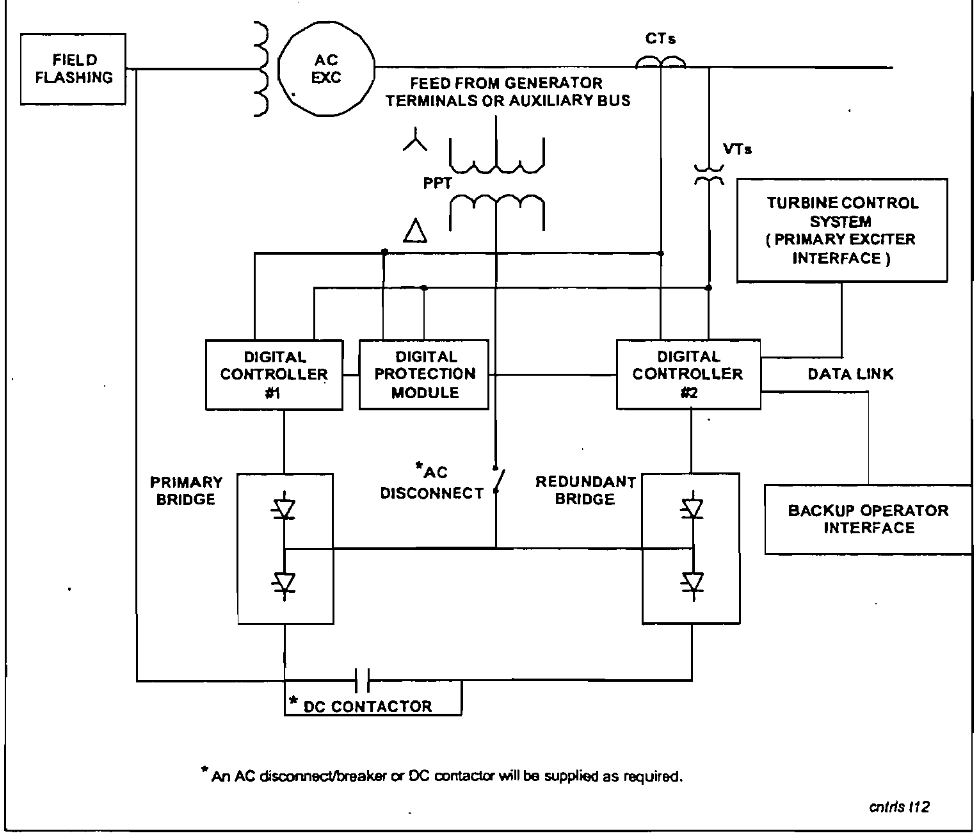
In addition to the relaying mounted in the generator protection panel, the gas turbine control system handles protective functions such as generator temperature protection, synchronizing check, backup frequency and reverse power.

Generator control and monitoring are primarily accomplished via the gas turbine control system operator interface. The operator interface handles manual and auto-synchronizing, speed raise/lower, voltage raise/lower, and generator breaker control. Also displayed are frequency and voltage for the generator and bus, breaker status, field current and voltage, along with the status of permissives.

5.3.7 Static Voltage Regulator for Bus Fed Excitation

The exciter is a digital, static, potential source excitation system. The system comes equipped with a full-wave thryristor bridge, which supplies excitation power to the rotating field winding of the main ac generator. In addition, all control and protective functions are implemented in the system software. Digital technology allows the exciter to maintain 99.98% availability. The following is a one-line diagram of the excitation system.

Static Excitation System with Redundant Bridge and Control
(Typical)



5.3.7.1 System Components

The exciter is comprised of the following four basic components as described below:

1. Power conversion module
2. Digital controller
3. Excitation transformer
4. Communication interface

5.3.7.1.1 Power Conversion Module

A three phase, full-wave thyristor bridge is the standard conversion module for the digital excitation system. The standard current capability of the bridge is 6% above the calculated rated full load field current of the generator.

The thyristor bridge assembly is forced air cooled. The cooling assemblies are all energized during normal operation. Thermostats are used to monitor the power conversion module temperature. An alarm is provided for a high temperature level and a trip is provided at a higher temperature level.

5.3.7.1.2 Excitation Transformer

The excitation transformer (power potential transformer) is separate from the exciter. The power to the transformer is obtained from a station auxiliary bus. The purpose of this transformer is to step the voltage down to the required level for the excitation system.

With the use of a regulator in the static exciter, it is not necessary to specify transformer full capacity taps above and below normal on the primary winding. The transformer rating is chosen so that the transformer can deliver the excitation required for the application at 110% rated generator terminal voltage on a continuous basis.

5.3.7.1.3 Digital Controller

The digital controller consists of several microprocessor I/O boards, and a power supply. Cell gating of the SCRs is controlled by one of the microprocessors. If redundant controls are provided, each controller section has its own power supply to ensure backup in the event of a power supply failure.

5.3.7.1.4 Communication Interface

The turbine control interface (HMI) is the primary interface with the exciter. Communication between the turbine control and exciter utilizes a single or redundant datalink. All exciter control logic and display data utilize this datalink. The exciter trip contact (94EX) is hardwired directly to the generator lockout relay and a single global alarm contact (30EX) is hardwired to the turbine control.

5.3.7.2 System Features

Following are descriptions of selected features of the exciter system. For a complete list of system features and accessories, please refer to the Scope of Supply section of the proposal.

5.3.7.2.1 Interface with the Gas Turbine Control System

The exciter is connected to the gas turbine control system through a digital datalink. This enables the gas turbine control system to provide a digital window into the exciter through which all pertinent variables can be monitored and controlled.

5.3.7.2.2 Protection Controller

The protection controller is separate from the main controller(s) and serves as a backup to the limiters located within the controller. The output of the protection controls transfer to backup control/bridge. The protection features provided are as follows:

- Volts/Hertz, dual level (24EX)
- Loss of excitation (40EX)
- Bridge ac phase unbalance (47EX)

5.3.7.2.3 Spare Power Conversion Module as Redundant Bridge

A complete digital controller and rectifier bridge are provided as backup to the primary controller and bridge.

If the protection module senses a condition that would normally initiate a trip signal, it will force a transfer to the redundant system before the trip contact is necessary. The transfer to the redundant system occurs with the generator on-line and does not affect generator output.

5.3.7.2.4 Power System Stabilizer (PSS)

The power system stabilizer function is incorporated into the exciter software. A signal representing the integral of accelerating power is introduced into the automatic voltage regulator algorithm to enable the generator to produce and transmit large power levels in a stable manner by reducing low frequency rotor oscillations

5.3.7.2.5 Enclosure

The exciter, located in a NEMA-1 stand-alone enclosure, contains the SCR power conversion module and regulator with all standard control and protection functions, plus auxiliary functions such as the de-excitation module and shaft voltage suppression circuit.

5.3.7.3 Related Services

5.3.7.3.1 Power System Stabilizer Tuning Study

GE provides engineering consulting services for tuning the power system stabilizer for optimal performance at the installation site. This includes studies to determine the optimum settings and producing computer models for use in transient stability analysis.

In order to complete the analyses described, GE typically requires data on the system strength at the HV bus (short circuit MVA) and data on the step-up transformer impedance. Copies of any pertinent interconnection specifications or performance requirements for the AVR/PSS should also be provided for use in determining the proper tuning.

5.3.7.3.2 Power System Stabilizer Testing

GE provides engineering services for testing of the AVR/PSS at commissioning (plant startup), or a later date. The purpose of the tests is to verify that the AVR/PSS performance meets existing specifications and requirements and to validate the calculated results from the tuning study. Sometimes this testing is required by the utility regulatory commission for acceptance of the plant performance as it relates to system interconnection requirements. A report documenting the test results compared to the performance requirements is the deliverable following testing.

ATTACHMENT 3

ENVIRONMENTAL AND ENERGY IMPACTS STUDY FOR NO_X BACT ANALYSIS

As presented in the Competitive Power Ventures (CPV) Air Permit Application, emissions of NO_x are subject to Best Available Control Technology (BACT) requirements due to the facility's ozone attainment status. BACT is defined as an emission limitation based on the maximum degree of reduction, on a case-by-case basis, taking into account energy, environmental and economic impacts.

The proposed combined cycle project includes the use of General Electric (GE) 7FA combustion turbines. GE 7FA combustion turbines are expected to emit uncontrolled NO_X emissions at a concentration of 9 ppmvd @ 15% O_2. This emission rate is achieved by the use of dry low-NO_X burners. A BACT analysis was performed, and CPV has concluded that the option of installing a selective catalytic reduction (SCR) control system will satisfy BACT requirements and achieve a controlled NO_X emission rate of 3.5 ppmvd @ 15% O_2. The option of installing a $SCONO_X$ system was addressed, and it is shown to not be economically or technically feasible, since $SCONO_X$ systems have a low cost-effectiveness for this project and have only been used on small turbines (less than 35 MW output). Even though SCR controls have been proposed, drawbacks to SCR do exist and include environmental and energy impacts. The following discussion provides additional detail of environmental and energy impacts associated with the SCR system.

Environmental Impacts of a SCR Control System

SCR is often considered BACT for NO_X emissions on natural gas-fired combined cycle combustion turbines in ozone attainment areas. It has been argued that dry low-NO_x turbines should not apply additional SCR controls as it can have a negative affect environmentally. An SCR system involves injecting anhydrous or aqueous ammonia (NH_3) into the flue gas upstream of a catalyst bed. On the catalyst surface, NH_3 reacts with NO_X contained within the air to form nitrogen gas and water. The following environmental issues are a result of the addition of SCR controls to a combustion turbine flue gas stream:

Ammonia Slip Impacts

Ammonia salts (fine particle) formation - the presence of an SCR catalyst will increase the conversion of SO_2 to SO_3, which may then react with water to form sulfuric acid, or with ammonia slip to form ammonia sulfates (fine particles), resulting in increased total particulate matter emissions. Ammonia sulfates are corrosive and can stick to the heat recovery surfaces, duct work, or the stack at low temperatures. Increased particulate emissions effect visibility (note that a Class I area, Chassahowitzka Wilderness Area, is within 200 km of the proposed facility) and can cause human health problems.

Acidifying deposition – NO_X emissions contribute to the formation of acid aerosols, while ammonia neutralizes atmospheric acidity. Once deposited, however, derivatives of both NO_X and ammonia can contribute to the acidification of terrestrial soils and surface waters.

Eutrophication – when deposited on water surfaces, oxidized or reduced nitrogen promotes the growth of aquatic plants, such as algae, and the resulting bacteria consumes the oxygen in the water.

Possible conversion to nitrous oxide (N_2O) – once deposited on soil, a small fraction of ammonia emissions is converted by soil microbes to N_2O, which is a greenhouse gas and which depletes stratospheric ozone.

Ammonia Storage and Handling

Storage/Handling – an anhydrous or aqueous ammonia storage tank will be required at a facility utilizing SCR controls. Ammonia is identified by EPA as an extremely hazardous substance. It is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose or throat. Additionally, ammonia vapors may form an explosive mixture with air.

Applicable requirements – facilities that handle over 10,000 pounds of anhydrous ammonia or more than 20,000 pounds of ammonia in an aqueous solution of 20% ammonia or greater must prepare a Risk Management Plan (RMP) and implement a RMP to prevent accidental releases.

Catalyst Disposal

Spent catalyst waste – the catalyst in the SCR degrades over time and needs to be replaced, about once every three years. The amount of spent catalyst waste is dependent on several factors, including the amount of catalyst used in the system, the life of the catalyst, and the amount of spent catalyst recycling that occurs.

Energy Impacts of a SCR Control System

The installation of a SCR control system in the flue gas stream has several operating effects on the combustion turbine and are listed as follows:

Pressure Drop

The SCR unit causes a pressure drop in the flue gas stream and the resultant back-pressure exerted on the combustion turbine decreases the power output.

Heat Rate Increase

The pressure drop effect will result in an increased heat rate for the turbine to supplement the power loss.

Fuel Use Increase

The increase in the heat rate of the turbine will require additional fuel usage.

Revenue Loss from Maintenance/Malfunctions

The facility may experience unplanned shutdowns for catalyst change-out, maintenance, and replacement. Downtime periods of combustion turbines result in revenue losses for a facility, since the turbines can only operate with the SCR controls working properly.

The following table is a demonstration of how the proposed SCR controls effects the performance of the GE 7FA combustion turbine:

TABLE A. ENERGY IMPACTS OF SCR CONTROLS

Pressure Drop across SCR system (inches H_2O)	Lost Output due to Pressure Drop (kW-hr/yr)	Increased Heat Rate of Combustion Turbine (Btu/kW-hr)	Additional Fuel Consumption due to Heat Rate Increase (mmBtu/yr)
3.7	4,082,160	24.7	37,310

Notes:

1. Increased heat rate based on pressure drop. Similar project experienced a 10 Btu/kw-hr increase due to a 1.5 pressure drop from a control device.
2. Annual lost electrical output and additional fuel consumption based on 8,760 hours of operation.

ATTACHMENT 4

CPV GULFCOAST											
HAZARDOUS AIR POLLUTANTS EMISSIONS											
	DISTILLATE					NATURAL GAS					
	Emission Factor	Maximum Heat Input	Emission Rate	Operating Period	Annual Emissions	Emission Factor	Maximum Heat Input	Emission Rate	Operating Period	Annual Emissions	Total Annual Emissions
Pollutant	(lb/MMBtu)	(MMBtu/hr)	(lb/hr)	(Hours)	(TPY)	(lb/MMBtu)	(MMBtu/hr)	(lb/hr)	(Hours)	(TPY)	(TPY)
Arsenic	1.10E-05	1918	2.11E-02	720	7.60E-03						7.60E-03
Beryllium	3.10E-07	1918	5.95E-04	720	2.14E-04						2.14E-04
Cadmium	4.80E-06	1918	9.21E-03	720	3.31E-03						3.31E-03
Chromium	1.10E-05	1918	2.11E-02	720	7.60E-03						7.60E-03
Lead	1.40E-05	1918	2.69E-02	720	9.67E-03						9.67E-03
Manganese	7.90E-04	1918	1.52E+00	720	5.45E-01						5.45E-01
Mercury	1.20E-06	1918	2.30E-03	720	8.29E-04						8.29E-04
Nickel	4.60E-06	1918	8.82E-03	720	3.18E-03						3.18E-03
Selenium	2.50E-05	1918	4.80E-02	720	1.73E-02						1.73E-02
Acetaldehyde						4.00E-05	1700	6.80E-02	8040	2.73E-01	2.73E-01
Acrolein						6.40E-06	1700	1.09E-02	8040	4.37E-02	4.37E-02
1,3-Butadiene	1.60E-05	1918	3.07E-02	720	1.10E-02	4.30E-07	1700	7.31E-04	8040	2.94E-03	1.40E-02
Benzene	5.50E-05	1918	1.05E-01	720	3.80E-02	1.20E-05	1700	2.04E-02	8040	8.20E-02	1.20E-01
Ethylbenzene						3.20E-05	1700	5.44E-02	8040	2.19E-01	2.19E-01
Formaldehyde	2.80E-04	1918	5.37E-01	0	0.00E+00	7.10E-04	1700	1.21E+00	8760	5.29E+00	5.29E+00
Naphthalene	3.50E-05	1918	6.71E-02	720	2.42E-02	1.30E-06	1700	2.21E-03	8040	8.88E-03	3.31E-02
PAH	4.00E-05	1918	7.67E-02	720	2.76E-02	2.20E-06	1700	3.74E-03	8040	1.50E-02	4.27E-02
Propylene Oxide						2.90E-05	1700	4.93E-02	8040	1.98E-01	1.98E-01
Toluene						1.30E-04	1700	2.21E-01	8040	8.88E-01	8.88E-01
Xylenes						6.40E-05	1700	1.09E-01	8040	4.37E-01	4.37E-01
										Total HAPs	**8.15E+00**

Notes:

Hazardous air pollutant emission factors taken from USEPA document Compilation of Air Pollutant Emission Factors AP-42, Fifth Edition, Volume I: *Stationary Point and Area Sources*, Section 3.1 Stationary Gas Turbines, dated 4/2000:

Table 3.1-3. Emission Factors For Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines

Table 3.1-4. Emission Factors For Hazardous Air Pollutants from Distillate Oil-Fired Stationary Gas Turbines

Table 3.1-5. Emission Factors For Metallic Hazardous Air Pollutants from Distillate Oil-Fired Stationary Gas Turbines

ATTACHMENT 5

BPIP INPUT FILE

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'METERS'    1.0
'UTMN'      0
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'hrsg'      1        0
 4        22.86
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4.88       6.10
4.88       28.96
-4.88      28.96
'sturb'     1        0
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19.20      34.44
64.92      34.44
64.92      64.92
19.20      64.92
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6.10      -28.35
21.34      -28.35
21.34      -13.11
6.10      -13.11
'cell2'     1        0
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21.34      -28.35
36.58      -28.35
36.58      -13.11
21.34      -13.11
'cell3'     1        0
 4        16.764
36.58      -28.35
51.82      -28.35
51.82      -13.11
36.58      -13.11
'cell4'     1        0
 4        16.764
51.82      -28.35
67.06      -28.35
67.06      -13.11
51.82      -13.11
'cell5'     1        0
 4        16.764
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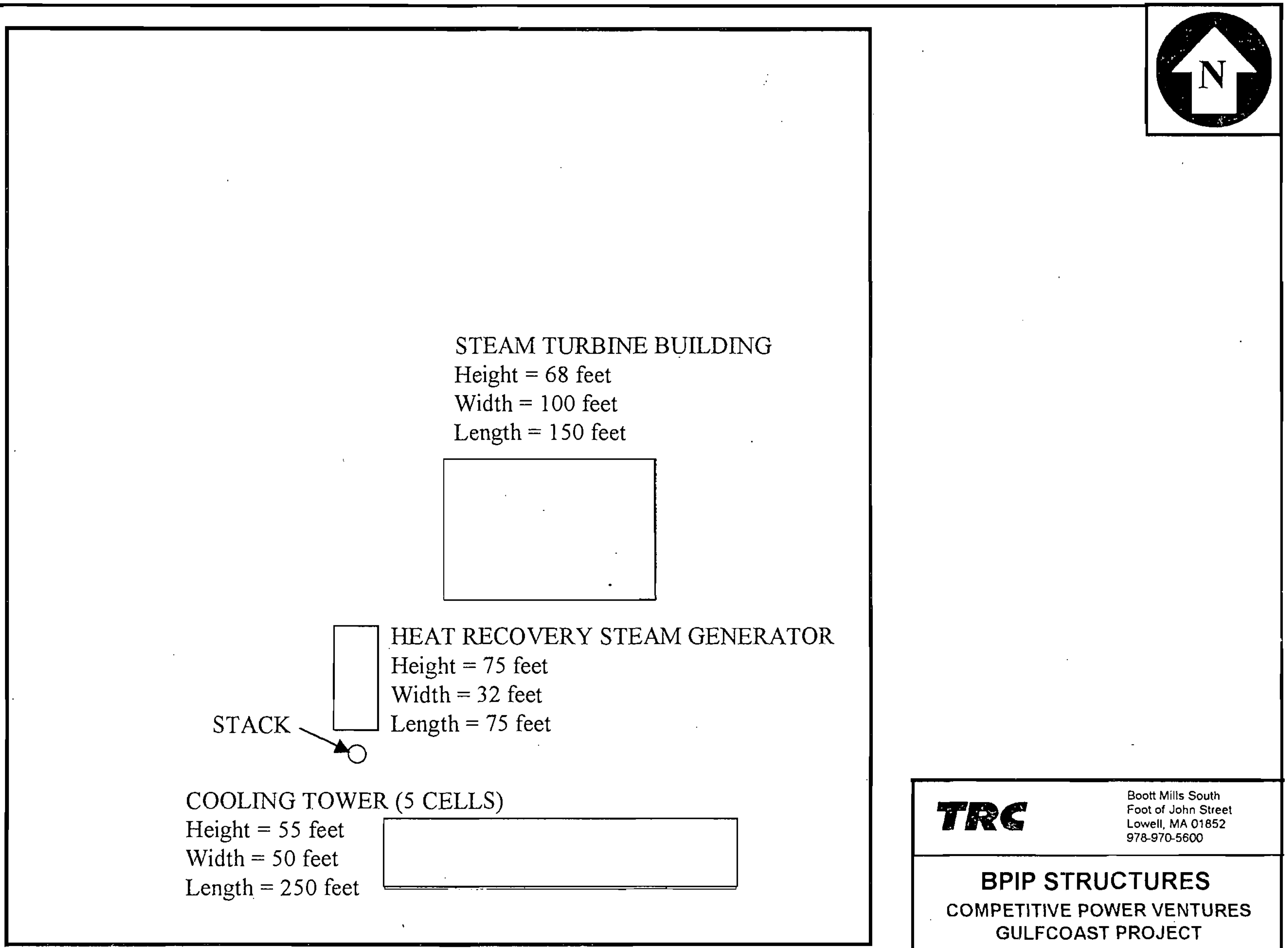
67.06	-28.35			
82.30	-28.35			
82.30	-13.11			
67.06	-13.11			
10				
'25/50 '	0	45.72	0.00	0.00
'25/75 '	0	45.72	0.00	0.00
'25F '	0	45.72	0.00	0.00
'59F '	0	45.72	0.00	0.00
'72/50 '	0	45.72	0.00	0.00
'72/75 '	0	45.72	0.00	0.00
'72F '	0	45.72	0.00	0.00
'97/50 '	0	45.72	0.00	0.00
'97/75 '	0	45.72	0.00	0.00
'97F '	0	45.72	0.00	0.00



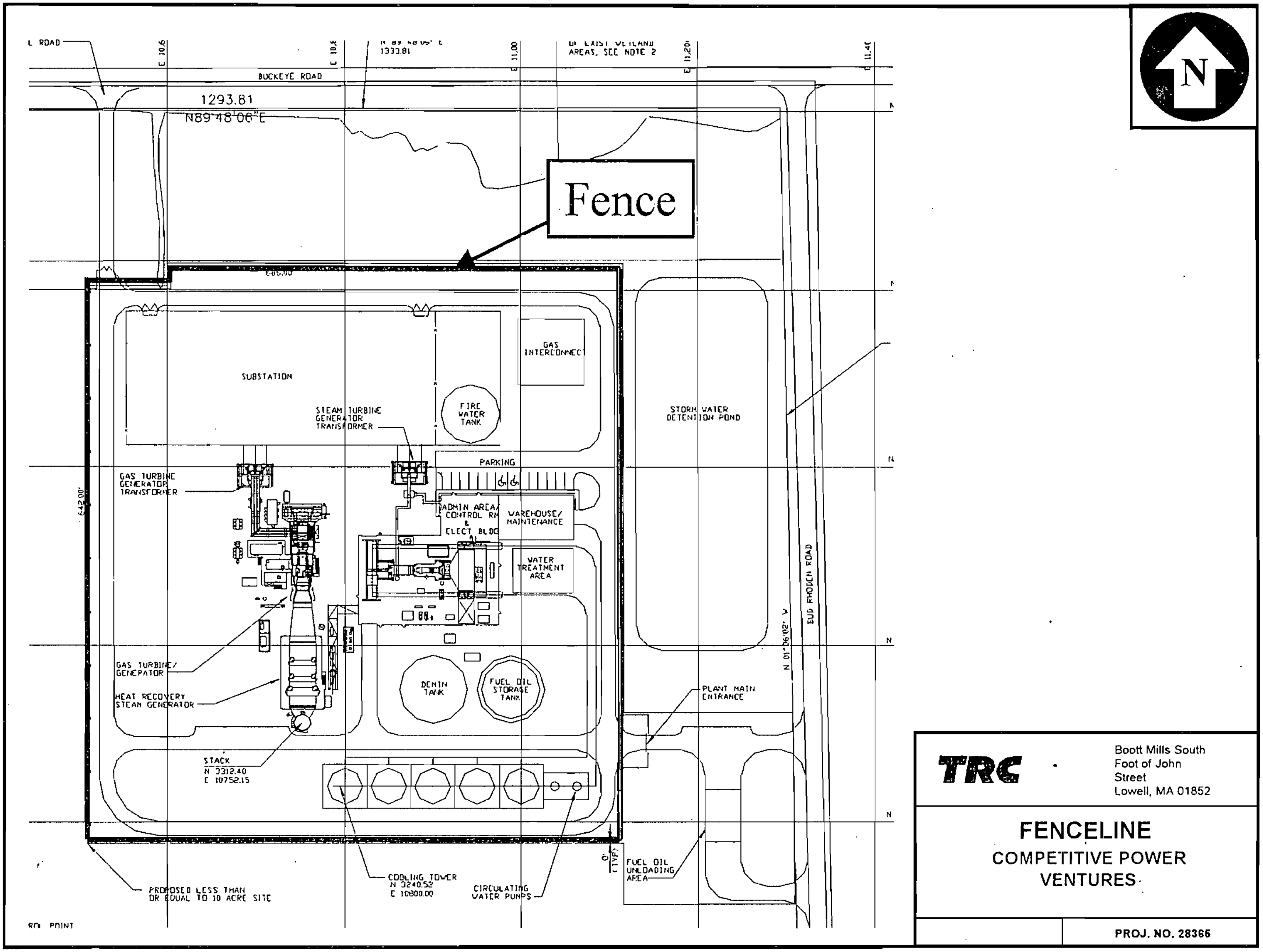
TRC
Boott Mills South
Foot of John Street
Lowell, MA 01852
978-970-5600

BPIP STRUCTURES

COMPETITIVE POWER VENTURES
GULFCOAST PROJECT

FIGURE 1 | PROJ. NO. 28366

ATTACHMENT 6



TRC

Boott Mills South
Foot of John
Street
Lowell, MA 01852

FENCELINE

COMPETITIVE POWER
VENTURES

PROJ. NO. 28366

ATTACHMENT 7

U.S.FISH&WILDLIFE SERVICE
AIR QUALITY BRANCH
P.O. BOX 25287, Denver, CO 80225-0287

Date: September 27, 2000

Telephone: (303) 969-2617
Fax: (303) 969-2822

To: Al Linero
Patty Adams
Cleve Holladay

From: Ellen Porter

Subject: CPV Gulfcoast, Ltd. PSD-FL-300

We have reviewed the Prevention of Significant Deterioration Application for CPV Gulfcoast, Ltd. Proposed combined-cycle 250 MW power generation facility in Manatee County. The facility is located 97 km south of Chassahowitzka Wilderness, a Class I air quality area administered by the U.S. Fish and Wildlife Service. Emissions increases include 126 tons per year (tpy) of nitrogen oxides (NOx), 76 tpy of sulfur dioxide, and 102 tpy of PM-10.

CPV is proposing to use selective catalytic reduction (SCR) to control NOx emissions to 3.5 ppm while burning gas and 10 ppm while burning oil. We agree that this represents best available control technology.

CPV evaluated potential impacts to Class I increments. Predicted impacts were below the significant impact levels for nitrogen dioxide, sulfur dioxide, and PM-10. CPV also evaluated its potential contribution to haze at Chassahowitzka. Their analysis, using IWAQM Phase 2, predicted a 2% change in light extinction, less than the 5% screening level recommended by FWS. However, CPV located its receptors for the analysis incorrectly, placing all receptors within Chassahowitzka instead of using the circular ring of receptors decribed in the IWAQM Phase 2 document. Because CPV's emissions are relatively low and well-controlled with

SCR, and the facility is 97 km from the Class I area, we believe that the project has low potential to contribute significantly to haze at Chassahowitzka. Therefore, we will not require CPV to revise their analysis. However, future applicants should be advised to follow the IWAQM Phase 2 recommendations.

Thank you for giving us the opportunity to comment on this project.

Jeb Bush
Governor

Department of Environmental Protection

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

David B. Struhs
Secretary

October 9, 2000

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Gary Lambert
Executive Vice President
CPV Gulfcoast, Ltd
45 Bristol Road, Suite 101
Easton, Massachussets 02375

Re: DEP File No. 0810194-001-AC (PSD-FL-300)
Proposed 244 .9 MW Combined Cycle Power Plant

Dear Mr. Lambert:

On September 11, 2000 the Department received your application and complete fee for an air construction permit for a 244.9 megawatts (MW) combined cycle power plant near Piney Point in Manatee County, Florida. The application is incomplete. In order to continue processing your application, the Department will need the additional information requested below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form

Please submit the following information:

1. Process flow diagram.
2. Combustion Turbine: Is this combustion turbine equipped with evaporative inlet air cooling system (foggers)? Will the unit operate while both fogging and power augmenting? Please explain. Will this turbine always operate in the combined cycle mode? What is the heat rate of this project (Btu/kwh)? Submit General Electric performance data sheets for this turbine.
3. Heat Recovery Steam Generator: Is the HRSG supplementally- fired? If so, what, is the heat input of the duct burner. What is the model and manufacturer of the duct burner and HRSG if already selected? Submit the manufacturer performance sheets if available. How much steam is produced at this unit?
4. Power Augmentation: How much extra power is produced in the power augmentation mode? Provide a schematic of the power augmentation operation mode. What is the manufacturer's maximum recommended period (hr/year, hr/month) for operation in the power augmentation mode.

5. Automated Control System: What type of control system is recommended by the combustion manufacturer (i.e. Mark V control system, etc).
6. Storage Tanks: What are the capacities of the tanks associate with this plant?
7. Ancillary Equipment: The application only lists the CT, HRSG and the Cooling Tower. Would this plant include an Emergency Generator and Diesel Fired Pump, gas heaters, or any other ancillary equipment?
8. Selective Catalytic Reduction (SCR) system:
   - The application states that GE does not recommend operation of the SCR during distillate fuel operation. However a 30 days at full load while burning oil and a 10 ppm NO_X limit is being proposed. Please explain.
   - What is the ammonia slip proposed for this project (ppm)?
   - Submit the environmental and energy impact analysis for this project while using SCR.
9. Estimate emissions of hazardous air pollutants (HAPs). Show basis. Indicate if HAPs emissions from this project are less than 25 ton/yr for all HAPs and less than 10 ton/yr for a single HAP.
10. Page twenty one of the application states that there is a graphic showing the location of the stacks and buildings in Appendix D-1, however, this graphic is absent from the appendix. Please provide this graphic along with the BPIP input file.
11. Please provide information that shows that the site boundary used in the impact modeling will be land owned or controlled by CPV Gulfcoast, Ltd. with a physical barrier to public access.
12. The table entitled 'Gulfcoast-Single CT Firing Oil (150-foot stack)' in Appendix D identifies the 97/50 operating scenario as the worst case impact scenario for PM_{10}. However, this was not the scenario that was used in the PM_{10} modeling that included the cooling towers. Please re-evaluate the PM_{10} Class II SIL modeling by using the 97/50 operating scenario.
13. The set of 13 discrete receptors for the Chassahowitzka NWR that the Department provided to TRC were intended for use in a regular CALPUFF analysis. If the applicant proposes to show compliance with modeling requirements by using the CALPUFF LITE screening method, then a ring of receptors as described on pages 6-8 in the *IWAQM Phase 2 Summary Report* should be utilized to show compliance with both increment consumption and regional haze requirements.
14. Please provide the meteorological files that were utilized in the CALPUFF LITE modeling analysis, and a listing of the parameters that were used to create them.
15. Class I increment and regional haze modeling should be conducted by using the worst case operating load for each pollutant (i.e. 100% load at 25°F for NO_x and SO_2, and 50% load at 25°F for PM_{10}).

REFERENCES

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[2] Telecom. Linero, A.A., FDEP and Chalfin, J., GE. NO_X control technology for fuel oil.

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[4] Compliance Manual. California EPA, CARB Compliance Division. Gas Turbines. June 1996.

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[11] Letter. Bedwell, A.F., Goal Line to Linero, A.A., FDEP. Re: $SCONO_X$ 21000 Hour Report. September 29, 2000.

[12] News Release. ABB Alstom Power, Environmental Segment. ABB Alstom Power to Supply Groundbreaking $SCONO_X$™ Technology. December 1, 1999.

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[15] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

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[18] Zachary, J, Joshi, S., and Kagolanu, R., Siemens. "Challenges Facing the Measurement and Monitoring of Very Low Emissions in Large Scale Gas Turbine Projects." Power-Gen Conference. Orlando, Florida. December 9-11, 1998.

[19] General Electric. Combined Cycle Startup Curves. June 19, 1998.

APPENDIX GC

GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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.

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Transmittal Form

TO: Cathy Sellers
Moyle Flanigan Katz Kolins Raymond & Sheehan
The Perkins House, 118 North Gadsden St.
Tallahassee, FL 32301

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RE: CPV Gulfcoast Project	

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SIGNED: Scott Sumner

Scott Sumner, P.E.

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BUREAU OF AIR REGULATION

Responses to Florida DEP Comments on CPV Gulfcoast Power Generation Facility

DEP File No. 0810194-001-AC (PSD-FL-300)

Prepared by:

TRC
Boott Mills South
Foot of John Street
Lowell, MA 01852
(978) 970-5600

November 3, 2000

Responses to Florida DEP Comments on CPV Gulfcoast Power Generation Facility

DEP File No. 0810194-001-AC (PSD-FL-300)

1. *Process flow diagram.*

A process flow diagram is contained in Attachment 1. This diagram presents the typical operation of the combined cycle power generation equipment at the site average ambient temperature of 72°F and 100% load with power augmentation.

2. *Combustion Turbine: Is this combustion turbine equipped with evaporative inlet air cooling system (foggers)? Will the unit operate while both fogging and power augmenting? Please explain. Will this turbine always operate in the combined cycle mode? What is the heat rate of this project (Btu/kwh)? Submit General Electric performance data sheets for this turbine.*

The combustion turbine is not equipped with evaporative coolers.

The turbine will always operate in a combined cycle mode. No provisions are made in the design to bypass the HRSG.

The heat rate is 6,542 Btu/kW at an ambient temperature of 72°F and 100% load with power augmentation as shown in Attachment 1.

3. *Heat Recovery Steam Generator: Is the HRSG supplementally-fired? If so, what, is the heat input of the duct burner. What is the model and manufacturer of the duct burner and HRSG if already selected? Submit the manufacturer performance sheets if available. How much steam is produced at this unit?*

The HRSG will not include duct burners.

The HRSG manufacturer has not been selected.

Steam production is provided on the process flow diagram contained in Attachment 1 for typical plant operation.

4. *Power Augmentation: How much extra power is produced in the power augmentation mode? Provide a schematic of the power augmentation operation mode. What is the manufacturer's maximum recommended period (hr/year, hr/month) for operation in the power augmentation mode.*

Power augmentation (PA) increases maximum combustion turbine output from 162,100 kW without PA to 177,300 kW with PA at typical operating conditions (see Attachment 1). There is no limit to operating in the PA mode (steam injection mode) as long as the ambient operating restrictions are followed. Steam injection is restricted to periods when the ambient temperature is above 59°F.

5. *Automated Control System: What type of control system is recommended by the combustion manufacturer (i.e. Mark V control system, etc).*

The new power generation equipment will include a SPEEDTRONIC Mark V Triple Modular Redundant microprocessor gas turbine control system. A detailed description of this system is contained in Attachment 2, Section 5.3 Gas Turbine-Generator Controls and Electric Auxiliaries.

6. *Storage Tanks: What are the capacities of the tanks associate with this plant?*

Facility storage tanks include:

- Fire Water Storage (300,000 gallons, Diameter: 50 feet, Height: 20 feet)
- Demineralized Water Storage (1,500,000 gallons, Diameter: 75 feet, Height: 48 feet)
- Fuel Oil Storage (1,000,000 gallons, Diameter: 65 feet, Height: 48 feet)
- Ammonium Hydroxide Storage (12,000 gallons, Diameter: 12 feet, Height: 14 feet)

7. *Ancillary Equipment: The application only lists the CT, HRSG and the Cooling Tower. Would this plant include an Emergency Generator and Diesel Fired Pump, gas heaters, or any other ancillary equipment?*

Ancillary equipment will include:

- One diesel fired 250 hp fire water pump and
- One 500 kW emergency generator for safe shutdown.

8. *Selective Catalytic Reduction (SCR) system:*

- *The application states that GE does not recommend operation of the SCR during distillate fuel operation. However a 30 days at full load while burning oil and a 10 ppm NO_X limit is being proposed. Please explain.*
- *What is the ammonia slip proposed for this project (ppm)?*
- *Submit the environmental and energy impact analysis for this project while using SCR.*

SCR operation when firing distillate causes an increase in ash (ammonia bisulfate) buildup and corrosion on the surfaces downstream of the SCR that is much greater than with natural gas firing. The GE recommendation is based on the need for increased maintenance, not on the inability of the combined cycle unit to fire distillate.

The proposed ammonia slip limit is 5 ppmvd @ 15% O_2.

Environmental and energy impact analyses are contained in Attachment 3.

9. *Estimate emissions of hazardous air pollutants (HAPs). Show basis. Indicate if HAPs emissions from this project are less than 25 ton/yr for all HAPs and less than 10 ton/yr for a single HAP.*

The HAP annual emission calculations based on AP-42 Emission Factors are contained in Attachment 4. The maximum individual HAP annual emissions are less than 10 tons per year and the combined HAP annual emission estimate is less than 25 tons per year.

10. *Page twenty one of the application states that there is a graphic showing the location of the stacks and buildings in Appendix D-1, however, this graphic is absent from the appendix. Please provide this graphic along with the BPIP input file.*

The graphic showing the stack and plant structures and the BPIP input file are contained in Attachment 5.

11. *Please provide information that shows that the site boundary used in the impact modeling will be land owned or controlled by CPV Gulfcoast, Ltd. with a physical barrier to public access.*

Access to the site will be restricted by fence located along the site boundary as shown in Attachment 6. The model receptor net work was developed to identify the maximum air quality impact of the power generation equipment and cooling tower emissions consistent with this restricted access site boundary.

12. *The table entitled 'Gulfcoast-Single CT Firing Oil (150-foot stack)' in Appendix D identifies the 97/50 operating scenario as the worst case impact scenario for PM_{10}. However, this was not the scenario that was used in the PM_{10} modeling that included the cooling towers. Please re-evaluate the PM_{10} Class II SIL modeling by using the 97/50 operating scenario.*

The cooling tower will be equipped with automatic controls that will turn off one or more cooling fans at reduced load and/or in cool weather when the full capacity of the cooling tower is not required. Operation of the fan(s) will be based on the temperature of the cooling water returned to the condenser and a fan may be turned on and off as required to modulate the temperature. No more than 3 fans will operate at any time when the combustion turbine operates at 50 % load.

The cooling tower drift rate and associated particulate emissions are directly proportional to the number of operating fans. The unit impact of the cooling tower particulate emissions (air quality impact per unit of emissions) is greater than the combustion turbine due to the lower release height, less buoyancy, and greater downwash effects. Accordingly, the 40% reduction in emissions from the cooling tower (five cells to three cells) associated with the combustion turbine operating at 50% load causes a net reduction in total facility air quality impact when compared with the power generation equipment and cooling tower operating at maximum load.

13. *The set of 13 discrete receptors for the Chassahowitzka NWR that the Department provided to TRC were intended for use in a regular CALPUFF analysis. If the applicant proposes to show compliance with modeling requirements by using the CALPUFF LITE screening method, then a ring of receptors as described on pages 6-8 in the IWAQM Phase 2 Summary Report should be utilized to show compliance with both increment consumption and regional haze requirements.*

Based on the memorandum contained in Attachment 7 from Ellen Porter (U.S. Fish & Wildlife Service, Air Quality Branch), dated September 27, 2000, no response is required.

14. *Please provide the meteorological files that were utilized in the CALPUFF LITE modeling analysis, and a listing of the parameters that were used to create them.*

Based on the memorandum contained in Attachment 7 from Ellen Porter (U.S. Fish & Wildlife Service, Air Quality Branch), dated September 27, 2000, no response is required.

15. *Class I increment and regional haze modeling should be conducted by using the worst case operating load for each pollutant (i.e. 100% load at 25 °F for NO_x and SO_2, and 50% load at 25 °F for PM_{10}).*

Based on the memorandum contained in Attachment 7 from Ellen Porter (U.S. Fish & Wildlife Service, Air Quality Branch), dated September 27, 2000, no response is required.

Date: 11/2/00

Scott Sumner, P.E.

ATTACHMENT 1

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CPV - Gulfcoast - STAG

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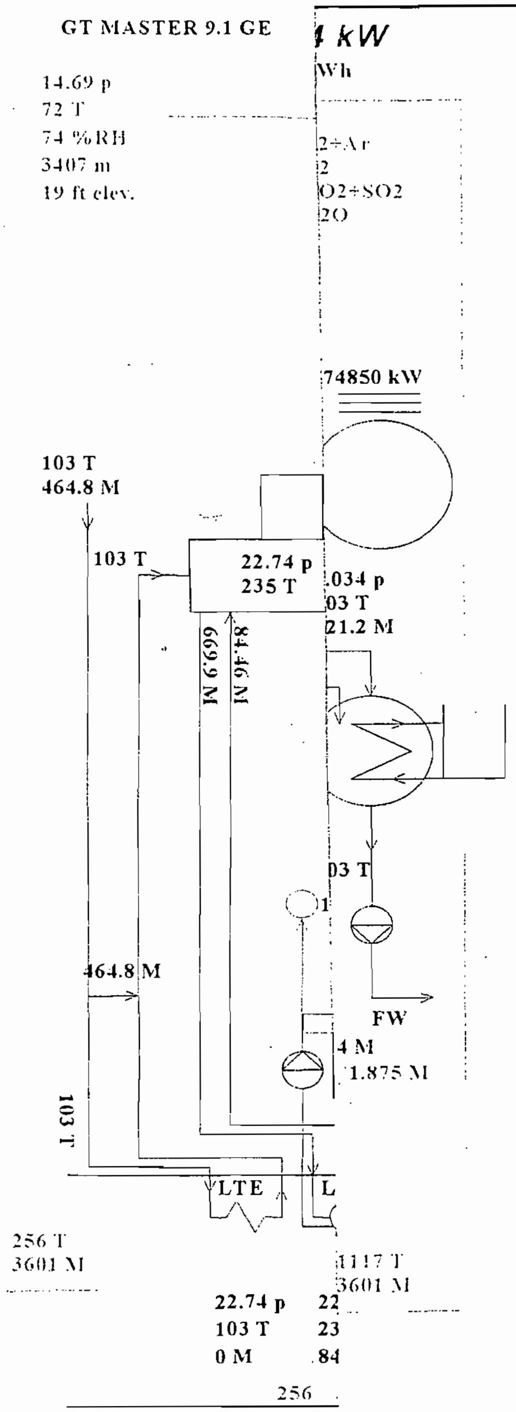

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Thursday, October 26, 2000

DEP File No. 0810194-001-AC (PSD-FL-300) 11/03/00

ATTACHMENT 2

5. Typical Gas Turbine-Generator Description

5.1 Gas Turbine Systems

5.1.1 Gas Turbine

The MS7001(FA) gas turbine has a single shaft, bolted rotor with the generator connected to the gas turbine through a solid coupling at the compressor or "cold" end. This configuration improves alignment control and provides an axial exhaust–optimal for combined cycle or waste heat recovery applications. The major features of the MS7001(FA) gas turbine are described below:

5.1.2 Compressor Section

The axial flow compressor has 18 stages with modulating inlet guide vanes and provides a 15.2 to 1 pressure ratio. Interstage air extraction is used for cooling and sealing air for turbine nozzles, wheelspaces, and bearings, and for surge control during start up.

5.1.2.1 Compressor Rotor

The compressor rotor consists of a forward stub shaft with the stage zero rotor blades, a sixteen blade and wheel assembly for stages 1 to 16, and an aft stub shaft with the stage 17 rotor blades. Rotor blades are inserted into broached slots located around the periphery of each wheel and wheel portion of the stub shaft. The rotor assembly is held together by fifteen axial bolts around the bolting circle. The wheels are positioned radially by a rabbeted fit near the center of the discs. Transmission of torque is accomplished by face friction at the bolting flange.

Selective positioning of the wheels is made during assembly to reduce the rotor balance correction. The compressor rotor is dynamically balanced after assembly and again after the compressor and turbine rotors are mated. They are precision balanced prior to assembly into the stator.

5.1.2.2 Compressor Blade Design

The airfoil shaped compressor rotor blades are designed to compress air efficiently at high blade tip velocities. Compressor blades are made from high corrosion resistance material which eliminates the need for a coating. These forged blades are attached to their wheels by dovetail connections. The dovetail is accurately machined to maintain each blade in the desired location on the wheel.

Stator blades utilize square bases for mounting in the casing slots. Blade stages zero through four are mounted by axial dovetails into blade ring segments. The blade ring segments are inserted into circumferential grooves in the casing and are secured with locking rings. Stages 5 through 16 are mounted on individual rectangular bases that are inserted directly into circumferential grooves in the casings. Stage 17 and the exit guide vanes are cast segments.

5.1.2.3 Compressor Stator

The casing is composed of three major subassemblies: the inlet casing, the compressor casing, and the compressor discharge casing. These components in conjunction with the turbine shell, exhaust frame/diffuser, and combustion wrapper form the compressor stator.

The casing bore is maintained to close tolerances with respect to the rotor blade tips for maximum aerodynamic efficiency. Borescope ports are located throughout the machine for component inspection. In addition all casings are horizontally split for ease of handling and maintenance.

5.1.2.3.1 Inlet Casing

The primary function of the inlet casing, located at the forward end of the gas turbine, is to direct the air uniformly from the inlet plenum into the compressor. The inlet casing also supports the number 1 thrust bearing assembly and the variable inlet guide vanes, located at the aft end.

5.1.2.3.2 Compressor Casing

The compressor casing contains compressor stages zero through 12. Extraction ports in the casing allow bleeds to the exhaust plenum during start-up and extraction of air to cool the second and third stage nozzles.

5.1.2.3.3 Compressor Discharge Casing

The compressor discharge casing contains 13th- through 17th- stage compressor stators and one row of exit guide vanes. It also provides an inner support for the first-stage turbine nozzle assembly and supports the combustion components. Air is extracted from the compressor discharge plenum to cool the stage one nozzle vane, retaining ring, and shrouds.

Similarly, air extracted from the compressor discharge plenum is used to provide the following:

- Atomizing air for liquid fuel
- Fuel system purge air
- Inlet bleed heat
- Compressor surge control

The compressor discharge casing consists of two cylinders connected by radial struts. The outer cylinder is a continuation of the compressor casing and the inner cylinder surrounds the compressor aft stub shaft. A diffuser is formed by the tapered annulus between the outer and inner cylinders. The compressor discharge casing is joined to the combustion wrapper at the flange on its outermost diameter.

5.1.3 Turbine Section

In the three stage turbine section, energy from hot pressurized gas produced by the compressor and combustion section is converted to mechanical energy. The turbine section is comprised of the combustion wrapper, turbine rotor, turbine shell, exhaust frame, exhaust diffuser, nozzles and diaphragms, stationary shrouds, and aft (number 2) bearing assembly.

5.1.3.1 Turbine Rotor

The turbine rotor assembly consists of a forward shaft, three turbine wheels, two turbine spacer wheels, and an aft turbine shaft which includes the number 2 journal bearing. The forward shaft extends from the compressor rotor aft stub shaft flange to the first stage turbine wheel. Each turbine wheel is axially separated from adjacent stage(s) with a spacer wheel. The spacer wheel faces have radial slots for cooling air passages, and the outer surfaces are machined to form labyrinth seals for interstage gas sealing.

Selective positioning of rotor members is performed during assembly to minimize balance corrections of the assembled rotor. Concentricity control is achieved with mating rabbets on the turbine wheels, spacers, and shafts. Turbine rotor components are held in compression by bolts. Rotor torque is accomplished by friction force on the wheel faces due to bolt compression.

The turbine rotor is cooled by air extracted from compressor stage 17. This air is also used to cool the turbine first- and second-stage buckets plus the rotor wheels and spacers.

5.1.3.2 Turbine Bucket Design

The first-stage buckets use forced air convection cooling in which turbulent air flow is forced through integral cast-in serpentine passages and discharged from holes at the tip of the trailing edge of the bucket. Second-stage buckets are cooled via radial holes drilled by a shaped tube electromechanical machining process. Third-stage buckets do not require air cooling.

Second- and third-stage buckets have integral tip shrouds which interlock buckets to provide vibration damping and seal teeth that reduce leakage flow. Turbine buckets are attached to the wheel with fir tree dovetails that fit into matching cutouts at the rim of the turbine wheel. Bucket vanes are connected to the dovetails by shanks which separate the wheel from the hot gases and thereby reduce the temperature at the dovetail. All turbine buckets are coated to provide corrosion resistance.

The turbine rotor assembly is arranged to allow buckets to be replaced without having to unstack the wheels, spacers and stub shaft assemblies. Similarly, buckets are selectively positioned such that they can be replaced individually or in sets without having to rebalance the wheel assembly.

5.1.3.3 Turbine Stator

The turbine stator is comprised of the combustion wrapper, turbine shell, and the exhaust frame. Like the compressor stator, the turbine stator is horizontally split for ease of handling and maintenance.

5.1.3.3.1 Combustion Wrapper

The combustion wrapper, located between the compressor discharge casing and the turbine shell, facilitates removal and maintenance of the transition pieces and stage one nozzle.

5.1.3.3.2 Turbine Shell

The turbine shell provides internal support and axial and radial positions of the shrouds and nozzles relative to the turbine buckets. This positioning is critical to gas turbine performance. Borescope ports are provided for inspection of buckets and nozzles.

5.1.3.3.3 Exhaust Frame

The exhaust frame is bolted to the aft flange of the turbine shell and consists of an outer and an inner cylinder interconnected by radial struts. The inner cylinder supports the number 2 bearing. The tapered annulus between the outer and inner cylinders forms the axial exhaust diffuser. Gases from the third-stage turbine enter the diffuser where the velocity is reduced by diffusion and pressure is recovered, improving performance.

Cooling of the exhaust frame, number 2 bearing, and diffuser tunnel is accomplished by motor-driven blowers. These motor driven blowers are located on the top of the gas turbine enclosure.

5.1.3.4 Turbine Nozzle Design

The turbine section has three stages of nozzles (stationary blades) with air cooling provided to all three stages. The first- and second-stage nozzles are cooled by a combination of film cooling (gas path surface), impingement cooling, and convection cooling in the vane and sidewall regions. The third stage uses convection cooling only.

All turbine nozzles consist of multi-vane segments. First-stage turbine nozzle segments are contained by a retaining ring which remains centered in the turbine shell. The second- and third-stage nozzle segments are held in position by radial pins from the shell into axial slots in the nozzle outer sidewall.

5.1.3.5 Bearings

The MS7001(FA) gas turbine contains two journal bearings to support the turbine rotor and one dual direction thrust bearing to maintain the rotor-to-stator axial position. The bearings are located in two housings: one at the inlet and one at the center of the exhaust frame. All bearings are pressure lubricated by oil supplied from the main lubrication oil system. The number 1 bearing (journal and thrust) is accessed by removing the top half of the compressor inlet casing. The number 2 bearing is readily accessible through the tunnel along the centerline of the exhaust diffuser. (Removal of the turbine casing is not required for bearing maintenance.) Bearing protection includes vibration sensors and drain oil temperature thermocouples.

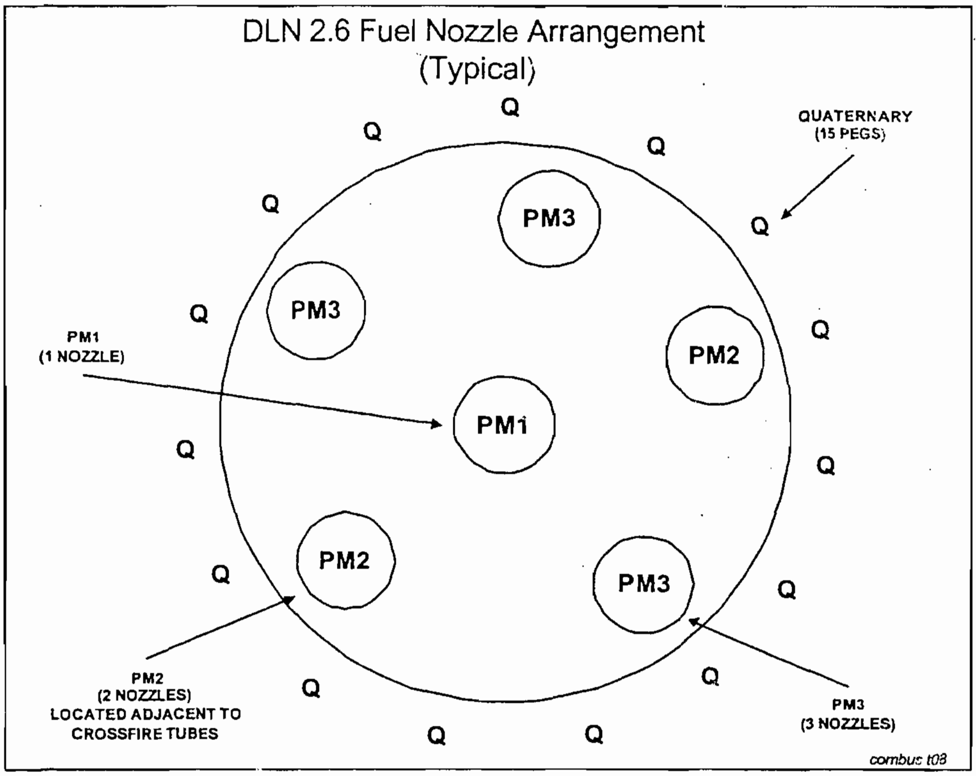
5.1.4 Combustion

5.1.5 Dry Low NOx 2.6 Combustion System

The Dry Low NOx 2.6 combustor was designed to minimize emissions when operating on gas fuel but is capable of operation with either gas or liquid fuel. Optimal emissions are achieved through the regulation of fuel distribution to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each fuel nozzle assembly is calculated to maintain unit load and fuel split which optimizes turbine emissions.

5.1.5.1 Fuel Nozzle Arrangement

The DLN 2.6 combustion system consists of six fuel nozzles per combustion can, each operating as a fully premixed combustor. One fuel nozzle is located in the center of the combustion can with five nozzles located radially from the first as shown in the illustration below. The center nozzles is identified as PM1 (Pre Mix 1). Two outer nozzles located adjacent to the crossfire tubes are identified as PM2 (Pre Mix 2). The remaining three outer nozzles are identified as PM3 (Pre Mix 3). Another fuel passage is located in the airflow upstream of the premix nozzles, circumferentially around the combustion can. This passage is identified as the quaternary fuel pegs.



Fuel flow to the six fuel nozzles and quaternary pegs is controlled by independent control valves, each controlling flow split and unit load. The gas fuel system consists of the gas fuel stop/ratio valve, gas control valve one (PM1), gas control valve two (PM2), gas control valve three (PM3), and gas control valve four (Quat).

The stop/ratio valve (SVR) is designed to maintain a predetermined pressure at the inlet of the gas control valves. Gas control valves one through four regulate the desired gas fuel flow delivered to the turbine in response to the command signal fuel stoke reference (FSR) from the gas turbine control panel. The DLN 2.6 control system is designed to ratio FSR into a Flow Control Reference. The flow control philosophy is performed in a cascading routine, scheduling a percentage flow reference for a particular valve, and driving the remainder of the percentage to the next valve reference parenthetically downstream in the control software.

5.1.5.2 Chamber Arrangement

The gas turbine employs fourteen combustors designated as combustion chambers. There are two spark plugs and four flame detectors in selected chambers with crossfire tubes connecting adjacent chambers. Each combustor consists of a six nozzle/endcover assembly, forward and aft combustion casings, flow sleeve assembly, multi-nozzle cap assembly, liner assembly and transition piece assembly. A quaternary nozzle arrangement penetrates the circumference of the combustion chamber, porting fuel to casing injection pegs located radially around the casing.

5.1.5.3 Spark Plug Ignition System

Two spark plugs located in different combustion chambers are used to ignite fuel flow. These spark plugs are energized to ignite fuel at firing speed during start-up only. Flame is propagated to those combustion chambers without spark plugs through crossfire tubes connecting adjacent combustion chambers around the gas turbine.

5.1.5.4 Flame Detectors

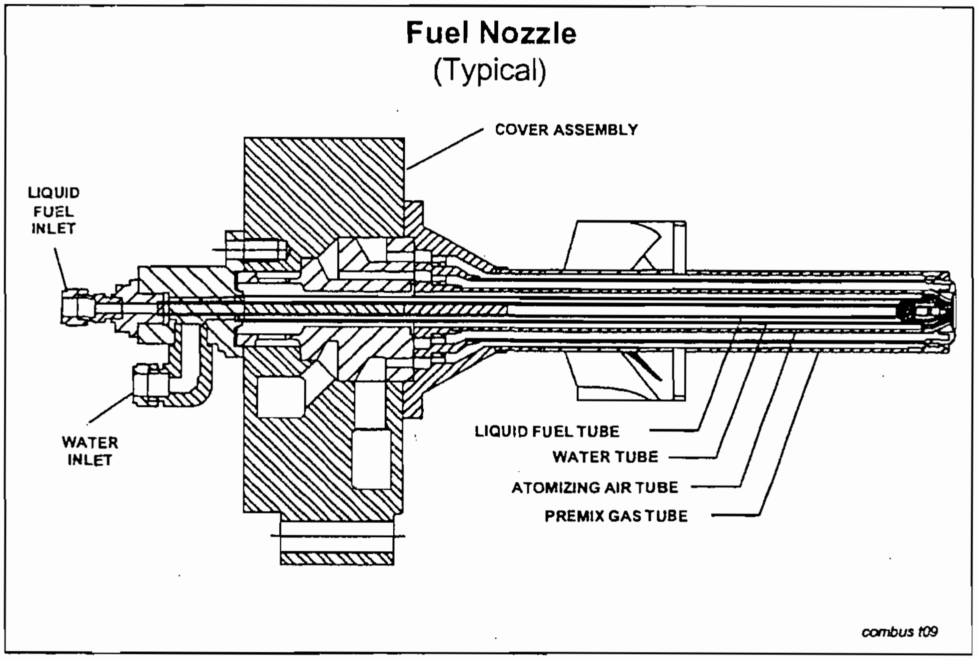
Reliable detection of flame location in the DLN 2.6 system is critical to the control of the combustion process and to protection of the gas turbine hardware. Four flame detectors are mounted in separate combustion chambers around the gas turbine to detect flame in all modes of operation. The signals from these flame detectors are processed in control logic and used for various control and protection functions.

5.1.5.5 Gas Fuel Operation

The DLN 2.6 fuel system operation is fully automated, sequencing the combustion system through a number of staging modes prior to reaching full load. The primary controlling parameter for fuel staging is the calculated combustion reference temperature. Other DLN 2.6 operation influencing parameters available to the operator are inlet guide vane (IGV) temperature control "ON" or "OFF" and inlet bleed heat "ON" or "OFF". To achieve maximum exhaust temperature, as well as an expanded load range for optimal emissions, both IGV temperature control and inlet bleed heat should be selected "ON".

5.1.5.5.1 Liquid Fuel Operation

Because liquid fuel injection occurs at the tips of the outer five fuel nozzle only, operation on liquid fuel is always in diffusion mode. A water injection passage, which is integral to the fuel nozzle as illustrated below, is used for NOx abatement while operating on liquid fuel.



5.1.5.6 Inlet Guide Vane Operation

The DLN 2.6 combustor emission performance is sensitive to changes in fuel/air ratio. The combustor was designed according to the airflow regulation scheme used with IGV temperature control. Optimal combustor operation is dependent upon proper operation along the predetermined temperature control scheme. Controlled fuel scheduling is dependent upon the state of IGV temperature control.

IGV temperature control "ON" is also referred to as a combined cycle operation while IGV temperature control "OFF" is referred to as simple cycle operation.

5.1.5.7 Fuel Flow Monitoring Equipment

The following fuel flow equipment is provided for integration by the customer into the fuel supply line:

- Gas
  - Meter tube and orifice with delta P transducers for flow indication
  - Transmitter for supply temperature indication
  - Static pressure transducer
- Distillate

— Fuel flowmeter

Flowmeter is installed on the fuel forwarding skid.

5.1.5.8 Water Injection System

The water injection system consists of pumping and metering equipment for supplying water to the combustion system for:

- NOx emission control

All piping and components which come into contact with water are stainless steel. The control system provides the above using minimum water injection and minimum degradation in heat rate by modulating the water injection rate proportional to fuel consumption.

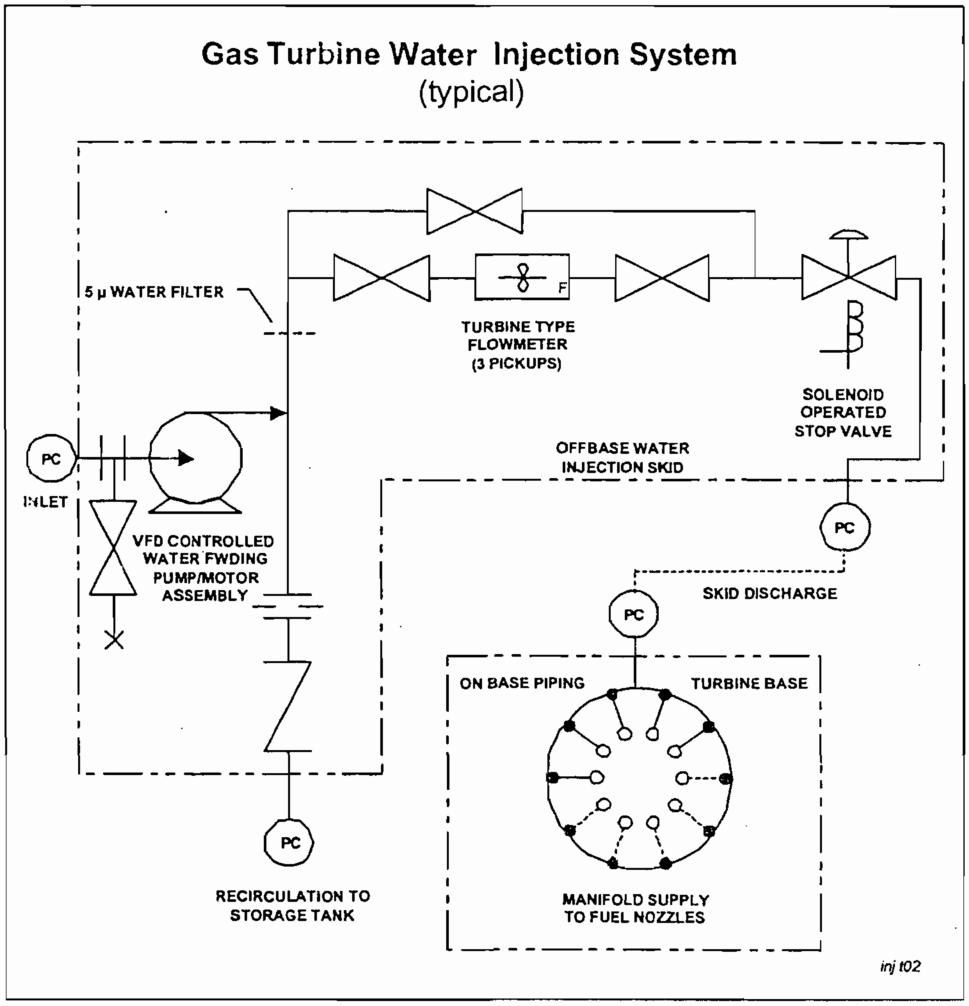
5.1.5.8.1 On-Base Equipment

The on-base equipment includes water supply manifold(s), water injection spray nozzles built into the fuel nozzles, and a piping connection to the off-base water supply.

Also located on-base are the controls for the water injection system consisting of automatic sequencing and flow rate control and operator interfaces for monitoring and recording of the water to fuel ratio and fuel flow.

5.1.5.8.2 Off-Base Water Injection Skid

The water injection skid is a self-contained system used to transport treated water from the customer's storage facility to the gas turbine at the proper pressure and flow rate. The skid includes the following components as illustrated in the diagram below:



5.1.5.8.2.1 Inlet Water Strainer

An inlet Y-strainer removes particles from the water before entering the injection pump. An inlet water pressure switch is included to monitor the differential across the strainer and signal an alarm through the gas turbine control system when cleaning is required.

5.1.5.8.2.2 Water Injection Pump

A single motor driven, high pressure centrifugal water injection pump is used to deliver the water to the gas turbine. The pump includes a variable frequency drive with pump/motor speed feedback. A pressure transmitter is supplied to monitor the water pressure at the pump discharge. The pump motor includes a space heater for anti-moisture condensation.

5.1.5.8.2.3 Water Filter

After exiting the pump, the water is cleaned using a five micron nominally rated filter. A differential pressure switch is included to signal through the gas turbine control system when filter cleaning is needed.

5.1.5.8.2.4 Water Flowmeter

Water usage is recorded by a turbine flowmeter with three identical pick-ups/transmitters and downstream strainer.

5.1.5.8.2.5 Solenoid Stop Valve

A water actuated solenoid stop valve is installed at the outlet connection of the water injection skid. The system also includes an actuation pressure regulator, actuation pressure relief valve, quick release valve, and actuation last-chance filter.

5.1.5.8.2.6 Electrical Equipment

Interconnecting wiring, conduit, junction box, and motor control center are included for the equipment mounted on the skid.

5.1.5.8.2.7 Skid Features

The skid includes a structural steel base, interconnecting piping for the skid mounted equipment, check valves, pressure gauges, inlet water temperature gauge, and manual isolation valves.

5.1.5.8.2.8 Enclosure

A weatherproof enclosure with ventilation fan and lighting is provided.

A space heater with controlling thermostat is supplied with the enclosure to guard against freezing.

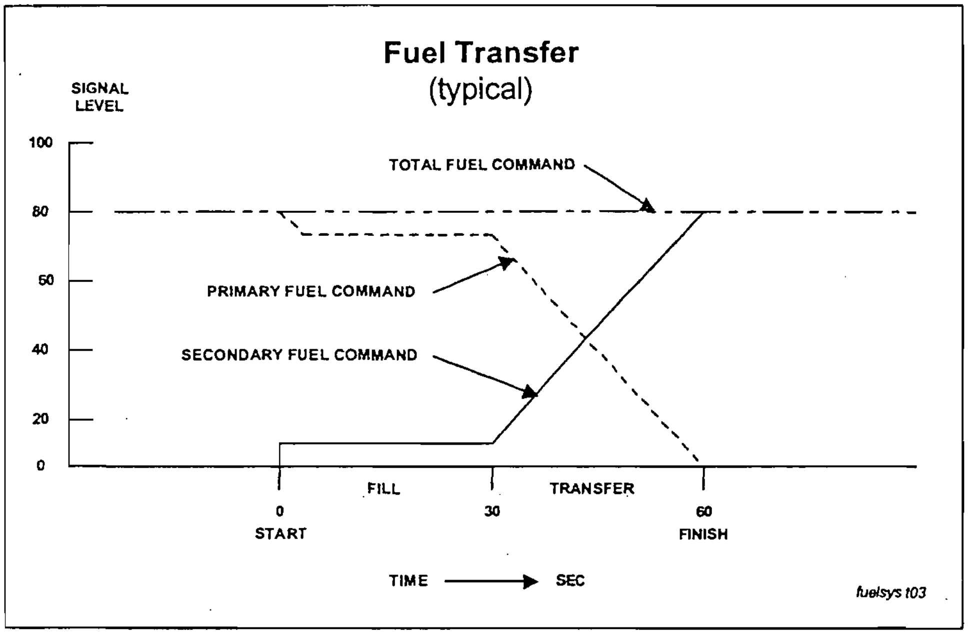
5.1.6 Fuel System

5.1.6.1 Dual Fuel System

The dual fuel system allows the gas turbine to operate on either gas or distillate fuel. Either may be used for start up. Transfers from one fuel to the other may be initiated by the operator prior to start up or at any time after completion of the starting sequence. Transfers from distillate to gas may be required to be made within a load range which results in completing the fuel transfer without staging from one gas fuel combustion mode to another.

Since gas is typically the primary fuel and distillate the backup fuel, transfers from gas to distillate are automatically initiated on low gas supply pressure, provided that liquid fuel is available and provided there is adequate time to start the fuel forwarding pump. Transfer back to the primary fuel is by operator initiation only in order to ensure the integrity of the fuel supply and to prevent oscillatory operation if the gas supply pressure is marginal at the transfer initiation pressure. The operator should confirm the availability of the primary fuel supply prior to initiating the transfer.

A typical fuel transfer is illustrated below. During fuel transfer, the energy equivalent of fuel flow as a function of the fuel command is matched between the two fuels to insure that equal fuel commands will result in equal energy release in the gas turbine combustors.



The transfer sequence is divided into two parts: a line filling period and the actual transfer. During the first period, the incoming fuel command increases to a level that will allow filling of the system in about thirty seconds, and the outgoing fuel command decreases by an equivalent amount. After fuel has reached the fuel nozzles, the incoming fuel is ramped up to equal the total fuel demand, and the outgoing fuel is ramped down to zero. Since total energy to the gas turbine is held reasonably constant, load variations are minimal—generally less than five percent of nameplate rating (for a properly matched and tuned system).

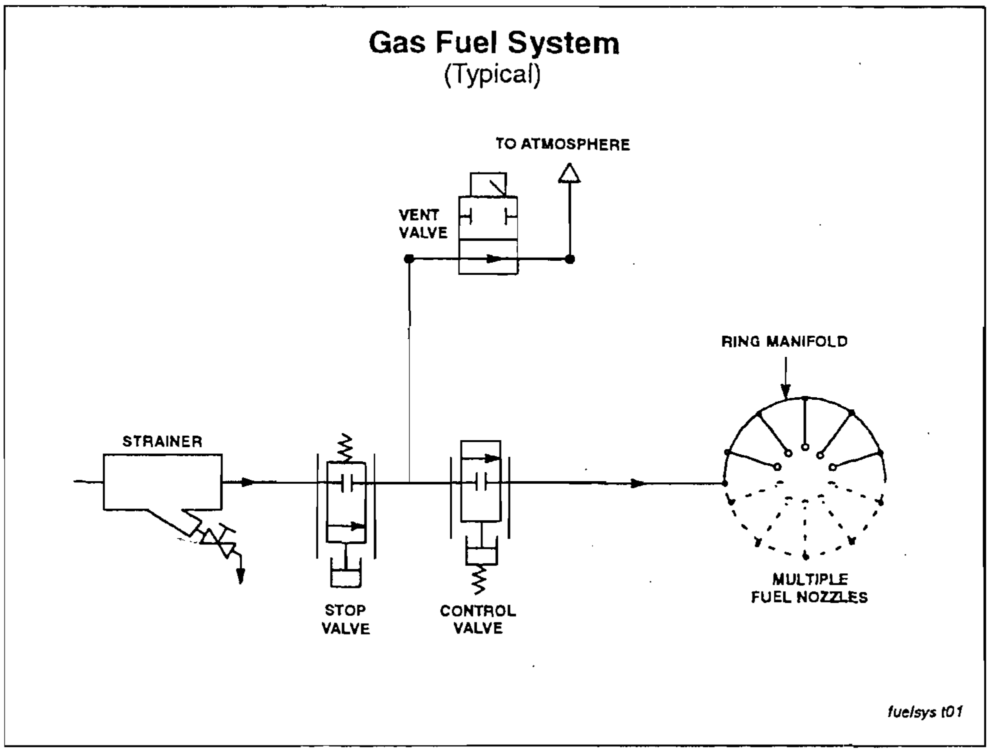
The next step in fuel transfer is purging the inactive fuel system and verifying proper operation. During purge of the inactive fuel system, the purge process introduces a limited amount of additional fuel injected into the turbine. The purge sequencing is designed to minimize this effect of this additional fuel flow. Purging of liquid fuel nozzles is initiated during the fuel transfer which causes random opening of purge check valves and significantly reduces load spikes.

If diluent injection is used to for emissions control, the fuel transfer is completed before diluent injection is initiated.

The gas and liquid fuel systems components are described in the sections which follow.

5.1.6.2 Gas Fuel System

The gas fuel system modulates the gas fuel flow to the turbine. Proper operation of the gas fuel system requires that the gas be supplied to the gas fuel control system at the proper pressure and temperature. The pressure is required to maintain proper flow control. The fuel gas temperature must ensure that the required hydrocarbon superheat is maintained. For discussion of fuel gas supply requirements in the Reference Documents - Process Specification Fuel Gases for Combustion in Heavy-Duty Gas Turbines. Major system components, as shown in the illustration which follows, are described below.



5.1.6.2.1 Strainer

A single strainer is used to remove impurities from the gas. A pressure switch which monitors the differential across the strainer will signal an alarm through the gas turbine control system when the pressure drop across the strainer indicates cleaning is required.

5.1.6.2.2 Fuel Gas Stop/Speed Ratio and Control Valves

The fuel gas stop/speed ratio and control valves allow fuel flow when the turbine starts and runs, control the fuel flow, and provide protective fuel isolation when the turbine is shut down. In systems with multiple control valve configuration, the control valves also maintain the fuel split among the fuel nozzles.

5.1.6.2.3 Vent Valve

When the gas fuel system is shut off, both the stop valve and the control valve(s) are shut. A vent valve is opened between the stop valve and the control valve(s). The vent valve permits the fuel gas to exit to the atmosphere when the turbine is shut down or switched to an alternate fuel.

5.1.6.2.4 Flow Measurement System

The gas fuel flow measurement system uses a flow metering tube with precision orifice. The pressure drop across the orifice is used to determine the fuel flow. To accommodate the large flow turndown, two delta-pressure transducers with different, but over-lapping ranges, are used.

5.1.6.2.5 Fuel Manifold and Nozzles

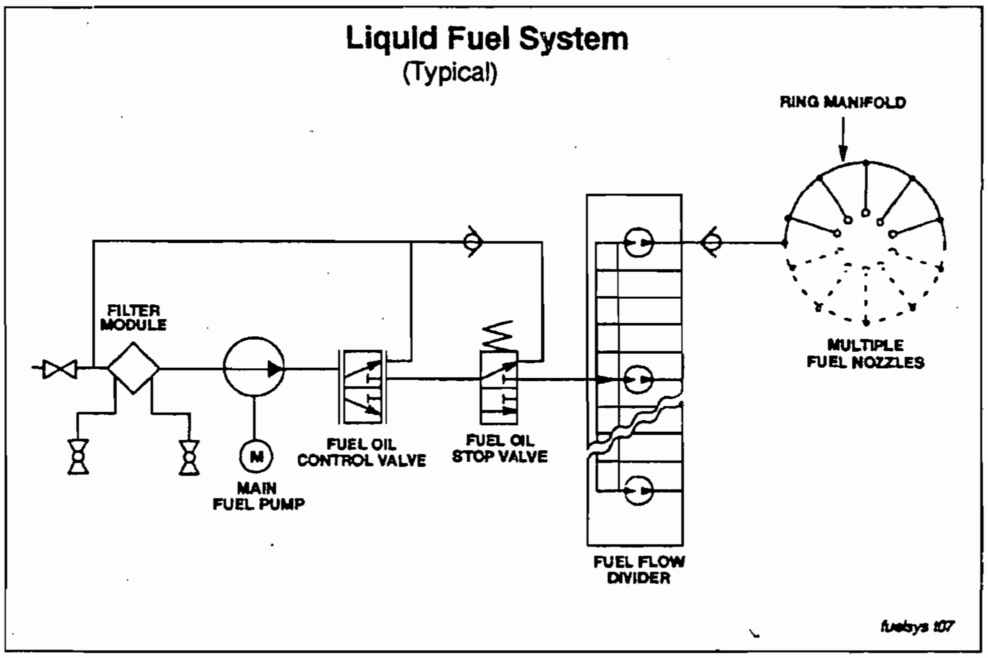
The fuel manifold connects the gas fuel nozzles which distribute the gas fuel into the combustion chambers. For staged combustion systems, more than one manifold is used.

5.1.6.2.6 Piping

The gas fuel system uses stainless steel fuel gas piping with carbon steel flanges.

5.1.6.3 Liquid Fuel System

The liquid fuel system delivers the fuel oil from the fuel forwarding system to the gas turbine combustion chambers. The system filters the fuel and controls the fuel flow to each of the nozzles in the gas turbine combustion chambers. Major system components, as shown in the illustration which follows, are described below.



5.1.6.3.1 Liquid Fuel Filter

Duplex low pressure fuel oil filters remove particles from the fuel before it reaches the main fuel oil pump. Pressure switches monitor the differential across each filter will signal an alarm through the gas turbine control system when transfer or changeout is required.

5.1.6.3.2 Fuel Oil Stop Valve

The on-base fuel oil stop valve allows fuel flow when the turbine starts and runs and provides protective fuel isolation when the turbine is shutdown.

5.1.6.3.3 Main Liquid Fuel Pump

A single 100% capacity motor-driven main fuel pump supplies high pressure fuel oil for normal start and operation of the gas turbine.

5.1.6.3.4 Bypass Valve

The liquid fuel system pumps fuel to the flow divider. Between the pump and the flow divider, a return line back to fuel storage permits some of the pump flow to be subtracted so that all of the pump output does not go to the turbine. An electro-hydraulically controlled valve uses flow subtraction to maintain proper fuel flow to the turbine combustion system.

5.1.6.3.5 Fuel Flow Divider

A mechanical fuel flow divider metering system distributes the liquid fuel flow equally to the gas turbine combustion chambers. The fuel flow divider includes magnetic pick-ups which detect the speed of rotation of the flow divider and provide feedback to the control system.

5.1.6.3.6 Fuel Nozzles

Fuel nozzles distribute the fuel into the combustion chambers. A selector valve assembly is included for reading individual fuel nozzle pressure at the output of the flow divider.

5.1.6.3.7 Atomizing Air System

The atomizing air system is used to atomize the liquid fuel for combustion.

The system uses a single air to water U-tube heat exchanger located on the turbine base to cool turbine compressor discharge air for entry into the atomizing air compressor. The air is filtered before it is used to atomize the liquid fuel for combustion.

A motor driven atomizing air compressor atomizes the liquid fuel for combustion. A throttling valve is included to reduce the atomizing air compressor outlet pressure for purging liquid fuel nozzles.

The atomizing air equipment is mounted on a combined Liquid Fuel/Atomizing Air Skid which includes a gauge/switch panel, and a weatherproof enclosure.

5.1.6.3.8 Piping

The liquid fuel system uses stainless steel fuel oil piping with carbon steel flanges.

5.1.6.4 Distillate Fuel Forwarding System

The distillate fuel forwarding system is a factory assembled pumping unit. It is a common system used to transfer the distillate fuel oil from the fuel storage tanks to two gas turbines at the proper pressure, temperature and flow rate. The skid, which includes a structural steel base and carbon steel piping, is designed for outdoor operation without an enclosure. Major system components are described below.

5.1.6.4.1 Inlet Isolation Valve

The inlet isolation valve allows the unit to be isolated and shut down for maintenance.

5.1.6.4.2 Duplex Strainer

The system includes a duplex-type strainer with cleanout drains to remove particles from the fuel before it reaches the fuel pump. A pressure switch which monitors the differential across the strainers will signal an alarm through the gas turbine control system when cleaning is required.

5.1.6.4.3 AC Motor-Driven Fuel Pumps

Dedicated ac motor driven fuel pumps supply the on-base high pressure main fuel oil pump for normal start and operation of each gas turbine. Fuel pump operation continues until the gas turbine is shut down or tripped out at which time system operation is stopped automatically by the gas turbine control system.

5.1.6.4.4 Backup AC Motor-Driven Fuel Pump

A single backup pump is included to provide protection against main fuel pump failure for either turbine. The main and backup pumps are driven by separate ac motors in a lead-lag relationship to balance the number of starts on each. Check valves in the discharge piping of each pump prevent backflow through the non-operating pump.

5.1.6.4.5 Fuel Heating

Distillate fuel oil is pumped to heaters which contain electric resistance heating elements and fuel passages arranged inside a welded steel shell. Thermostats control the temperature of the heaters to maintain the fuel temperature within the viscosity range limits required for proper atomization by the fuel nozzles in the combustion system. The heaters will not operate unless the ac pump is running.

Fuel heaters and accessories are mounted on a separate heater skid due to the size of the heaters required.

5.1.6.4.6 Relief Valve

The fuel heater vessel is protected against excessive pressure by a relief valve in the event of fluid thermal expansion with the isolation valves closed. The relief valve discharges into a piping bypass leading to the customer's connection for return to the storage tank. An over-temperature switch is also located in the piping bypass. The switch will signal an alarm through the gas turbine control system if the distillate fuel oil temperature exceeds its setting.

5.1.6.4.7 Pressure Regulating Valve

A pressure regulating valve is used to maintain the fuel pressure at the customer's connection within the limits required for the on-base turbine fuel system.

5.1.6.4.8 Flowmeter

A flowmeter with mechanical readout is installed in the fuel forwarding skid piping to record the amount of fuel being used per turbine.

5.1.6.4.9 Pulse Generator

Pulse generators are included to provide indication of distillate fuel flow rate at a remote location such as the plant distributed control system (DCS).

5.1.6.4.10 Solenoid Stop Valve

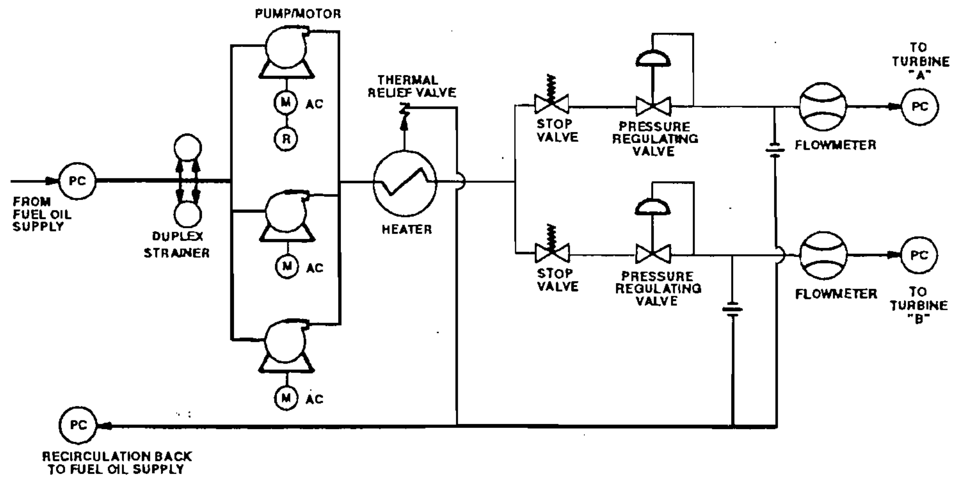
A normally closed, solenoid stop valve is installed at the outlet connection of the forwarding skid. This stop valve operates in conjunction with the on-base fuel oil stop valve to shut off fuel flow when the turbine is shut down. A constant recirculation loop from the downstream side of the pressure regulating valve to the storage tank is provided to prevent deadheading of the pump when the solenoid stop valve is closed.

5.1.6.4.11 Distillate Fuel Forwarding Skid Enclosure

While the fuel forwarding skid is designed for outdoor operation, a weatherproof enclosure is provided to protect against harsh weather conditions in areas subject to very low ambient temperature or heavy rains.

The enclosure is made up of steel panels that fit over the entire fuel forwarding skid, including the roof. Equipment can be easily maintained and removed via access doors and removable panels in the enclosure. Convenience lighting, receptacles and air vents with dust shields are also included.

Liquid Fuel Forwarding System Supplying Two Gas Turbines w/ Fuel Oil Heater
(Typical)



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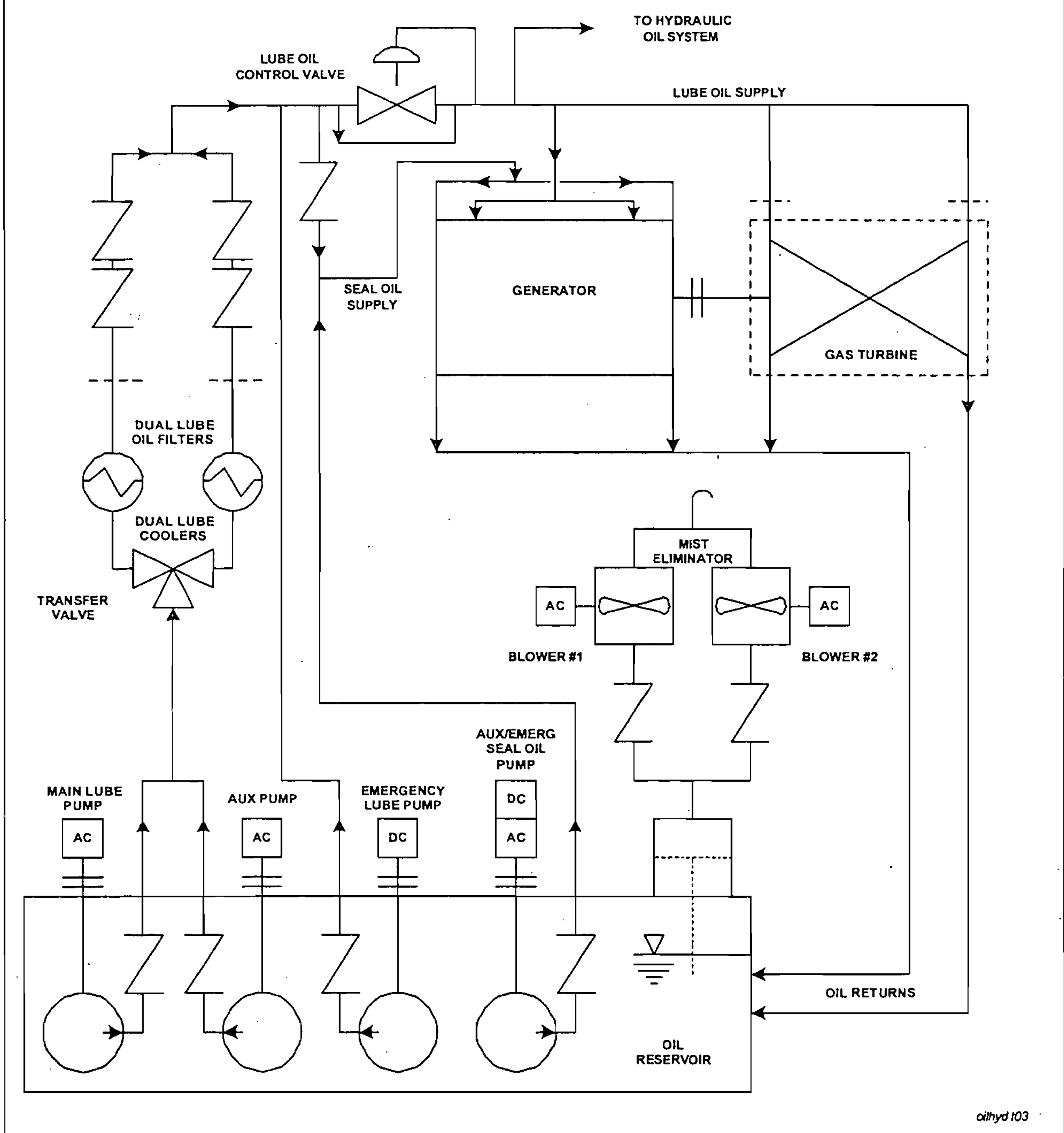
5.1.7 Lubricating and Hydraulic Systems

The lubricating provisions for the turbine and generator are incorporated into a common lubrication system. Oil is taken from this system, pumped to a higher pressure, and used in the hydraulic system for all hydraulic oil control system components. The lubrication system includes oil pumps, coolers, filters, instrumentation and control devices, a mist elimination device and an oil reservoir as shown in the system illustration below. Following the illustration is a brief description of the major system components.

Lube Oil System
MS7001(FA) and MS9001(FA)
(Typical)



5.1.7.1 Pumps

The lubrication system relies on several pumps to distribute oil from the oil reservoir to the systems which need lubrication. Similarly, redundant pumps are used to distribute high pressure oil to all hydraulic oil control system components. These and other oil pumps are listed below.

- Lubrication oil pumps
  - Dual redundant ac motor-driven main lubrication oil pumps are provided.
  - A partial flow, dc motor-driven, emergency lubrication oil centrifugal pump is included as a back up to the main and auxiliary pumps.
- Hydraulic pumps
  - Dual redundant ac motor-driven variable displacement hydraulic oil pumps are provided.
- Seal oil pump
  - An auxiliary generator seal oil pump driven by piggyback ac/dc motors is provided as backup to distribute seal oil to the generator.
- Oil Pump for pressure lift journal bearings
  - Oil for the pressure lift bearings is provided by the hydraulic oil pump.

5.1.7.2 Coolers

The oil is cooled by dual stainless steel plate/frame oil-to-coolant heat exchangers with transfer valve. The coolers have an ASME code stamp.

5.1.7.3 Filters

Dual, full flow filters clean the oil used for lubrication. Each filter includes a differential pressure transmitter to signal an alarm through the gas turbine control system when cleaning is required. A replaceable cartridge is utilized for easy maintenance. Filters have an ASME code stamp.

Dual filters clean the oil for the hydraulic system. Each filter includes a differential pressure transmitter to signal an alarm through the gas turbine control system when cleaning is required. A replaceable cartridge is utilized for easy maintenance. Filters have an ASME code stamp.

5.1.7.4 Mist Elimination

Lubrication oil mist particles are entrained in the system vent lines by sealing air returns of the gas turbine lubricating system. In order to remove the particles, a lube vent demister is used as an air-exhaust filtration unit. The demister filters the mist particles and vents the air to the atmosphere while draining any collected oil back to the oil reservoir.

The lube vent demister assembly consists of a holding tank with filter elements, motor-driven blowers, and relief valve. One assembly is provided for the vent line from the lubrication oil reservoir.

5.1.7.5 Oil Reservoir

The oil reservoir has a nominal capacity of 6200 gallons (23,470 liters) and is mounted within the accessory module. It is equipped with lubrication oil level switches to indicate full, empty, high level alarm, low level alarm, and low level trip. In addition the following are mounted on the reservoir:

- Oil tank thermocouples
- Oil heaters
- Oil filling filter
- Oil reservoir drains

5.1.8 Inlet System

5.1.8.1 General

Gas turbine performance and reliability are a function of the quality and cleanliness of the inlet air entering the turbine. Therefore, for most efficient operation, it is necessary to treat the ambient air entering the turbine and filter out contaminants. It is the function of the air inlet system with its specially designed equipment and ducting to modify the quality of the air under various temperature, humidity, and contamination situations and make it more suitable for use. The inlet system consists of the equipment and materials defined in the Scope of Supply chapter of this proposal. The following paragraphs provide a brief description of the major components of the inlet system.

5.1.8.2 Inlet Filtration

5.1.8.2.1 Inlet Filter Compartment

The self-cleaning inlet filter compartment utilizes high efficiency media filters which are automatically cleaned of accumulated dust, thereby maintaining the inlet pressure drop below a preset upper limit. This design provides single-stage high efficiency filtration for prolonged periods without frequent replacements. Appropriate filter media is provided based on the site specific environmental conditions.

Dust-laden ambient air flows at a very low velocity into filter modules which are grouped around a clean-air plenum. The filter elements are pleated to provide an extended surface. The air, after being filtered, passes through venturis to the clean air plenum and into the inlet ductwork.

As the outside of the filter elements become laden with dust, increasing differential pressure is sensed by a pressure switch in the plenum. When the setpoint is reached, a cleaning cycle is initiated. The elements are cleaned in a specific order, controlled by an automatic sequencer.

The sequencer operates a series of solenoid-operated valves, each of which controls the cleaning of a small number of filters. Each valve releases a brief pulse of high pressure air into a blowpipe which has orifices located just above the filters. This pulse shocks the filters and causes a momentary reverse flow, disturbing the filter cake. Accumulated dust breaks loose, falls, and disperses. The cleaning cycle continues until enough dust is removed for the compartment pressure drop to reach the lower setpoint. The design of the sequencer is such that only a few of the many filter elements are cleaned at the same time. As a consequence, the airflow to the gas turbine is not significantly disturbed by the cleaning process.

The filter elements are contained within a fabricated steel enclosure which has been specially designed for proper air flow management and weather protection.

Self-cleaning filters require a source of clean air for pulse-cleaning. Compressor discharge air is used as the pulse air source for filter cleaning. It is reduced in pressure, cooled and dried. This air is already clean because it has been filtered by the gas turbine's inlet air filter. When compressor discharge air is used to pulse the filter, cleaning is possible only when the gas turbine is running.

5.1.8.3 Inlet System Instrumentation

5.1.8.3.1 Inlet System Differential Pressure Indicator

Standard pressure drop indicator (gauge) displays the pressure differential across the inlet filters in inches of water.

5.1.8.3.2 Inlet System Differential Pressure Alarm

When the pressure differential across the inlet filters reaches a preset value, an alarm is initiated. This alarm may signify a need to change the filter elements.

5.1.9 Exhaust System

The exhaust system arrangement includes the exhaust diffuser. After exiting the last turbine stage, the exhaust gases enter the exhaust diffuser section in which a portion of the dynamic pressure is recovered as the gas expands. The gas then flows axially into the exhaust system.

5.1.10 Gas Turbine Packaging

5.1.10.1 Enclosures

Gas turbine enclosures consist of several connected sections forming an all weather protective housing which may be structurally attached to each compartment base or mounted on an off-base foundation. Enclosures provide thermal insulation, acoustical attenuation, and fire extinguishing media containment. For optimum performance of installed equipment, compartments include the following as needed:

- Ventilation
- Heating
- Cooling

In addition, enclosures are designed to allow access to equipment for routine inspections and maintenance.

5.1.10.2 Acoustics

Measuring procedures will be in accordance with ASME PTC 36 (near field) and/or ANSI B133.8 (far field).

For acoustic guarantees, please refer to the Performance Guarantees section of the proposal.

5.1.10.3 Painting

The exteriors of all compartments and other equipment are painted with alkyd or epoxy primer prior to shipment. The exterior surfaces of the inlet compartment and inlet and exhaust duct are painted with one coat of inorganic zinc primer.

Interiors of all compartments are painted as well with the turbine compartment interior receiving high-temperature paint. The interior and exterior of the inlet system are painted with zinc rich paint.

5.1.10.4 Lighting

AC lighting on automatic circuit is provided in the turbine and accessory compartments. When ac power is not available, a dc battery-operated circuit supplies a lower level of light automatically.

Fluorescent lighting is also provided in the PEECC.

5.1.10.5 Wiring

The gas turbine electrical interconnection system includes on-base wiring, terminal boards, junction boxes, etc. as well as compartment interconnecting cables. Junction boxes are selected to meet the environmental requirement of the Customer but are, in general, of steel or cast aluminum construction. Terminal boards within junction boxes are of the heavy duty industrial type selected for the particular environment in which the junction box is located. On-base gas turbine wire termination uses spring tongue crimped type terminals. Generator wire termination are ring type. Control panel wiring is General Electric type SIS Vulkene insulated switchboard wire, AWG #14-41 Strand SI-57275. Ribbon cables are used as appropriate.

5.1.11 Fire Protection System

Fixed temperature sensing fire detectors are provided in the gas turbine, accessory and liquid fuel/atomizing air compartments, and #2 bearing tunnel. The detectors provide signals to actuate the low pressure carbon dioxide (CO2) automatic multi-zone fire protection system. Nozzles in these compartments direct the CO2 to the compartments at a concentration sufficient for extinguishing flame. This concentration is maintained by gradual addition of CO2 for an extended period.

The fire protection system is capable of achieving a non-combustible atmosphere in less than one minute, which meets the requirements of the United States National Fire Protection Association (NFPA) #12.

The supply system is composed of a low pressure CO2 tank with refrigeration system mounted off base, a manifold and a release mechanism. Initiation of the system will trip the unit, provide an alarm on the annunciator, turn off ventilation fans and close ventilation openings.

5.1.12 Cleaning Systems

5.1.12.1 On-Line and Off-Line Compressor Water Wash

Compressor water wash is used to remove fouling deposits which accumulate on compressor blades and to restore unit performance. Deposits such as dirt, oil mist, industrial or other atmospheric contaminants from the surrounding site environment, reduce air flow, lower compressor efficiency, and lower compressor pressure ratio, which reduce thermal efficiency and output of the unit. Compressor cleaning removes these deposits to restore performance and slows the progress of corrosion in the process, thereby increasing blade wheel life.

On–line cleaning is the process of injecting water into the compressor while running at full speed and some percentage of. load. Off–line cleaning is the process of injecting cleaning solution into the compressor while it is being turned at cranking speed. The advantage of on–line cleaning is that washing can be done without having to shut down the machine. On–line washing, however, is not as effective as off–line washing; therefore on–line washing is used to supplement off–line washing, not replace it.

The on–base compressor washing features are described and illustrated below.

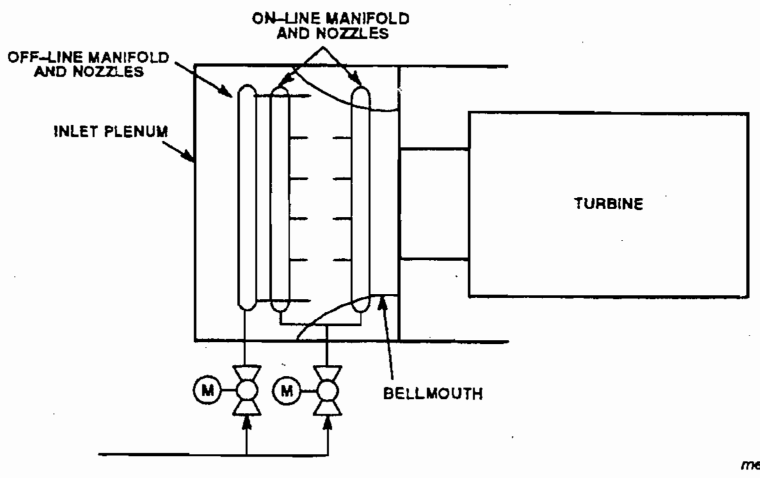
5.1.12.1.1 On–Line Manifold and Nozzles

The on–line washing components consist of two piping manifolds, spray nozzles (one in the forward bellmouth and one in the aft bellmouth), and an on/off control valve which is also controlled by the turbine control panel. The turbine control system is equipped with software to perform an automatic on–line wash by simply initiating the wash from the turbine control panel.

5.1.12.1.2 Off–Line Manifold and Nozzles

Off-line washing is a manual operation because of the large number of manual valves on the turbine which need to be manipulated in order to perform an off-line wash. During off-line washing, cleaning solution (water and/or detergent) is injected into the compressor while it is being turned at crank speed. The cleaning solution is sprayed into the compressor inlet, covering the entire circumference. This should continue until the runoff is free of contaminants.

Water Wash Off and On–Line Manifold and Nozzles
(Typical)



5.1.12.1.3 Water Wash Skid

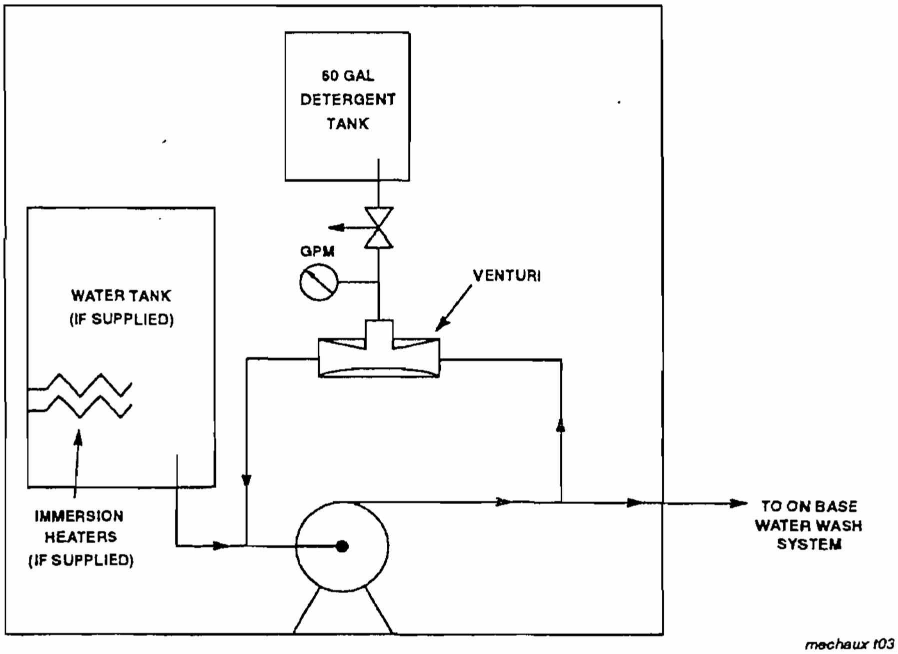
The off–base water wash skid is used for injecting cleaning solution into the compressor for off–line cleaning. The skid contains a water pump, a detergent storage tank, piping, and a venturi eductor capable of delivering solution at the proper flow, pressure and mix ratio.

In addition, the water wash skid is equipped with the following features:

- Water storage tank with freeze protection
- Enclosure for outdoor installation

Typical water wash skid features are shown in the illustration which follows.

Compressor Water Wash Skid
(Typical)



5.1.13 Starting System

5.1.13.1 Cooldown System

The cooldown system provides uniform cooling of the rotor after shutdown. A low speed turning gear with motor is used for the cooldown system.

5.1.13.2 Static Start System

5.1.13.2.1 Operation

The static start system uses a Load Commutating Inverter (LCI) adjustable frequency drive as the starting means for the gas turbine. By providing variable frequency power directly to the generator terminals, the generator is used as a synchronous motor to start the gas turbine. The generator will be turning at approximately 6 rpm, via a low speed turning gear, prior to starting. With signals from the turbine control, the LCI will accelerate or decelerate the generator to a self-sustaining speed required for purge, light-off, waterwash etc. Deceleration is a coast down function.

The system can accelerate the gas turbine-generator without imposing high inrush currents, thereby avoiding traditional voltage disturbances on the ac station service line.

Conventional three phase, 12-pulse bridge circuits are used for the rectifier and inverter and are connected through a dc link inductor. An isolation transformer is required to provide three phase power, impedance for fault protection, and electrical isolation from system disturbances to ground.

Starting excitation is provided by the generator excitation system.

5.1.13.2.2 System Protection

The drive system protective strategy is to provide a high level of fault protection for the major equipment. The rectifier inverter includes voltage surge protection and full fault suppression capability for internal faults or malfunctions. A drive system monitor and diagnostic fault indications continuously monitor the condition and operation of the LCI.

5.1.13.2.3 Equipment

5.1.13.2.3.1 Low Speed Turning Gear

The turning gear assembly is located on the collector end of the generator and is used for slow speed operation (approximately 6 rpm), cooldown and standby turning, and rotor breakaway during startup.

5.1.13.2.3.2 LCI Power Conversion Equipment

The LCI power conversion equipment is mounted in a NEMA 1 ventilated enclosure and consists of the following:

- 12-pulse converter with series redundant thyristor cells to rectify ac line power to controlled voltage dc power.

- Inverter with series redundant cells to convert dc link power to controlled frequency ac power.
- Cooling system using a liquid coolant to transfer heat from heat producing devices, such as SCRs and high wattage resistors, to a remote liquid-liquid heat exchanger. The system is closed-loop with a covered reservoir for makeup coolant. Coolant circulates from the pump discharge to the heat exchanger to the power conversion bridges and returns to the pump. A portion of the coolant bypasses to a deionizer system to maintain coolant resistivity. Redundant pumps are provided.
- LCI control panel containing microprocessor system control logic for firing, drive sequencing, diagnostics and protective functions, acceleration (ramping function), excitation system interface, and input/output signal interfacing.

  Note: The control panel is located in the LCI enclosure and includes door mounted panel meters and operator devices.

5.1.13.2.3.3 DC Link Reactor

The dc link reactor helps smooth the dc current to eliminate coupling between the frequencies of the converter and inverter and provides protection during system faults by limiting the current.

The dc link is a dry-type, air core reactor which is convection cooled. It is located in an outdoor protective enclosure and electrically connected between the converter and the inverter.

5.1.13.2.3.4 Isolation Transformer

The isolation transformer provides electrical isolation and impedance for system protection against notching and harmonic distortion. The transformer has two secondary windings and is designed for service with a three phase, six pulse power converter connected to each secondary winding. One transformer is provided for each LCI.

The transformer is a three winding, oil filled type for outdoor mounting.

5.1.13.2.3.5 Motorized Disconnect Switch

A motorized disconnect switch is provided to disconnect the static start system during normal generator operation. The disconnect switch is electrically connected between the LCI and the feed for the generator stator.

5.1.14 Miscellaneous Parts

As a service to the customer and to facilitate an efficient installation of the gas turbine, GE provides for shipment of miscellaneous parts needed during field installation.

Shipment is in a single 96" x 96" x 192" (2438 mm x 2438 mm x 4877 mm) weather-tight cargo container. The plywood container, which can be opened from one end, is outfitted with shelves and bins for parts storage. The container comprises what amounts to a "mobile stockroom" and is designed for transport by truck or rail.

Within the container, each part is packed, identified with its own label or tag, and stowed in an assigned bin or shelf. A master inventory list furnished with the container provides the location of each part for ease in locating the item.

An additional box approximately 60" x 60" x 216" (1524 mm x 1524 mm x 5486 mm) is furnished for the interconnecting piping.

5.2 Gas Turbine Generator

5.2.1 Electrical Rating

The generator is designed to operate within Class "B" temperature rise limits, per ANSI standards, throughout the allowable operating range. The insulation systems utilized throughout the machine are proven Class "F" materials.

The generator is designed to exceed the gas turbine capability at all ambient conditions between 0 and 120°F.

5.2.2 Packaging

The 7FH2 generator is designed for compactness and ease of service and maintenance. Location permitting, the unit ships with the rotor, gas shields and end shields factory assembled. The high voltage bushings, bearings, oil deflectors, hydrogen seals, and coolers are also factory assembled. The collector cab ships separately for assembly to the generator at the customer's site. Clearances of the bearings, rub rings, fans, hydrogen seals and deflectors are factory fitted and only require a minimum amount of field inspection of these components.

All generator wiring, including winding and gas RTDs, bearing metal and drain TCs, and vibration detection systems are terminated on the main unit with level separation provided.

Prior to full assembly, the generator stator receives a pressure test at 150% of operating pressure followed by a leakage test at 100% of operating pressure.

Feed piping between the bearings are stainless steel and mounted on the units in the factory to a common header. All connections to the end shields are assembled. All assembled piping is welded without backing rings and a first pass TIG weld. A full oil flush is performed prior to shipping.

Some amount of field assembly is required but should be limited to the following:

- Factory fitted bearing drain piping and bearing drain enlargement (BDE)
  - Matched, marked, and shipped separate
  - Loop seal between BDE and drain tank are stainless steel and ship loose
- Water manifolds are factory fitted and shipped separate
- Collector compartment:
  - Collector end housing and brush rigging are shipped as part of the collector compartment and require some assembly and alignment
  - Interconnecting piping from cab to generator
  - Interconnecting wiring from cab to generator

5.2.3 Frame Fabrication

The frame is a stiff structure, constructed to be a hydrogen vessel and to be able to withstand in excess of 200PSI. It is a hard frame design with its four-nodal frequency significantly above 120Hz. The ventilation system is completely self contained, including the gas coolers within the structure. The gastight structure is constructed of welded steel plate, reinforced internally by radial web plates and axially by heavy wall pipes, bars and axial braces.

A series of floating support rings and core rings are welded to keybars which in turn support the core, allowing the entire core to be spring mounted at twenty locations. This arrangement isolates the core vibration, resulting from the radial and tangential magnetic forces of the rotor, by damping the amplitude and reducing the transmissibility by 20:1 Excessive movement of the core, as may result from out of phase synchronization, is limited by the use of stop collars at certain circumferential locations around the frame. The clearance is designed to allow the spring action of the bar to be unrestricted during normal operation but to transmit the load of excessive movement through the structure prior to yielding of any of the components. This entire arrangement is in keeping with long standard practices and experience with similar frame designs which have proven to be very effective and reliable.

The stator frame is supported on four welded-on feet attached at the lower portion of the fabrication. All the weight of the unit and the operating loads are carried through the structure by the web plates and the wrapper to the feet. The machined portion of the feet are located 85" below the centerline of the unit.

5.2.4 Core

The core is laminated from grain oriented silicon steel to provide maximum flux density with minimum losses, thereby providing a compact electrical design. The laminations are coated on both sides to ensure electrical insulation and reduce the possibility of localized heating resulting from circulation currents.

The overall core is designed to have a natural frequency in excess of 170 hertz, well above the critical two-per-rev electromagnetic stimulus from the rotor. The axial length of the core is made up of many individual segments separated by radial ventilation ducts. The ducts at the core ends are made of stainless steel to reduce heating from end fringing flux. The flanges are made of cast iron to minimize losses. To ensure compactness, the unit receives periodic pressing during stacking and a final press in excess of 700 tons after stacking.

5.2.5 Rotor

The rotor is machined from a single high alloy steel forging. The two pole design has 24 axial slots machined radially in the main body of the shaft. The axial vent slots machined directly into the main coil slot are narrower then the main slots and provide the direct radial cooling of the field copper.

The two retaining rings are of the body mounted design. The rings are made of 18 Mn - 18 Cr forged material which offers excellent protection against stress corrosion cracking.

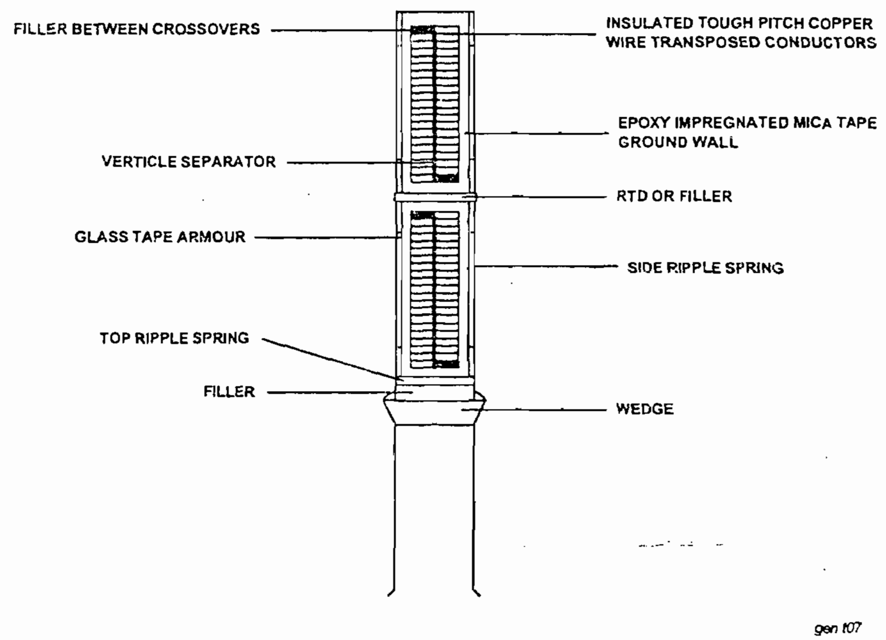
The coil wedges are segmented stainless steel. Radial holes are drilled in the wedges for ventilation passages.

A shrunk-on coupling is assembled after the collector rings are on, and provides the interface point to the flex-coupling connection to the turning gear. This arrangement is used with a static start system.

5.2.6 Field Assembly

The field consists of several coils per pole with turns made from high conductivity copper. Each turn has slots punched in the slot portion of the winding to provide direct cooling of the field.

Stator Slot Section
(Typical)



The slot armor used in the slots is a Class ""F"" rigid epoxy glass design. An insulated cover is positioned on the bottom of each slot armor and on top of the subslot vent. The cover will provide the required creepage between the lower turn and the shaft. Epoxy glass insulation strips are used between each coil turn. A pre-molded glass retaining ring insulation is utilized over the end windings and a partial amortisseur is assembled under the rings to form a low resistance circuit for eddy currents to flow. The rotor is designed to accommodate static start hardware utilizing slot amortisseurs.

The collector assembly incorporates all the features of GE proven generator packages with slip on insulation over the shaft and under the rings. The collector rings use a radial stud design to provide electrical contact between the rings and the field leads. The rings are designed to handle the excitation requirements of the design (approximately 2200 amps on cold day operation and 1900 amps at rated conditions).

The entire rotor assembly, weighing 74,000 pounds is balanced up to 20% over operating speed.

5.2.7 End Shield/Bearing

The unit is equipped with end shields on each end designed to support the rotor bearings, to prevent gas from escaping, and to be able to withstand a hydrogen explosion in the unlikely event of such a mishap. In order to provide the required strength and stiffness, the end shield is constructed from steel plate and is reinforced. The split at the horizontal joint allows for ease of assembly and removal.

The horizontal joints, as well as the vertical face which bolts to the end structure, are machined to provide a gas tight joint. Sealing grooves are machined into these joints. These steps are taken to prevent gas leakage between all the structural components for pressures up to 45 psig.

The center section of the end shields contain the bearings, oil deflectors and hydrogen seals. The lower halves of the bearings are equipped with dual element thermocouples. The leads are connected through a quick disconnect through the end shield to allow ease of bearing removal.

Vertically split inner and outer oil deflectors are bolted into the end shield and provide sealing of the oil along the shaft. The deflectors are either fabricated or cast aluminum. All faces of the deflectors have "O" ring grooves to provide additional protection from oil leaks. All annular areas formed between the set of teeth are designed to provide minimum pressure drops and have oil gutters machined in to prevent oil from backdripping on the shaft.

The hydrogen seal casing and seals, which prevent hydrogen gas from escaping along the shaft, utilize steel babbitted rings. Pressurized oil for the seals is supplied from the main oil system header to the seal oil control unit, where it is regulated. The seal oil control unit is factory assembled packaged system and is located in the collector end compartment and includes the following components:

- Differential pressure regulator valve with bypass
- Differential pressure gage (seal oil pressure vs. casing gas pressure) and two differential pressure switches: one for alarm and one for actuating the dc emergency seal oil pump
- Shut-off and isolation valves for operation and maintenance

The collector end bearing and hydrogen seals are insulated from the rotor to prevent direct electrical contact between the rotor and the end shield. Both end shields have proximity type vibration probes. These are located axially at the bearing. Mounting for velocity type vibration sensors is also provided on the surface of the bearing caps.

All exiting wiring from the temperature indication devices and the insulating test leads are brought out of the unit through gas tight conex type seals to prevent any chance of a hydrogen leak.

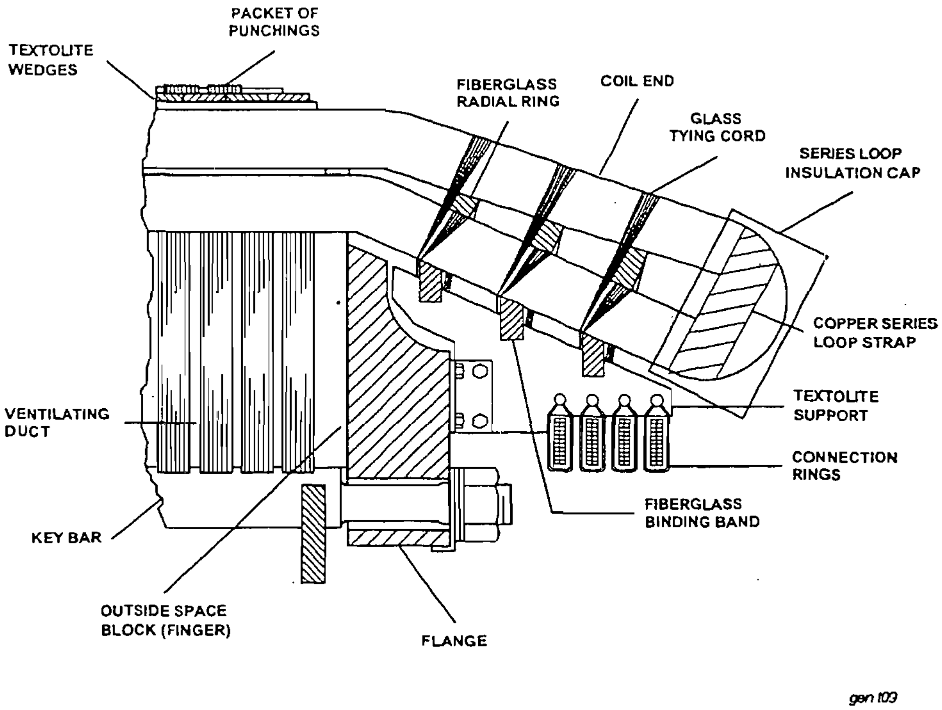
5.2.8 Winding

The armature winding is a three phase, two circuit design consisting of "Class F" insulated bars. The stator bar stator ground insulation is protected with a semi-conducting armor in the slot and GE's well proven voltage grading system on the end arms.

The ends of the bars are pre-cut and solidified prior to insulation to allow strap brazing connections on each end after the bars are assembled. An epoxy resin filled insulation cap is used to insulate the end turn connections.

The bars are secured in the slot with side ripple springs (SRS) to provide circumferential force and with a top ripple spring (TRS) for additional mechanical restraint in the radial direction. The end winding support structure consists of glass binding bands, radial rings, and the conformable resin-impregnated felt pads and glass roving to provide the rigid structure required for system electrical transients.

Stator End Winding Structure
(Typical)



5.2.9 Lead Connections

All the lead connection rings terminate at the top of the excitation end of the unit and the six high voltage bushings (HVBs) exit at the top of the frame.

Each of the circuits are connected to the high voltage bushings (HVBs.) The bushings, which provide a compact design for factory assembly and shipment, are positioned in the top of the frame and are offset to allow proper clearances to be maintained. This configuration also allows connections to the leads to be staggered and provides ease of bolting and insulation.

The bushings are made up of porcelain insulators containing silver plated copper conductors which form a hydrogen tight seal. The bushings are assembled to non-magnetic terminal plates to minimize losses. Copper bus is assembled to the bushings within an enclosure. Customer connections are made beyond the terminal enclosure and the specific mating arrangements are provided within the enclosure, not inside the generator.

5.2.10 Lubrication System

Lubrication for the generator bearings is supplied from the turbine lubrication system. Generator bearing oil feed and drain interconnecting lines are provided, and have a flanged connection at the turbine end of the generator package for connection to the turbine package.

5.2.11 Hydrogen Cooling System

The generator is cooled by a recirculating hydrogen gas stream cooled by gas-to-water heat exchangers. Cold gas is forced by the generator fans into the gas gap, and also around the stator core. The stator is divided axially into sections by the web plates and outer wrapper so that in the center section cold gas is forced from the outside of the core toward the gap through the radial gas ducts, and in the end section it passes from the gas gap toward the outside of the core through the radial ducts. This arrangement results in substantially uniform cooling of the windings and core.

The rotor is cooled externally by the gas flowing along the gap over the rotor surface, and internally by the gas which passes over the rotor and windings, through the rotor ventilating slots, and radially outward to the gap through holes in the ventilating slot wedges.

After the gas has passed through the generator, it is directed to five horizontally mounted gas-to-water heat exchangers. After the heat is removed, cold gas is returned to the rotor fans and recirculated.

5.2.12 Hydrogen Control Panel

To maintain hydrogen purity in the generator casing at approximately 98 percent, a small quantity of hydrogen is continuously scavenged from the seal drain enlargements and discharged to atmosphere. The function of the hydrogen control panel is to control the rate of scavenging and to analyze the purity of the hydrogen gas. The panel is divided into two compartments, the gas compartment and the electrical compartment, which are separated by a gas-tight partition.

5.2.12.1 Control Panel Functions

The GE hydrogen control panel is designed for use on hydrogen cooled generators with scavenging systems. The panel functions are described below:

- The hydrogen control panel allows manual control of the continuous scavenging rate, both turbine end and collector end, via metering valves.
- Hydrogen from the generator turbine end and generator collector end is continuously monitored for purity. At predetermined time intervals, the purity of the generator core gas is also checked. Two independent, switchable, triple range hydrogen purity analyzers are used, thus providing total redundancy, for two out of two voting. Each display and control panel will include three digital displays providing real time readout of gas purity, gas temperature and the status of the analyzers operating parameters. All information is provided to the station DCS via contact inputs and 4-20 milliamp analog signals.
- In the event that one of the analyzers detect a drop in purity, a confirmation by the other gas analyzer is performed. Time for the measurement, which requires reconfiguration of the valves, as well as the handling of possible disagreements in measurement results, is also negotiated between the analyzers.
- In the event that either analyzer indicates a low purity alarm, the rate of scavenging is increased automatically and an alarm is annunciated.
- All components used in the hydrogen control panel are specifically designed and / or third party approved for use in an Class I, Division I, Group B environment.

5.2.12.2 Control Panel Devices

5.2.12.2.1 Differential Pressure Gas Transmitter

The differential pressure gas transmitter measures the generator fan differential gas pressure. It provides a 4-20 mA DC signal proportional to differential gas pressure and includes a 316L stainless steel diaphragm all housed in a Factory Mutual approved explosion proof enclosure.

5.2.12.2.2 Differential Gas Pressure Gage

The differential gas pressure gage provides local indication of the generator fan differential gas pressure. The gage is flush mounted, waterproof, dual range and stainless steel movements.

5.2.12.2.3 Gas Pressure Transmitter

The gas pressure transmitter measures the generator core gas pressure or machine gas pressure as it is sometimes called. It provides a 4-20 mA DC signal proportional to gas pressure and includes a 316L stainless steel diaphragm all housed in a Factory Mutual approved explosion proof enclosure.

5.2.12.2.4 Gas Pressure Gage

The gas pressure gage provides local indication of the generator core gas pressure. The gage is flush mounted, water proof, dual range and stainless steel movements.

5.2.12.2.5 Total Gas Flowmeter

The total gas flowmeter provides local indication of the total flow of scavenged gas. The flowmeter is a flush mounted, in line, direct read flowmeter with stainless steel body.

5.2.12.2.6 Gas Analyzer Flowmeters (2)

Gas analyzer flowmeters provide local indication and control of the gas flow through each of the gas analyzers. Each flowmeter is a flush mounted, in line, direct read flowmeter with stainless steel body.

5.2.12.2.7 Gas Purifiers (3)

Gas purifiers remove oil, water and foreign particles from each of the gas sampling lines (turbine end, collector end and core gas).

5.2.12.2.8 Moisture Indicators (3)

Moisture indicators provide local indication relating to the operating condition of the gas purifiers in each of the gas sampling lines (turbine end, collector end and core gas).

5.2.12.2.9 Control Cabinet

The standard cabinet is NEMA 1 rated and mounted in the collector compartment.

5.2.12.2.10 Solenoid Valves

All solenoid valves have stainless steel bodies with class H temperature rated coils. The solenoids are also third party approved for use in a Class 1, Division 1, Group B environment.

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 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. Alternatively to annual testing in a given year, periodic tuning data may be provided to demonstrate compliance in the year the tuning is conducted. 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.

35. Compliance with the VOC Emission Limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, 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. Upon request from DEP, the CEMS emission rates for NO_X on each 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. These excess emissions periods shall be reported as required in Condition 24 and 45. [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, that 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.

51. Continuous Compliance with the 74.9 MW Steam Power Generated Limitation:

Electrical power from the steam-electrical generator shall be limited to 74.9 MW on an hourly basis. CPV shall be capable of demonstrating to the Department, continuous compliance with the 74.9 MW limit by the stored information in the power plant's electronic data system.

Exceedance of this limit is not allowed and can result in a requirement to obtain plant certification under Sections 403.501-518, F.S.

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)

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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 technology 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		3.5 - NG 15 - FO	SCR	2x170 MW WH501F Under Review
Calpine Osprey, FL	527	3.5 – NG		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 NO_X 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	20 lb/hr – NG 51 lb/hr – FO 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 ______________
- 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.

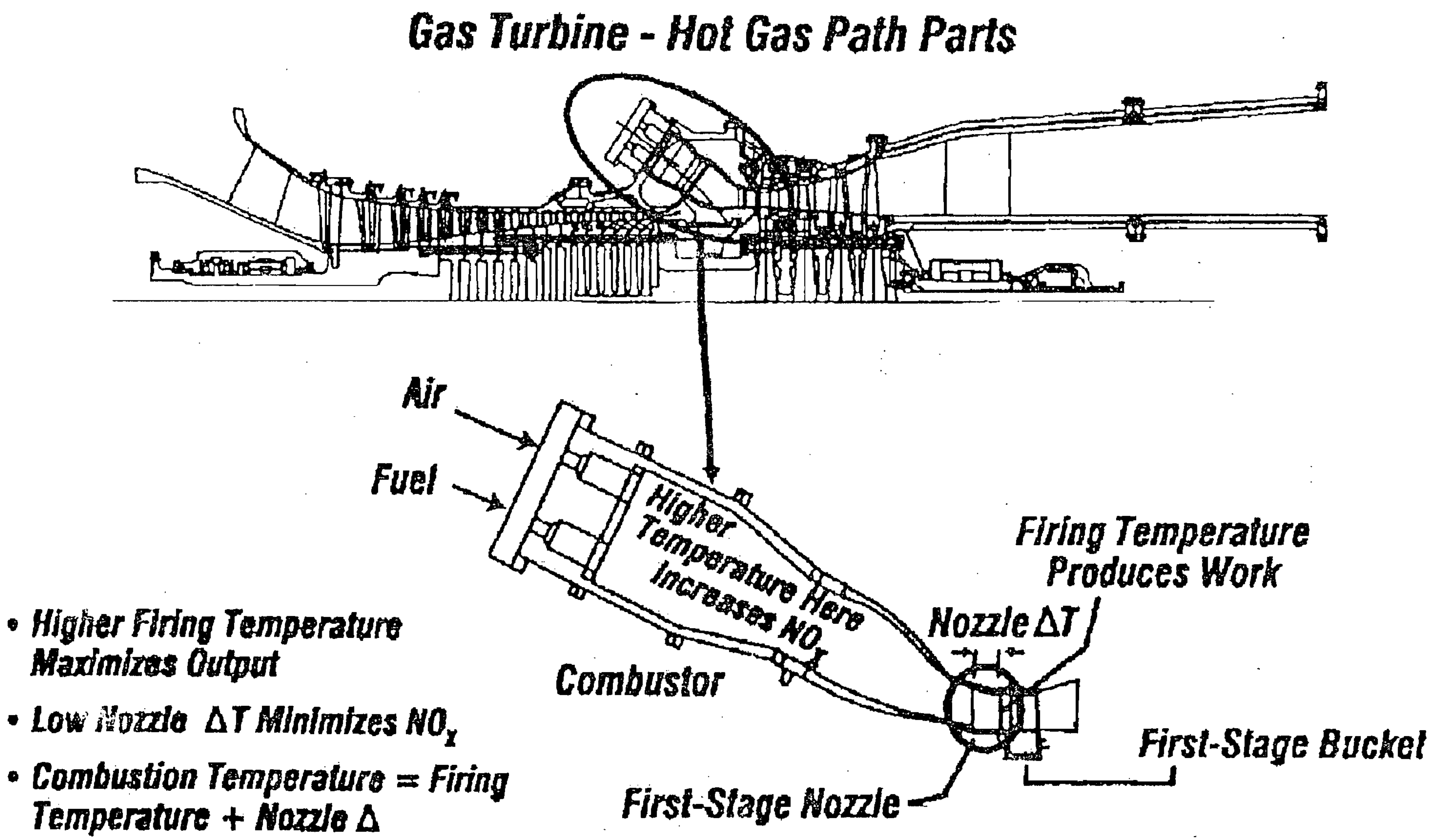


Figure 1 – Relation Between Flame Temperature and Firing Temperature

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)

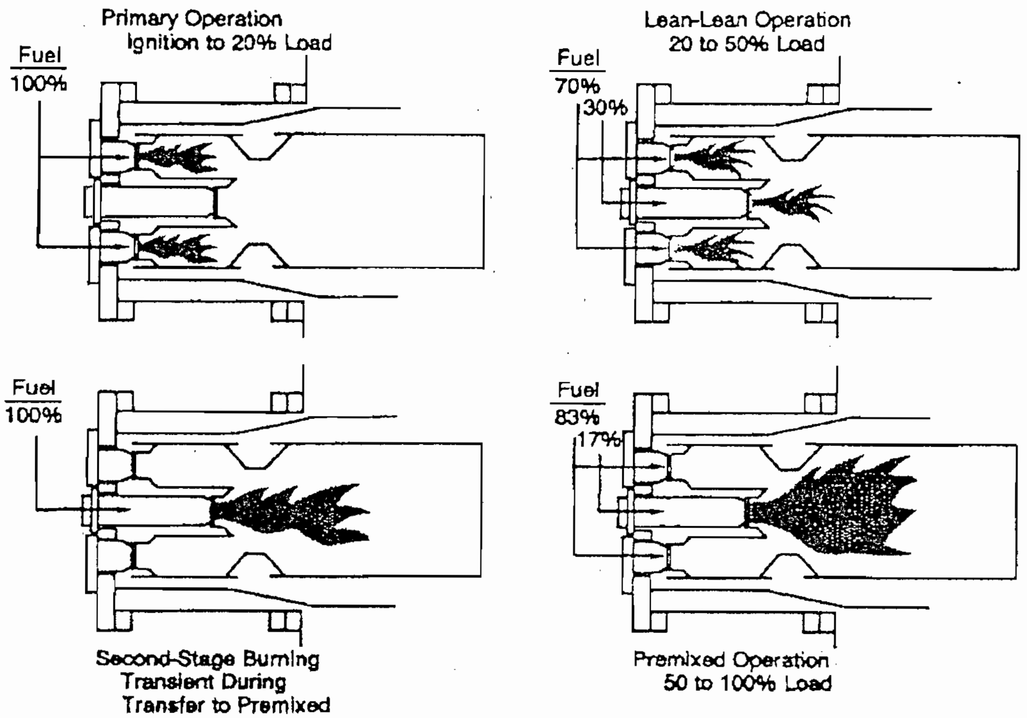
The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to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



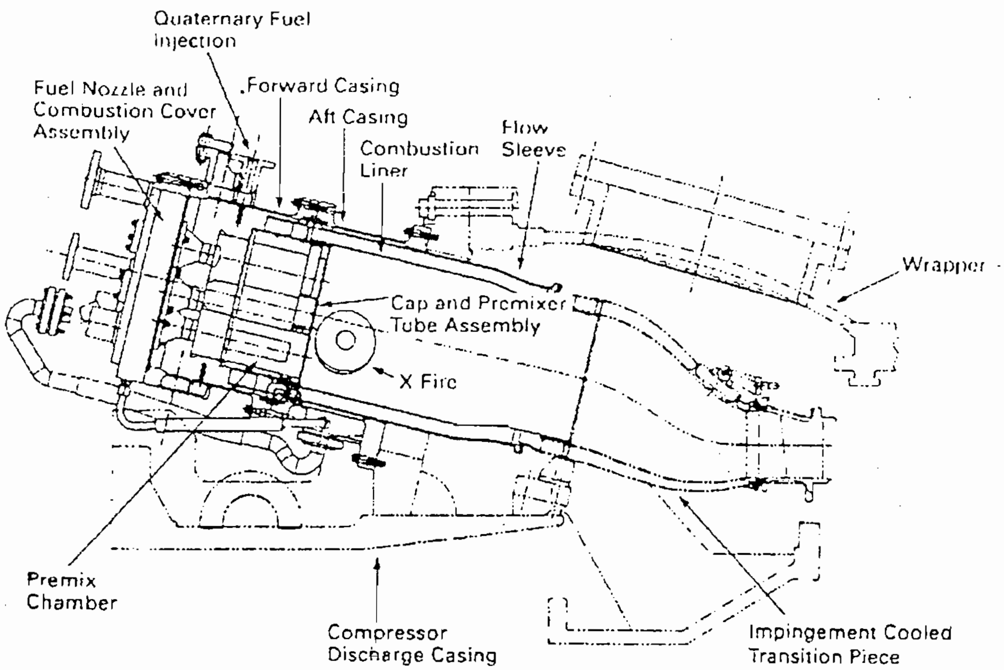


Figure 2 – Dry Low NO_X Operating Modes – DLN-1
Cross Section of GE DLN-2

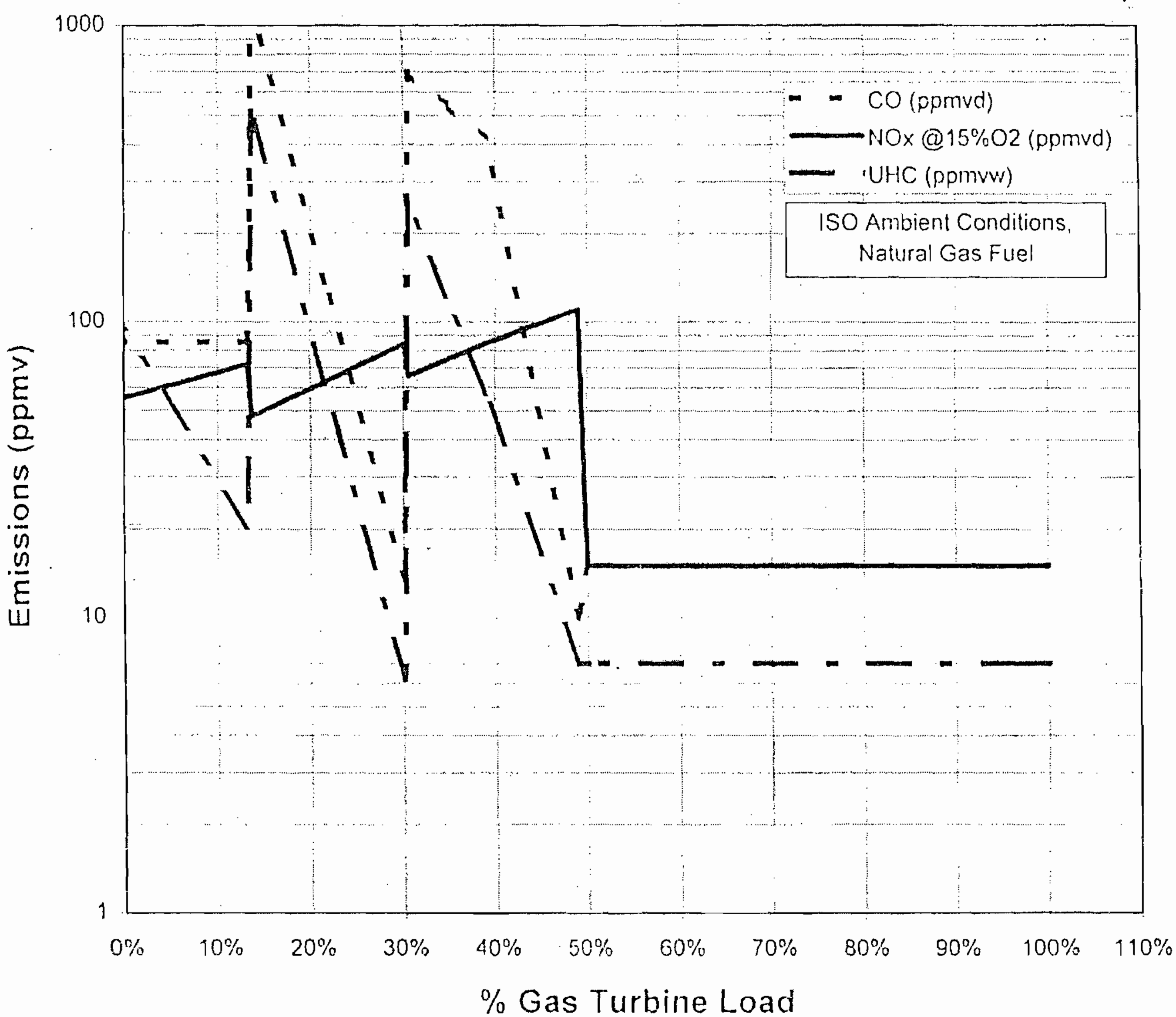


Figure 3 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

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

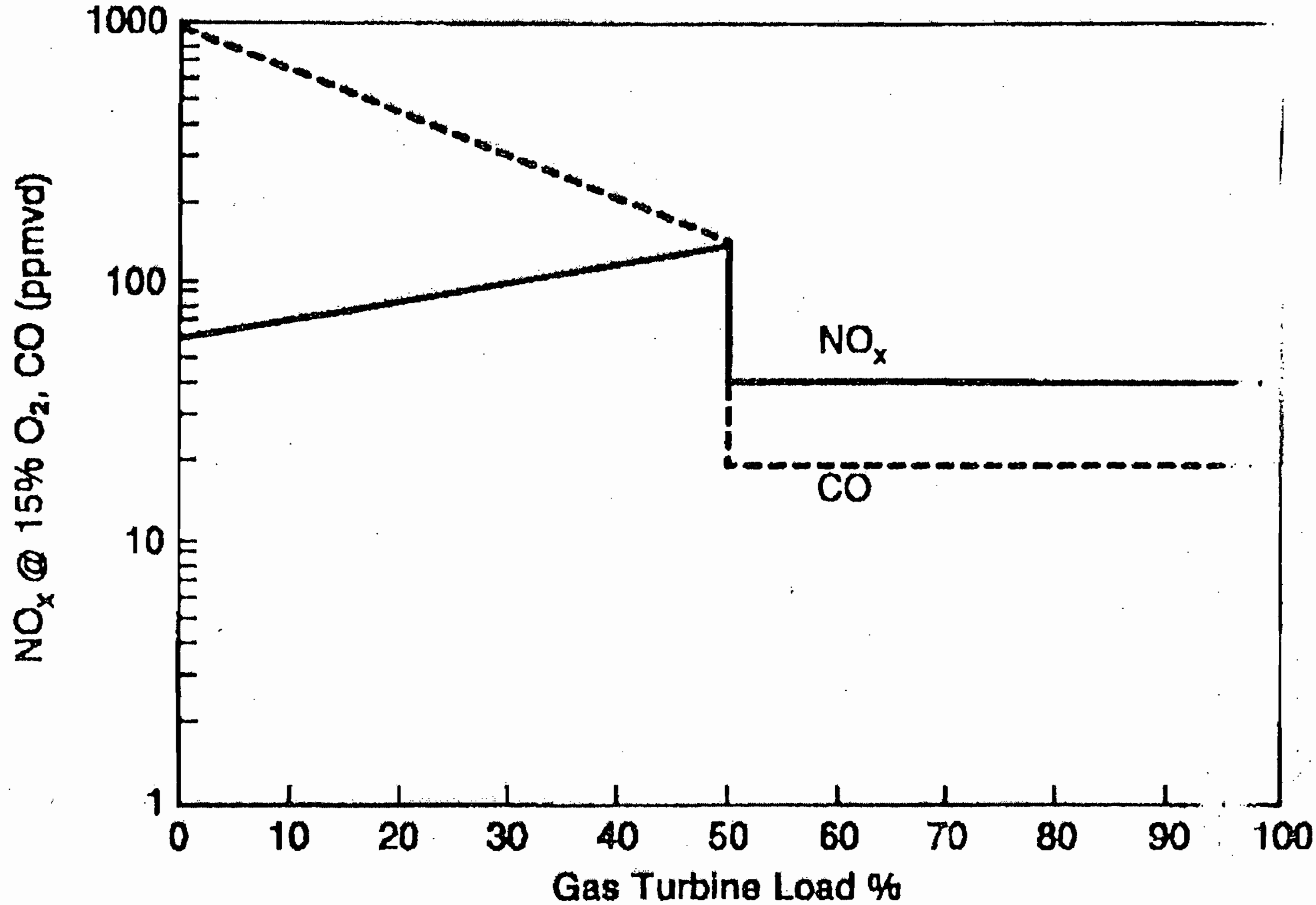


Figure 4 – Emissions Performance for DLN-2 Combustors Firing Fuel Oil in Dual Fuel GE 7FA Turbine

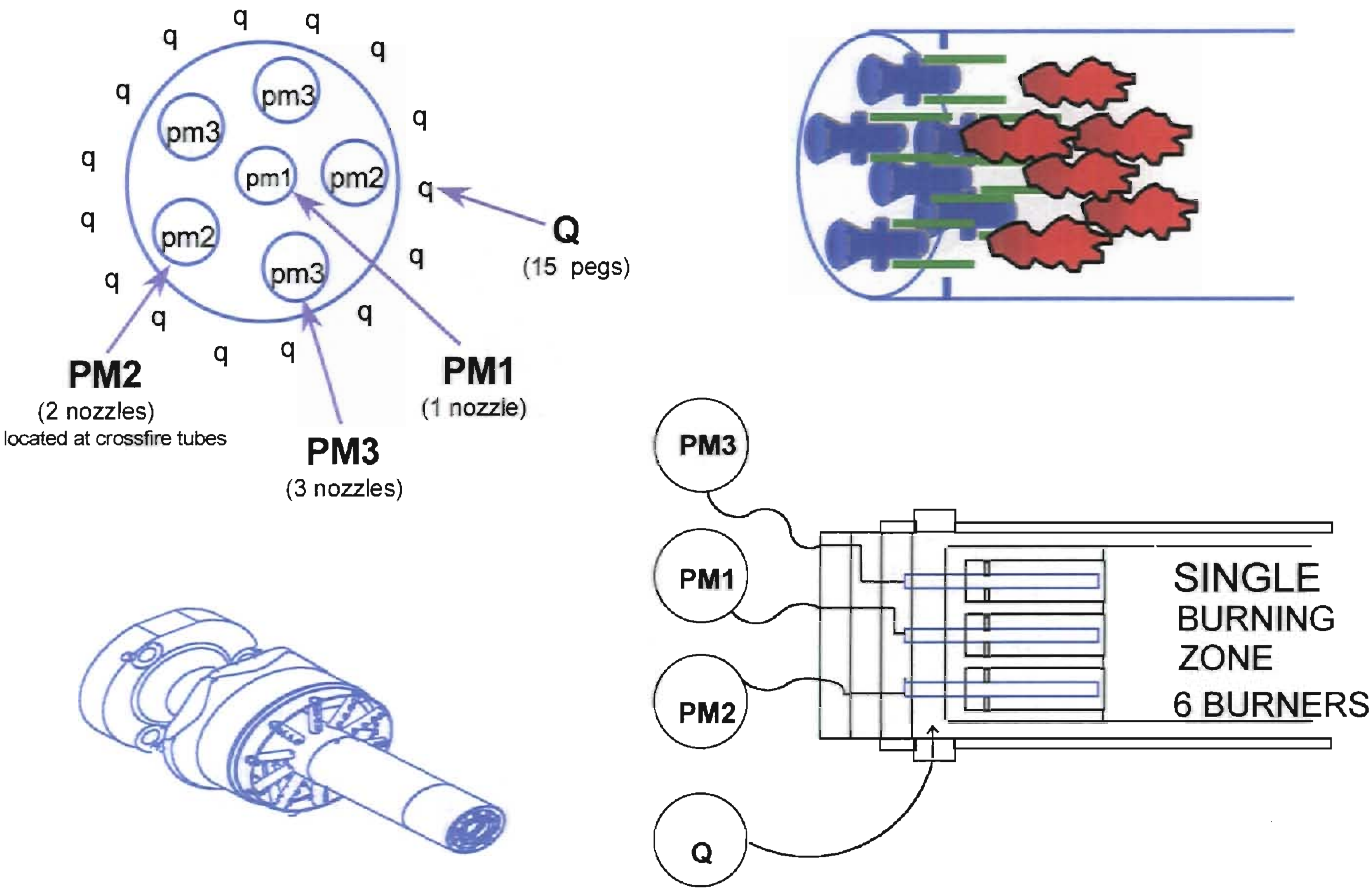


Figure 5 - DLN2.6 Fuel Nozzle Arrangement

The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X and 9 ppmvd of CO. 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.[1] 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 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.

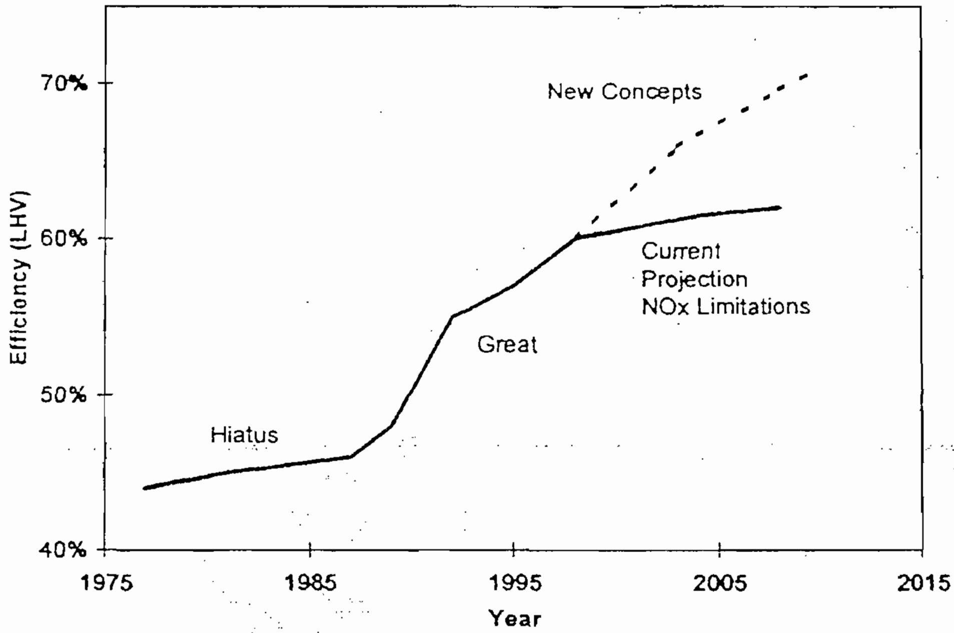


Figure 6 – Efficiency Increases in Combustion Turbines

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[2], 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.[3] The details are not available in English.

Catalytic Combustion: XONON ™

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.[4] 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™.[5] 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.[6] 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. TECO proposes 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.

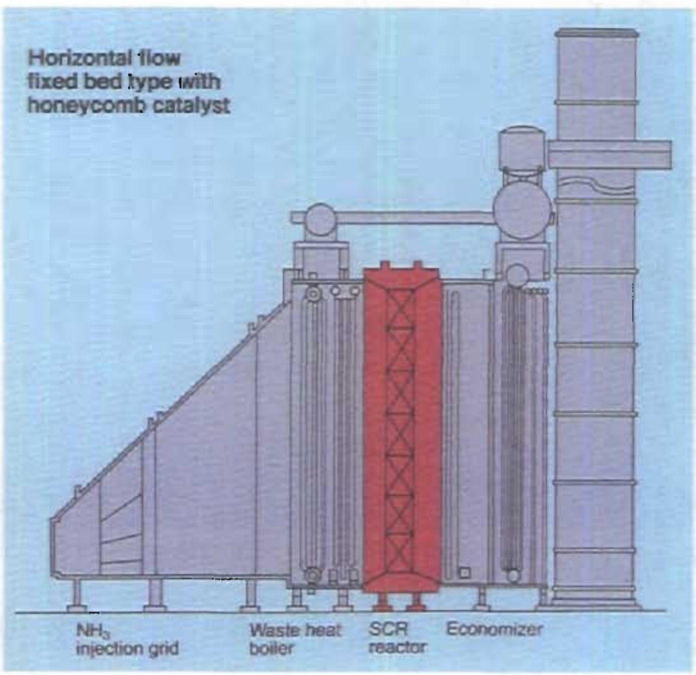


Figure 7 – SCR System within HRSG

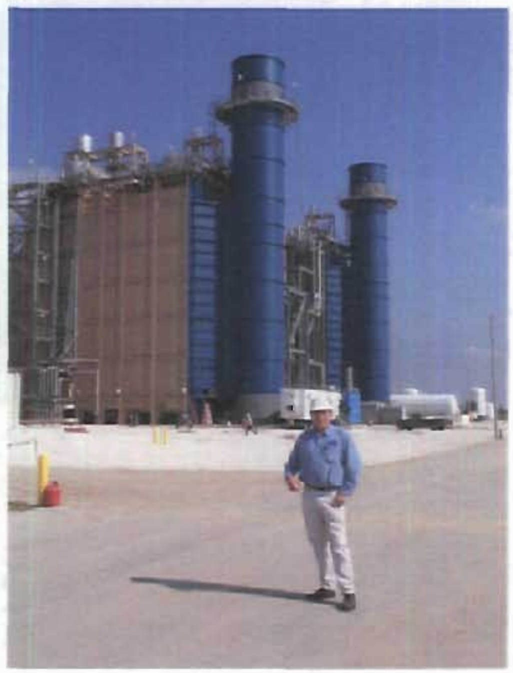


Figure 8 – FPC Hines Power Block I

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.

In a project such as the CPV Gulfcoast Energy Center, the DLN system will reduce potential emissions from about 200 ppmvd to 9 ppmvd while firing gas. The DLN system is a sophisticated combustion system that optimizes efficiency and emissions. An SCR system at the CPV project will further reduce emissions to about 3.5 ppmvd at a substantial cost with add-on control equipment that does nothing to enhance efficiency. It increases PM formation and substitutes another pollutant (ammonia) while bringing NO_X emissions to levels equal to the uncertainty in the measurement method.

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.[7]

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.[8] The overall project includes several more 250 MW blocks with SCR for control.[9] 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.[10] 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, Goaline submitted information to EPA and states in support of its contention that the technology has achieved 1 ppmvd in practice.[11]

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."[12] 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.[13] GE 7FA units achieved similar results when firing gas at the FPL Martin Power Plant.[14]

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.[15]

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 increase. The emission limit of 20 ppmvd during limited fuel oil firing appears reasonable, although 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.[16]

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, the unit is capable of achieving and has achieved 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.[17]

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the CPV project assuming full load. Values for NO_X 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 @15% O_2 (gas) 10 ppmvd@15% O_2 (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	20 lb/hr (gas) 53 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).[18]

- 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 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}.
- 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 values of 20 and 53 lb/hr for natural gas and oil respectively will be included in the permit. These values include front and back-half catch.
- 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 plus back-half catch, Initial test, thereafter VE as surrogate)
Volatile Organic Compounds	Method 25A corrected by methane from Method 18 (Initial tests only)
SO_2/SAM	Record keeping for the sulfur content of fuels delivered to the site
Carbon Monoxide	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 in simple cycle or 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.[19]

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
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By: Approved By:

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

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

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	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

CPV Gulfcoast

Postmark Here

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

SENDER: *COMPLETE THIS SECTION*

- 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.
- Attach this card to the back of the mailpiece, or on the front if space permits.

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)*
B. Date of Delivery 2.12.01

C. Signature
x [signature] ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

BRAINTREE, MA FEB 12 2001 USPS 02184-99

3. Service Type
☑ Certified Mail ☐ Express Mail
☐ Registered ☑ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1449 4307

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

The Bradenton Herald
P.O. Box 921
Bradenton, FL 34206

RETURN SERVICE
REQUESTED

PRESORTED
FIRST CLASS

BRADENTON FL
JAN-9'01
PB METER
6742826
U.S POSTAGE
0.27 8

AUHB 32399

PLEASE INCLUDE TOP PORTION OF STATEMENT

PLACE
STAMP
HERE

Bradenton Herald

Finance Department
P.O. Box 921
Bradenton, Fl 34206-0921

BRADENTON HERALD

www.bradenton.com
P.O. Box 921
Bradenton, FL 34206-0921
102 Manatee Avenue West
Bradenton, FL 34205-8894
941/745-7064

RECEIVED

DEC 12 2000

BUREAU OF AIR REGULATION

Bradenton Herald
Published Daily
Bradenton, Manatee, Florida

STATE OF FLORIDA
COUNTY OF MANATEE;

Before the undersigned authority personally appeared Sheila Dalesio, who on oath says that she is a Legal Advertising Representative of the Bradenton Herald, a daily newspaper published at Bradenton in Manatee County, Florida; that the attached copy of the advertisement, being a Legal Advertisement in the matter of NOTICE OF PUBLIC MEETING in the Court, was published in said newspaper in the issues of DECEMBER 5, 2000.
Affiant further says that the said publication is a newspaper published at Bradenton, in said Manatee County, Florida, and that the said newspaper has heretofore been continuously published in said Manatee County, Florida, each day and has been entered as second-class mail matter at the post office in Bradenton, in said Manatee County, Florida for a period of 1 year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sheila Dalesio
(Signature of Affiant)

Sworn to and subscribed before me this
6th Day of December, 2000

DIANE S. BACRO
Notary Public - State of Florida
My Commission Expires Aug 15, 2003
Commission # [illegible]

Diane S. Bacro
SEAL & Notary Public
Personally Known X OR Produced Identification ______
Type of Identification Produced ______

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION NOTICE OF PUBLIC MEETING CPV GULFCOAST LTD. POWER PROJECT

The Department of Environmental Protection gives notice that a public meeting to which all persons are invited will be held regarding the Department's Intent to issue an Air Construction permit to CPV Gulfcoast, Ltd., to construct a nominal 245 megawatt (MW) combined cycle (74.9 MW steam cycle) electrical power generating plant near Piney Point in Manatee County, Florida. The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality (PSD) and Best Available Control Technology (BACT).

The meeting will be held at **7:00 p.m., Monday, January 8, 2001, at Blackburn Elementary School,** in the Cafetorium, 3904 17th Street East, Palmetto, Florida. Department staff will be available from 6:00 p.m. to 7:00 p.m. to discuss the proposed permit on an informal basis. CPV Gulfcoast Limited also will have representatives present to discuss the project from 6:00 pm to 7:00 p.m. Beginning at 7:00 p.m., the Department will accept oral and written public comments and provide the status of the Department's Intent to Issue an air Construction Permit.

The Public Notice of Intent to Issue an Air Construction Permit was published in the Bradenton Herald on November 25, 2000. The public meeting was requested pursuant to the procedures described in the Public Notice. A copy of the agenda and the Department's proposed permit and supporting documents are available for review during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 South Magnolia Drive, Suite 4
Tallahassee, Fl 32301
Telephone:(850) 488-0114
Fax: (850) 922-6979

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Fl. 33619-8218
Telephone:(813) 744-6100
Fax: (813) 744-6084

The Department's technical evaluations and Draft Permit can be viewed at www.dep.state.fl.us/air/permitting.htmby clicking on Utility and Other Facility permits.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodation to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist in the Bureau of Personnel at (850) 488-2996. If you are speech or hearing impaired, please contact the agency by call (800) 955-8771 (TDD).
12/5/00

BRADENTON HERALD

www.bradenton.com
P.O. Box 921
Bradenton, FL 34206-0921
102 Manatee Avenue West
Bradenton, FL 34205-8894
941/748-0411 ext. 7065

Bradenton Herald
Published Daily
Bradenton, Manatee, Florida

STATE OF FLORIDA
COUNTY OF MANATEE;

Before the undersigned authority personally appeared Sandy Riley, who on oath says that she is a Legal Advertising Representative of the Bradenton Herald, a daily newspaper published at Bradenton in Manatee County, Florida; that the attached copy of the advertisement, being a Legal Advertisement in the matter of PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT in the Court, was published in said newspaper in the issues of 11/25/00.
Affiant further says that the said publication is a newspaper published at Bradenton, in said Manatee County, Florida, and that the said newspaper has heretofore been continuously published in said Manatee County, Florida, each day and has been entered as second-class mail matter at the post office in Bradenton, in said Manatee County, Florida for a period of 1 year next preceding the first publication of the attached copy of advertisement; and affiant further says that she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Sandy Riley
(Signature of Affiant)

Sworn to and subscribed before me this
27th Day of November, 2000

DIANE S. BACRO
Notary Public - State of Florida
My Commission Expires Aug 15, 2003
Commission # CC863180

Diane S. Bacro
SEAL & Notary Public
Personally Known ✓ OR Produced Identification______
Type of Identification Produced________________________________

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0810194-001-AC and PSD-FL-300

CPV Gulfcoast Power Generating Facility 245 Megawatt Combined Cycle Power Project

Manatee County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to CPV Gulfcoast Ltd. The permit is to construct nominal 245 megawatt (MW) combined cycle electrical power generating plant near Piney Point in Manatee County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration of Air Quality (PSD), for emissions of particulate matter (PM/PM 10) carbon monoxide (CO), sulfur dioxide (SO2), sulfuric acid mist, and nitrogen oxides (NOx). A maximum achievable control technology (MACT) determination for hazardous air pollutants was not required. The applicant's name and address are CPV Gulfcoast Ltd., 45 Bristol Road, Suite 101, Easton, MA 02375.

The project consists of: a nominal 170 MW General Electric 7FA combustion turbine-electrical generator; an unfired heat recovery steam generator capable of raising sufficient steam to generate another (maximum) 74.9 MW from a steam-electrical generator; a 150-foot stack; a mechanical draft cooling tower; a 1.0 million gallon fuel oil storage tank, and other ancillary equipment. Back-up distillate fuel oil will be burned for a maximum of 720 hours per year.

NOx emissions will be controlled by selective catalytic reduction (SCR) to achieve 3.5 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 10 ppmvd while burning low sulfur distillate fuel oil. Emissions of CO will be controlled to 9 and 20 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM 10, SO2, sulfuric acid mist, volatile organic compounds, hazardous air pollutants (HAP), and will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and low sulfur (0.05 percent) distillate fuel oil. Ammonia emissions generated due to NOx control will be limited to 5 ppmvd.

The following table summarizes the maximum emissions (in tons per year) of regulated air pollutants as a result of this project.

POLLUTANTS	MAXIMUM POTENTIAL EMISSIONS	PSD Significant Emission Rate
PM/PM 10	102	25/15
Sulfuric acid mist	12	7
SO 2	76	40
NO x	126	100
VOC	15	40
CO	222	100
HAP	8	NA

An air quality impact analysis was conducted. Maximum impacts due to proposed emissions from the project are less than the applicable PSD Class II significant impact levels for all applicable pollutants. Therefore no increment consumption analysis was required. Emissions from the facility will not cause or contribute to a violation of any state or federal ambient air quality standards. The project has no significant impact on the PSD Class I Chassahowitzka National Wilderness Area.

The Department will issue the FINAL permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "Public Notice of Intent to Issue Air Construction Permit." Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Fl. 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

This project is not subject to Chapter 403, Sections 403.501-518. "Florida Electrical Power Plant Siting Act", because the steam (electrical) generating capacity is less than 75 MW.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice sections 120.60F(3) of the Florida statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent. whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F. S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28.106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information; (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) a concise statement of the ultimate facts alleged, as well as the rules and statutes which entitle the petitioner to relief; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m. Monday through Friday, except legal holidays, at:

Dept. of Environmental Protection Bureau of Air Regulation
111 S. Magnolia Drive,Ste4
Tallahassee, FL 32301
Ph. (850)488-1344
Fax: (850) 922-6979

Dept. of Environmental Protection Southwest District Office
3804 Coconut Drive
Tampa, FL. 33619-8218
Ph. (813) 744-6100

Manatee County Environment Management Department
202 Sixth Ave. E.
Bradenton, FL 34208
Ph. (941) 742-5980
Fax; 941-742-5996

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The Department's technical evaluations and Draft Permit can be viewed at www.dep.state.fl.us/air/permitting.htm by clicking on Utility and Other Facility Permits.

11/25/00

7099 3400 0000 1453 3525

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

Article Sent To:
Mr. Gary Lambert, Exe. V.P.
CPV Gulfcoast

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Mr. Gary Lambert
Street, Apt. No.; or PO Box No.
45 Bristol Road, Suite 101
City, State, ZIP+4
Easton, MA 02375

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- 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.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Gary Lambert, Exe. V.P.
CPV Gulfcoast, Ltd
45 Bristol Road, Suite 101
Easton, MA 02375

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 11-30
C. Signature
X
☐ Agent
☐ Addressee
D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1453 3525

PS Form 3811, July 1999 — Domestic Return Receipt — 102595-99-M-1789

7099 3400 0000 1452 9931

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
Return Receipt Fee (Endorsement Required)		
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 Bristol Road, Ste 101
City, State, ZIP+4
Easton, MA 02375

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- 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.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Gary Lambert
Executive Vice President
CPV Gulfcoast, Ltd
45 Bristol Road, Suite 101
Easton, MA 02375

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*

B. Date of Delivery 1-2-02

C. Signature
X

☐ Agent
☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1452 9931

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

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

7099 3400 0000 1453 2337

Article Sent To:
Gary Lambert

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

10/9/00
Gulfcoast -
Postmark Here

Name (Please Print Clearly) (to be completed by mailer)
Mr. Gary Lambert
Street, Apt. No.; or PO Box No.
45 Bristol Rd., Ste. 101
City, State, ZIP+4
Easton MA 02375

PS Form 3800, July 1999 — See Reverse for Instructions

SENDER: *COMPLETE THIS SECTION*

- 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.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Gary Lambert
Executive Vice President
CPV Gulfcoast, Ltd
45 Bristol Rd, Ste 101
Easton, MA 02375

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)*
B. Date of Delivery 10-12

C. Signature
x Darcy Campbell ☐ Agent ☐ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3400 0000 1453 2337

PS Form 3811, July 1999 — Domestic Return Receipt — 102595-99-M-1789